FILE

(163)

PUCO EXHIBIT FILING

Date of Hearing: 9-30-2015

Case No. 14-1693-EL-RDR, 14-1694-EL-AAM

PUCO Case Caption: In the Matter of the Application Seeking approval of Ohio Power Company's Proposal to Enter into an affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

In the Matter of the Application of Ohio Power Company for approval of Certain ~~accoun~~ accounting authority.

List of exhibits being filed: Volume III

SC - 4 - 5

OMAEG 6

~~ELPC 5~~

IEU 2 - 3 - 4 - 5 - 6 - 7

KROGER 1

Reporter's Signature:

Date Submitted: 10-14-15

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

\- - -

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.	: Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	: Case No. 14-1694-EL-AAM

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PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-D, Columbus, Ohio, called at 9 a.m. on Wednesday, September 30, 2015.

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VOLUME III

\- - -

ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
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Pearce
EXHIBIT 2
Date: 9/24/2015
SC 4

OHIO POWER COMPANY'S RESPONSES TO
OHIO CONSUMERS' COUNSEL'S DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
SUPPLEMENTAL FIFTH SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-5-055 Produce a copy of each Long Term North American Energy Market Forecast from 2010 until today.

RESPONSE

Please refer to attached file OCC-RPD-5-05.

Prepared by: Karl R. Bletzacker

Supplemental response September 1, 2015

Please see Supplemental 2015H1_LTF_FT_Base_Nominal_2015_04_24.xls.

Prepared by: Karl R. Bletzacker

PENGAD 800-631-6989
EXHIBIT
SC-4

Power Prices ($/MWh) -Nominal $'s									
	PJM - AEP GEN HUB		SPP		ERCOT North		ERCOT South		ERCO
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
2013	34.37	23.40	34.02	23.50	30.71	29.33	30.96	29.60	29.94
2014	37.94	24.50	41.16	26.95	37.88	35.77	38.06	35.99	36.96
2015	48.38	28.52	47.93	30.98	41.67	39.60	41.81	39.73	40.66
2016	55.92	34.10	53.00	35.50	45.32	43.11	46.02	43.79	44.39
2017	58.33	37.38	55.91	37.99	46.97	44.72	47.52	45.26	45.95
2018	59.02	38.37	56.96	39.47	47.75	45.50	48.23	45.95	46.69
2019	59.69	39.25	58.35	41.11	48.47	46.09	48.68	46.28	47.29
2020	61.51	40.76	60.60	43.05	49.80	47.64	50.12	47.85	48.64
2021	64.04	42.25	64.14	45.34	52.21	50.02	52.58	50.23	51.01
2022	72.74	53.89	71.59	54.52	60.55	58.14	60.94	58.39	59.26
2023	74.33	54.86	73.41	55.90	61.42	58.99	61.78	59.22	60.11
2024	75.87	56.20	76.11	57.84	63.28	60.71	63.56	60.85	61.90
2025	77.51	57.24	78.77	59.67	64.72	62.29	65.13	62.49	63.37
2026	78.86	58.16	79.76	61.29	65.57	63.20	65.91	63.32	64.19
2027	80.60	59.05	82.49	63.15	67.33	64.82	67.65	64.89	65.91
2028	81.99	60.20	84.68	64.68	68.27	66.00	68.59	66.01	66.83
2029	83.65	61.45	86.60	66.55	69.88	67.52	70.21	67.49	68.43
2030	84.41	62.69	89.22	68.29	70.73	68.41	70.96	68.30	69.24
2031	86.04	64.20	91.67	70.46	72.40	70.04	72.58	69.85	70.89
2032	88.14	66.16	95.35	73.61	74.37	71.77	74.46	71.54	72.76
2033	90.15	68.50	97.29	75.30	75.34	73.20	75.53	72.91	73.78
2034	88.94	70.00	91.11	72.19	77.14	75.05	77.23	74.62	75.53
2035	91.25	71.70	94.28	74.87	78.90	76.72	78.98	76.30	77.27

T West Off-Peak	Coal ($/ton) FOB -Nominal $'s 12395 Btu/lb 1.6# SO2 CAPP	12500 Btu/lb 1.6# SO2 CAPP CSX-Rail	12000 Btu/lb 1.2# SO2 CAPP Compliance	12000 Btu/lb 1.67# SO2 CAPP NYMEX	12500 Btu/lb 6# SO2 NAPP High Sulfur	13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin
28.53	63.46	64.00	75.00	62.85	55.00	58.65	49.45
34.91	68.42	69.00	77.00	66.50	57.00	62.40	51.45
38.60	72.39	73.00	78.00	71.00	59.00	64.90	53.45
42.24	73.25	73.87	72.90	71.20	61.00	67.10	53.15
43.75	74.60	75.23	72.60	71.90	71.14	69.49	53.95
44.44	77.38	78.04	72.60	72.10	75.06	73.82	56.91
44.89	81.77	82.46	72.60	72.10	79.83	79.15	60.65
46.42	86.29	87.02	75.00	74.20	83.40	84.25	63.42
48.75	86.35	87.08	76.20	74.80	83.50	83.42	63.56
56.79	90.99	91.76	80.70	79.70	85.91	86.80	65.01
57.60	94.43	95.23	84.80	83.30	88.34	91.73	67.85
59.26	96.90	97.72	91.01	89.07	88.78	91.96	68.04
60.84	99.97	100.82	92.49	93.10	88.63	91.75	68.27
61.70	103.53	104.41	104.05	102.11	88.74	91.91	68.37
63.28	105.71	106.61	106.91	104.97	89.30	91.16	68.47
64.43	108.22	109.14	108.12	106.18	89.70	89.82	68.07
65.91	112.66	113.61	115.22	113.28	89.90	91.81	68.57
66.76	117.43	118.42	117.18	116.75	90.10	93.44	69.57
68.35	119.98	121.00	119.15	120.25	91.10	94.98	69.77
70.04	122.95	123.99	125.74	123.80	93.40	97.99	71.57
71.44	126.16	127.23	127.51	129.25	97.39	101.99	73.82
73.23	130.12	131.22	129.29	130.76	102.12	105.20	77.82
74.87	133.27	134.40	134.21	132.27	105.59	108.36	80.81

8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado
11.25	10.10	35.59
12.50	10.70	35.83
13.50	11.35	38.27
13.20	11.35	38.42
13.44	11.75	39.10
13.68	11.96	39.19
14.42	12.45	39.39
15.49	13.23	39.29
15.44	13.19	40.46
16.36	13.96	40.56
16.97	14.49	41.15
16.73	14.29	41.53
16.68	14.24	43.19
16.88	14.45	43.39
17.14	14.62	45.14
17.38	15.10	46.41
17.89	15.42	46.60
20.10	17.28	47.12
22.48	19.54	46.96
26.50	23.24	47.00
30.05	26.38	47.48
33.38	29.39	48.26
32.80	28.78	49.24

Natural Gas ($/mmbtu) -Nominal $'s				
Henry Hub	TCO Pool	ıinion South Point	TCO Deliv	HSC
4.04	4.11	4.08	4.39	3.91
5.05	5.10	5.06	5.40	4.94
5.47	5.49	5.48	5.80	5.37
5.83	5.85	5.84	6.17	5.73
6.01	6.03	6.02	6.35	5.91
6.12	6.14	6.13	6.46	6.02
6.19	6.21	6.20	6.53	6.09
6.43	6.45	6.44	6.78	6.33
6.75	6.77	6.76	7.11	6.65
7.18	7.20	7.19	7.54	7.08
7.30	7.32	7.31	7.67	7.20
7.51	7.52	7.52	7.88	7.40
7.75	7.76	7.75	8.12	7.64
7.85	7.86	7.86	8.23	7.74
8.04	8.06	8.05	8.42	7.94
8.22	8.24	8.23	8.61	8.12
8.41	8.42	8.41	8.79	8.30
8.52	8.54	8.53	8.91	8.42
8.73	8.75	8.74	9.13	8.63
8.94	8.96	8.95	9.34	8.84
9.16	9.18	9.17	9.56	9.06
9.39	9.41	9.40	9.80	9.29
9.61	9.63	9.62	10.02	9.51

PEPL TX-OK	Swing Service Adder	Uranium Fuel UO2 ($/mmbtu) - Nominal $'s	Emissions ($/ton) -Nominal $'s			
			SO_2	NO_x Annual	NO_x Summer	($/metric tonne) - Nominal $'s CO_2
3.79	0.25	0.82	0	0	0	0.00
4.80	0.25	0.84	0	0	0	0.00
5.22	0.25	0.85	0	0	0	0.00
5.58	0.25	0.87	0	0	0	0.00
5.76	0.25	0.89	0	0	0	0.00
5.87	0.25	0.91	0	0	0	0.00
5.94	0.25	0.92	0	0	0	0.00
6.18	0.25	0.94	0	0	0	0.00
6.50	0.25	0.96	0	0	0	0.00
6.93	0.25	0.98	0	0	0	15.08
7.05	0.25	1.00	0	0	0	15.28
7.26	0.25	1.02	0	0	0	15.48
7.49	0.25	1.04	0	0	0	15.67
7.60	0.26	1.06	0	0	0	15.88
7.79	0.26	1.08	0	0	0	16.08
7.97	0.27	1.10	0	0	0	16.29
8.15	0.27	1.13	0	0	0	16.50
8.27	0.28	1.15	0	0	0	16.72
8.48	0.28	1.17	0	0	0	16.94
8.69	0.28	1.19	0	0	0	17.16
8.91	0.28	1.22	0	0	0	17.38
9.14	0.28	1.24	0	0	0	17.60
9.36	0.28	1.27	0	0	0	17.84

Heat Rates (mmbtu/MWh)						Capacity Prices ($/MW- Nominal $'s
AEP GEN HUB - HR	SPP - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR		AEP GEN HUB Hub Cap.
8.44	9.01	7.87	7.93	6.81		23.03
7.45	8.60	7.67	7.71	6.85		85.05
8.83	9.20	7.77	7.80	7.02		131.83
9.58	9.51	7.92	8.05	7.21		91.30
9.69	9.72	7.96	8.06	7.25		132.49
9.63	9.72	7.95	8.03	7.24		199.74
9.64	9.85	7.97	8.01	7.25		215.54
9.55	9.83	7.88	7.93	7.18		231.74
9.47	9.89	7.86	7.92	7.19		248.55
10.12	10.35	8.56	8.62	7.86		265.99
10.17	10.43	8.54	8.59	7.85		284.08
10.10	10.51	8.55	8.59	7.86		302.83
10.00	10.52	8.48	8.53	7.81		321.95
10.04	10.51	8.47	8.51	7.81		341.74
10.01	10.61	8.49	8.53	7.83		362.23
9.97	10.64	8.42	8.46	7.77		383.42
9.95	10.63	8.42	8.46	7.79		394.85
9.90	10.81	8.41	8.43	7.77		403.15
9.85	10.84	8.40	8.42	7.77		411.61
9.85	10.99	8.42	8.43	7.80		420.26
9.83	10.93	8.32	8.35	7.72		429.08
9.46	9.97	8.31	8.32	7.71		438.09
9.48	10.08	8.30	8.31	7.71		447.29

-day) - SPP Cap.	Renewable Energy Subsidies ** ($/MWh) Nominal $'s	Inflation Factor
25.00	48.40	2.10%
25.00	48.60	2.10%
26.47	49.20	2.50%
33.73	45.40	2.60%
41.30	46.60	2.50%
49.16	47.60	2.30%
57.40	48.60	2.30%
65.93	49.50	2.30%
74.80	50.60	2.20%
84.04	51.70	2.30%
93.64	52.80	2.20%
103.63	53.90	2.20%
113.90	55.00	2.20%
124.55	56.10	2.20%
135.60	57.10	2.20%
147.06	58.10	2.10%
158.95	59.30	2.10%
171.26	60.10	2.10%
184.03	0.00	2.10%
197.25	0.00	2.10%
210.95	0.00	2.10%
224.92	0.00	2.10%
239.59	0.00	2.10%

SO2 Prices by State

SO2 Prices	AL	AR	CT	DC
2013	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00
0	0.00	0.00	0.00	0.00
State Price	0.00	0.00	0.00	0.00

DE	FL	GA	IA	IL	IN	KS	KY	LA	MA	MD	ME	MI
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

MN	MO	MS	MT	NC	ND	NE	NH	NJ	NM	NS	NY	OH
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

OK	PA	RI	SC	SD	TN	TX	VA	VT	WI	WV
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Pearce
EXHIBIT 3
Date: 9/24/2015
SC 5

Power Prices ($/MWh) -Nominal $'s

Year	PJM - AEP Gen Hub On-Peak	PJM - AEP Gen Hub Off-Peak	SPP_Central On-Peak	SPP_Central Off-Peak	SPP_KSMO On-Peak	SPP_KSMO Off-Peak	ERCOT_NORTH On-Peak	ERCOT_NORTH Off-Peak	ERCOT On-Peak
2016	35.34	26.65	37.04	26.84	36.80	26.60	35.48	29.01	35.57
2017	38.62	27.41	42.20	29.41	41.87	29.14	40.68	31.70	40.80
2018	40.37	28.22	44.33	30.73	44.01	30.45	42.98	32.90	43.17
2019	43.12	30.31	47.10	32.84	46.82	32.55	44.20	33.94	44.40
2020	44.97	32.05	48.64	34.53	48.36	34.24	45.77	35.48	46.00
2021	47.42	33.59	51.41	36.41	51.14	36.11	47.94	37.01	48.21
2022	62.04	47.94	64.33	49.56	64.02	49.15	58.96	45.70	59.35
2023	63.73	48.59	66.59	50.57	66.29	50.16	60.97	45.89	61.51
2024	66.89	50.93	69.56	52.70	69.34	52.31	64.12	47.80	64.68
2025	69.81	52.82	72.19	54.65	71.99	54.25	66.05	49.61	66.66
2026	72.39	54.98	74.83	56.98	74.73	56.60	68.21	51.87	68.92
2027	75.10	56.64	77.35	58.44	77.21	58.05	69.88	52.21	70.58
2028	77.21	58.27	79.55	60.11	79.41	59.70	72.22	53.63	72.95
2029	79.93	60.58	82.76	62.81	82.77	62.45	74.43	56.34	75.17
2030	82.57	62.38	86.48	65.60	86.37	65.17	76.19	57.21	76.92
2031	85.39	64.62	90.82	69.13	90.79	68.72	78.60	59.59	79.45
2032	88.74	66.97	95.25	72.48	95.07	72.01	80.69	61.28	81.54
2033	92.42	70.20	98.87	75.55	98.71	75.06	82.66	63.45	83.58
2034	93.33	71.58	100.67	77.56	100.52	77.07	85.17	66.08	86.21
2035	95.81	74.02	103.10	79.87	102.96	79.37	87.11	67.23	88.18
2036	99.04	76.49	106.30	82.36	106.01	81.77	89.88	69.25	90.99
2037	101.38	78.90	108.11	84.29	107.95	83.75	92.09	70.88	93.35
2038	104.70	81.50	111.18	86.72	111.07	86.17	94.23	72.69	95.60
2039	105.73	83.17	112.15	88.23	111.95	87.63	96.59	74.77	98.18
2040	108.64	85.64	114.82	90.53	114.64	89.90	99.00	76.32	100.60
2041	110.08	87.49	116.47	92.36	116.09	91.68	101.20	78.02	103.02
2042	112.43	89.33	119.32	94.70	119.09	94.03	103.09	79.73	105.11
2043	114.44	91.67	121.59	97.08	121.35	96.41	105.36	81.57	107.34
2044	115.92	93.50	123.81	99.43	123.61	98.72	107.62	83.98	109.92
2045	119.58	96.27	127.28	102.06	127.13	101.37	109.47	85.44	111.79
2046	121.34	98.43	128.64	103.83	128.39	103.09	111.38	86.97	113.89

PENGAD 800-631-6989
EXHIBIT
SC-5

_South	ERCOT_West	
Off-Peak	On-Peak	Off-Peak
29.28	36.19	29.50
32.03	41.50	32.28
33.32	43.86	33.52
34.38	45.15	34.64
36.00	46.76	36.23
37.57	48.97	37.79
46.43	60.11	46.54
46.64	62.16	46.73
48.58	65.37	48.67
50.46	67.36	50.55
52.76	69.56	52.84
53.08	71.26	53.22
54.58	73.63	54.67
57.34	75.87	57.44
58.22	77.66	58.34
60.72	80.06	60.73
62.40	82.18	62.44
64.64	84.20	64.72
67.31	86.74	67.37
68.48	88.70	68.57
70.60	91.42	70.58
72.30	93.65	72.26
74.17	95.87	74.14
76.32	98.27	76.25
77.90	100.68	77.82
79.74	102.87	79.58
81.53	104.79	81.32
83.35	107.07	83.20
85.94	109.33	85.59
87.46	111.20	87.09
89.08	113.16	88.70

				Coal ($/ton) FOB
12395 Btu/lb 1.6# SO2 CAPP	12500 Btu/lb 1.6# SO2 CAPP CSX-Rail	12000 Btu/lb 1.2# SO2 CAPP Compliance	12000 Btu/lb 1.67# SO2 CAPP NYMEX	12500 Btu/lb 6# SO2 NAPP High Sulfur
65.50	66.05	70.85	65.85	55.18
67.83	68.40	72.60	66.04	55.89
68.58	69.16	74.26	68.32	58.19
69.48	70.06	76.35	70.24	61.31
73.14	73.76	80.39	73.96	64.64
75.62	76.26	83.12	76.47	66.28
79.42	80.09	87.31	80.32	70.39
81.64	82.33	89.75	82.57	70.85
84.77	85.49	93.21	85.76	77.93
87.76	88.51	96.50	88.78	80.25
90.36	91.13	99.37	91.42	83.64
93.80	94.59	103.15	94.90	85.13
97.98	98.81	107.77	99.15	87.26
100.66	101.51	110.72	101.86	89.54
104.34	105.23	114.78	105.60	90.46
105.31	106.21	115.85	106.58	92.47
108.46	109.38	119.31	109.76	94.06
111.36	112.30	122.51	112.71	97.52
114.29	115.26	125.73	115.67	99.66
117.88	118.88	129.69	119.31	103.14
120.82	121.85	132.93	122.29	105.72
123.84	124.89	136.25	125.35	108.36
126.94	128.02	139.66	128.48	111.07
130.11	131.22	143.15	131.70	113.85
133.37	134.50	146.73	134.99	116.69
136.70	137.86	150.40	138.36	119.61
140.12	141.31	154.16	141.82	122.60
142.92	144.13	157.24	144.66	125.05
145.78	147.01	160.38	147.55	127.56
148.69	149.95	163.59	150.50	130.11
151.67	152.95	166.86	153.51	132.71

-Nominal $'s

13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin	8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado
61.51	40.00	15.05	11.50	34.86
62.25	42.25	16.11	12.30	36.81
64.64	43.56	17.28	13.56	37.16
67.89	45.92	18.81	14.74	39.42
71.34	48.60	21.38	16.80	42.50
73.05	50.19	22.86	17.97	44.26
77.32	53.49	23.49	18.47	48.46
77.80	51.01	21.62	16.88	48.15
85.17	55.88	22.51	17.60	50.15
87.58	56.30	24.10	18.91	53.85
91.11	57.53	26.99	21.26	53.59
92.66	57.91	25.82	20.19	56.34
94.87	59.93	26.60	20.73	59.61
97.24	64.10	30.95	24.40	65.58
98.19	65.72	30.05	23.52	68.73
100.29	68.05	33.82	26.64	69.19
101.94	69.56	35.56	27.87	70.19
105.54	74.69	38.63	30.21	72.54
107.77	78.16	41.10	32.02	75.69
111.39	80.24	46.37	36.36	79.69
114.17	82.24	47.53	37.27	81.68
117.03	84.30	48.72	38.20	83.72
119.95	86.41	49.93	39.16	85.81
122.95	88.57	51.18	40.13	87.96
126.02	90.78	52.46	41.14	90.16
129.17	93.05	53.77	42.17	92.41
132.40	95.38	55.12	43.22	94.72
135.05	97.28	56.22	44.09	96.62
137.75	99.23	57.34	44.97	98.55
140.51	101.21	58.49	45.87	100.52
143.32	103.24	59.66	46.78	102.53

Natural Gas ($/n

Henry Hub	TCO Pool	Dominion South Point Pool
4.34	4.13	3.83
5.09	4.81	4.62
5.40	5.10	4.95
5.50	5.18	5.12
5.60	5.29	5.23
5.82	5.49	5.50
6.28	5.98	5.87
6.60	6.30	6.20
6.80	6.47	6.40
6.96	6.62	6.62
7.13	6.76	6.79
7.30	6.92	6.96
7.47	7.09	7.14
7.65	7.26	7.33
7.83	7.44	7.49
8.00	7.61	7.68
8.19	7.79	7.87
8.39	7.99	8.07
8.59	8.20	8.28
8.80	8.38	8.50
9.02	8.63	8.71
9.24	8.85	8.92
9.45	9.08	9.12
9.66	9.31	9.31
9.87	9.52	9.52
10.08	9.74	9.73
10.29	9.95	9.94
10.50	10.16	10.15
10.71	10.37	10.36
10.92	10.57	10.57
11.13	10.79	10.78

nmbtu) -Nominal $'s				Uranium Fuel UO2 ($/mmbtu) - Nominal $'s	Emissions ($/ton) -Nominal $'s		
TCO Deliv	HSC	PEPL TX-OK	Swing Service Adder		SO_2	NO_x Annual	NO_x Summer
4.39	4.42	4.25	0.25	0.87	0	0	0
5.08	5.18	5.01	0.25	0.89	0	0	0
5.37	5.49	5.30	0.25	0.91	0	0	0
5.46	5.59	5.39	0.25	0.92	0	0	0
5.56	5.69	5.48	0.25	0.94	0	0	0
5.77	5.91	5.75	0.25	0.96	0	0	0
6.28	6.37	6.20	0.25	0.98	0	0	0
6.59	6.69	6.52	0.25	1.00	0	0	0
6.77	6.88	6.68	0.25	1.02	0	0	0
6.92	7.05	6.83	0.25	1.04	0	0	0
7.06	7.22	6.97	0.26	1.06	0	0	0
7.23	7.39	7.13	0.26	1.08	0	0	0
7.40	7.56	7.30	0.27	1.10	0	0	0
7.57	7.74	7.47	0.27	1.13	0	0	0
7.76	7.91	7.66	0.28	1.15	0	0	0
7.93	8.09	7.85	0.28	1.17	0	0	0
8.12	8.28	8.04	0.28	1.19	0	0	0
8.32	8.48	8.26	0.28	1.22	0	0	0
8.53	8.68	8.47	0.28	1.24	0	0	0
8.72	8.89	8.69	0.28	1.27	0	0	0
8.97	9.11	8.89	0.28	1.29	0	0	0
9.20	9.32	9.09	0.28	1.32	0	0	0
9.43	9.53	9.30	0.28	1.35	0	0	0
9.66	9.75	9.49	0.28	1.37	0	0	0
9.89	9.96	9.69	0.28	1.40	0	0	0
10.10	10.17	9.90	0.28	1.43	0	0	0
10.31	10.38	10.11	0.28	1.46	0	0	0
10.53	10.59	10.32	0.28	1.49	0	0	0
10.74	10.80	10.53	0.28	1.52	0	0	0
10.96	11.00	10.73	0.28	1.55	0	0	0
11.17	11.22	10.95	0.28	1.58	0	0	0

($/metric tonne) - Nominal $'s CO_2	Heat Rates (mmbtu/MWh)				
	AEP GEN HUB - HR	SPP_Central - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR
0.00	8.59	8.76	8.05	8.07	8.30
0.00	8.05	8.45	7.88	7.90	8.20
0.00	7.95	8.39	7.85	7.88	8.21
0.00	8.33	8.75	7.92	7.96	8.31
0.00	8.52	8.90	8.06	8.10	8.44
0.00	8.66	8.97	8.13	8.18	8.52
15.00	10.40	10.40	9.28	9.34	9.61
15.29	10.15	10.25	9.14	9.22	9.46
15.58	10.36	10.44	9.33	9.42	9.69
15.88	10.57	10.58	9.39	9.48	9.77
16.19	10.73	10.75	9.47	9.57	9.88
16.51	10.87	10.88	9.49	9.58	9.89
16.84	10.92	10.93	9.57	9.66	9.98
17.17	11.03	11.10	9.63	9.73	10.05
17.50	11.11	11.31	9.64	9.74	10.04
17.85	11.24	11.60	9.74	9.84	10.13
18.19	11.41	11.88	9.77	9.87	10.16
18.54	11.59	12.00	9.76	9.87	10.15
18.88	11.40	11.92	9.82	9.95	10.19
19.24	11.45	11.89	9.81	9.93	10.21
19.60	11.50	11.99	9.89	10.01	10.23
19.95	11.47	11.91	9.89	10.03	10.21
20.33	11.56	11.98	9.90	10.05	10.20
20.69	11.37	11.83	9.92	10.09	10.19
21.08	11.41	11.86	9.95	10.11	10.21
21.46	11.31	11.78	9.97	10.15	10.21
21.86	11.31	11.81	9.95	10.15	10.19
22.26	11.28	11.80	9.96	10.15	10.19
22.66	11.19	11.77	9.98	10.19	10.20
23.08	11.31	11.87	9.95	10.16	10.16
23.50	11.26	11.76	9.94	10.17	10.15

Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	 SPP_Central/KSMO Cap.	Renewable Energy Subsidies ** ($/MWh) -Nominal $'s	Inflation Factor
91.30	72.66	43.30	0.70%
94.74	103.82	32.60	2.50%
187.37	160.48	21.80	2.60%
260.32	218.21	11.00	2.70%
287.24	276.27	0.00	2.60%
314.48	324.65	0.00	2.30%
331.79	331.79	0.00	2.20%
339.09	339.09	0.00	2.20%
346.21	346.21	0.00	2.10%
353.48	353.48	0.00	2.10%
360.90	360.90	0.00	2.10%
368.12	368.12	0.00	2.00%
375.48	375.48	0.00	2.00%
382.99	382.99	0.00	2.00%
390.65	390.65	0.00	2.00%
398.47	398.47	0.00	2.00%
406.44	406.44	0.00	2.00%
414.56	414.56	0.00	2.00%
422.44	422.44	0.00	1.90%
430.47	430.47	0.00	1.90%
439.08	439.08	0.00	2.00%
447.86	447.86	0.00	2.00%
456.81	456.81	0.00	2.00%
465.95	465.95	0.00	1.90%
475.27	475.27	0.00	1.90%
484.78	484.78	0.00	1.90%
494.47	494.47	0.00	1.90%
504.36	504.36	0.00	1.90%
514.45	514.45	0.00	1.80%
524.74	524.74	0.00	1.80%
535.23	535.23	0.00	1.80%

INTERROGATORY

INT-1-003 Referencing Exhibit KDP-1 at page 2:

a. Under the section labeled "Capacity Entitlement," list the items that would be adjustments to gross capacity revenues for deriving "net capacity revenues."

b. Under the section labeled "Energy Entitlement," list the items that would be adjustments to gross energy revenues for deriving "net energy revenues."

c. Under the section labeled "Ancillary Services Entitlement," list the items that would be adjustments to gross ancillary services revenues for deriving "net ancillary services revenues."

RESPONSE

a. Capacity adjustments would include all adjustments that PJM makes in the normal course of awarding capacity revenues to capacity market participants. This would include revenue increases or decreases resulting from EFOR adjustments, Base Residual capacity auction activity and incremental capacity auction activity, for example. These types of adjustments are detailed in the publicly available PJM tariff. The term "net capacity revenues" is meant to convey that the actual capacity revenues attributable to these units, net of any positive or negative adjustments, will be included in the PPA.

b. Energy adjustments would include all adjustments that PJM makes in the normal course of awarding energy revenues to energy market participants, which are detailed in the publicly available PJM tariff. The term "net energy revenues" is meant to convey that the actual energy revenues attributable to these units, net of any positive or negative adjustments, will be included in the PPA.

c. Ancillary Services revenue adjustments would include all adjustments that PJM makes in the normal course of awarding these revenues to ancillary services market participants, which are detailed in the publicly available PJM tariff. The term "net ancillary services revenues" is meant to convey that the actual ancillary services revenues and charges attributable to these units, net of any positive or negative adjustments, will be included in the PPA.

Prepared by: Kelly D. Pearce

OMAEG EX. 6

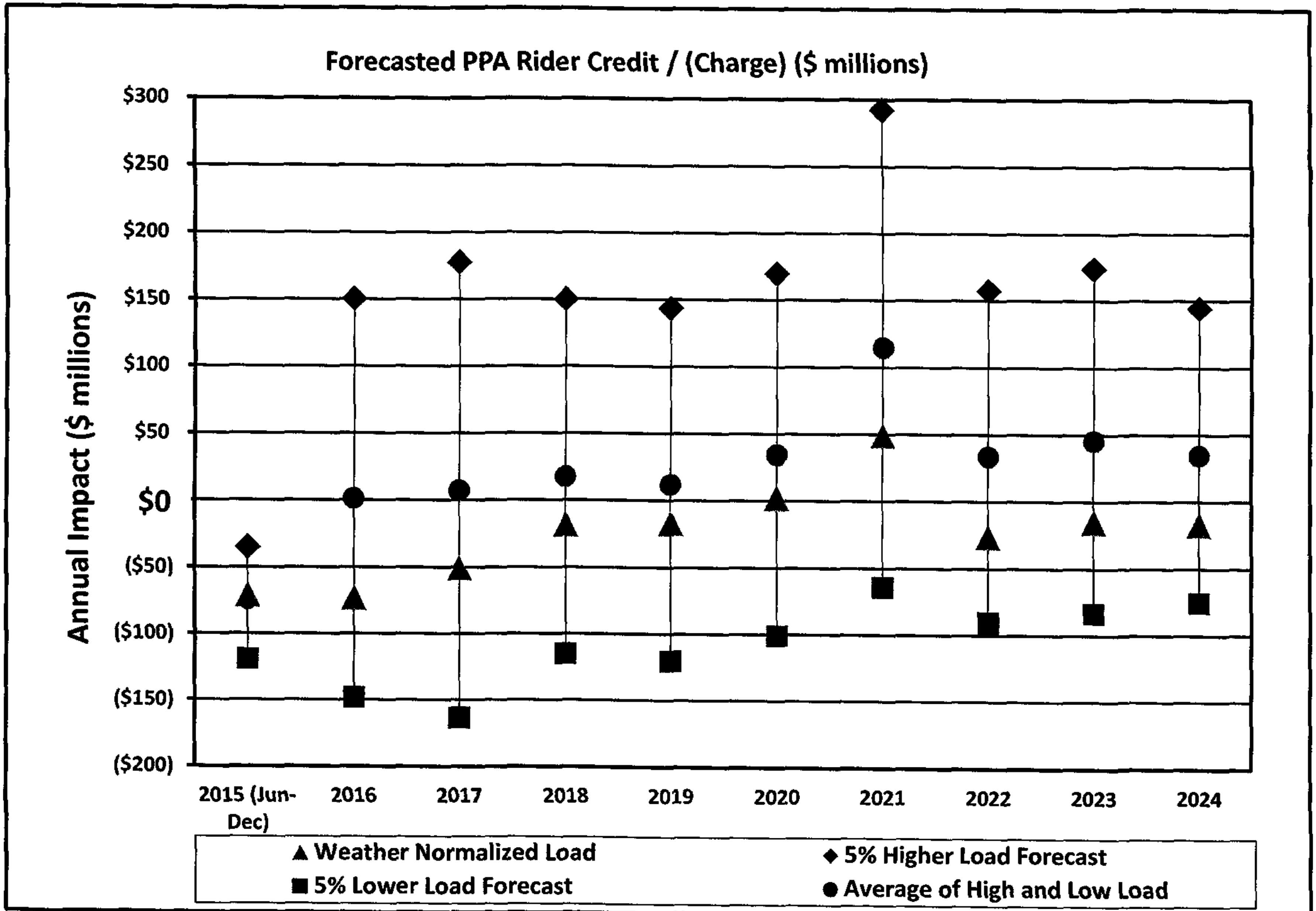
INT-1-003 Continued

SUPPLEMENTAL RESPONSE

During the preparation of discovery responses the Company determined that one of the cases utilized a different coal cost assumption at Conesville than the other cases. As a result, the weather normalized case has been modified to use the same Conesville coal cost assumptions as the other cases. The revised forecast is provided in IEU-RPD 1-003 Competitively Sensitive Confidential Supplemental Attachment 1.

The original forecast case results were included in the Company's filing in the direct testimony of Company witness Pearce. Dr. Pearce's Figure 1 and Exhibit KDP 2 have been revised to reflect the change to the weather normalized case, and are presented in IEU RPD-1-003 Supplemental Attachment 2.

Prepared by: Kelly D. Pearce


Forecasted PPA Rider Credit / (Charge) ($ millions)
Annual Impact ($ millions)
$300
$250
$200
$150
$100
$50
$0
($50)
($100)
($150)
($200)
2015 (Jun-Dec)
2016
2017
2018
2019
2020
2021
2022
2023
2024
Weather Normalized Load
5% Higher Load Forecast
5% Lower Load Forecast
Average of High and Low Load

AEP Ohio PPA Forecast Workpapers

FORECASTED OHIO PPA RIDER IMPACTS
COMBINED CARDINAL, CONESVILLE, STUART AND ZIMMER
$ in Millions (Nominal)

50% Equity, 50% Debt, ROE: 11.23%, Cost of Debt 4.73%

5% Higher Load Forecast											
Year	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
PJM Revenues	$474	$1,083	$1,135	$1,172	$1,216	$1,251	$1,408	$1,482	$1,449	$1,486	$12,156
Agreement Costs	$509	$933	$957	$1,022	$1,072	$1,081	$1,116	$1,325	$1,275	$1,341	$10,631
Net PPA Rider Credit / (Charge)	($35)	$150	$178	$150	$144	$170	$293	$157	$174	$144	$1,526

Average of High and Low Forecast											
Year	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
PJM Revenues	$420	$908	$920	$995	$1,015	$1,040	$1,143	$1,287	$1,242	$1,276	$10,245
Agreement Costs	$497	$906	$912	$977	$1,003	$1,006	$1,028	$1,253	$1,196	$1,241	$10,020
Net PPA Rider Credit / (Charge)	($77)	$1	$7	$18	$12	$35	$114	$34	$45	$35	$224

Weather Normalized Case											
Year	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
PJM Revenues	$435	$851	$890	$978	$1,029	$1,034	$1,111	$1,236	$1,228	$1,281	$10,073
Agreement Costs	$505	$924	$940	$996	$1,046	$1,032	$1,062	$1,262	$1,244	$1,298	$10,309
Net PPA Rider Credit / (Charge)	($71)	($73)	($50)	($18)	($17)	$2	$49	($26)	($15)	($17)	($236)

5% Lower Load Forecast											
Year	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
PJM Revenues	$366	$732	$704	$817	$815	$829	$877	$1,091	$1,035	$1,066	$8,333
Agreement Costs	$485	$880	$867	$931	$935	$930	$941	$1,181	$1,118	$1,141	$9,410
Net PPA Rider Credit / (Charge)	($119)	($148)	($163)	($114)	($120)	($101)	($64)	($90)	($83)	($75)	($1,077)

OHIO POWER COMPANY'S RESPONSES TO
INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-003 Provide an interactive Excel spreadsheet containing the detailed calculations, including all individual cost items supporting the projected "Agreement costs" shown on Exhibit KDP-2 for the period 2015 through 2024.

RESPONSE

The IEU_RPD-1-003 **COMPETITIVELY-SENSITIVE Confidential** Attachments 1 and 2 for Excel spreadsheets containing the requested information for the period June 1, 2015 to December 31, 2024.

Attachment 1 contains the supporting information for the High Load, Weather Normalized Load and Low Load scenarios presented in Exhibit KPD-2. The Average of the High and Low Forecast was a simple average of the summarized results of the High and Low scenarios in Exhibit KDP-2, and therefore supporting data was not averaged at the detailed level for each of the individual PPA cost components.

Attachment 2 represents a forecast of electric plant in service, accumulated depreciation and depreciation expense. These forecasted values are common to all three scenarios.

Confidential attachments will be provided to parties who have executed a Protected Agreement.

Prepared by: Kelly D. Pearce

SUPPLEMENTAL RESPONSE JANUARY 20, 2015

During the preparation of discovery responses the Company determined that one of the cases utilized a different coal cost assumption at Conesville than the other cases. As a result, the weather normalized case has been modified to use the same Conesville coal cost assumptions as the other cases. The revised forecast is provided in IEU-RPD 1-003 Competitively Sensitive Confidential Supplemental Attachment 1.

The original forecast case results were included in the Company's filing in the direct testimony of Company witness Pearce. Dr. Pearce's Figure 1 and Exhibit KDP 2 have been revised to reflect the change to the weather normalized case, and are presented in IEU RPD-1-003 Supplemental Attachment 2.

Prepared by: Kelly D. Pearce

RPD-1-003 CONTINUED

Supplemental response to address the Company's Amended Application filed on May 15, 2015

Please refer to IEU_RPD-1-003 Competitively Sensitive Confidential Second Supplemental Attachments 1A,1B,1C, 2 and 3 for the support for the Exhibit KPD-2 filed with Company witness Pearce's testimony in the Company's May 15 Amended Application.

Second Supplement Attachments 1A, 1B and 1C contain the supporting information for the High Load, Low Load, and Weather Normalized Load scenarios, respectively, presented in Exhibit KPD-2. The Average of the High and Low Forecast was a simple average of the summarized results of the High and Low scenarios in Exhibit KDP-2, and therefore supporting data was not averaged at the detailed level for each of the individual PPA cost components.

Second Supplement Attachment 2 represents a forecast of electric plant in service, accumulated depreciation and depreciation expense. These forecasted values are common to all three scenarios.

Second Supplement Attachment 3 supports the OVEC demand charge forecast.

Prepared by: Kelly D. Pearce

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Approval of Full Legal Corporate Separation and Amendment to Its Corporate Separation Plan	)))))	Case No. 12-1126-EL-UNC

REPLY COMMENTS OF OHIO POWER COMPANY

Ohio Power Company (dba AEP Ohio) filed its Application on March 30, 2012 to obtain all necessary authorizations and approvals (1) for full legal corporate separation (also known as structural corporate separation) such that the transmission and distribution assets of AEP Ohio will continue to be held by the distribution utility and AEP Ohio's generation assets and liabilities will be transferred to AEP Generation Resources Inc., an affiliate (AEP Genco), (2) to implement amendments to AEP Ohio's existing corporate separation plan necessary to reflect structural corporate separation that will be effective upon the transfer of AEP Ohio's generation assets and liabilities to its affiliate and (3) for certain waivers related to the foregoing authorizations that the Commission may grant for good cause under Ohio Admin. Code Rule 4901:1-37-02(C). By Entry dated July 9, 2012, the Attorney Examiner set a procedural schedule requiring comments/objections to be filed by Staff and interveners by July 27, 2012. In response to this schedule, Staff and the following interveners filed initial comments:

Constellation NewEnergy, Inc. and Exelon Generation Company, LLC (Exelon)
FirstEnergy Solutions Corp. (FES)
Industrial Energy Users-Ohio (IEU)
Office of the Ohio Consumers' Counsel (OCC)
OMA Energy Group (OMA)
The Kroger Company (Kroger)
Staff

AEP Ohio hereby submits its reply comments.

I. Overview of Application

Full structural legal separation is a critical prerequisite of the Company's Modified ESP proposal in Case Nos. 11-346-EL-SSO *et al.* (Modified ESP.) Specifically, full structural legal separation (*i.e.*, generation divestiture) is a necessary requirement to transition toward and implement an auction-based SSO, which is a cornerstone of both Ohio policy and the Company's Modified ESP proposal. Because the Modified ESP proposal is premised on Commission approval of full structural legal separation, the Company addressed its corporate separation plan in the Modified ESP case.[1] Thus, approval of corporate separation in this proceeding is a critical condition precedent to accepting and implementing the Modified ESP. In addition to the detailed information contained in its March 30, 2012 Application, the following reply comments direct the Commission to relevant information provided in the Modified ESP case as well.

A. Description of corporate separation and asset transfer

The principal purpose of the corporate separation filing is to achieve full structural corporate separation of AEP Ohio's generation and marketing businesses, on the one hand, from its transmission and distribution businesses, on the other, consistent with Ohio's corporate separation mandate. (AEP Ohio Ex. 103 at 4; App at 1-2.) Corporate separation is a fundamental requirement of the Company's plan that will lead to full market-based pricing of generation service for retail customers and will promote retail shopping in Ohio. (*Id.*) Under corporate separation, transmission and distribution-related assets of AEP Ohio will remain in AEP Ohio,

[1] The Commission may wish to take administrative notice of the record in 11-346-EL-SSO *et al.* Company witnesses Powers and Nelson, in particular, discuss the Company's corporate separation plan in their testimony in support of the Modified ESP. Corporate separation issues were addressed in the Modified ESP proceeding through the Company's application, testimony, cross examination, hearing exhibits and briefing. Citations to exhibits and transcripts in this document refer to the record in that case.

PENGAD 800-631-6989 EXHIBIT IEU-2

which will essentially be a wires-only company upon closing. (*Id.*) AEP Ohio's existing generation units and contractual entitlements, fuel-related assets and contracts, and other assets related to the generation business will be transferred at net book value to the AEP Genco. (*Id.* at 5.; Tr. II at 507-08.) AEP Ohio does not plan to transfer its renewable purchase agreements to AEP Genco. (AEP Ohio Ex. 103 at 4; App at 5.) The renewable energy credits associated with those agreements will stay with AEP Ohio, which will remain subject to state-imposed renewable energy obligations. (*Id.*) AEP Genco will also assume at closing the liabilities associated with the transferred assets including the retired plants and the liabilities associated with the retired plants. (*Id.*)

Immediately after transferring the assets and liabilities to AEP Genco, the plan is for Appalachian Power Company (APCo) to obtain the transferred interest in Unit No. 3 of the Amos generating plant and appurtenant interconnection facilities and related assets and liabilities (APCo already owns the remaining interest in Amos Unit No. 3) and a portion of the Mitchell generating plant and appurtenant interconnection facilities and related assets and liabilities (collectively, "Mitchell"), with the remainder of Mitchell being transferred to Kentucky Power Company (KPCo). (*Id.*; App at 9) Mr. Powers's direct testimony in the Modified ESP proceeding provides the rationale that APCo and KPCo have long relied on AEP Ohio generating assets through the Pool Agreement to supply part of the capacity and energy needed to meet their respective load requirements (and APCo and KPCo have long paid for using those assets through capacity equalization charges.) (AEP Ohio Ex. 101 at 22.) The applicable Amos and Mitchell units are physically located in West Virginia and are of sufficient capacity to cover the expected shortfall (including the required reserve margin) for those FRR companies after the existing pool agreement is terminated. (*Id.*) Thus, the secondary transfers to APCo and KPCo are logical and

appropriate. While AEP Ohio continues to transparently discuss the subsequent transfer plans, it is important to understand that the planned secondary transfers are distinct transactions after the initial divestiture and are beyond this Commission's authority and jurisdiction under R.C. 4928.17 to implement corporate separation.[2]

The long-term indebtedness of AEP Ohio is composed of general obligations that are not secured by the generation assets being transferred to the AEP Genco or by any other assets of the Company. (AEP Ohio Ex. 103 at 5.) This unsecured, long-term indebtedness currently consists of two types: senior notes and pollution control revenue bonds ("PCRBs".) (*Id.*; App at 5.) In order to manage debt maturities before the closing of corporate separation, AEP Ohio may issue short term debt or new notes to AEP and use the proceeds to repay those debt maturities in the normal course of business. (*Id.*) The notes would be subject to approval by the Commission. (*Id.*)

The proposed corporate separation plan includes several steps, each of which will occur one after another at closing. (*Id.* at 6.) The steps of the transaction are detailed in the Company's Application at pages 4-6. Exhibit PJN-1 to Mr. Nelson's direct testimony in the Modified ESP case is a chart showing AEP Ohio, the other AEP East operating companies, and the AEP Genco on a pre- and post-corporate separation basis. (*Id.* at Ex. PJN-1.)[3] The Company intends to close the corporate separation transaction on January 1, 2014. (*Id.* at 6.) But a final order approving

[2] In this regard, AEP Ohio notes that the precise division of the Mitchell plant as between APCo and KPCo is still being evaluated and the Company reserves the right to incorporate changes into the final plan proposed for FERC approval. Of course, the PUCO is not approving the secondary transactions as part of this proceeding and it will have an opportunity to intervene and comment on the proposed plan once it is finalized and filed with the FERC.

[3] AEP Ohio states at page 15 of its Application, "Once FERC approves full, legal corporate separation, the Company, pursuant to the Corporate Separation Plan, will update the list of affiliates and corporate structure set forth in Exhibit 1 to its plan and its Cost Allocation Manual to add AEP Generation, remove CSP in recognition of its merger into AEP Ohio and record any other accumulated changes in corporate structure." Staff requests an update of AEP Ohio's corporate organizational chart to reflect the legal entities that are related to American Electric Power Company, Inc. (Staff at 2.) The Company has not forgotten about its commitment, and it will provide the lists as soon as the updated information is available.

corporate separation is needed from the Commission as soon as possible in order to implement the Modified ESP and avoid termination of it.

II. AEP Ohio reply to specific comments

For the most part, the initial comments are very similar to those filed by the same commenters in Case No. 11-5333-EL-UNC. That case concerned a nearly identical application by the Company. For instance, the proposed amendments to the existing corporate separation plan and the basic structure of the asset transfer were the same as at issue here. The Company sought the same waivers as well. The only notable difference between the two cases is that 11-5333 was predicated on the September 7, 2011 Stipulation in Case Nos. 11-346-EL-SSO *et al.*, and there was very little discussion of corporate separation issues in that proceeding. In contrast, the pending Application is a prerequisite to the Company's Modified ESP proposal, and there has been testimony, discovery, and cross examination conducted by the commenters regarding the Company's corporate separation Application in that case.

The point to keep in mind when considering the issues raised by commenters is that the overwhelming majority of these comments have been considered and rejected by the Commission when it approved the Company's similar application in 11-5333. There are, however, some new comments not raised before because they concern issues unique to the Company's Modified ESP proposal. The Commission need not address these issues in this proceeding as they are not necessary in connection with the Commission's review and approval of the Company's Application under R.C. 4928.17(A) and Ohio Admin. Code Rules 4901:1-37-06 and 4901:1-37-09. Those ESP issues will be more appropriately addressed by the Commission in the Modified ESP case and, based on its scheduled early August 2012 decision in the Modified ESP case, it is likely that the Commission will have already decided the ESP issues

prior to or contemporaneously with deciding this case. The Company will address each of the major comments in turn below but failure to address each comment should not be viewed as agreement by the Company.

1. Approval of the Application is in the public interest

A. Comments

IEU states that in 2000 the Commission approved a structural corporate separation plan that did not address pooling issues, and the Company has not shown why that plan cannot or should not be implemented or that the proposed legal corporate separation is superior. (IEU at 3.) IEU also asserts that the Company has not shown how the transfers will affect future SSO prices. (IEU at 7.) OMA notes that the Company's current corporate separation plan complies with the mandates of 4928.17(C), but AEP Ohio has not shown that a transition from functional to full legal corporate separation is in the public interest. (OMA at 4.) Incredibly, OMA maintains that complying with the law requiring full legal corporate separation is insufficient to satisfy that the plan is in the public interest. (OMA at 4.) Nor, in OMA's view, does merely stating that corporate separation is necessary to facilitate the ESP and move to an auction-based SSO sufficient to demonstrate that the plan is in the public interest. (OMA at 5.)

B. AEP Ohio Reply

Approving the Application is in the public interest, because it is instrumental in fulfilling both long-overdue statutory mandates and existing state policy. The corporate separation plan for AEP Ohio has been based on functional separation since 2001. R.C. 4928.17(C) only permits functional separation "for an interim period" and otherwise mandates structural separation. The decade-long interim period should end, and the Commission should fulfill the statutory mandate by swiftly approving full legal separation for AEP Ohio. Doing so promotes the public interest by permitting AEP Ohio to restructure in a way that will pave the path to a competitively bid SSO and more competitive choice for electric service in Ohio.

The objective and purpose of the proposed generating asset transfer is to fulfill the mandate of R.C. 4928.17 and terminate the "interim" plan of functional separation for AEP Ohio. AEP Genco will receive the legacy generating assets and can provide competitive retail generation services as well as engage in sales for resale as regulated by the FERC. The impact of corporate separation on the current and future SSO is clear in that it will ultimately lead to full market-based pricing of generation service for retail customers and will promote retail shopping in Ohio. Transforming the AEP Ohio business model through corporate separation is critical to facilitating an auction-based SSO, similar to other electric utilities in Ohio. Contrary to the commenters' concerns, this progression is in the public interest and helps fulfill R.C. Chapter 4928's competitive policies.

2. Waiver of market value study continues to be appropriate

A. Comments

OCC advances three arguments in opposition to waiver. First, OCC contends that the net present value of the AEP East generation fleet is $22 billion over 30 years. (OCC at 6.) According to OCC, a "significant portion" of those cash flows are attributable to the Company and exceed the $6 billion net book value of those assets. OCC argues that the Commission should therefore consider the market value of the assets before it approves the transfer. (OCC at 6-7.) Second, OCC argues that transferring the assets at less than market value will result in compensation for the Company that is too low and cause a subsidy to flow to the AEP Genco, which is contrary to the public interest, threatens development of a competitive generation market, and is inconsistent with state policy to ensure supplier diversity. (OCC at 7.) Third,

OCC argues that transferring the assets at book value also denies consumers their share of the "market premiums" associated with the assets to which they are entitled because they have been charged a return on and of those plants for many years, paid for their operating expenses, and bore the risk of their loss and obsolescence. (OCC at 7-8.) Customers, according to OCC, should reap the benefits of these investments and should therefore benefit from their appreciation in value (*i.e.*, any market premium over the assets' book value). (OCC at 8.)

Similar to OCC, IEU argues that the recovery by the Company of any above-market generation revenue for capacity (and any RSR revenues authorized by the Commission) would be contrary to the netting principles of 4928.39 (regarding total allowable transition costs under SB 3) if at the same time the Company conveys the above-book value of its generating assets to its affiliates. (IEU at 9.) Similar to OCC, IEU also contends that the Company's internal analysis shows that future cash flows from generation services are in excess of book value. (IEU at 9.) IEU also asserts that the Company's request to transfer the Amos and Mitchell units has not been demonstrated to be in the public interest and proposes that the Commission should include a binding commitment in the plan under which the Company and its affiliates will consent to the full authority of the Commission under 4928.18. (IEU at 8.)

FES comments that the Company has not provided the required information about the transaction, including market value of the assets, making review difficult. (FES at 2, n.3.) Similarly, after acknowledging that the Company has asked for a waiver of the hearing and submission of market values, OMA notes that the Company has the burden of proof and has not provided sufficient or the minimum information required to approve the application. (OMA at 3.)

B. AEP Ohio Reply

The Commission should reject the position of commenters that insist on a market valuation study being conducted and litigated before approving the transfer of assets. The position that a market valuation is needed rests on false assumptions that have no basis in Ohio law. Section 4928.17, Revised Code, requires corporate separation but does not indicate any need for a market valuation and contains no indication that any gain (whether artificial or real) should be captured. Customers pay for electric service and are not investors in utility plant in service, whether it is poles and wire or a power plant. (*In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Columbus Southern Power Company and Related Matters*, Case No. 88-102-EL-EFC, Opinion and Order (October 28, 1988) at pp. 14-16, and Entry on Rehearing (December 20, 1988) at p. 8.) Under SB 3, all of these generation assets were subjected to market and EDUs therefore were given a temporary opportunity to recover stranded generation investments during a transition period. The General Assembly simultaneously required generation divestiture and did not provide for any gain, whether real or artificial, to be flowed back to ratepayers. The market valuation concept is reflected in the Commission's rules; it has no statutory basis and has never been enforced against any electric utility in implementing corporate separation. These factors not only provide a supporting rationale as to why a waiver of the rule is necessary, but they also illustrate why OCC's notion that transferring assets at net book value somehow creates a profit is artificial and inaccurate. There is no reason to believe that market value is above book value – indeed, this notion conflicts with the positions taken by OCC and others in the 10-2929 case that AEP Ohio's cost-based rate was substantially "above market." (OCC Initial Post Hearing Brief in Case No. 10-2929-EL-UNC at pp. 2, 9.)

Generation divestiture from the EDU to an affiliate does not create any premium or gain for AEP – it is simply transferring assets from one affiliate to another within the same holding company – as required by Ohio law. OCC's windfall argument is based on a speculative presumption of high market value of the generation assets and incorrectly assumes that ratepayers have an ownership interest in such assets. Requiring AEP Ohio to recognize a gain or loss on the transfer would, in reality, cause an arbitrary financial impact on the Company that would not be shared with ratepayers whether a gain or loss. In addition to being unprecedented and unfair, such an approach would create a "poison pill" in connection with the Modified ESP proposal. It is unacceptable to AEP Ohio to leave the corporate separation issue open and subject AEP Ohio to a potential arbitrary gain or loss at a later date; it is crucial that corporate separation be resolved now and that the assets be transferred at net book value. AEP Ohio cannot move forward under the Modified ESP without these issues resolved on that basis.

Contrary to commenters' desires, future transactions or disposition of the generation assets upon or after corporate separation from the EDU are not matters of concern under R.C. 4928.17 or the Commission's rules. The statute and the Commission's rules are concerned with the divestiture of generation assets from the EDU. They are not concerned with future performance of those assets, future environmental rules or market conditions that may affect the value of the assets or whether there are subsequent transactions (known or unknown) that would alter the ownership or economic value of the assets. Accounting for such potential future gains or losses would be inappropriate because it is without basis under the corporate separation statute or rules. In addition, it would be inconsistent with the Commission's application of those rules to other electric utilities.

Furthermore, the commenters' opposition to a net book value transfer should be rejected because they did not timely object to AEP Ohio's waiver request (conceded by OMA at p. 3), and they should be equitably estopped because they lobbied (successfully) for Duke Ohio to be permitted to transfer its assets at net book value. (Stipulation and Recommendation in Case Nos. 11-3549-EL-SSO, *et al.*, at pages 3 and 25-26.) The Commission determined based on similar information that it was in the public interest to waive Rule 4901:1-37-09(C)(4) and allow Duke Ohio to transfer its generation assets at net book value. If that treatment was in the public interest in considering the proposal of Duke Ohio, it is also in the public interest to grant AEP Ohio's similar waiver request. Further, it is not in the public interest for the Commission to apply the same rule to similar facts in an inconsistent manner. Doing so creates an unfair and unlevel playing field for competition.

As a threshold matter, R.C. 4928.17 – the controlling statute regarding corporate separation matters – requires the Commission to ensure that an approved corporate separation plan does not extend an undue advantage or preference in the provision of competitive electric services. *See* R.C. 4928.17(A)(3.) Granting Duke Ohio's affiliate full and final approval for generation divestiture up front and waiving the filing and process rules, while simultaneously deferring approval of AEP Ohio's transfer of assets to AEP Genco and possibly subjecting it to market valuation studies and protracted litigation, serves to provide Duke Ohio with an undue preference and advantage in violation of this statute. The better approach is to grant AEP Ohio the same relief afforded to Duke Ohio.

An inconsistent application of the corporate separation statutory provisions and rules would be anticompetitive and would provide one entity a competitive advantage in violation of R.C. 4928.02. If Duke Ohio is able to transfer its generation assets at net book value and AEP

Ohio is subject to greater scrutiny and a different valuation methodology, then Duke Ohio would be receiving an unfair benefit from the truncated process, which would allow Duke Ohio to avoid the costs associated with complying with O.A.C. 4901:1-37-09(C)(4), and potentially transfer its assets at a different valuation level. Nowhere is the direct difference more obvious than in the case of the jointly owned utility assets. If Duke Ohio were able to transfer those assets at net book value to its competitive generation affiliate but AEP Ohio was required to transfer its assets to AEP Genco at a potentially greater cost, over a greater period of time, and in some cases to even transfer the same assets under a different methodology, then Duke's competitive generation company would be receiving a competitive advantage over the AEP Genco.

IEU (at 9) and OCC (at 6) rely on an accounting analysis performed in late 2011 by AEP in conjunction with the (now-rejected) 11-346 Stipulation, in an attempt to support their speculation that the market value of the generation assets is greater than the book value. The internal AEP accounting memorandum performed a long-term analysis of the entire AEP-East generation fleet to determine whether the total expected revenue stream for the life of the assets exceeds their book value. The accounting memorandum makes clear that the impairment analysis of the generation fleet was done through a 30-year long-term view and from the aggregated perspective of AEP East (versus a narrow view of RPM pricing just for the shopping portion of AEP Ohio's load in Ohio.) (OCC Ex. 104.) In other words, the memorandum merely concludes that the combination of revenue streams from all of the AEP East regulated rates over 30 years exceeded the net book value of the plants. For purposes of this accounting impairment query, the generation plants outside of Ohio were presumed to be cost-based regulated for the entire life of the facility. Mathematically, the net present value of the future payment stream for individual generation assets (or groups of assets) within Ohio could be zero and the impairment test would still pass based on the lifetime revenue analysis for AEP East collectively. In reality, the accounting analysis was done for a completely unrelated purpose and it does not support the OCC/IEU notion that market value of the generating assets should be explored or required as part of corporate separation.

In sum, there is no mandatory requirement that generation assets be transferred at market value and there is no reason why AEP Ohio should not be permitted to transfer its assets at net book value – especially given that the criticisms of the waiver request have no basis under Ohio law, are speculative and without record support. The Commission has not required any EDU to produce market valuation studies in order to obtain corporate separation approval under R.C. 4928.17 and doing so here would create an unfair and unlevel playing field in violation of Ohio law.

3. No new issues raised regarding hearing waiver

OMA is the sole commenter to advocate for a hearing in its initial comments. (OMA at 6.) Aside from being untimely, which OMA concedes, the Commission should reject OMA's plea and grant AEP Ohio's waiver request. OMA did not identify any need for a hearing, as all of the issues have been adequately addressed during the comment cycle, and there is no need to conduct an evidentiary hearing. These matters were also discussed in detail as part of the Modified ESP case in which OMA and all the commenters have actively participated. The Commission, consequently, should grant AEP Ohio's request for a waiver of any hearing required in this matter under Rule 4901:1-37-09(D). OAC.

4. Disposition of PCRBs

A. Comments

Staff states that the Company's request to not transfer $296 million of PCRBs should be

denied because (1) as a general principle, debt associated with generation assets should follow the assets, and (2) the Company has not quantified the impact on it if the debt is transferred. (Staff at 1-2.) Staff recommends that if the Company wants to renew its request, it should do so within six months of the completion of corporate separation and quantify the negative impacts of the transfer on the Company. FES states that all PCRBs regardless of tender date should be transferred because they are generation-related debt. (FES at 7.) IEU contends that AEP Ohio has unlawfully and unreasonably proposed to retain certain PCRBs even though they are directly related to generation plant. (IEU at 10.)

B. AEP Ohio Reply

As a threshold matter, the PCRBs are tax-exempt, general obligations of the Company and are not secured debt linked directly to its generation assets. (App. at 5.) Further, the PCRBs are a flexible, low-cost form of debt. (App. at 6; AEP Ohio Ex. 102 at 10.) So, the Company proposed and continues to recommend that the PCRBs with tender dates prior to the closing of corporate separation be transferred to the AEP Genco, as described in the Application; while PCRBs with tender dates after the closing of corporate separation would be retained by AEP Ohio, which only represent 7% of the Company's overall debt with the level shrinking to 3% after 2014. Thus, consistent with AEP Ohio's application, all liabilities associated with the assets being transferred at net book value will be assumed by AEP Genco, including the retired plants and the liabilities associated with the retired plants, which is similar to the arrangement the Commission approved in the Duke Stipulation.

Transfer of PCRBs is not possible prior to the tender dates instead those bonds would have to be defeased on the date of corporate separation at substantial cost. If the Commission does not concur that the PCRBs with tender dates after the closing of corporate separation be retained by the Company, the Company would seek to transfer those PCRBs consistent with Condition 3 of its Application (p. 8), which is intended to address transfers that could impose substantial additional costs on the Company. These provisions are essentially identical to the condition accepted by the Commission in Section VIII.B of the Duke Stipulation, which states "that contractual obligations arising before the signing of the Stipulation shall be permitted to remain with Duke Energy Ohio without Commission approval for the remaining period of the contract but only to the extent that assuming or transferring such obligations is prohibited by the terms of the contract or would result in substantially increased liabilities for Duke Energy Ohio if Duke Energy Ohio were to transfer such obligations to its subsidiary or affiliate." FirstEnergy received similar treatment when it transferred its generation assets. Accordingly, AEP Ohio's alternative request is for the Commission to afford the Company the same treatment in its transfer of PCRBs that have tender dates after the projected close of corporate separation as it has other Ohio electric utilities, including as reflected in Section VIII.B of the Duke Stipulation.

Staff's recommendation appears to be inconsistent with the prior approach but is ambiguous. The Duke order exempts transfer of prior contractual obligations provided the transfer is contractually prohibited or a premature transfer would increase the utility's costs. Staff's suggestion for the Company is that "within six months of completion of corporate separation, should OPCo wish to renew this request, require OPCo to include in its request a quantification of the negative impact of transferring the $296 million in PCRBs to its affiliate generation company using any financing options available to it." (Staff at 2.) If Staff's recommendation means that the PCRBs are exempt from the initial divestiture transfer and will be subject to the same kind of standard as the Duke order without being required to affirmatively request Commission approval to retain the PCRBs by the Company, it can agree to that

approach, as an alternative to the Company's primary request to exempt the PCRBs with tender dates after corporate separation to be retained. But if Staff's recommendation means that the transfer of PCRBs must be initially made at the closing of corporate separation and then a separate request should be made to see if they should be transferred back to the Company from the AEP Genco, that approach is not workable and the Company would be required to defease all of the bonds early.

In sum, the Commission should: (a) grant the Company's primary request to allow the PCRBs with tender dates beyond the corporate separation closing date to be retained permanently by the Company; or (b) adopt the same approach taken in the Duke order and set forth Condition 3 of the Application which allows the Company to effectuate the transfer of the PCRBs in an orderly fashion without the Company incurring unnecessary additional costs.

5. Allocation of debts and liabilities and audit

IEU alleges that the Company has not shown that long-term debt used to fund generation investment will be properly allocated to AEP Genco. (IEU at 10.) IEU also states that the Company admitted that administrative and general (A&G) expenses are not currently and will not be properly allocated. (*Id.*) Further, IEU objects to the Company's alleged failure to propose an independent auditor to evaluate Company's requested plan. (IEU at 10-11.) IEU's claim that the Company admitted in its Application that A&G expenses will not be properly allocated is false and mischaracterizes the Company's statements. In the Application (Attachment A at 4), the Company stated that some A&G expenses are directly assigned wherever possible and some A&G expenses billed from AEPSC are allocated to each function based on FERC accepted allocation methodologies. Obviously, directly assigning costs wherever possible and otherwise using reasonable and equitable allocated methods accepted by FERC does not result in inappropriate allocation of costs – there is no indication of any problem or impropriety with this approach, and IEU's characterization is false and otherwise lacks merit. In addition, the Company has proposed audit terms in Condition 1 of its Application, including the ability for Staff, at the Commission's discretion, to retain an independent auditor to audit the terms and conditions of the transfer of the generation assets to ensure compliance with the terms approved by the Commission for the transfer of those assets. (Application at 8.) These are identical audit terms to those approved by the Commission for Duke Ohio in Section VIII.B of the Duke Stipulation.

6. Disposition of REPAs

A. Comments

FES states that it cannot tell whether all or just some of the REPAs are being left behind at Company and not transferred to AEP Genco. (FES at 2.) FES takes no position on whether they should be transferred, but FES asserts that the Company should not be able to "cherry pick" which ones stay or go, and the Commission should clarify that they should be treated as a group. (FES at 2-3.)

B. AEP Ohio Reply

The Company explained at page 5 of the Application that as part of the generation divestiture process the following REPAs would remain with AEP Ohio and not be transferred to AEP Genco: the 99 MW Timber Road wind REPA, the 100 MW Fowler Ridge II wind REPA, and the 10 MW Wyandot solar REPA. As a threshold matter, it should be noted that the REPAs are not necessarily "generation assets" under R.C. 4928.17(E) or OAC Chapter 4901:1-37. Thus, transfer of the REPAs does not necessarily require Commission approval or need not be addressed in a corporate separation plan or amendment. Nevertheless, in an abundance of

caution and in the spirit of full disclosure, the Company did reference the REPAs in its Application. In any case, AEP Ohio believes that the most direct and efficient way to preserve flexibility is to leave the existing REPAs behind in the transfer of generating assets to AEP Genco. That way, the RECs associated with these long-term REPAs (which were purchased for compliance with Ohio's renewable portfolio requirements for the benefit of ratepayers) would continue to be available after legal separation to help satisfy AEP Ohio's renewable compliance mandate. Accordingly, the Company would exclude these REPAs from the generation assets being proposed for transfer approval as part of its Application. There is no basis for FES's allegation that AEP Ohio is trying to "cherry pick" which REPAs would be transferred, as AEP Ohio clearly indicated that its proposal was to retain all of the existing REPAs within AEP Ohio and explained the reasons supporting this proposal (to the extent it is even relevant under R.C. 4928.17).

7. Other issues indirectly related to corporate separation that should be addressed in the Modified ESP case

(a) The SSO Agreement is justified

i. Comments

FES notes that the Commission should rule that approval of corporate separation does not constitute approval of the SSO agreement between AEP Genco and AEP Ohio, and the Commission should reserve judgment on that issue. (FES at 3.) FES summarizes the arguments it made in the Modified ESP proceeding that the contract is imprudent, contrary to FERC precedent, and that there should be an RFP for the SSO service. (FES at 3.)

IEU contends that the proposed SSO agreement will require SSO customers to continue to pay above-market rates for generation, which is contrary to state policy. (IEU at 11.) According to IEU, AEP Ohio is trying to set up a preemption claim if it obtains FERC approval of the SSO Agreement, even though it believes the SSO Agreement would also violate FERC affiliate transaction requirements and not be approved by FERC. (IEU at 11.)

ii. AEP Ohio Reply

In the Modified ESP, the Company proposes that there will be an auction-based competitive bidding process for the delivery period beginning January 1, 2015 for energy and a separate auction for delivery beginning June 1, 2015 for both energy and capacity. Between the time of corporate separation and the delivery date of the January 1, 2015 SSO energy auction, the AEP Genco will sell wholesale power to AEP Ohio under a full requirements agreement to supply AEP Ohio's non-shopping retail load. The SSO Contract will allow AEP Ohio to serve SSO customers, *i.e.*, those AEP Ohio retail customers that are not being served by a CRES provider. From January 1, 2015 through May 31, 2015, the AEP Genco will provide capacity but will no longer supply the energy for SSO customers under the SSO contract. Beginning June 1, 2015 both energy and capacity will be provided by the SSO auction and, therefore, the SSO contract between the AEP Genco and AEP Ohio ends on that date.

It is highly ironic and disingenuous that FES is the one complaining about the prospect of the SSO agreement, because FES supported the FirstEnergy operating companies' SSO power requirements for years under an identical approach. As it relates to AEP Ohio, however, the key point is that AEP Ohio is a captive seller of capacity to support shopping load, given its FRR obligations, and must fulfill its obligations throughout the term of the ESP even after corporate separation. Thus, there needs to be an arrangement to provide SSO service supporting the same retail rates being agreed to by AEP Ohio during the entire ESP term. The retail SSO rates approved by the Commission in the Modfied ESP will not be altered by the SSO Contract, which in any event the Company intends that it will compensate the Genco at a rate that approximates

the rate paid by its customers for SSO service. As a result, FES's objection to the SSO is without merit. IEU's argument about setting up a preemption claim is also a "red herring" because the same retail rates will apply after corporate separation as before – and throughout the ESP term – so there is no potential adverse impact on SSO rates.

(b) RSR Revenues to AEP Genco

i. Comments

OCC argues that by remitting RSR revenues to AEP Genco, AEP Ohio will be providing an unlawful subsidy to its affiliate. (OCC at 11.) According to OCC, the transfer of RSR revenues from AEP Ohio to the AEP Genco violates (a) 4928.02(H), which is the state policy prohibiting anti-competitive subsidies, (b) 4928.17(A)(2), because a corporate separation plan must prevent an unfair competitive advantage from being conferred on an affiliate, and (c) 4928.17(A)(3), which requires the plan to be sufficient to ensure that no undue preference is extended to an affiliate. (OCC at 11-12.)

FES states that it is the Company's position that it intends to essentially continue functional separation until June 1, 2015 with all generation revenues going to the AEP Genco. (FES at 4-5.) Per FES witness Lesser's testimony in the Modified ESP case, according to FES, passing RSR revenue to AEP Genco would result in an anti-competitive cross-subsidy to AEP Genco. (FES at 5.) FES, therefore, urges the Commission to ensure that RSR revenues terminate on the date of corporate separation. (FES at 5.) According to FES, the Company argued in testimony in the Modified ESP that it might incur financial harm absent the RSR in 2013, prior to corporate separation in 2014. (FES at 4, n. 9.) But FES argues that the Company's testimony shows that it will not incur any financial harm in 2014 or 2015. (Id.) In addition, because AEP Genco is not a utility, FES contends that the Commission cannot establish a charge to pass through its embedded costs of generation post-corporate separation. (FES at 4, n.10.)

ii. AEP Ohio Reply

In general, AEP Ohio will pass through generation-related revenues to the AEP Genco for providing capacity and/or energy for the SSO load. AEP Ohio will pay the AEP Genco the non-fuel generation charges billed to AEP Ohio's SSO customers under applicable retail rate schedules, as well as the AEP Genco's actual fuel costs. (AEP Ohio Ex. 103 at 7.) AEP Ohio will also reimburse AEP Genco, on a dollar-for-dollar basis, for any transmission, ancillary, and/or other service charges that AEP Genco may be billed by PJM in connection with the SSO Contract. (*Id.*) In addition, revenues that AEP Ohio may receive from PJM in connection with capacity payments made by CRES providers under PJM's Reliability Assurance Agreement ("RAA") would be remitted to the AEP Genco in return for AEP Genco providing capacity to AEP Ohio to fulfill AEP Ohio's Fixed Resource Requirement (FRR) obligations, as well as the obligations of the CRES providers. (*Id.*) Also, capacity payments will be made by AEP Ohio to the AEP Genco in connection with the energy only auctions occurring while AEP Ohio is still an FRR entity in PJM. (*Id.*) Any revenues related to moving to a competitive generation market in Ohio, such as the Retail Stability Rider, will also be remitted to the AEP Genco as compensation for the fulfillment of its obligations. (*Id.* at 8; Tr. II at 519, 614.)

The relevant commenters fail to acknowledge that without these revenues the deal will not take place. Specifically, the assets being transferred need the financial support that comes with the RSR. Collection of RSR revenues by AEP Ohio allow the Company to pay AEP Genco for capacity to meet its FRR commitment. Without the certainty of these additional RSR revenues, AEP Genco cannot credibly proceed with the transaction. Notably, the commenters do

not cite any law that requires AEP Genco to lose millions of dollars, which would be the effect of not allowing AEP Ohio to pass through RSR revenues to AEP Genco. Their comments are not based in reality and should not be given any credibility by the Commission. In sum, there are four primary reasons that it is appropriate for AEP Ohio to pass through SSO revenues to the AEP Genco during the latter portion of the ESP term following corporate separation: (1) the Commission has approved functional separation for AEP Ohio at every step of the process during the past 12 years, and AEP Ohio presently remains a vertically-integrated utility in a lawful manner; (2) for part of the ESP term, AEP Ohio will (according to plan) be legally separated but remain obligated to provide SSO service at the agreed rates for the entire ESP term; (3) during this latter period, the AEP Genco will be obligated to support SSO service through the provision of adequate capacity and energy, and it is only appropriate that it receives the same revenue streams agreed to by AEP Ohio for doing so; and (4) there will be an SSO agreement between AEP Ohio and the AEP Genco covering this arrangement, which is subject to review and approval by the FERC.

(c) Elimination of the Pool Modification Rider through acceptance of corporation separation plan without modification

i. Comments

FES comments that AEP has stated that it will not seek compensation for termination of the pool if corporate separation, including the Amos and Mitchell transfers, is approved. (FES at 5-6.) According to FES, there is no justification for recovery by AEP Genco of any lost pool revenues after corporate separation . (FES at 6.) If corporate separation is rejected, the PMR should be evaluated in the Modified ESP as an additional cost of the Modified ESP. (Id.) If the Commission approves corporate separation as requested, FES advocates that it should make clear Company is not entitled to any lost pool revenues. (Id.)

ii. AEP Ohio Reply

As AEP Ohio has already indicated the Pool Modification Rider will not be triggered or applicable if the Commission approves AEP Ohio's proposed corporate separation plan without modification and the plan is implemented.

(d) Additional issues pending in other cases are not properly raised in this docket

i. Comments

Exelon argues that because the Company proposes to corporately separate effective January 1, 2014, there is no reason why, and no record evidence supporting that, the SSO auction for capacity and energy could not be advanced a year to June 1, 2014 from June 1, 2015, as proposed in Exelon's Initial Brief in the Modified ESP case. (Exelon at 2.) Exelon also advocates that the SSO contract with the AEP Genco should end earlier on that date. (Id.) IEU makes a general objection that the Application does not commit to an immediate SSO auction in order to advance state policy. (IEU at 12.)

Kroger also raises an issue concerning potential deferrals. Kroger asserts that the Company should collect deferred capacity costs through AEP Genco from generation customers through a bypassable charge rather than from all distribution/connected customers. Kroger asserts this because, in its view, distribution customers would somehow subsidize shopping customers. (Kroger at 2.) Kroger notes that this docket is the appropriate case in which the Commission should ensure that all generation costs are allocated solely to the AEP Genco. (Kroger at 2.) According to Kroger, the regulatory asset of deferred capacity costs should be assigned to books of the AEP Genco. (Kroger at 3.)

ii. AEP Ohio Reply

These issues, including Kroger's self-serving position on the bypassability of deferred capacity costs, have been addressed in the Modified ESP and Capacity Case dockets and do not relate to the corporate separation application being considered in this proceeding. (AEP Ohio Reply Brief at 21-23, 25-27, 39 (defending the proposed nonbypassability and rate design of the RSR) and 42-48 (defending transition to auction-based SSO). It is likely that the Commission will have already decided those issues as part of its decision in the Modified ESP case by the time it issues a decision in this proceeding. In any case, those issues are beyond the scope of this proceeding and should not be considered herein.

8. IEU's motion to dismiss should be denied

Finally, IEU's comments also contain a cursory argument in support of dismissal. (IEU at 1-3.) IEU did not submit a proper motion under Rule 4901-1-12, OAC, and it would be improper for IEU to file a reply in support of its dismissal argument. In any case, IEU summarily asserts that the Application does not fulfill the requirements of Rule 4901:1-37-09(C), OAC, which requires that the following be addressed: (1) object and purpose of the sale or transfer and the terms and conditions of the same, (2) demonstrate how the sale or transfer will affect the current and future SSO, (3) demonstrate how the proposed sale or transfer will affect the public interest, and (4) state the fair market value and book value of the property to be transferred and indicate how the fair market value was determined. Of course, IEU acknowledges that item (C)(4) is the subject of the pending motion for waiver (and it has also been further addressed above). AEP Ohio described the object and purpose of the proposed transfer extensively in the Application and in the record in the *Modified ESP* cases, as referenced above. AEP Ohio also addressed the impact on the current and future SSO, item (C)(2), in the

Application at pages 3-4. With regard to the overall standard of demonstrating the proposed transfer is in the public interest, AEP Ohio addressed this through the Application, its comments and through the Modified ESP record. Through its motion to dismiss, IEU merely disagrees with the Company's proposal and generically registers its qualitative opinion that the Application is subjectively "deficient" in support of its cursory dismissal request. AEP Ohio has already addressed the IEU's various substantive criticisms above. AEP Ohio submits that IEU's position on these matters should be rejected when the Commission substantively evaluates the merits of the Application.

CONCLUSION

The Commission should expeditiously grant the Application without modification.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and accurate copy of the foregoing reply comments was served this 3rd day of August, 2012 by electronic mail, upon the persons listed below.

/s/ Steven T. Nourse
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IEU-Ohio
EXHIBIT 3

OHIO POWER COMPANY'S RESPONSES TO
OHIO ENERGY GROUP'S DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
THIRD SET

INTERROGATORY

INT-3-013 Refer to Attachment 1 to the Company's response to IEU-INT-1-010, which provided actual historic cost information for each of the proposed PPA units at December 31, 2013. In this response, the Company included numerous ARO amounts in the book cost for various plant accounts for the various PPA units.

a. Please provide the ARO liability amounts for each of the proposed PPA units at December 31, 2013.

b. Please indicate whether the ARO liability amounts were included in accumulated depreciation. If not, then please explain why the Company did not include the ARO liability amounts in the accumulated depreciation and net book value.

c. Please provide the FERC account where the ARO liability amounts are recorded.

d. Please confirm that the ARO asset and liability initially are equivalent and equal to the present value of the future cost of legal retirement obligations.

e. Please confirm that the ARO asset is depreciated over the life of the underlying asset.

f. Please confirm that the ARO liability increases each accounting period by the accretion expense.

g. Please confirm that the ARO liability is reduced by amounts expended to perform the legal retirement obligations and that a gain or loss is recognized when the legal retirement obligation is completed that is calculated as the difference between the ARO liability and the actual costs incurred.

h. Please confirm that the Company agrees that if the ARO asset amounts are included in the net book value, that the ARO liability amounts should be included in the accumulated depreciation or otherwise subtracted from rate base. If the Company disagrees with this principle, then please provide all reasons why it disagrees.

RESPONSE

a. AEP's ownership share of ARO liability amounts for each of the proposed PPA units at December 31, 2013:

Cardinal, Unit 1 - $8,805,719
Conesville, Unit 4 - $12,611,466
Conesville, Units 5 & 6 - $31,265,425
Stuart, Units 1, 2, 3 & 4 - $1,691,918
Zimmer, Unit 1 - $492,362

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INT-3-013 Continued

b. The ARO liability amounts for the PPA units were recorded in account 230 and were not included in accumulated depreciation. However, AEPGR did include the ARO liability as a reduction to rate base. The depreciation of the ARO asset is included in accumulated depreciation.

c. FERC account where ARO liability amounts are recorded - account 230.

d. Confirmed, upon the initial establishment, the ARO asset and liability are equivalent.

e. Confirmed.

f. Confirmed.

g. Confirmed.

h. For this unique and limited circumstance of the PPA whereby only certain assets are included through end of life, the proposed PPA has included both the ARO asset and the ARO liability in rate base.

Prepared by: Thomas E. Mitchell and Kelly D. Pearce

IEU Ohio
EXHIBIT 4

OHIO POWER COMPANY'S RESPONSES TO
OHIO CONSUMERS' COUNSEL'S DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
FIRST SET

INTERROGATORY

INT-1-016 The summary of the Power Purchase and Sale Agreement indicates that the term is "including any post-retirement period necessary to fulfill all asset retirement obligations and complete any other removal projects" (Exhibit KDP at page 1):

a. When will the cost of "all asset retirement obligations" be charged to the Company?

b. What are "other removal projects"?

c. When will the cost of "other removal projects" be charged to the Company?

d. What are the estimated costs for "all asset retirement obligations" for each of the PPA Units?

e. What are the estimated costs of "other removal projects" for each of the PPA Units?

RESPONSE

a. Please refer to Attachment 1 in the Company's supplemental response to IEU-RPD-1-002.

b. Other removal projects in this context means the cost of removing and disposing of the plant/unit and all other related facilities, coal inventory and all equipment from the plant sites after each plant/unit has been retired, as well as any other site remediation work related to retirement of the unit.

c. Please refer to Attachment 1 in the Company's supplemental response to IEU-RPD-1-002.

d. Estimated future costs for retirement-related projects for which asset retirement obligations are currently recorded on AEPGR's books for the PPA Plants is as follows:

Cardinal - $36,232,536
Conesville - $69,010,241
Stuart - $ 8,104,396
Zimmer - $ 7,439,739

The Company does not have an estimate of the costs by unit.

e. The Company does not have an estimate of these costs.

Prepared by: Kelly D. Pearce

EXHIBIT
IEU 4
PENGAD 800-631-6989

State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent Market Monitor for PJM

3.12.2015

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2014 State of the Market Report for PJM*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2014 State of the Market Report for PJM*.

TABLE OF CONTENTS

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- Planned Generation. As of December 31, 2014, 68,108.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,689.4 MW as of December 31, 2014. Of the capacity in queues, 8,729.4 MW, or 12.8 percent, are uprates and the rest are new generation. Wind projects account for 15,660.0 MW of nameplate capacity or 23.0 percent of the capacity in the queues. Combined-cycle projects account for 41,239.6 MW of capacity or 60.5 percent of the capacity in the queues.
- Generation Retirements. As shown in Table 12-6, 26,679.8 MW have been, or are planned to be, retired between 2011 and 2019, with all but 2,140.8 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.6 percent, of all MW planned for retirement from 2015 through 2019.
- Generation Mix. A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 1,992.5 MW of coal fired steam capacity are currently in the queue, 9,222.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,894.8 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS). In contrast, 43,697.3 MW of gas fired capacity are in the queue, while only 1,951 MW of natural gas units are planned to retire. The replacement of steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog of incomplete studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company of the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. PJM actively engaged in an iterative process with Artificial Island

1 PJM. OATT Parts IV & VI.

project sponsors to modify the technical aspects of proposals and to allow updated cost estimates. The process has been controversial and is ongoing.

Backbone Facilities

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

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[2]

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[3] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Not Adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to permit competition between incumbent transmission providers and nonincumbent providers. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate transmission outage tickets when the outage is rescheduled. (Priority: Low. New recommendation. Status: Not adopted.)

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

3 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

Conclusion

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

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

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

The PJM rules for competitive transmission development should build upon Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent providers. One way to do this is to consider utilities' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

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 time lag and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On December 31, 2014, 68,108.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,689.4 MW as of December 31, 2014. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). In 2014, 2,659.0 MW of nameplate capacity were added in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2014

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

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. The duration of the queue period has varied. Queues A and B were open for a year. Queues C-T were open for six months. Starting in February 2008, Queues

U-Y1 were open for three months. Starting in May 2012, the duration of the queue period was set to six months, starting with Queue Y2. Queue AA2 is currently open.

All projects that have been entered in a queue have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years, at which point it is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs. Projects that entered the queue after February 1, 2011 face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[4]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between September 30, 2014 and December 31, 2014 for ongoing projects, i.e. projects with the status active, under construction or suspended.[5] Projects that are already in service are not included here. The total MW in queues increased by 7,534.6 MW, or 12.4 percent, from 60,573.8 MW at the end of the third quarter of 2014. The change was the result of 10,237.7 MW in new projects entering the queue, 2,334.5 MW in existing projects withdrawing, and 397.3 MW going into service. The remaining difference is the result of projects adjusting their expected MW. More MW were added to the queue in the last quarter of 2014 than the 2,992.7 MW and 2,340.9 MW added in the prior two quarters of 2014. There were five large projects that contributed to this increase, including a 1,710 MW coal plant project to replace the Hatfield plant retired in October, 2013 and four natural gas projects that added a total of 3,962 MW to queue capacity.[6]

Table 12-2 Queue comparison by expected completion year (MW): September 30, 2014 vs. December 31, 2014[7]

	As of 9/30/2014	As of 12/31/2014	Quarterly Change (MW)	Quarterly Change (percent)
≤ 2013	0.0	0.0	0.0	NA
2014	5,321.4	4,604.5	(716.9)	(13.5%)
2015	13,098.3	13,992.5	894.2	6.8%
2016	15,484.3	16,974.2	1,489.8	8.8%
2017	11,958.1	14,075.1	2,117.0	15.0%
2018	11,891.5	12,587.0	695.5	5.5%
2019	1,148.0	3,051.0	1,903.0	62.4%
2020	78.2	1,152.0	1,073.8	93.2%
2021	0.0	78.2	78.2	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	60,573.8	68,108.4	7,534.6	12.4%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between September 30, 2014 and December 31, 2014. For example, 10,397.7 MW entered the queue in the third quarter, 160.0 MW of which were withdrawn before the quarter ended. Of the total 36,722.1 MW marked as active at the beginning of this quarter, 2,273.7 MW were withdrawn, 70.0 MW were suspended, 2,754.6 MW started construction, and 65.2 went into service by the end of the fourth quarter. The "Under Construction" column shows that 3,010.6 MW began construction in the fourth quarter of 2014, in addition to the 18,617.0 MW of capacity that maintained the status "under construction" from the previous quarter.

4 See PJM. Manual 14C. "Generation and Transmission Interconnection Process," Revision 8 (December 20, 2012), Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

5 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

6 The queue data in this section are now based on PJM queue data while prior reports relied on public queue data only.

7 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-3 Change in project status (MW): September 30, 2014 vs. December 31, 2014

		Status at 12/31/2014				
Status at 9/30/2013	Total at 9/30/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q4 2014)		10,237.7	0.0	0.0	0.0	160.0
Active	36,722.1	31,491.3	70.0	2,754.6	65.2	2,273.7
Suspended	4,501.8	0.0	4,341.8	256.0	0.0	0.0
Under Construction	19,349.9	0.0	340.0	18,617.0	332.1	60.8
In Service	38,053.4	0.0	0.0	0.0	37,944.4	43.0
Withdrawn	269,264.9	0.0	0.0	0.0	0.0	272,093.1
Total at 12/31/2014		41,729.0	4,751.8	21,627.6	38,341.7	274,630.6

Table 12-4 Capacity in PJM queues (MW): At December 31, 2014[8]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,347.0	25,450.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	15,832.7	20,478.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	4,151.2	4,682.2
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,770.0	8,620.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	16,886.8	17,682.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	22,013.9	23,203.5
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,738.3	3,841.3
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	218.0	0.0	0.0	2,425.5	2,643.5
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	150.0	0.0	3,705.6	4,360.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	10,527.0
O Expired 31-Jul-05	0.0	1,688.2	225.0	212.0	5,466.8	7,592.0
P Expired 31-Jan-06	0.0	3,255.2	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	105.0	3,147.9	1,594.0	0.0	9,686.7	14,533.6
R Expired 31-Jan-07	0.0	1,386.4	1,668.3	300.0	19,400.6	22,755.3
S Expired 31-Jul-07	0.0	3,301.3	644.3	490.0	12,706.5	17,142.0
T Expired 31-Jan-08	1,010.0	1,310.0	3,048.0	0.0	22,188.3	27,556.3
U Expired 31-Jan-09	1,430.0	925.3	567.0	459.9	29,974.6	33,356.8
V Expired 31-Jan-10	1,772.4	1,812.8	1,469.3	148.0	12,169.4	17,371.9
W Expired 31-Jan-11	2,648.0	650.4	1,999.4	1,923.5	17,093.6	24,314.9
X Expired 31-Jan-12	5,250.8	322.0	7,457.6	395.8	16,942.0	30,368.2
Y Expired 30-Apr-13	6,729.7	212.5	2,460.1	592.6	16,023.3	26,018.0
Z Expired 30-Apr-14	9,527.9	107.4	244.2	20.0	4,789.1	14,688.6
AA1 Expired 31-Oct-14	12,844.8	0.0	0.0	0.0	166.0	13,010.8
AA2 through 31-Dec-14	410.5	0.0	0.0	0.0	0.0	410.5
Total	41,729.0	38,509.7	21,627.6	4,751.8	290,072.8	396,690.9

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the regional transmission expansion plan (RTEP) process and the total amount of capacity that had been included in each queue. All items in queues A-L are either in service or have been withdrawn. As of December 31, 2014, there are 68,108.4 MW of capacity in queues that are not yet in service, of which 7.0 percent is suspended and 31.8 percent is under construction. The remaining 61.3 percent, or 41,729.0 MW, have not yet begun construction.

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

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active as of December 31, 2014, by unit type, control zone and LDA.[9] As of December 31, 2014, 68,108.4MW of capacity were in generation request queues for construction through 2024, compared to 60,573.8 MW at September 30, 2014.[10] Table 12-5

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

10 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 15,660.1 MW of wind resources and 2,978.0 MW of solar resources, the 68,108.4 MW currently active in the queue would be reduced to 52,637.8 MW.

also shows the planned retirements for each zone. The geographic distribution of generation in the queues shows that new capacity is being added in all LDAs, but planned retirements are more prevalent in EMAAC than in SWMACC and WMAAC. The net effect is that, by 2024, capacity in WMAAC will increase by more than it will increase in EMAAC and SWMAAC.

A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 1,992.5 MW of coal fired steam capacity are currently in the queue, 9,222.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,894.8 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS). Although the MATS deadline is April 16, 2015, some units were granted a 45-day extension. In contrast, 43,697.3 MW of gas fired capacity are in the queue while only 1,951.0 MW of natural gas units are planned to retire. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-6, 26,679.8 MW is planned to be retired between 2011 and 2019, with all but 2,140.8 MW retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.6 percent, of all MW planned for deactivation from 2015 through 2019. Table 12-6 shows 323.0 MW still pending for 2014. This value reflects the pending deactivation of two Dominion units, which were scheduled to retire on December 31, 2014. It was determined that these units are required for reliability so their deactivation has been postponed. A map of retirements between 2011 and 2019 is shown in Figure 12-1, and a detailed list of pending deactivations is shown in Table 12-7.

Table 12-6 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,129.2
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	2,949.3
Planned Retirements 2014	323.0
Planned Retirements 2015	10,313.0
Planned Retirements Post-2015	2,140.8
Total	26,679.8

Table 12-5 Queue capacity by control zone and LDA (MW) at December 31, 2014[11]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,486.0	302.8	0.0	0.0	0.0	72.7	0.0	0.0	373.0	2,234.5	206.2
	DPL	1,301.2	17.0	0.0	0.0	0.0	450.3	19.9	2.0	279.0	2,069.4	34.0
	JCPL	2,555.0	0.0	0.0	0.0	0.0	673.1	0.0	40.0	0.0	3,268.1	1,084.5
	PECO	1,054.5	10.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	1,398.2	0.0
	PSEG	3,187.9	286.0	10.6	0.0	0.0	169.6	3.0	3.0	0.0	3,660.1	2,139.0
	EMAAC Total	9,584.6	615.8	14.3	0.0	330.0	1,365.7	22.9	45.0	652.0	12,630.3	3,463.7
SWMAAC	BGE	0.0	256.0	29.0	0.4	0.0	25.0	132.0	0.0	0.0	442.4	74.0
	Pepco	2,614.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,614.5	1,204.0
	SWMAAC Total	2,614.5	256.0	29.0	0.4	0.0	25.0	132.0	0.0	0.0	3,056.9	1,278.0
WMAAC	Met-Ed	800.0	91.5	0.0	0.0	35.0	3.0	401.0	0.0	0.0	1,330.5	0.0
	PENELEC	2,517.0	612.2	61.8	45.3	0.0	13.5	0.0	47.5	418.6	3,715.8	603.0
	PPL	5,317.0	0.0	5.0	0.0	0.0	129.0	16.0	60.0	899.0	6,426.0	0.0
	WMAAC Total	8,634.0	703.7	66.8	45.3	35.0	145.5	417.0	107.5	1,317.6	11,472.3	603.0
Non-MAAC	AEP	5,724.0	51.0	18.0	19.5	102.0	98.4	245.0	68.0	7,287.8	13,613.7	5,367.0
	APS	2,691.4	12.0	99.6	77.0	0.0	107.8	1,717.2	11.0	964.6	5,680.5	0.0
	ATSI	3,912.0	0.4	1.7	0.0	0.0	0.0	135.0	0.0	518.0	4,567.1	737.3
	ComEd	1,970.0	593.3	15.3	22.7	0.0	15.0	27.0	100.6	3,428.0	6,171.9	251.0
	DAY	0.0	0.0	1.9	112.0	0.0	23.4	32.5	20.0	300.0	489.8	271.8
	DEOK	513.0	0.0	0.0	0.0	0.0	40.0	50.0	20.0	0.0	623.0	163.0
	DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	124.0
	Dominion	5,256.1	62.0	11.0	0.0	1,594.0	1,157.2	62.5	128.0	1,192.1	9,462.9	323.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	195.0
	Essential Power	135.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.0	0.0
	Non-MAAC Total	20,406.5	718.7	147.5	231.2	1,696.0	1,441.8	2,269.2	347.6	13,690.5	40,948.9	7,432.1
Total		41,239.6	2,294.2	257.6	276.8	2,061.0	2,978.0	2,841.1	500.1	15,660.1	68,108.4	12,776.8

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

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

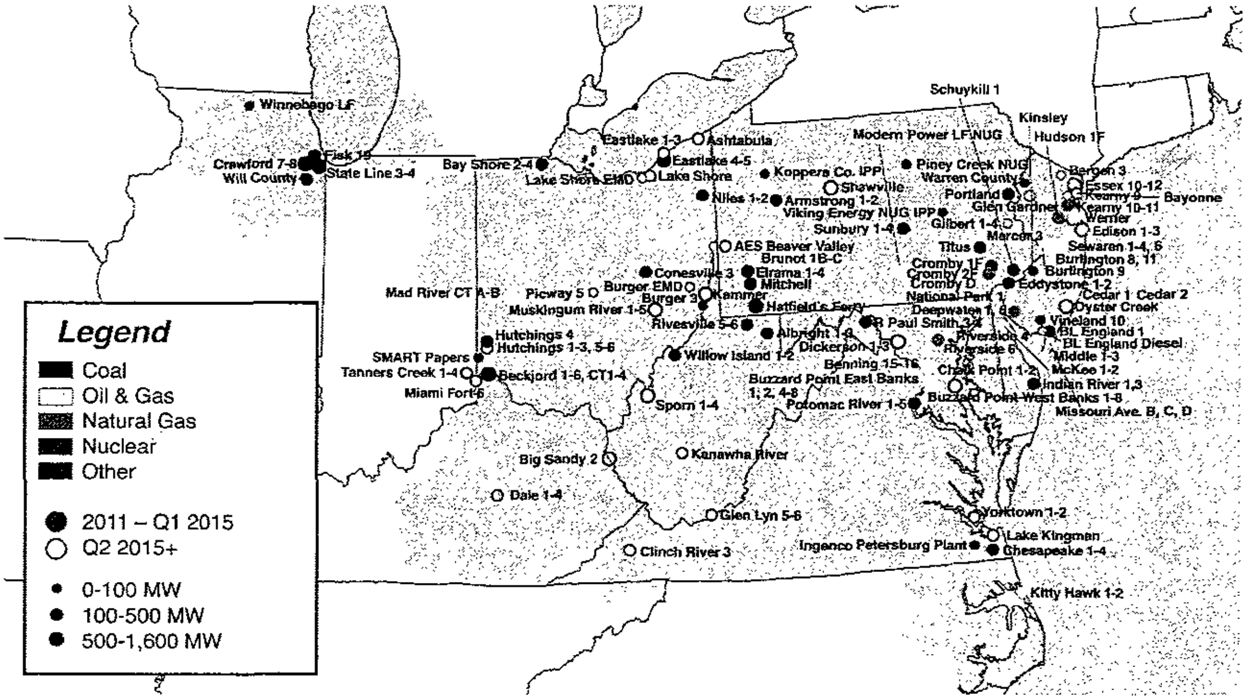


Table 12-7 Planned deactivations of PJM units, as of December 31, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Eastlake 1-3	ATSI	327.0	Coal	Steam	15-Apr-15
Lake Shore 18	ATSI	190.0	Coal	Steam	15-Apr-15
Lake Shore EMD	ATSI	4.0	Diesel	Diesel	15-Apr-15
Will County	ComEd	251.0	Coal	Steam	15-Apr-15
Dale 1-4	EKPC	195.0	Coal	Steam	16-Apr-15
Shawville 1-4	PENELEC	603.0	Coal	Steam	16-Apr-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	31-May-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Big Sandy 2	AEP	800.0	Coal	Steam	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Miami Fort 6	DEOK	163.0	Coal	Steam	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Burger EMD	ATSI	6.3	Diesel	Diesel	31-May-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-18
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		12,776.8			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.4 percent of all MW retiring during this period are coal steam units. These units have an average age of 56.4 years and an average size of 166.6 MW. This indicates that on average, retirements have consisted of smaller sub-critical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	124	166.6	56.4	20,659.6	77.4%
Diesel	7	11.0	43.9	77.2	0.3%
Heavy Oil	4	68.5	57.3	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
LFG	15	76.6	43.8	1,148.7	4.3%
Light Oil	4	6.5	14.8	26.1	0.1%
Natural Gas	50	59.9	46.4	2,996.5	11.2%
Nuclear	1	614.5	50.0	614.5	2.3%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	228	117.0	50.8	26,679.8	100.0%

Actual Generation Deactivations in 2014

Table 12-9 shows the units that were deactivated in 2014.[12]

Table 12-9 Unit deactivations in 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Duke Energy	Walter C Beckjord 4	150.0	Coal	DEOK	56	17-Jan-14
Modern Mallard Energy	Modern Power Landfill NUG	8.0	LFG	Met-Ed	56	03-Feb-14
Rockland Capital	BL England 1	113.0	Coal	AECO	51	01-May-14
Calpine Corporation	Deepwater 1	78.0	Natural gas	AECO	55	31-May-14
Calpine Corporation	Deepwater 6	80.0	Natural gas	AECO	60	01-Jun-14
NRG Energy	Portland 1	158.0	Coal	Met-Ed	56	01-Jun-14
NRG Energy	Portland 2	243.0	Coal	Met-Ed	52	01-Jun-14
Exelon Corporation	Riverside 6	115.0	Natural gas	BGE	44	01-Jun-14
PSEG	Burlington 9	184.0	Kerosene	PSEG	42	01-Jun-14
Corona Power	Sunbury 1-4	347.0	Coal	PPL	63	18-Jul-14
Integrys Energy	Winnebago Landfill	6.4	LFG	ComEd	07	01-Nov-14
Duke Energy	Walter C Beckjord 5-6	652.0	Coal	DEOK	49	01-Oct-14
Dominion	Chesapeake 1-4	576.0	Coal	Dominion	57	23-Dec-14
Duke Energy	Walter C Beckjord GT1-4	188.0	Coal	DEOK	43	25-Dec-14
PSEG	Kinsley Landfill	0.9	LFG	PSEG	30	31-Dec-14
Total		2,949.3				

Generation Mix

As of December 31, 2014, PJM had an installed capacity of 201,689.4 MW (Table 12-10). This measure differs from capacity market installed capacity because it includes energy-only units, uses non-derated values for solar and wind resources, and does not include external units.

Table 12-10 Existing PJM capacity: At December 31, 2014 (By zone and unit type (MW))[13]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	705.9	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,495.5
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	24,264.8	4.0	1,953.2	38,024.2
APS	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	1,058.5	9,008.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	6,540.0	0.0	0.0	11,050.4
BGE	0.0	720.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,449.9
ComEd	2,270.1	7,244.0	100.2	0.0	0.0	10,473.5	9.0	5,417.1	4.5	2,431.9	27,950.3
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	3,179.8	40.0	0.0	4,636.9
DEOK	47.2	842.0	0.0	0.0	0.0	0.0	0.0	4,382.0	0.0	0.0	5,271.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	784.0	0.0	0.0	2,826.3
Dominion	5,493.6	3,874.8	153.8	0.0	3,589.3	3,581.3	2.7	8,403.0	0.0	0.0	25,098.5
DPL	1,189.3	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	4,759.8
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,882.0	0.0	0.0	2,726.0
EXT	1,471.0	297.9	0.0	0.0	269.1	12.5	0.0	5,253.5	0.0	0.0	7,304.0
JCPL	1,692.5	1,233.1	16.1	0.0	400.0	614.5	96.3	10.0	0.0	0.0	4,062.5
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	836.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,219.8
PENELEC	0.0	407.5	45.8	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,690.5
Pepco	1,807.9	616.2	60.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,135.8
PPL	3,091.3	2,653.8	12.0	0.0	5.0	3,493.0	108.2	2,050.1	2.0	0.0	11,415.4
PSEG	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
Total	30,472.8	31,421.8	826.2	30.0	8,378.0	33,744.6	317.1	89,798.3	98.9	6,601.7	201,689.4

12 See PJM. "*PJM Generator Deactivations*," <*http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx*> (Accessed January 05, 2015).

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

Table 12-11 PJM capacity (MW) by age (years): at December 31, 2014

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 16	24,285.3	19,118.2	507.5	30.0	141.6	0.0	317.1	3,755.4	98.9	6,601.7	54,855.7
16 to 30	5,655.5	5,343.4	113.5	0.0	3,318.2	10,224.5	0.0	7,879.1	0.0	0.0	32,534.2
31 to 45	532.0	4,817.8	73.9	0.0	722.0	22,905.6	0.0	45,038.6	0.0	0.0	74,089.9
46 to 60	0.0	2,142.4	129.3	0.0	2,575.0	614.5	0.0	28,745.9	0.0	0.0	34,207.1
61 to 75	0.0	0.0	2.0	0.0	428.9	0.0	0.0	4,230.3	0.0	0.0	4,661.2
76 and over	0.0	0.0	0.0	0.0	1,192.3	0.0	0.0	149.0	0.0	0.0	1,341.3
Total	30,472.8	31,421.8	826.2	30.0	8,378.0	33,744.6	317.1	89,798.3	98.9	6,601.7	201,689.4

Figure 12-2 PJM capacity (MW) by age (years): at December 31, 2014

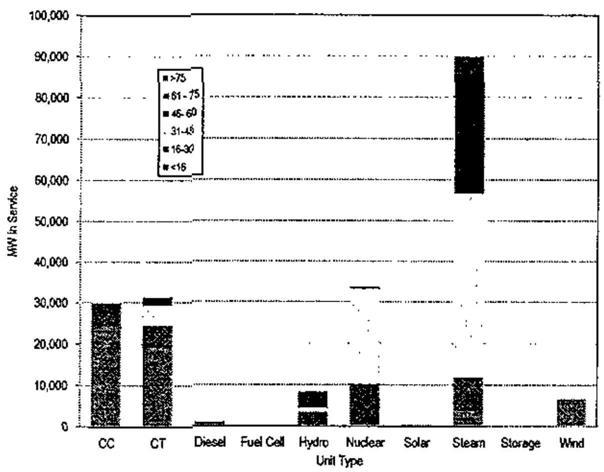


Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 30 years comprise 110,568.5 MW, or 55.4 percent, of the total capacity of 201,689.4 MW. Units older than 45 years comprise 40,209.6 MW, or 19.9 percent of the total capacity.

Table 12-12 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix, noting the generators in excess of 40 years of age as of December 31, 2014, which are likely to retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. Existing capacity in SWMAAC is currently 63.7 percent steam; this would be reduced to 45.0 percent by 2024. CC and CT generators would comprise 40.2 percent of total capacity in SWMAAC in 2024.

In Non-MAAC zones, 81.1 percent of all generation 40 years or older, as of December 31, 2014, is steam, primarily coal.[14] If the older coal units retire and if all queued wind MW are built as planned, by 2024, wind farms would account for 11.4 percent of total non-derated ICAP MW in Non-MAAC zones.

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

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of December 31, 2014[15]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198.0	1.6%	10,084.0	29.7%	9,584.6	0.0	19,668.6	45.6%
	Combustion Turbine	4,041.8	31.8%	7,249.2	21.4%	615.8	2,196.2	5,668.8	13.1%
	Diesel	58.9	0.5%	149.7	0.4%	14.3	8.0	156.0	0.4%
	Fuel Cell	0.0	0.0%	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,042.0	16.0%	2,047.0	6.0%	0.0	0.0	2,047.0	4.7%
	Nuclear	2,865.3	22.5%	8,654.3	25.5%	330.0	0.0	8,984.3	20.8%
	Solar	0.0	0.0%	253.2	0.7%	1,365.7	0.0	1,618.9	3.8%
	Steam	3,523.0	27.7%	5,475.1	16.1%	22.9	1,259.5	4,238.5	9.8%
	Storage	0.0	0.0%	3.0	0.0%	45.0	0.0	48.0	0.1%
	Wind	0.0	0.0%	7.5	0.0%	652.0	0.0	659.5	1.5%
	EMAAC Total	12,729.0	100.0%	33,953.0	100.0%	12,630.3	3,463.7	43,119.6	100.0%
SWMAAC	Combined Cycle	0.0	0.0%	230.0	2.2%	2,614.5	0.0	2,844.5	23.3%
	Combustion Turbine	873.3	15.0%	1,811.7	17.4%	256.0	0.0	2,067.7	16.9%
	Diesel	0.0	0.0%	28.3	0.3%	29.0	0.0	57.3	0.5%
	Hydroelectric	0.0	0.0%	0.0	0.0%	0.4	0.0	0.4	0.0%
	Nuclear	866.0	14.8%	1,716.0	16.5%	0.0	0.0	1,716.0	14.1%
	Solar	0.0	0.0%	0.0	0.0%	25.0	0.0	25.0	0.2%
	Steam	4,098.5	70.2%	6,644.6	63.7%	132.0	1,278.0	5,498.6	45.0%
	SWMAAC Total	5,837.8	100.0%	10,430.6	100.0%	3,056.9	1,278.0	12,209.5	100.0%
WMAAC	Combined Cycle	0.0	0.0%	3,918.9	16.7%	8,634.0	0.0	12,552.9	36.6%
	Combustion Turbine	713.5	6.7%	1,430.2	6.1%	703.7	0.0	2,133.9	6.2%
	Diesel	46.2	0.4%	147.7	0.6%	66.8	6.0	208.5	0.6%
	Hydroelectric	887.2	8.3%	1,238.4	5.3%	45.3	0.0	1,283.7	3.7%
	Nuclear	805.0	7.5%	3,325.0	14.2%	35.0	0.0	3,360.0	9.8%
	Solar	0.0	0.0%	15.0	0.1%	145.5	0.0	160.5	0.5%
	Steam	8,225.5	77.0%	12,163.4	52.0%	417.0	597.0	11,983.4	35.0%
	Storage	0.0	0.0%	20.0	0.1%	107.5	0.0	127.5	0.4%
	Wind	0.0	0.0%	1,150.6	4.9%	1,317.6	0.0	2,468.2	7.2%
	WMAAC Total	10,677.4	100.0%	23,409.2	100.0%	11,472.3	603.0	34,278.5	100.0%
Non-MAAC	Combined Cycle	244.0	0.5%	16,239.9	12.1%	20,406.5	0.0	36,646.4	21.9%
	Combustion Turbine	1,250.6	2.5%	20,930.7	15.6%	718.7	0.0	21,649.4	12.9%
	Diesel	71.8	0.1%	500.5	0.4%	147.5	10.3	637.7	0.4%
	Hydroelectric	1,702.0	3.4%	5,092.6	3.8%	231.2	0.0	5,323.8	3.2%
	Nuclear	6,301.9	12.4%	20,049.3	15.0%	1,696.0	0.0	21,745.3	13.0%
	Solar	0.0	0.0%	49.0	0.0%	1,441.8	0.0	1,490.8	0.9%
	Steam	41,179.7	81.1%	65,515.2	48.9%	2,269.2	7,421.8	60,362.6	36.1%
	Storage	0.0	0.0%	75.9	0.1%	347.6	0.0	423.5	0.3%
	Wind	0.0	0.0%	5,443.6	4.1%	13,690.5	0.0	19,134.1	11.4%
	Non-MAAC Total	50,750.0	100.0%	133,896.7	100.0%	40,948.9	7,432.1	167,413.5	100.0%
All Areas	Total	79,994.2		201,689.4		68,108.4	12,776.8	257,021.0	

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

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[16] These changes included reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR).

Small Generator Interconnection

Due to the growing number of small generating facilities, FERC issued Order No. 2006 to extend interconnection service to devices used for the production of electricity having a capacity of no more than 20 MW and established the Small Generator Interconnection Procedures (SGIP) and a Small Generator Interconnection Agreement (SGIA).[17] The SGIP and SGIA are consistent with the standard Large Generator Interconnection Procedures document (LGIP) and standard Large Generator Interconnection Agreement (LGIA) for generating facilities larger than 20 MW, established in FERC Order No. 2003.[18]

FERC Order No. 792 was issued on November 22, 2013, to make several amendments to the SGIP and SGIA.[19] One revision is a provision for the option of a pre-application report of existing information about system conditions at a possible Point of Interconnection. This order also increases the threshold to participate in the Fast Track Process from 2 MW to 5 MW, but only for inverter-based machines.[20] The thresholds for all other eligible types (synchronous & induction) will remain at 2 MW. Another revision is to the customer options meeting and the supplemental review following the failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer.[21] This includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably. In addition, the SGIP Facilities Study Agreement will be revised to allow written comments to the Transmission Provider, similar to what is currently allowed for large generator projects. Finally, the SGIP and SGIA will now specifically include energy storage devices.[22] PJM filed these revisions to the OATT with FERC on August 4, 2014.23 No protests or comments were filed. An order is pending.

Interconnection Study Phase

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-13 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (CSA). It further states that a feasibility study should take no longer than 334 days from the day it entered the queue.[24] Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage.[25]

Table 12-14 shows the milestone due when projects were withdrawn, for all withdrawn projects.[26] Of the projects withdrawn, 49.7 percent were withdrawn before the Impact Study was completed.

16 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000, <*http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx*>.

17 See *Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs. ¶31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

18 See *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (2005), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005).

19 See *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013) (Order No. 792).

20 See Order No. 792 at P 106.

21 See *Id.* at P 106.

22 See 145 FERC ¶ 61,159 at P 228 (2013).

23 See "PJM Compliance Filing," Docket No. ER14-2590-000 (August 4, 2014).

24 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," Revision 15 (April 17, 2014), p.37.

25 See PJM. Manual 14B. "PJM Region Transmission Planning Process," Revision 27 (April 23, 2014), p.82.

26 In some cases, a Wholesale Market Participation Agreement (WMPA) is executed instead of an Interconnection Service Agreement (ISA).

Table 12-13 PJM generation planning process[27]

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

Table 12-14 Last milestone completed at time of withdrawal

Milestone Completed	Projects Withdrawn	Percent
Never Started	194	12.2%
Feasibility	596	37.5%
Impact	515	32.4%
Facility	98	6.2%
Interconnection Service Agreement (ISA)	136	8.6%
Construction Service Agreement (CSA) or beyond	49	3.1%
Total	1,588	100.0%

Table 12-15 and Table 12-16 show the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 887 days, or 2.4 years, between entering a queue and going into service. Nuclear, hydro, and wind projects tend to take longer to go into service. The average time to go into service for all other fuel types is 753 days. For withdrawn projects, there is an average time of 654 days between entering a queue and withdrawing.

Table 12-15 Average project queue times (days) at December 31, 2014

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,060	710	59	3,890
In-Service	887	691	0	4,024
Suspended	1,914	697	699	3,652
Under Construction	1,736	883	367	6,380
Withdrawn	654	656	0	4,249

Table 12-16 presents information on the actual time in the stages of the queue for those projects not yet in service. Of the 549 projects in the queue as of December 31, 2014, 42 had a completed feasibility study and 186 were under construction.

Table 12-16 PJM generation planning summary: at December 31, 2014

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	124	22.6%	102	458
Feasibility Study	42	7.7%	351	882
Impact Study	84	15.3%	1,107	3,160
Facility Study	21	3.8%	1,394	2,549
Interconnection Service Agreement (ISA)	18	3.3%	684	2,527
Construction Service Agreement (CSA)	3	0.5%	283	302
Under Construction	186	33.9%	1,413	3,811
Suspended	71	12.9%	1,647	3,587
Total	549	100.0%		

Regional Transmission Expansion Plan (RTEP)

Artificial Island

PJM has been seeking transmission solutions to improve stability and operational performance issues, as well to eliminate potential planning criteria violations in the Artificial Island Area, which includes the Salem and Hope Creek nuclear plants. PJM developed a new transmission expansion project solicitation process in two Order No. 1000 FERC compliance filings (dated October 25, 2012, and July 22, 2013), and described its approach as "utiliz[ing] the study process proposed under Order No. 1000."[28][29] PJM evaluated 26 proposals based on factors including siting, permitting, line crossings, outage requirements, and impacts to the Salem nuclear plant.

To date, PJM has engaged in an iterative process with Artificial Island project sponsors to modify the proposals and to allow updated cost estimates.

27 Other agreements may also be required, e.g. Interconnection Construction Service Agreement (ICSA), Upgrade Construction Service Agreement (UCSA). See PJM. "Manual 14C: Generation and Transmission Interconnection Process," Revision 08 (December 20, 2012) p.29.

28 See "FERC Order 1000 Implementation" at <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx>.

29 See PJM filing, Docket No. ER15-639-000 (Dec. 16, 2014) at 7.

The Transmission Expansion Advisory Committee (TEAC) recommended that PSE&G be selected to proceed with the Artificial Island project.[30] [31] On July 23, 2014, the PJM Board of Managers deferred the selection of a winner in order to review and address issues raised.[32]

On August 12, 2014, PJM requested additional information for five of the submitted proposals. The bidders for these proposals have been given the opportunity to supplement their proposals with updated cost estimates, as a result of PJM's modifications made during the initial evaluation.[33] All of the bidders responded by submitting the supplemental information requested.[34] PJM has engaged FERC's Alternative Dispute Resolution (ADR) process, which includes "an Administrative Law Judge present in a non-decisional role to ensure the fairness and due process" surrounding the final selection for this project.[35]

In a December 9, 2014, TEAC update on this project, PJM reported that input from permitting and regulatory entities had been gathered and additional constructability analysis and performance analysis had been conducted. The analysis includes a comparison of permitting and regulatory issues and a performance analysis. The selection process will also consider both the proposing entity's cost containment numbers as well as PJM cost estimates. A final selection has not yet been made.[36]

PJM's process has been controversial. On July 14, 2014, PHI and Exelon submitted a letter complaining "PJM adopted a sponsorship model ... and determine the best proposal amongst those submitted... PJM did not follow this process."[37] On January 29, 2015, PSEG filed a complaint alleging that PJM was not following the Order No. 1000 process, particularly objecting to the iterative nature of proposal development and the use of components of its proposal to enhance competing proposals.[38]

Other RTEP Proposals

The TEAC regularly reviews internal and external proposals to improve transmission reliability throughout PJM. On July 22, 2014, the PJM Board of Managers authorized $143.6 million to resolve baseline reliability violations. Subsequently, the RTEP proposal window 1, open from June 27 through July 28, 2014, yielded 106 baseline reliability projects proposals, encompassing 18 target transmission owner zones and 10 states.[39] None of these submissions were by a developer that was not a transmission owner. RTEP considered these proposals along with others reviewed at previous sub-regional RTEP (SRRTEP) and TEAC meetings that occurred between February and September, 2014. In the end, 22 projects were recommended by the TEAC and approved by the PJM Board All 22 projects were transmission owner upgrades with a total estimated cost of $81.5 million.[40]

The TEAC identified an additional $510 million in new baseline upgrades and changes to previously approved projects, as a result of the 2014 RTEP and 143 system impact studies performed on transmission planning projects. In addition, several immediate need reliability projects were also approved by the PJM Board.

RTEP's Proposal Window 2 closed on November 17, 2014, but an Addendum Proposal Window opened on January 20, 2015, because of a change in scope that will address a 2019 N-1-1 voltage drop. This window will remain open until February 3, 2015. In compliance with Order 1000, PJM also opened a Proposal Window on November 1, 2014, for all long term issues. It will remain open until February 27, 2017. For this window, PJM is using a multi-driver approach (MDA), and accepting proposals addressing not just long term

30 The TEAC Charter states: "PJM staff will be ultimately responsible for preparing and issuing all reports, running the committee meeting, management of data, final analytical work, and compilation and publication of other relevant documentation that may be required from time to time." <*http://www.pjm.com/~/media/committees-groups/committees/teac/postings/teac-charter.ashx*>.

31 See "Artificial Island Proposal Window," <*http://pjm.com/~/media/committees-groups/committees/teac/20140616/20140616-teac-artificial-island-recommendation.ashx*>, (June 16, 2014).

32 See Letter from Steve Herling, dated July 23, 2104 at <*http://www.pjm.com/~/media/committees-groups/committees/teac/20140807/20140807-teac-artificial-island-letter.ashx*>.

33 See Letter from Steve Herling, dated August 12, 2104 at <*http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/august-12-2014-supplemental-request-letter.ashx*>.

34 See "Supplemental Responses," at <*http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/closed-artificial-island-proposals.aspx*>.

35 See Letter from Pauline Foley, dated August 29, 2104 at <*http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/pjm-letter-to-chief-judge-wagner-regarding-artificial-island.ashx*>.

36 See TEAC "Artificial Island" presentation at <*http://www.pjm.com/~/media/committees-groups/committees/teac/20141209/20141209-artificial-island-update.ashx*>.

37 See Letter from PHI/Exelon to Howard Schneider, Chair, PJM Board, re PJM Process for Evaluating Artificial Island Proposals, which can be accessed at: <*https://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20140714-exelon-letter-regarding-the-pjm-process-for-evaluating-competitive-artificial-island-proposals.ashx*> .

38 Complaint of Public Service Electric and Gas Company Against PJM Interconnection, L.L.C., Docket No. EL15-40-000.

39 See "Transmission Expansion Advisory Committee Reliability Analysis Update," September 25, 2014, at <*http://www.pjm.com/~/media/committees-groups/committees/teac/20140925/20140925-reliability-analysis-update.ashx*>.

40 See "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," November 11, 2014, at <*http://www.pjm.com/~/media/committees-groups/committees/teac/20141111/20141111-board-approval-of-rtep-whitepaper.ashx*>.

reliability, but also energy market efficiency, capacity market efficiency, and public policy.[41]

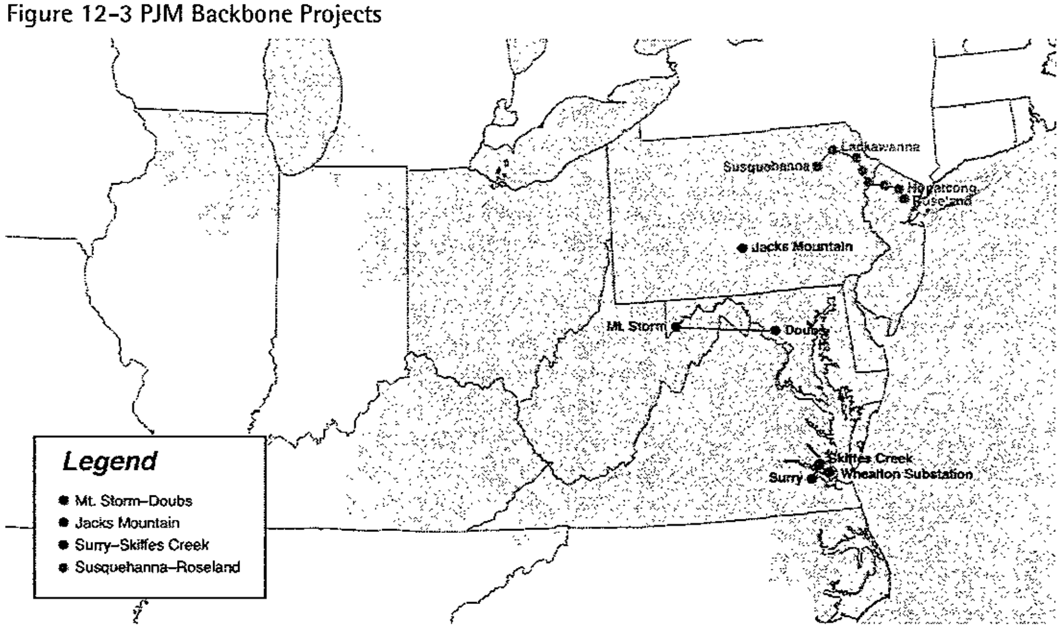
Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts

A FERC order issued on September 6, 2010, reestablished the terms of an agreement between Con Edison and PJM to provide power to New York City that had been in place since the 1970s. Part of the settlement included an agreement by both parties that Con Edison would henceforth be subject to PJM RTEP costs, from which they had been previously exempt.[42] On December 11, 2013, the PJM Board approved changes to the RTEP, which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[43] PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[44] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[45] PJM argued that the filed and approved RTEP cost allocation process was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-3 shows the location of these four projects.

Figure 12-3 PJM Backbone Projects



41 See "Transmission Expansion Advisory Committee 2014 Market Efficiency Analysis," October 09, 2014, at *<http://www.pjm.com/~/media/committees-groups/committees/teac/20141009/20141009-market-efficiency-analysis-update.ashx>*.

42 132 FERC ¶ 61,221 p.8 (2010).

43 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.

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

45 See *PJM Interconnection LLC* Docket No. ER14-972-000 (March 7, 2014).

The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability in its service areas. The first two phases, the line rebuild and the energizing of the Mount Storm switchyard, are complete. Construction plans for Phase 3, consisting of additional upgrades to the Mount Storm switchyard, are under development. Completion of this phase is expected by the end of 2015.[46]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. Transmission foundations are planned for fall 2015. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017.[47]

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland will be a new 500 kV transmission line connecting the Susquehanna, Lackawanna, Hopatcong, and Roseland buses. PPL is responsible for the first two legs. The Susquehanna-Lackawanna portion went into service on September 23, 2014, and the expectation, as of December 31, 2014, is that the Lackawanna-Hopatcong portion will be energized by June, 2015. The Hopatcong – Roseland leg, executed by PSE&G, was placed in service on April 1, 2014.[48]

The Surry Skiffes Creek 500kV was initiated in the fall of 2014 to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4, which occurred in December 2014, and Yorktown 1, which is pending. It will include a new 7.7 mile 500kV line between Surry and Skiffes, a new 20.25 mile 230kV line between Skiffes Creek and Whealton, and a new Skiffes Creek 500/230kV switching station. Dominion anticipates beginning construction in early 2015 and expects the 500kV line to be completed by January 1, 2016 and the 230kV line to be completed by April 30, 2016.[49]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

PJM designates some transmission facilities as reportable. A transmission facility is reportable if a change in its status can affect a transmission constraint on any Monitored Transmission Facility. A facility is also reportable if it impedes the free-flowing ties within the PJM RTO and/or adjacent areas.[50] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days. Table 12-17 shows the summary of transmission facility outage requests by duration.

Table 12-17 Transmission facility outage request duration: 2013 and 2014

	2013		2014	
Days	Number of Outage Requests	Percent	Number of Outage Requests	Percent
<=5	5,467	78.8%	6,135	77.2%
>5 & <=30	1,099	15.8%	1,298	16.3%
>30	375	5.4%	512	6.4%
Total	6,941	100.0%	7,945	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a "received status," based on its submission date, outage date, and outage duration. The received status can be on time, late or past deadline, as defined in Table 12-18.[51]

46 See Dominion "Mt. Storm-Doubs," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>
47 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.
48 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/ susquehanna-roseland.aspx>.
49 See "Surry-Skiffes Creek 500kV and Skiffes Creek-Whealton 230kV Projects,"which can be accessed at: <https://www.dom.com/corporate/what-we-do/electricity/transmission-lines-and-projects/surry-skiffes-creek-500kv-and-skiffes-creek-whealton-230kv-projects>.
50 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).
51 See "PJM. "Manual 3: Transmission Operations," Revision 46 (December 1, 2014), p.58.

Table 12-18 PJM transmission facility request status definition

Duration	Request Submitted Date	Ticket Status
>30 days	The earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
<=30 days and > 5 days	Before the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
<=5 days	Before the 1st of the month one month prior to the starting month of the outage	On Time
	After or on the 1st of the month one month prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-19 shows a summary of requests with on time received status. In 2014, 52.7 percent of outage requests received were on time, compared to 49.5 percent in 2013.

Once received, PJM schedules the request according to its priority, which is determined by its submission date. If a request has an emergency flag set, it has the highest priority and will be approved even if submitted past its deadline. Table 12-20 shows emergency request statistics. Overall, 15.1 percent of all outage requests submitted in 2014 were for emergency outages.

For late tickets, the outage request may be denied or cancelled if it is expected to cause congestion. Table 12-21 shows a summary of requests which PJM determined might cause congestion. Overall, 23.7 percent of all tickets submitted in 2014 were congestion tickets, compared to 23.5 percent in 2013.

Table 12-19 Transmission outage requests with on time status: 2013 and 2014

	2013			2014		
Days	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests
<=5	5,467	2,745	50.2%	6,135	3,271	53.3%
>5 & <=30	1,099	541	49.2%	1,298	688	53.0%
>30	375	150	40.0%	512	229	44.7%
Total	6,941	3,436	49.5%	7,945	4,188	52.7%

Table 12-20 Emergency transmission outage summary: 2013 and 2014

	2013			2014		
Days	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests
<=5	5,467	2,745	50.2%	6,135	3,271	53.3%
>5 & <=30	1,099	541	49.2%	1,298	688	53.0%
>30	375	150	40.0%	512	229	44.7%
Total	6,941	3,436	49.5%	7,945	4,188	52.7%

Table 12-21 Transmission facility outage ticket congestion status summary: 2013 and 2014

	2013			2014		
Submission Status	Number of Tickets	Number of Congestion Tickets	Percent of Congestion Tickets	Number of Tickets	Number of Congestion Tickets	Percent of Congestion Tickets
Late & Emergency	1,008	109	10.8%	1,190	93	7.8%
Late & Non-Emergency	2,497	340	13.6%	2,567	366	14.3%
On Time & Emergency	10	6	60.0%	7	1	14.3%
On Time & Non-Emergency	3,426	1,179	34.4%	4,181	1,419	33.9%
Total	6,941	1,634	23.5%	7,945	1,879	23.7%

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage (Table 12-22). In 2014, 10.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 14.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

An outage lasting five days or less, with an on-time status, can be rescheduled within the original scheduled month without losing its on-time status.[52] This rule allows a TO to move an outage to an earlier date than originally requested within the same month with very short notice. The short notice may create issues for PJM market participants if it affects market outcomes. The MMU recommends that PJM reevaluate all transmission outage tickets with outages lasting five days or less when the outage is rescheduled.

A transmission outage ticket with outage duration exceeding five days can retain its on-time status if the outage is moved to a future month, and the revision is submitted by the first of the month prior to the month in which new proposed outage will occur.[53] This rule creates the opportunity for TOs to submit a transmission outage that, once approved, acts as a reservation that does not require further review and allows postponements without review.

The MMU recommends that PJM reevaluate all transmission outage tickets with outages lasting more than five days when the outage is rescheduled.

Table 12-22 Rescheduled transmission outage request summary: 2013 and 2014

	2013					2014				
Duration	Number of Tickets	Number of Approved and Revised Tickets	Percent of Approved and Revised Tickets	Number of Approved and Cancelled Tickets	Percent of Approved and Cancelled Tickets	Number of Tickets	Number of Approved and Revised Tickets	Percent of Approved and Revised Tickets	Number of Approved and Cancelled Tickets	Percent of Approved and Cancelled Tickets
<=5 days	5,467	1,020	18.7%	801	14.7%	6,135	607	9.9%	972	15.8%
>5 & <=30 days	1,099	254	23.1%	117	10.6%	1,298	139	10.7%	115	8.9%
>30 days	375	82	21.9%	25	6.7%	512	63	12.3%	41	8.0%
Total	6,941	1,356	19.5%	943	13.6%	7,945	809	10.2%	1,128	14.2%

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

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

IEU-Ohio
Exhibit 6

State of the Market Report for PJM

January through June

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

8.13.2015

2015

EXHIBIT
PENGAD 800-631-6989
IEU6

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2015 Quarterly State of the Market Report for PJM: January through June.*[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M § II(f).
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: 2015 *Quarterly State of the Market Report for PJM: January through June.*

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Figures

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- Planned Generation. As of June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 192,864.9 MW as of June 30, 2015. Of the capacity in queues, 8,242.9 MW, or 10.6 percent, are uprates and the rest are new generation. Wind projects account for 15,297.5 MW of nameplate capacity or 19.7 percent of the capacity in the queues. Combined-cycle projects account for 49,851.5 MW of capacity or 64.4 percent of the capacity in the queues.
- Generation Retirements. As shown in Table 12-6, 26,967.6 MW have been, or are planned to be, retired between 2011 and 2019. Of that, 3,203.3 MW are planned to retire after 2015. In the first two quarters of 2015, 9,717.0 MW were retired, of which 7,537.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.
- Generation Mix. A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While only 1,936.0 MW of coal fired steam capacity are currently in the queue, 53,050.5 MW of gas fired capacity are in the queue. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. Excluding currently active projects and projects currently under construction, 2,182 projects, representing 262,424 MW, have completed the queue process since its inception. Of those, 566 projects, 32,622 MW, went into service. Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the process. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and the backlog of incomplete studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company of the transmission owner or the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning

1 See PJM, OATT Parts IV & VI.

criteria violations in this area. PJM staff announced on April 28, 2015, that they will recommend that the Board approve the Artificial Island project being designated to LS Power, PSEG, and PHI with a total cost estimate between $263M and $283M.[2]

Backbone Facilities

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

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[3]

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[4] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Not Adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014. Status: Partially adopted, 2014.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)

2 See PJM. "Artificial Island Recommendations," at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>
3 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.
4 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the Regional Transmission Expansion Plan. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

Conclusion

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

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

The PJM queue evaluation process should be improved to ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

The PJM rules for competitive transmission development through the Regional Transmission Expansion Plan should build upon Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant time lag and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 192,864.9 MW as of June 30, 2015. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). In the first six months of 2015, 2,505.8 MW of nameplate capacity went into service in PJM.

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

	MW
2000	505.0
2001	872.0
2002	3,841.0
2003	3,524.0
2004	1,935.0
2005	819.0
2006	471.0
2007	1,265.0
2008	2,776.7
2009	2,515.9
2010	2,097.4
2011	5,007.8
2012	2,669.4
2013	1,126.8
2014	2,659.0
2015	2,505.8

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. The duration of the queue period has varied. Queues A and B were open for a year. Queues C-T were open for six months. Starting in February 2008, Queues U-Y1 were open for three months. Starting in May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AB1 is currently open.

All projects that have been entered in a queue have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[5] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between March 31, 2015, and June 30, 2015, for ongoing projects, i.e. projects with the status active, under construction or suspended.[6] Projects that are already in service are not included here. The total MW in queues increased by 10,193.3 MW, or 15.2 percent, from 67,268.0 MW at the end of the first quarter of 2015. The change was the result of 15,803.5 MW in new projects entering the queue, 3,087.0 MW in existing projects withdrawing, and 1,827.0 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

5 See PJM. Manual 14C. "Generation and Transmission Interconnection Process," Revision 8 (December 20, 2012), Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

6 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-2 Queue comparison by expected completion year (MW): March 31, 2015 vs. June 30, 2015[7]

Year	As of 3/31/2015	As of 6/30/2015	Quarterly Change MW	Quarterly Change Percent
2015	15,609.4	12,632.6	(2,976.8)	(19.1%)
2016	17,453.7	16,466.5	(987.2)	(6.0%)
2017	12,878.1	13,821.4	943.3	6.8%
2018	14,139.0	14,603.1	464.1	3.2%
2019	4,191.8	12,274.8	8,083.0	65.9%
2020	1,152.0	4,442.0	3,290.0	74.1%
2021	250.0	1,377.0	1,127.0	81.8%
2022	0.0	250.0	250.0	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	67,268.0	77,461.3	10,193.3	15.2%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between March 31, 2015, and June 30, 2015. For example, 27,814.9 MW entered the queue in the second quarter of 2015, 15,803.5 MW of which are currently active and 12,011.5 MW of which were withdrawn before the quarter ended. Of the total 39,974.8 MW marked as active at the beginning of the quarter, 3,034.0 MW were withdrawn, 1,745.3 MW started construction, and 225.1 MW went into service by the end of the second quarter. The Under Construction column shows that 964.0 MW came out of suspension and 1,745.3 MW began construction in the second quarter of 2015, in addition to the 20,254.1 MW of capacity that maintained the status under construction from the previous quarter.

Table 12-3 Change in project status (MW): March 31, 2015 vs. June 30, 2015

Status at 3/31/2015	Total at 3/31/2015	Status at 6/30/2015 Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q2 2015)		15,803.5	0.0	0.0	0.0	12,011.5
Active	39,974.8	34,288.1	0.0	1,745.3	225.1	3,034.0
Suspended	5,224.8	0.0	4,036.8	964.0	200.0	24.0
Under Construction	22,068.4	0.0	369.5	20,254.1	1,401.8	29.0
In Service	38,975.3	0.0	0.0	0.0	38,969.6	0.0
Withdrawn	277,444.8	0.0	0.0	0.0	0.0	265,939.1
Total at 6/30/2015		50,091.6	4,406.3	22,963.4	40,796.5	281,037.5

7 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total amount of capacity that had been included in each queue. All items in queues A-L are either in service or have been withdrawn. As of June 30, 2015, there are 77,461.3 MW of capacity in queues that are not yet in service, of which 5.7 percent are suspended, 29.6 percent are under construction and 64.7 percent have not begun construction.

Table 12-4 Capacity in PJM queues (MW): At June 30, 2015[8]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,347.0	25,450.0
B Expired 31-Jan-99	0.0	4,465.0	0.0	0.0	14,620.7	19,085.7
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.7	4,001.7
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,182.0	8,032.6
E Expired 31-Jul-00	0.0	778.2	0.0	0.0	8,021.8	8,800.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,962.3	19,151.9
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	200.0	0.0	0.0	2,425.4	2,625.4
L Expired 31-Jan-04	0.0	252.5	0.0	0.0	4,033.7	4,286.2
M Expired 31-Jul-04	0.0	477.8	150.0	0.0	3,705.6	4,333.4
N Expired 31-Jan-05	0.0	2,382.8	38.0	0.0	8,090.3	10,511.0
O Expired 31-Jul-05	0.0	1,668.2	437.0	0.0	5,466.8	7,572.0
P Expired 31-Jan-06	0.0	3,255.2	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	105.0	3,147.9	1,594.0	0.0	9,686.7	14,533.6
R Expired 31-Jan-07	0.0	2,046.4	988.3	300.0	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,536.3	458.3	420.0	12,706.5	17,121.0
T Expired 31-Jan-08	675.0	1,911.0	2,011.8	428.0	22,488.3	27,514.1
U Expired 31-Jan-09	1,410.0	1,072.8	401.9	300.0	30,119.6	33,304.3
V Expired 31-Jan-10	1,249.2	1,812.8	1,774.3	148.0	12,016.4	17,000.7
W Expired 31-Jan-11	2,018.0	1,159.6	1,603.7	1,564.0	17,942.6	24,287.9
X Expired 31-Jan-12	3,045.5	359.0	8,993.9	383.8	17,586.0	30,368.2
Y Expired 30-Apr-13	3,623.5	474.0	3,910.9	630.8	17,336.3	25,975.3
Z Expired 30-Apr-14	8,392.7	220.3	457.5	21.7	5,579.9	14,672.0
AA1 Expired 31-Oct-14	10,919.6	5.3	81.5	0.0	1,243.8	12,250.2
AA2 Expired 30-Apr-15	15,661.8	0.0	0.0	0.0	1,383.8	17,045.6
AB1 Through 30-Jun-15	2,991.3	0.0	0.0	0.0	1.5	2,992.8
Total	50,091.6	40,796.5	22,963.4	4,406.3	281,037.5	399,295.4

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

Table 12-5 Queue capacity by control zone and fuel (MW) at June 30, 2015[9]

Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
AECO	1,276.0	295.3	0.0	0.0	0.0	73.2	0.0	20.0	373.0	2,037.5	8.0
AEP	6,111.0	51.0	17.8	46.5	102.0	118.4	209.0	72.0	7,312.0	14,039.7	0.0
AP	4,767.4	0.0	119.5	68.2	0.0	184.3	1,724.2	31.0	723.6	7,618.2	0.0
ATSI	4,052.0	0.8	21.6	0.0	0.0	0.0	0.0	0.0	518.0	4,592.4	0.0
BGE	0.0	0.0	30.3	0.4	0.0	23.1	132.0	0.0	0.0	185.8	6.3
ComEd	1,720.8	603.3	15.3	22.7	0.0	14.0	27.0	140.6	3,562.0	6,105.7	209.0
DAY	0.0	0.0	1.9	112.0	0.0	23.4	12.0	20.0	300.0	469.3	0.0
DEOK	513.0	0.0	6.4	0.0	0.0	125.0	50.0	18.0	0.0	712.4	0.0
DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0
Dominion	5,465.3	0.0	3.6	0.0	1,594.0	1,571.4	62.5	128.0	1,322.1	10,146.9	124.0
DPL	901.0	17.0	2.0	0.0	0.0	455.5	0.0	20.0	250.0	1,645.5	323.0
EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
JCPL	3,034.0	0.0	0.0	0.0	0.0	574.1	0.0	180.0	0.0	3,788.1	149.0
Met-Ed	1,250.0	86.6	0.0	0.0	16.8	3.0	401.0	0.0	0.0	1,757.4	614.5
PECO	4,229.5	0.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	4,563.2	0.0
PENELEC	3,841.0	592.3	181.2	40.0	0.0	13.5	0.0	68.4	413.3	5,149.7	50.8
Pepco	2,725.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,725.6	0.0
PPL	6,100.0	0.0	5.0	0.0	0.0	129.0	16.0	30.0	523.5	6,803.5	1,204.0
PSEG	3,659.9	1,096.1	13.6	0.0	0.0	145.9	0.0	0.0	0.0	4,915.5	0.0
RECO	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	611.0
Total	49,851.5	2,742.4	421.9	289.8	2,042.8	3,453.8	2,633.7	728.0	15,297.5	77,461.3	3,333.6

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active, by unit type, and control zone.[10] As of June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to 67,268.0 MW at March 31, 2015.[11] Table 12-5 also shows the planned retirements for each zone. A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While 53,050.5 MW of gas fired capacity are in the queue, only 1,936.0 MW of coal fired steam capacity are in the queue. The only new coal project since the second quarter a year ago is the new Hatfield unit, with 1,710 MW of capacity. This project entered the queue in October, 2014 and is intended to replace three coal units retired in October 2013 at the same location. With respect to retirements, 1,935.0 MW of coal fired steam capacity and 1,572.0 MW of natural gas capacity are slated for deactivation. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-6, 26,967.6 MW have been, or are planned to be, retired between 2011 and 2019. Of that, 3,203.3 MW are planned to retire after 2015.

9 This data includes only projects with a status of active, under-construction, or suspended.
10 Unit types designated as reciprocating engines are classified as diesel.
11 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 15,297.5 MW of wind resources and 3,453.8 MW of solar resources, the 77,461.3 MW currently active in the queue would be reduced to 62,011.1 MW.

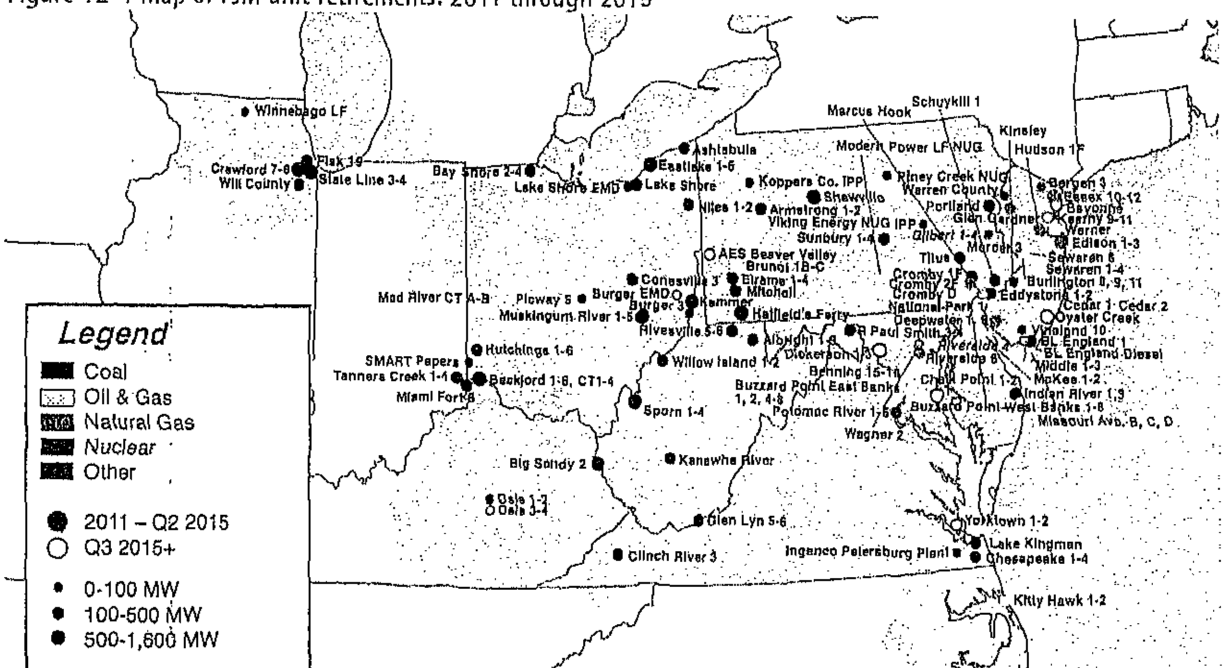
In the first two quarters of 2015, 9,717.0 MW were retired, of which 7,537.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2019

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	788.0	250.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	2,970.3
Retirements 2015	7,537.8	4.0	0.0	644.2	0.0	212.0	1,319.0	0.0	0.0	9,717.0
Planned Retirements 2015	124.0	6.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	130.3
Planned Retirements Post-2015	1,811.0	8.0	108.0	0.0	0.0	0.0	661.8	614.5	0.0	3,203.3
Total	20,940.6	71.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5	24.0	26,967.6

A map of these retirements between 2011 and 2019 is shown in Figure 12-1.

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



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

Table 12-7 Planned deactivations of PJM units, as of June 30, 2015

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Sep-15
Burger EMD	ATSI	6.3	Diesel	Diesel	18-Sep-15
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-17
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	*Natural gas*	*Steam*	13-May-19
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-19
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	*BGE*	*135.0*	*Coal*	*Steam*	*01-Jun-20*
Total		3,333.6			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019, while Table 12-9 shows these retirements by state. The majority, 77.5 percent of all MW retiring during this period are coal steam units. These units have an average age of 56.2 years and an average size of 165.9 MW. More than half of them, 51.6 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller sub-critical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	126	165.9	56.2	20,909.6	77.5%
Diesel	6	11.9	42.5	71.2	0.3%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
Landfill Gas	4	4.8	14.8	19.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.3%
Natural Gas	51	59.8	46.3	3,047.3	11.3%
Nuclear	1	614.5	50.0	614.5	2.3%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	230	117.3	50.8	26,967.6	100.0%

Table 12-9 Retirements (MW) by fuel type and state, 2011 through 2019

State	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wood Waste	Total
Delaware	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
Illinois	1,624.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	1,630.4
Indiana	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
Kentucky	995.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0
Maryland	1,454.0	0.0	74.0	0.0	0.0	0.0	115.0	0.0	0.0	1,643.0
Michigan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Jersey	136.0	8.0	0.0	828.2	4.7	212.0	2,680.5	614.5	0.0	4,483.9
North Carolina	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	31.0
Ohio	5,658.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,718.9
Pennsylvania	5,145.0	0.0	166.0	0.0	8.0	117.7	251.8	0.0	24.0	5,712.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	2,051.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,053.9
West Virginia	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Washington, DC	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	788.0
Total	20,940.6	71.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5	24.0	26,967.6

Actual Generation Deactivations in 2015

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

Table 12-10 Unit deactivations in 2015

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
First Energy	Eastlake 2	109.0	Coal	ATSI	62	06-Apr-15
First Energy	Eastlake 1	109.0	Coal	ATSI	62	09-Apr-15
First Energy	Eastlake 3	109.0	Coal	ATSI	61	10-Apr-15
First Energy	Ashtabula 5	210.0	Coal	ATSI	57	11-Apr-15
First Energy	Lake Shore 18	190.0	Coal	ATSI	53	13-Apr-15
First Energy	Lake Shore EMD	4.0	Diesel	ATSI	49	15-Apr-15
NRG Energy	Will County	251.0	Coal	Comed	58	15-Apr-15
EKPC	Dale 1-2	46.0	Coal	EKPC	61	16-Apr-15
Calpine Corporation	Cedar 2	21.6	Kerosene	AECO	43	01-May-15
NRG Energy	Gilbert 1-4	98.0	Natural gas	JCPL	45	01-May-15
NRG Energy	Glen Gardner 1-8	160.0	Natural gas	JCPL	44	01-May-15
Calpine Corporation	Middle 1-3	74.7	Kerosene	AECO	45	01-May-15
Calpine Corporation	Missouri Ave B, C, D	57.9	Kerosene	AECO	46	01-May-15
NRG Energy	Werner 1-4	212.0	Light oil	JCPL	43	01-May-15
PSEG	Bergen 3	21.0	Natural gas	PSEG	48	01-Jun-15
AEP	Big Sandy 2	800.0	Coal	AEP	46	01-Jun-15
PSEG	Burlington 8, 11	205.0	Kerosene	PSEG	48	01-Jun-15
AEP	Clinch River 3	230.0	Coal	AEP	54	01-Jun-15
PSEG	Edison 1-3	504.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 10-11	352.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 12	184.0	Natural gas	PSEG	43	01-Jun-15
AEP	Glen Lyn 5-6	325.0	Coal	AEP	65	01-Jun-15
AES Corporation	Hutchings 1-3, 5-6	271.8	Coal	DAY	65	01-Jun-15
AEP	Kammer 1-3	600.0	Coal	AEP	57	01-Jun-15
AEP	Kanawha River 1-2	400.0	Coal	AEP	62	01-Jun-15
PSEG	Mercer 3	115.0	Kerosene	PSEG	48	01-Jun-15
Duke Energy Kentucky	Miami Fort 6	163.0	Coal	DEOK	55	01-Jun-15
AEP	Muskingum River 1-5	1,355.0	Coal	AEP	60	01-Jun-15
PSEG	National Park 1	21.0	Kerosene	PSEG	46	01-Jun-15
AEP	Picway 5	95.0	Coal	AEP	60	01-Jun-15
PSEG	Sewaren 6	105.0	Kerosene	PSEG	50	01-Jun-15
AEP	Sporn 1-4	580.0	Coal	AEP	64	01-Jun-15
AEP	Tanners Creek 1-4	982.0	Coal	AEP	60	01-Jun-15
NRG Energy	Shawville 4	175.0	Coal	PENELEC	55	02-Jun-15
NRG Energy	Shawville 3	175.0	Coal	PENELEC	56	07-Jun-15
NRG Energy	Shawville 1	122.0	Coal	PENELEC	61	12-Jun-15
NRG Energy	Shawville 2	125.0	Coal	PENELEC	61	14-Jun-15
Portsmouth Genco	Lake Kingman	115.0	Coal	Dominion	27	19-Jun-15
Total		9,717.0				

Generation Mix

As of June 30, 2015, PJM had an installed capacity of 192,864.9 MW (Table 12-11). This measure differs from capacity market installed capacity because it includes energy-only units and uses non-derated values for solar and wind resources.

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

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	507.7	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,297.3
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	18,897.8	4.0	1,953.2	32,657.2
AP	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	1,058.5	9,008.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	5,813.0	0.0	0.0	10,323.4
BGE	0.0	840.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,569.9
ComEd	3,146.1	7,244.0	93.8	0.0	0.0	10,473.5	9.0	5,166.1	4.5	2,431.9	28,568.9
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	2,908.0	40.0	0.0	4,365.1
DEOK	47.2	654.0	0.0	0.0	0.0	0.0	0.0	3,730.0	2.0	0.0	4,433.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	784.0	0.0	0.0	2,826.3
Dominion	5,493.6	3,874.8	153.8	0.0	3,589.3	3,581.3	22.7	7,890.0	0.0	0.0	24,605.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	5,069.0
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,882.0	0.0	0.0	2,726.0
EXT	1,471.0	297.9	0.0	0.0	269.1	12.5	0.0	5,253.5	0.0	0.0	7,304.0
JCPL	1,692.5	763.1	19.9	0.0	400.0	614.5	96.3	10.0	0.0	0.0	3,596.3
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	836.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,219.8
PENELEC	0.0	407.5	45.8	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,690.5
Pepco	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
PPL	1,807.9	616.2	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,130.8
PSEG	3,091.3	1,132.0	11.1	0.0	5.0	3,493.0	124.8	2,050.1	2.0	0.0	9,909.3
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	31,658.0	29,163.8	817.7	30.0	8,378.0	33,744.6	353.7	82,016.5	100.9	6,601.7	192,864.9

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 69,760.2 MW, or 36.2 percent, of the total capacity of 192,864.9 MW.

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

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	27,279.5	21,754.9	557.0	30.0	189.6	0.0	353.7	5,212.9	100.9	6,601.7	62,080.2
20 to 40	3,936.5	2,913.9	88.8	0.0	3,557.2	22,906.4	0.0	27,621.7	0.0	0.0	61,024.5
40 to 60	442.0	4,495.0	169.9	0.0	3,010.0	10,838.2	0.0	47,545.4	0.0	0.0	66,500.5
More than 60	0.0	0.0	2.0	0.0	1,621.2	0.0	0.0	1,636.5	0.0	0.0	3,259.7
Total	31,658.0	29,163.8	817.7	30.0	8,378.0	33,744.6	353.7	82,016.5	100.9	6,601.7	192,864.9

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

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

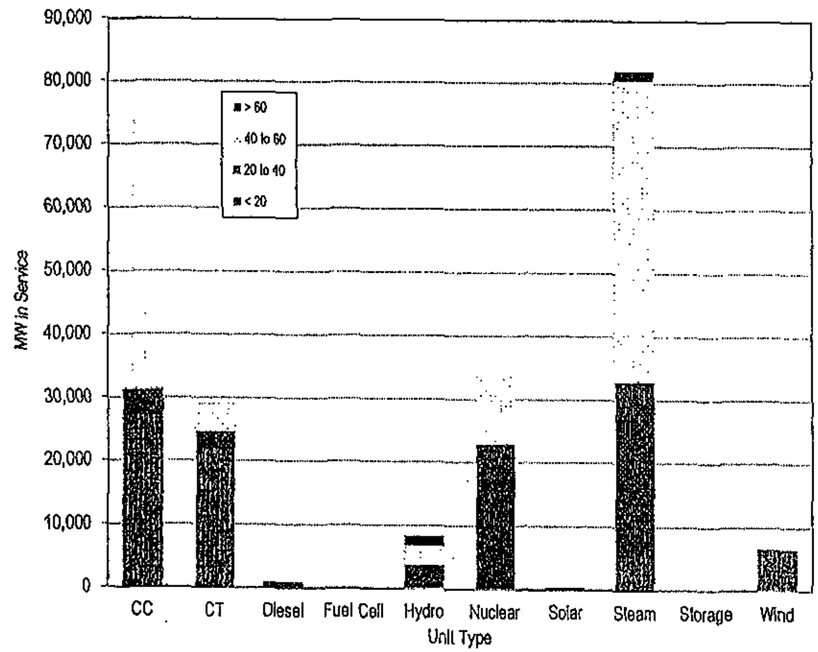


Table 12-13 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. Even though 69,760.2 MW of the total capacity are more than 40 years old, only 3,333.6 MW are planned to retire within the next five years. The expected role of gas-fired generation depends on projects in the queues and retirement of coal-fired generation. Existing capacity is 42.5 percent steam, which will be reduced to 31.9 percent by 2020 as a result of the addition of 44,498.5 MW of planned CC capacity. The percentage of CC capacity would increase from 16.4 percent to 29.7 percent of total capacity in PJM in 2020.

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

Unit Type	Current Generator Capacity	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity in 5 Years	Percent of Area Total
Combined Cycle	31,658.0	16.4%	44,498.5	0.0	76,156.5	29.7%
Combustion Turbine	29,163.8	15.1%	2,742.4	0.0	31,906.2	12.4%
Diesel	817.7	0.4%	415.5	14.3	1,218.9	0.5%
Fuel Cell	30.0	0.0%	0.0	0.0	30.0	0.0%
Hydroelectric	8,378.0	4.3%	154.7	0.0	8,532.7	3.3%
Nuclear	33,744.6	17.5%	448.8	614.5	33,578.9	13.1%
Solar	353.7	0.2%	3,170.8	0.0	3,524.5	1.4%
Steam	82,016.5	42.5%	2,633.7	2,704.8	81,945.4	31.9%
Storage	100.9	0.1%	311.6	0.0	412.5	0.2%
Wind	6,601.7	3.4%	12,657.4	0.0	19,259.1	7.5%
Total	192,864.9	100.0%	67,033.3	3,333.6	256,564.6	100.0%

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

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[14] These changes included reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR). PJM staff reported on June 11, 2015, that the study backlog has been significantly reduced.[15]

Interconnection Study Phase

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-14 is an overview of PJM's study process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-14 PJM generation planning process

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

Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage.[16] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rate is shown in Table 12-15. Disregarding projects still active or under construction, Table 12-15 shows the rate at which projects drop out of the queue as they move through the process. Out of 262,424 MW that entered the queue, 32,622 went into service, while the remaining 229,801 MW withdrew at some point. Of the withdrawals, 53.9 percent happened after the Feasibility study was completed, before proceeding to the next milestone.

Table 12-15 Completed (withdrawn or in service) queue MW (January 1, 1997 through June 30, 2015)

Milestone Completed	MW in Queue	Percent of Total in Queue	MW Withdrawn	Percent of Total Withdrawn
Enter Queue	262,424.1	100.0%	20,335.5	8.8%
Feasibility Study	242,088.6	92.3%	123,973.5	53.9%
System Impact Study	118,115.1	45.0%	48,040.5	20.9%
Facility Study	70,074.7	26.7%	22,860.8	9.9%
ISA/WMPA	47,213.9	18.0%	8,151.5	3.5%
CSA	39,062.4	14.9%	6,439.8	2.8%
In Service	32,622.6	12.4%	0.0	0.0%

Table 12-16 shows the milestone due when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 48.1 percent were withdrawn before the Impact Study was completed. Once an Interconnection Service Agreement (ISA), or a Wholesale Market Participation Agreement (WMPA), is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[17] [18] As expected, withdrawing at or beyond this point is uncommon; 201 projects, or 12.4 percent, of all projects withdrawn were withdrawn after reaching this milestone.

14 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000, <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>.
15 See PJM, Planning Committee "PJM Interconnection Queue Status & Statistics Update, Database Snapshot on 5/27/2015," at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>
16 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), p.70.
17 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)..." instead of an ISA. See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.8.
18 See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

Table 12-16 Last milestone completed at time of withdrawal (January 1, 1997 through June 30, 2015)

Milestone Completed	Projects Withdrawn	Percent
Never Started	171	10.6%
Feasibility Study	607	37.6%
Impact Study	532	32.9%
Facilities Study	105	6.5%
Interconnection Service Agreement (ISA)	37	2.3%
Wholesale Market Participation Agreement (WMPA)	110	6.8%
Construction Service Agreement (CSA) or beyond	54	3.3%
Total	1,616	100.0%

Table 12-17 and Table 12-18 show the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 937 days, or 2.6 years, between entering a queue and going into service. Nuclear, hydro, and wind projects tend to take longer to go into service. The average time to go into service for all other fuel types is 700 days. For withdrawn projects, there is an average time of 658 days between entering a queue and withdrawing.

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

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	976	687	15	3,890
In Service	937	683	1	4,024
Suspended	1,987	765	509	4,149
Under Construction	1,787	906	428	6,380
Withdrawn	658	656	1	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service. Of the 577 projects in the queue as of June 30, 2015, 68 had a completed feasibility study and 191 were under construction.

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

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	130	22.5%	713	2,555
Feasibility Study	68	11.8%	780	2,223
Impact Study	85	14.7%	1,366	3,890
Facilities Study	21	3.6%	1,773	3,291
Interconnection Service Agreement (ISA)	13	2.3%	780	1,858
Wholesale Market Participation Agreement (WMPA)	1	0.2%	427	427
Construction Service Agreement (CSA)	1	0.2%	1,554	1,554
Under Construction	191	33.1%	1,787	6,380
Suspended	67	11.6%	1,987	4,149
Total	577	100.0%		

The time it takes to complete a study depends on the backlog and the number of projects in the queue. The time it takes to complete a study does not necessarily depend on the size of the project. Renewable projects (solar, hydro, storage, biomass, wind) account for 61.4 percent of the total number of projects in the queue but only 25.6 percent of the non-derated MW. See Table 12-19.

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

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	1.0%	2,042.8	2.6%
Renewable	354	61.4%	19,806.5	25.6%
Traditional	217	37.6%	55,612.0	71.8%
Total	577	100.0%	77,461.3	100.0%

Role of Transmission Owners in Transmission Planning Study Phase

According to PJM Manual 14A, PJM, in coordination with the TOs, conducts the feasibility, system impact and facilities studies for every interconnection queue project. *It is clear that the TOs perform the studies.*[19] *The coordination* begins with PJM identifying transmission issues resulting from the generation projects. The TOs perform the studies and provide the mitigation requirements for each issue. A facilities study is required only for new generation and significant generation additions and is the study in which the TO is most involved. For a facilities study, the interconnected TO (ITO), as well as any other affected TOs, is required to conduct their own facilities study and provide a summary and results to PJM. PJM compiles these results, along with inputs from the developer, into PJM's models to confirm that the TOs' defined upgrades will resolve the issue. PJM writes the final facilities report, which includes the inputs, a description of the issues to be resolved, and the findings of all contributing TOs.[20]

Of 577 active projects analyzed, the developer and TO are part of the same company for 41 of the projects, or 11,390.5 MW of a total 59,225.2 MW, 19.2 *percent of the MW. Where the TO is a vertically integrated company that also* owns generation, there is a potential conflict of interest when the TO evaluates the interconnection requirements of new generation which is part of the same company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of its parent company.

Table 12-20 is a summary of the number of projects and total MW, by transmission owner parent company, which identifies the number of projects for which the developer and transmission owner are part of the same company. The Dominion Zone has eight related projects which account for 5,881.3 MW, 58.0 percent of the total MW currently in the queue in the Dominion Zone. Renewable projects comprise 3,075.6 MW, 72.1 percent, of unrelated projects in the queue in the Dominion Zone while natural gas projects total 5,465.3 MW, 53.9 percent of total MW in the queue. In contrast, the AEP Zone has 12 related projects, but they account for only 2.6 percent of its total MW currently in the queue.

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

	Number of Projects			Total MW		
Parent Company	Related	Unrelated	Percent Related	Related	Unrelated	Percent Related
AEP	12	73	14.1%	369.7	13,670.0	2.6%
AES	2	6	25.0%	32.0	437.3	6.8%
DLCO	0	1	0.0%		205.0	0.0%
Dominion	8	53	13.1%	5,881.3	4,265.6	58.0%
Duke	2	6	25.0%	52.0	660.4	7.3%
Exelon	7	66	9.6%	3,100.0	7,754.7	28.6%
First Energy	2	198	1.0%	1,736.0	21,169.8	7.6%
Pepco	0	80	0.0%		6,408.5	0.0%
PPL	0	26	0.0%		6,803.5	0.0%
PSEG	11	24	31.4%	1,923.1	2,992.4	39.1%
Total	44	533	7.6%	13,094.1	64,367.2	16.9%

These projects are shown by fuel type in Table 12-21. Natural gas generators comprise 69.6 percent of the total related MW in this table. Developers of coal and nuclear projects are almost entirely related to the TO, with 95.2 percent and 99.1 percent of MW. Developers are related to the TO for 17.2 percent of the natural gas project MW in the queue and 12.2 percent of the coal project MW. Wind and solar projects have no more than 1.0 percent of MW in development related to the TO.

19 See PJM, OATT, Part VI, § 210
20 See PJM, "Manual 14A, "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015),< http://www.pjm.com/documents/manuals.aspx>

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

				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12		72.0	34.0		137.0	102.0			14.7	10.0		369.7
		Unrelated	73	45.0	92.0	12.5	23.8	6,019.0				103.7	62.0	7,312.0	13,670.0
AES	DAY	Related	2		12.0								20.0		32.0
		Unrelated	6	1.9		112.0						23.4		300.0	437.3
DLCO	DLCO	Unrelated	1					205.0							205.0
Dominion	Dominion	Related	8					4,275.3	1,594.0					12.0	5,881.3
		Unrelated	53	62.5			3.6	1,190.0				1,571.4	128.0	1,310.1	4,265.6
Duke	DEOK	Related	2		50.0								2.0		52.0
		Unrelated	6				6.4	513.0				125.0	16.0		660.4
Exelon	BGE	Related	1									20.0			20.0
		Unrelated	7	25.0		0.4	4.0	1.3			132.0	3.1			165.8
	ComEd	Unrelated	48			22.7	28.6	2,337.8				10.0	144.6	3,562.0	6,105.7
	PECO	Related	6					2,750.0	330.0						3,080.0
		Unrelated	11				3.2	1,480.0							1,483.2
First Energy	APS	Related	2		1,710.0			26.0							1,736.0
		Unrelated	55			68.2	9.2	4,865.9				184.3	31.0	723.6	5,882.2
	ATSI	Unrelated	12				2.5	4,071.9						518.0	4,592.4
	JCPL	Unrelated	83					3,034.0				574.1	180.0		3,788.1
	Met-Ed	Unrelated	8					1,336.6	16.8	401.0		3.0			1,757.4
	PENELEC	Unrelated	40			40.0	4.0	4,610.5				13.5	68.4	413.3	5,149.7
Pepco	AECO	Unrelated	22				0.3	1,571.0				73.2	20.0	373.0	2,037.5
	DPL	Unrelated	50				2.0	918.0				455.4	20.0	250.0	1,645.4
	Pepco	Unrelated	8					2,725.6							2,725.6
PPL	PPL	Unrelated	26	16.0			5.0	6,213.0				16.0	30.0	523.5	6,803.5
PSEG	PSEG	Related	11					1,922.1				1.0			1,923.1
		Unrelated	24					2,847.5				144.9			2,992.4
Total		Related	44		1,844.0	34.0		9,110.4	2,026.0			15.7	32.0	12.0	13,074.1
		Unrelated	533	150.4	92.0	255.8	92.6	43,940.1	16.8	401.0	132.0	3,321.1	700.0	15,285.5	64,387.2

Regional Transmission Expansion Plan (RTEP)

PJM's Transmission Expansion Advisory Committee (TEAC), made up of PJM staff, is responsible for the Regional Transmission Expansion Plan (RTEP).[21] Transmission upgrades can be divided into three categories: network, supplemental, and baseline. Network upgrades are initiated by generation queue projects and are funded by the developers of the generation projects. Supplemental upgrades are initiated and funded by the TOs. Baseline upgrades are initiated by the TEAC to resolve reliability criteria violations not addressed in other ways. The costs of the baseline projects are allocated proportionally to all TOs who will benefit from the upgrade. The TEAC solicits proposals via fixed proposal windows to address these needs. The TEAC evaluates the proposals and recommends proposals to the PJM Board of Managers for approval. The TEAC typically makes these recommendations three times a year: in February, mid-summer and late fall.

On February 17, 2015, baseline projects with an estimated cost of $551.4 million were presented to and approved by the Board. New projects account

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

for $474.4 million of this amount and adjustments to previously approved baseline projects were $77.0 million.[22] Table 12-22 shows a summary of the new baseline upgrade costs for each TO.

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

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

The 2015 RTEP Proposal Window 1 opened on June 19, 2015, and will close on July 20, 2015. The scope for these proposals includes baseline N-1, generation deliverability and common mode outage, N-1-1, and load deliverability.[23]

Artificial Island Update

Artificial Island is an area in the PSEG Zone in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSEG, and from non-incumbents. PJM staff announced on April 28, 2015, that they will recommend that the Board apptove the assignment of the Artificial Island project to LS Power, a non-incumbent, PSEG, and PHI with a total cost estimate between $263M and $283M. Table 12-23 shows the details of the project allocation.

Table 12-23 Artificial Island recommended work and cost allocation

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

PJM received comments from PSEG & PSEG Nuclear, contesting the selection of LS Power for the construction of a 230kV line over the PSEG proposal. They argued that the PSEG proposal was inappropriately modified, resulting in a higher cost and a lower score and that several performance factors, including stability, installation complexity, long term maintenance and operational costs, and operational complexity were excluded. PSEG also argued that LS Power's cost cap is misleading and was misinterpreted by PJM staff to be more robust than it actually is. Atlantic Grid Holdings also questioned the robustness of the recommended design. The Delaware Riverkeeper Network raised environmental concerns.

On July 30, 2105, the PJM Board of Managers accepted PJM's recommendation.[24]

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

Cost Estimates and Allocations

Con Edison and Linden VFT

Following the RTEP Baseline upgrade filings, ER14-972-000 on January 10, 2014, and ER14-1485-000 on March 13, 2014, Con Edison and Linden VFT took issue with their cost allocations for two specific upgrades (Bergen-Linden

22 See PJM Staff Whitepaper,"Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," <http://www.pjm.com/~/media/committees-groups/committees/teac/20150409/20150409-february-2015-board-approval-of-rtep-whitepaper.ashx>
23 See TEAC webcast, June 24, 2015 at <http://mediastream.pjm.com/2015/0624/teac/2015-rtep-proposal/index.htm>
24 See PJM, "Artificial Island Project," July 29, 2015 <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>.

Corridor and Sewaren.) Both filed complaints (ConEd on November 7, 2014, and Linden on May 22, 2015) that the allocations violated Schedule 12 of the tariff and Schedule 6 of the PJM Operating Agreement, which address unreasonable cost allocations. Schedule 12 of the tariff states "If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions of this Section (b)(iii), the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis." Schedule 6 of the PJM Operating Agreement requires PJM to avoid an allocation of unreasonable costs in the RTEP project selection process.[25] [26] Finally, Order 1000 states that "costs must be allocated in a way that is roughly commensurate with benefits."[27]

ConEd argued, using the tariff language, that the cost allocation is "objectively unreasonable" and requested "an appropriate substitute proxy." ConEd's complaint was not that the solution-based DFAX method was necessarily faulty, but that the assumptions and inputs that PJM used to model ConEd were inaccurate and resulted in an over allocation to ConEd, Linden VFT, and Hudson Transmission Partners (HTP), and an under allocation to PSEG. PJM's response was that the substitute proxy was to be used when a DFAX could not otherwise be calculated, which did not apply in this case.[28] PJM also argued that ConEd had a chance to question the cost allocation during numerous TEAC meetings. ConEd replied that detailed information was not made available and thus ConEd was not aware of the significant allocation at that point. PSEG commented in support of the allocation. The FERC decision on June 18, 2015, accepted the PJM allocation and found that the DFAX method, as applied, was not faulty.[29]

Linden VFT commented in support of ConEd's complaint and filed a separate complaint on May 22, 2015.[30] In addition to the two upgrades that were the focus of the ConEd complaint, Linden added a third (Edison Rebuild).

25 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(G)
26 See PJM Operating Agreement, § 1.4(d)(ii)
27 See FERC Order 1000-B, §3, Paragraph 66
28 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(I)
29 See 151 FERC ¶ 61,227 (2015), <http://www.pjm.com/~/media/documents/ferc/2015-orders/20150618-el14-972-002.ashx>.
30 See "Motion for Leave to Answer and Limited Answer of Linden VFT, LLC," Docket No. EL15-18-000 (November 19, 2014)

The allocations in dispute were a result of a new approach to transmission upgrade cost allocation, applied for the first time to the transmission costs resulting from the 2013 RTEP.[31] Linden VFT argued that the DFAX calculations assume peak conditions and therefore maximum firm transmission withdrawal rights (FTWRs), but during peak periods, Linden VFT is least likely to use its full FTWRs because the flow is going in the other direction.[32]

Artificial Island

After the Artificial Island recommendation was presented by PJM Staff on April 28, 2015, Delaware Public Service Commission, Delaware Division of the Public Advocate, Old Dominion Electric Cooperative (ODEC), the Maryland Public Service Commission (MD PSC), and Delaware Governor Jack Markell raised concerns regarding the allocation of 99.9 percent of the costs for the 230kV line portion of the Artificial Island project to PHI.[33]

TransSource

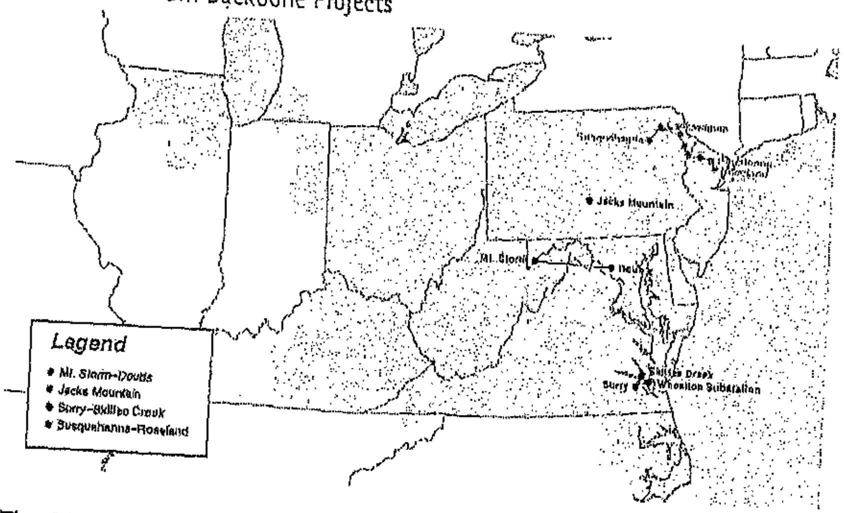
TransSource LLC stated, in a complaint filed on June 23, 2015, that PJM is not being transparent with respect to the development of its cost estimates in the System Impact Study (SIS) phase of three TransSource queue projects. TransSource seeks an order directing PJM to provide data and working papers related to the SIS sufficient to fully evaluate the basis of cost estimates that TransSource considers excessive. PJM responded that it has provided all work papers relevant to the SIS and objects to the complaint on procedural grounds.[34]

31 See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013)
32 See "Complaint and Request for Fast Track Processing of Linden VFT, LLC," Docket no. EL15-67-000 (May 22, 2015)
33 See PJM Board Communications. Responses at <http://www.pjm.com/about-pjm/who-we-are/pjm-board/public-disclosures.aspx>
34 See Motion to Dismiss Complaint and Answer to Complaint Submitted on Behalf of PJM Interconnection, L.L.C., Docket No. EL15-79-000 (July 10, 2015).

Backbone Facilities

PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-3 shows the location of these four projects.

Figure 12-3 PJM Backbone Projects



The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability. The first two phases, the line rebuild and the energizing of the Mount Storm switchyard, are complete. Construction plans for Phase 3, consisting of additional upgrades to the Mount Storm switchyard, are under development. Completion of this phase is expected by the end of 2015.[35]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. This project is currently in the engineering and design phase. Transmission foundations are planned for fall 2015. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017.[36]

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland is a new 101-mile 500 kV transmission line connecting the Susquehanna, Lackawanna, Hopatcong, and Roseland buses. PPL is responsible for the first two legs and PSEG for the third. The Susquehanna-Lackawanna portion went into service on September 23, 2014, and the Lackawanna-Hopatcong portion was energized on May 11, 2015. The Hopatcong - Roseland leg was placed in service on April 1, 2014.[37] This project is now complete.

The Surry Skiffes Creek 500kV was initiated in the fall of 2014 to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4, which occurred in December 2014, and Yorktown 1, which is pending. It will include a new 7.7 mile 500kV line between Surry and Skiffes, a new 20.25 mile 230kV line between Skiffes Creek and Whealton, and a new Skiffes Creek 500/230kV switching station. PJM's required in service date for the 500kv portion was June 1, 2015. This project has been delayed by legal challenges. BASF Corporation raised environmental concerns with the siting and the design. James City County and James River Association (JCC) argued that the switching station is not part of the transmission line and therefore should be subject to local zoning ordinances. In an April 16, 2015, ruling, the Supreme Court of Virginia rejected BASF's claim but agreed with JCC.[38] On April 30, 2015, Dominion filed a petition for rehearing and will wait for the follow-

35 See Dominion "Mt. Storm-Doubs," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx

36 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

37 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.

38 BASF Corporation v SCC, et al., Record No. 141009 et al.

up ruling before they will begin construction but they are proceeding with the planning.[39] Dominion anticipates beginning construction in the summer of 2015 and expects to energize both the 230kV line and the 500kV line by January 31, 2017.[40]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

PJM designates some transmission facilities as reportable. A transmission facility is reportable if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free-flowing ties within the PJM RTO and/or adjacent areas. If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable.[41] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days. Table 12-24 shows that 78.5 percent of the requested outages were planned for five days or shorter and 5.3 percent of requested outages were planned for longer than 30 days in the first six months of 2015. All of the outage data in this section are for outages scheduled to occur in the first six months of 2015, regardless of when they were initially submitted.

Table 12-24 Transmission facility outage request summary by planned duration: January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	8,039	79.8%	8,279	78.5%
>5 & <=30	1,537	15.3%	1,705	16.2%
>30	493	4.9%	564	5.3%
Total	10,069	100.0%	10,548	100.0%

39 See "Surry-Skiffes Creek 500kV," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/surry-skiffes-creek.aspx>.
40 See "Surry-Skiffes Creek 500kV and Skiffes Creek-Whealton 230kV Projects,"which can be accessed at: <https://www.dom.com/corporate/what-we-do/electricity/transmission-lines-and-projects/surry-skiffes-creek-500kv-and-skiffes-creek-whealton-230kv-projects>.
41 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request, based on its submission date, outage planned starting and ending date, and outage planned duration. The received status can be on time, late or past deadline, as defined in Table 12-25.[42] The purpose of the rules is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right ("FTR") auctions so that market participants have complete information on which to base their FTR bids.[43]

Table 12-25 PJM transmission facility outage request received status definition

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

Table 12-26 shows a summary of requests by received status. In the first six months of 2015, 52.8 percent of outage requests received were late.

Table 12-26 Transmission facility outage request summary by received status: January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	4,214	3,825	8,039	52.4%	4,545	3,734	8,279	54.9%
>5 & <=30	771	766	1,537	50.2%	846	859	1,705	49.6%
>30	172	321	493	34.9%	183	381	564	32.4%
Total	5,157	4,912	10,069	51.2%	5,574	4,974	10,548	52.8%

42 See "PJM. "Manual 3: Transmission Operations," Revision 46 (December 1, 2014), p.58.
43 See 97 FERC ¶ 61,010 (October 3, 2001).

Once received, PJM processes the request according to its priority, which is determined by its submission date. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline. Table 12-27 is a summary of outage requests by emergency status. Of all outage requests submitted in the first six months of 2015, 13.0 percent were for emergency outages.

Table 12-27 Transmission facility outage request summary by emergency: January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,238	6,801	8,039	15.4%	1,069	7,210	8,279	12.9%
>5 & <=30	200	1,337	1,537	13.0%	237	1,468	1,705	13.9%
>30	89	404	493	18.1%	63	501	564	11.2%
Total	1,527	8,542	10,069	15.2%	1,369	9,179	10,548	13.0%

A late outage request may be denied or cancelled by PJM if it is expected to cause congestion based on PJM's analysis. Table 12-28 is a summary of outage requests by congestion status. Of all outage requests submitted in the first six months of 2015, 9.6 percent were expected to cause congestion and the percentage of outage requests flagged for congestion is similar across the categories of planned duration.

Table 12-28 Transmission facility outage request summary by congestion: June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	679	7,360	8,039	8.4%	766	7,513	8,279	9.3%
>5 & <=30	148	1,389	1,537	9.6%	188	1,517	1,705	11.0%
>30	44	449	493	8.9%	57	507	564	10.1%
Total	871	9,198	10,089	8.7%	1,011	9,537	10,548	9.6%

Table 12-29 shows the outage requests summary by received status, congestion status and emergency status. In the first six months of 2015, 72.6 percent of late requests were non-emergency outages while 4.8 percent of late non-emergency outage requests were expected to cause congestion in the first six months of 2015.

Table 12-29 Transmission facility outage requests that by received status, congestion and emergency: January through June of 2014 and 2015

		2014 (Jan - Jun)				2015 (Jan - Jun)			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	44	1,475	1,519	2.9%	55	1,308	1,363	4.0%
	Non Emergency	167	3,226	3,393	4.9%	172	3,439	3,611	4.8%
On Time	Emergency	0	8	8	0.0%	0	6	6	0.0%
	Non Emergency	660	4,489	5,149	12.8%	784	4,784	5,568	14.1%
	Total	871	9,198	10,069	8.7%	1,011	9,537	10,548	9.6%

Once PJM processes an outage request, the outage request is labelled as submitted, received, denied, approved, cancelled by company, revised, active or complete according to the processed stage of a request.[44] Table 12-30 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. All process status categories except cancelled, complete or denied are in the In Process category in Table 12-30. Table 12-30 shows that 62.8 percent of late, non-emergency, outage requests which were expected to cause congestion were approved and completed and 6.6 (67 out of 1,011) percent of the outage requests which were expected to cause congestion were denied in the first six months of 2015.

Table 12-30 Transmission facility outage requests that might cause congestion status summary: January through June of 2014 and 2015

		2014 (Jan - Jun)						2015 (Jan - Jun)					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	2	41	1	0	44	93.2%	7	47	0	1	55	85.5%
	Non Emergency	29	117	1	20	167	70.1%	38	108	2	24	172	62.8%
On Time	Non Emergency	133	485	1	41	660	73.5%	223	516	3	42	784	65.8%
	Total	164	643	3	61	871	73.8%	268	671	5	67	1,011	66.4%

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-31 is a summary of all the outage requests planned for the first six months of 2014 and 2015 which were approved and then cancelled or revised by TOs at least once. In the first six months of 2015, 2.7 percent of transmission outage requests were approved by PJM and then revised by the TOs, and 12.9 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-31 Rescheduled transmission outage request summary: January through June of 2014 and 2015

	2014 (Jan - Jun)					2015 (Jan - Jun)				
Days	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled
<=5	8,039	270	3.4%	1,173	14.6%	8,279	207	2.5%	1,186	14.3%
>5 & <=30	1,537	68	4.4%	116	7.5%	1,705	54	3.2%	129	7.6%
>30	493	14	2.8%	30	6.1%	564	25	4.4%	50	8.9%
Total	10,069	352	3.5%	1,319	13.1%	10,548	286	2.7%	1,365	12.9%

All late rescheduled outages are reevaluated by PJM. An on-time transmission outage ticket with duration of five days or less with an on-time status can retain its on-time status if the outage is rescheduled within the original scheduled month.[45] This rule allows a TO to move an outage to an earlier date than originally requested within the same month with very little notice.

An on-time transmission outage ticket with duration exceeding five days can retain its on-time status if the outage is moved to a future month, and the revision is submitted by the first of the month prior to the month in which new proposed outage will occur.[46] This rescheduling rule is much less strict than the rule that

44 PJM. Markets and Operations. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx>
45 PJM. "Manual 3: Transmission Outages," Revision 46 (December 1, 2014), p. 63.
46 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 64.

applies to the first submission of outage requests with similar duration. When first submitted, the outage request planned to last longer than five days needs *to be submitted the first of the month six months prior to the month in which* the outage was expected to occur.

These rules mean that an outage, once approved, acts as a reservation that *does not require further review and allows rescheduling without review.*

The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the *standard rules for late submissions to any such outages.*

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR auctions. It is critical that outages are known with enough lead time prior to FTR auctions both so that market participants can understand market conditions and so that PJM can accurately model market conditions. Outage requests must be submitted according to rules based on planned outage duration (Table 12-25). The rules defining when an outage is late are based on the timing of FTR auctions. When an outage request is submitted late, the *outage will be marked as late and may be denied if it is expected to cause* congestion.

There are Long Term, Annual and Monthly Balance of Planning Period *auctions in the FTR market. When modeling transmission outages in the* annual ARR allocation and FTR auction, PJM does not consider outages with planned duration shorter than two weeks, does consider some outages with planned duration longer than two weeks but shorter than two months, and *does consider all outages with planned duration longer than or equal to two* months. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[47]

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

Table 12-32 shows that 89.9 percent of the outage requests for outages expected to occur during the planning period 2014 to 2015 were planned *for less than two weeks and that 47.7 percent of all outage requests for the* planning period were submitted late according to outage submission rules.

Table 12-32 Transmission facility outage requests by received status: Planning period 2014 to 2015

Planned Duration	On Time	Late	Total	Percent Late
<2 weeks	9,300	8,346	17,646	47.3%
>=2 weeks & <2 months	805	821	1,626	50.5%
>=2 months	155	192	347	55.3%
Total	10,260	9,359	19,619	47.7%

Once received, PJM processes outage requests in the following priority order: emergency transmission outage request, transmission outage requests submitted On Time, and transmission submitted Late. If two outage requests submitted by different transmission owners are expected to occur during the same period, the outage submitted first is processed first by PJM. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline after PJM determines that the outage does not result in Emergency Procedures.[48] Table 12-33 shows outage requests summary by emergency status. Of all outage requests submitted late in the 2014 to 2015 *planning year, 72.7 percent were for non-emergency outages.*

Table 12-33 Transmission facility outage requests by received status and emergency: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Emergency	Non Emergency	Percent Non Emergency	Emergency	Non Emergency	Percent Non Emergency
<2 weeks	13	9,287	99.9%	2,363	5,983	71.7%
>=2 weeks & <2 months	0	805	100.0%	155	666	81.1%
>=2 months	0	155	100.0%	35	157	81.8%
Total	13	10,247	99.9%	2,553	6,806	72.7%

48 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 67 and p.68.

PJM analyzes expected congestion for both on time and late outage requests. A late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-34 shows a summary of requests by congestion flag and received status. Overall, 5.3 percent of all tickets submitted late in the 2014 to 2015 planning year were requests that might cause congestion.

Table 12-34 Transmission facility outage requests by received status and congestion: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Congestion Expected	No Congestion Expected	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Percent Congestion Expected
<2 weeks	1,334	7,966	14.3%	445	7,901	5.3%
>=2 weeks & <2 months	160	645	19.9%	43	778	5.2%
>=2 months	32	123	20.6%	6	186	3.1%
Total	1,526	8,734	14.9%	494	8,865	5.3%

Table 12-35 shows that 86.5 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed and that 86.5 percent of late outage requests with a duration of two months or longer were completed.

Table 12-35 Transmission facility outage requests by received status and processed status: Planning period 2014 to 2015

Planned Duration	Processed Status	On Time	Percent	Late	Percent
<2 weeks	In Process	23	0.2%	166	2.0%
	Denied	106	1.1%	91	1.1%
	Cancelled by Company	2,766	29.7%	1,193	14.3%
	Completed	6,405	68.9%	6,895	82.6%
Total		9,300	100.0%	8,345	100.0%
>=2 weeks & <2 months	In Process	1	0.1%	9	1.1%
	Denied	0	0.0%	2	0.2%
	Cancelled by Company	194	24.1%	100	12.2%
	Completed	610	75.8%	710	86.5%
Total		805	100.0%	821	100.0%
>=2 months	In Process	0	0.0%	7	3.6%
	Denied	0	0.0%	0	0.0%
	Cancelled by Company	38	24.5%	19	9.9%
	Completed	117	75.5%	166	86.5%
Total		155	100.0%	192	100.0%

Table 12-36 shows outage requests in more detail. It shows that there were 821 outage requests with a duration of two weeks or longer but shorter than two months were submitted late, of which 40 were non-emergency and expected to cause congestion in the 2014 to 2015 planning year. Of the 40 such requests, 33 were approved and completed. For the outages planned for two months or longer, there are 347 total outages, of which 192 requests were late. The six outages that were non-emergency and expected to cause congestion were all approved and completed.

Table 12-36 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning period 2014 to 2015

		On time					Late				
		Emergency Congestion Expected		Non Emergency Congestion Expected			Emergency Congestion Expected		Non Emergency Congestion Expected		
Planned Duration	Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
<2 weeks	In Progress	0	0	2	21	23	0	77	3	86	166
	Denied	0	0	72	34	106	1	8	39	43	91
	Cancelled by Company	1	1	362	2,402	2,766	9	133	75	977	1,194
	Completed	0	11	897	5,497	6,405	96	2,039	222	4,538	6,895
Total Submission		1	12	1,333	7,954	9,300	106	2,257	339	5,644	8,346
>=2 weeks & <2 months	In Progress	0	0	1	0	1	0	4	0	5	9
	Denied	0	0	0	0	0	0	0	2	0	2
	Cancelled by Company	0	0	30	164	194	0	5	5	90	100
	Completed	0	0	129	481	610	3	143	33	531	710
Total Submission		0	0	160	645	805	3	152	40	626	821
>=2 months	In Progress	0	0	0	0	0	0	1	0	6	7
	Denied	0	0	0	0	0	0	0	0	0	0
	Cancelled by Company	0	0	3	35	38	0	1	0	18	19
	Completed	0	0	29	88	117	0	33	6	127	166
Total Submission		0	0	32	123	155	0	35	6	151	192

If an outage request were submitted after the Annual FTR Auction bidding opening date, the outage would not be considered in the FTR model. If an outage were submitted on-time according to the transmission outage rules, it may not be modeled in the FTR model if it is submitted after the Annual FTR Auction bidding opening date. Table 12-38 shows that 84.0 percent of outage requests labelled on time according to rules were submitted after the annual FTR bidding opening date.

Table 12-37 Transmission facility outage requests by submission status and bidding opening date: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,040	8,260	88.8%	78	8,267	99.1%
>=2 weeks & <2 months	475	330	41.0%	77	744	90.6%
>=2 months	127	28	18.1%	18	174	90.6%
Total	1,642	8,618	84.0%	173	9,185	98.2%

Table 12-38 shows that 83.1 percent of late outage requests which were submitted after the Annual FTR Auction bidding opening date were approved and complete.

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this.

Table 12-38 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning period 2014 to 2015

Planned Duration	Completed Outages	Total	Percent
<2 weeks	6,837	8,267	82.7%
>=2 weeks & <2 months	650	744	87.4%
>=2 months	150	174	86.2%
Total	7,637	9,185	83.1%

Transmission Facility Outage Analysis in the Day-Ahead Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market both so that market participants can understand market conditions and so that PJM can accurately model market conditions.

There may be more than one instance for each outage request due to the change of the processed status. PJM maintains all the history of outage requests including all the processed status changes and all the starting or ending date changes. For example, if an outage requested were submitted, received, approved and completed, the four occurrences, termed instances, of the outage request will be stored in the database. In the day-ahead market transmission outage analysis, all instances of the outages planned in the 2014/2015 planning year are included. Table 12-39 shows that 14.6 percent of non-emergency outage request instances were submitted late for the day-ahead market and were expected to cause congestion.

Table 12-39 Transmission facility outage request instance summary by congestion and emergency: Planning period 2014 to 2015

For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	310	3,916	4,226	7.3%
	Non Emergency	2,677	15,682	18,359	14.6%
On Time	Emergency	816	11,101	11,917	6.8%
	Non Emergency	15,197	88,362	103,559	14.7%
	Total	19,000	119,061	138,061	13.8%

Table 12-40 shows that there were 22,585 instances related to outage requests which were expected to occur in the planning period 2014 to 2015 , of which 3,043 (13.5 percent) had the status submitted, cancelled by company or revised and 205 (0.9 percent) had the status submitted, cancelled by company or revised and were expected to cause congestion.

Table 12-40 Transmission facility outage request instance status summary by congestion and emergency: Planning period 2014 to 2015

	Late For Day-ahead Market					On Time For Day-ahead Market				
	Emergency		Non Emergency			Emergency		Non Emergency		
	Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
Submitted	24	984	71	668	1,747	113	1,515	2,292	15,835	19,755
Cancelled by Company	8	41	86	703	838	8	132	593	4,273	5,006
Revised	14	131	48	265	458	215	3,649	2,678	13,927	20,469
Total	46	1,156	205	1,636	3,043	336	5,296	5,563	34,035	45,230
Other	264	2,760	2,472	14,046	19,542	480	5,805	9,634	54,327	70,246
Total	310	3,916	2,677	15,682	22,585	816	11,101	15,197	88,362	115,476

IEU-Ohio Ex. 7

Weather normalized benefit to customers (nominal)	$31,000,000	Exhibit KDP-2, page 1 of 1
Years over which benefit realized October 2015 through December 2024	9.25	Exhibit KDP-2, page 1 of 1
Annual benefit to customers	$3,351,351	
Estimated annual MWH sales	43,643,000	Allen workpapers
Customer credit/(Charge)per MWH	$0.0768	

PENGAD 800-631-6989
EXHIBIT
IEU 7

Kro291

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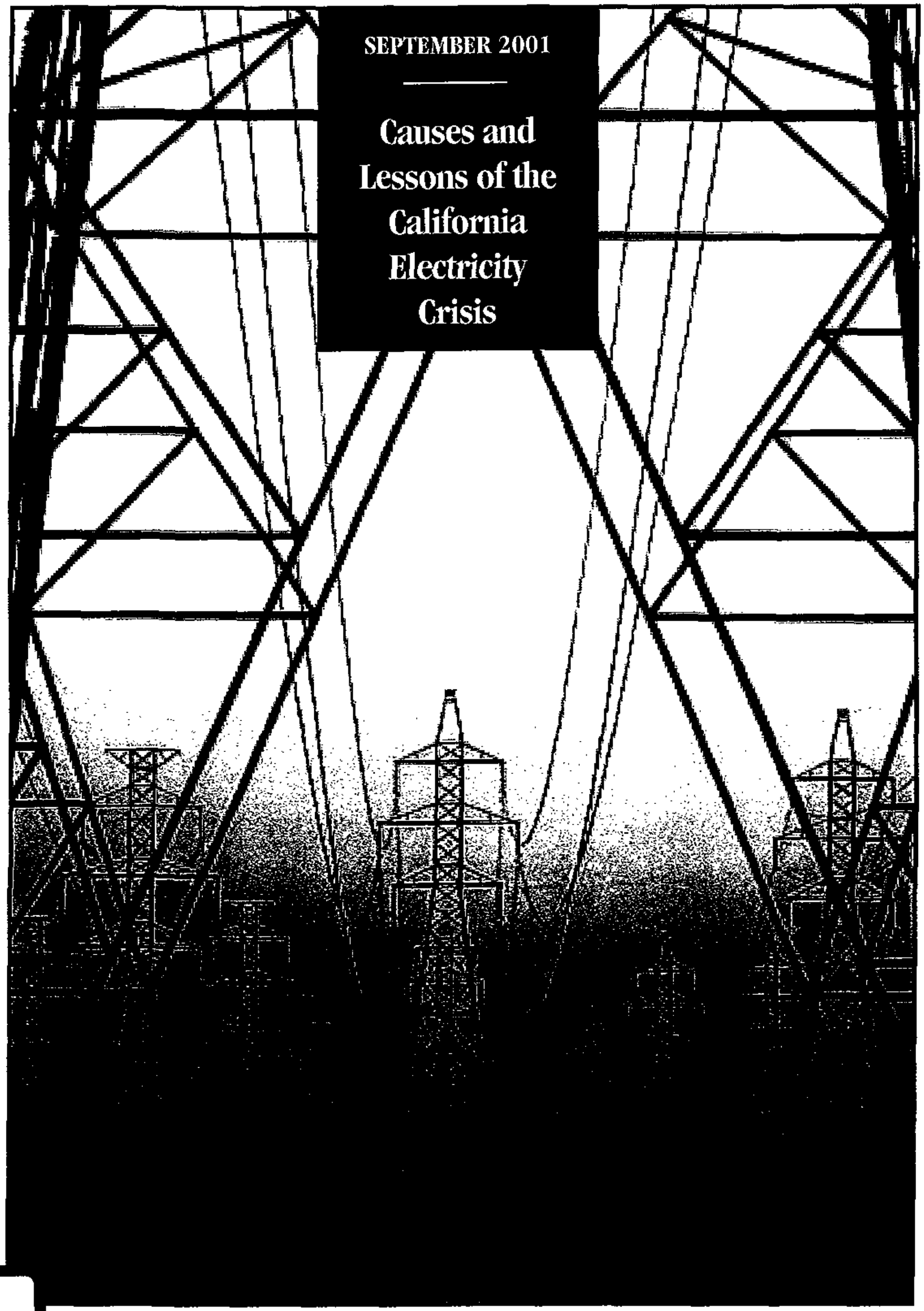
CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

A CBO PAPER



SEPTEMBER 2001

Causes and Lessons of the California Electricity Crisis

CAUSES AND LESSONS OF THE CALIFORNIA ELECTRICITY CRISIS

September 2001

The Congress of the United States
Congressional Budget Office

PREFACE

This Congressional Budget Office (CBO) paper looks at California's attempt to restructure its electric utility industry and at the crisis in the state's electricity market that began in 2000. The paper focuses on the various conditions in western states that put stress on California's energy market. It also examines some of the elements of the state's restructuring plan that turned that stress into a crisis.

Richard Farmer of CBO's Microeconomic and Financial Studies Division and Dennis Zimmerman of the Tax Analysis Division, along with Gail Cohen, formerly of CBO, wrote the paper under the supervision of Roger Hitchner, Tom Woodward, and David Moore. Amy Abel of the Congressional Research Service provided useful comments, as did William Hogan of the John F. Kennedy School of Government at Harvard University and Douglas N. Jones of the School of Public Policy and Management at Ohio State University.

Christian Spoor edited the paper, and Leah Mazade proofread it. Angela Z. McCollough prepared the paper for publication, Lenny Skutnik produced the printed copies, and Annette Kalicki prepared the electronic versions for CBO's Web site (www.cbo.gov).

Dan L. Crippen
Director

September 2001

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BOXES

SUMMARY

The 1996 law that restructured California's electricity industry was intended to be the first step toward lower electricity prices for 70 percent of the state's population. Few observers foresaw the situation that would exist in California by the summer of 2001. Just five years after restructuring became law, the state's electricity market was commonly described as being in crisis. The goals of restructuring—lower prices for residential customers and more competitive prices for industrial customers—seemed farther away than ever.

This paper addresses four questions:

- What happened in California's electricity market from the mid-1990s through the middle of 2001?
- What role did the state's restructuring plan play in those events?
- How did California respond to its market problems?
- What can other governments learn from California's experience?

Developments in the Electricity Market

California began the formal process of restructuring its electricity market in 1994 (see Box 1 for a chronology of that restructuring). In doing so, the state was building on federal actions dating back to the late 1970s that were intended to increase competition in electricity markets throughout the nation. By 1996, a restructuring plan was enacted to change the sources and pricing of electricity for customers of three large investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Together, those utilities served almost three-quarters of the state's electricity users. (The rest were served mainly by publicly owned, or municipal, utilities, which were not covered by the plan.) California's restructuring plan was based on the assumption that greater competition among independent power generators would cause wholesale prices for electricity to fall. That assumption seemed reasonable in part because in the mid-1990s, generating capacity in the western states exceeded the demand for electricity by roughly 20 percent.

By the summer of 2000, however, demand for electricity had outpaced the generating capacity available to supply the market. The reasons for that change included increases in the demand for electricity throughout the region (because of economic growth and weather) as well as losses of hydropower capacity and other conditions that limited power supplies. In that setting, the restructured wholesale market pushed electricity prices to unanticipated levels.

BOX 1.
A CHRONOLOGY OF ELECTRICITY RESTRUCTURING IN CALIFORNIA

1994: The California Public Utility Commission (PUC) begins a formal rulemaking procedure to consider approaches to restructuring the state's electricity market. That action builds on changes in federal law and regulation that began with the Public Utilities Regulatory Policy Act of 1978 and continued with the Energy Policy Act of 1992.

1996: California law AB 1890 codifies various regulatory changes and initiatives by the PUC. Those changes include requiring the state's three major investor-owned utilities—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—to sell half of their fossil-fuel capacity (they eventually sold all of it); transferring control of electricity transmission to a newly created nonprofit corporation, the California Independent System Operator (CAISO); creating another nonprofit corporation, the California Power Exchange (PX), to run wholesale auctions of electricity; and freezing retail electricity prices until 2002 (or such time as the utilities recover certain costs). The California state auditor reports that the western states as a whole have excess generating capacity of roughly 20 percent.

1998: The California PX begins operating at the end of March. Between August 1998 and March 1999, market-monitoring, surveillance, and market-analysis groups of the PX and CAISO issue reports expressing concern about the functioning of California's wholesale electricity market.

June 1999: The CAISO's Surveillance Committee recommends that investor-owned utilities be granted more authority to enter into long-term contracts.

July 1999: SDG&E recovers its stranded costs (the decline in the value of certain assets, such as generating facilities and long-term contracts with other suppliers, because of restructuring). As a result, it is allowed to charge its customers market prices for electricity.

2000: Growth of income in California and neighboring states—which affects the demand for electricity—accelerates. In California, total personal income, which had grown steadily since the restructuring debate began, jumps by about 9 percent from its level in 1999.

April 2000: The price that California's electricity generators pay for natural gas begins to climb from about $3.50 per thousand cubic feet (reaching more than $6 by November).

May 2000: The summer cooling season begins. May and June 2000 rank among the 15 hottest May-June periods of the past 100 years.

June 2000: Rising wholesale prices for electricity consistently exceed the frozen retail price. As a result, PG&E and SCE must sell purchased power at a loss. Customers of SDG&E, by contrast, pay the market price, which is three times higher than it was the previous summer. On June 14, PG&E interrupts service for the first time in its history, which affects 100,000 customers in San Francisco.

August 2000: The estimated annual prices that generators pay for pollution credits—which reflect the costs of producing electricity from fossil-fuel plants—rise to $30 per credit (from $10 in June). They reach $45 per credit by December.

BOX 1.
CONTINUED

September 2000: California enacts a law rolling back and freezing retail rates for SDG&E customers at the 1996 level.

October 2000: The PUC permits Southern California Edison to increase its short-term borrowing authority from $700 million to $2 billion to pay for power in the wholesale market.

November 2000: PG&E and SCE file for rate increases to cover power costs they could not collect from consumers. The Federal Energy Regulatory Commission (FERC) releases a report describing how market design and flawed regulatory policies in California have contributed to high prices.

December 2000: The CAISO declares many Stage 3 emergencies, warning of the prospect of blackouts as electricity reserves (the amount by which available generating capacity exceeds demand) fall below 1.5 percent during periods of peak demand. The U.S. Department of Energy orders electricity generators outside California to sell to the state's wholesale market. FERC imposes "soft" price controls (limits that may be exceeded in emergency circumstances) and directs California's investor-owned utilities to negotiate long-term supply contracts and reduce their reliance on the wholesale market.

January 2001: The PUC approves retail rate hikes for PG&E and SCE. The CAISO orders rolling blackouts on several occasions. Emergency orders by the governor direct the state's Department of Water Resources to buy power in response to the deteriorating financial condition of the three large investor-owned utilities. The PX suspends operations.

February 2001: The state negotiates and signs long-term agreements to buy power. It begins implementing a strategy intended to restore the financial health of the utilities, which includes having the state purchase major transmission lines.

March 2001: Rolling blackouts occur statewide. FERC directs 13 power suppliers to refund $69 million that it says they overcharged utilities in January. The PUC approves immediate increases in retail rates.

April 2001: PG&E declares Chapter 11 bankruptcy. Standard & Poor's downgrades California's bond rating (from AA to A-plus) because of the state's additional borrowing to address its electricity problems.

May 2001: California authorizes a $13 billion bond issue to finance its purchases of electricity. The North American Electric Reliability Council warns that the state could face 260 hours of rolling blackouts during the summer.

June 2001: FERC announces a price-mitigation plan for all of the western states, with wholesale prices to be capped at a level reflecting the highest cost of generating electricity in California.

July 2001: Moderate temperatures help keep the demand for electricity lower than during the previous summer. Even though water levels in the streams used to generate hydropower are low, declining demand for electricity and falling natural gas prices combine to push wholesale electricity prices to the lowest level since the spring of 2000. Prices in the spot market fall far below the level that the state is paying for electricity under its long-term contracts.

As the three large investor-owned utilities faced spiraling financial difficulties, and disruptions in electricity supplies appeared possible, some observers began to question whether the old regime (power monopolies overseen by state regulators) did a better job of meeting the demand for electricity than the new ideal (many independent producers interacting with consumers in a deregulated market). Observers pointed out that the parts of the California market outside the restructuring plan (mainly in the Los Angeles and Sacramento areas) faced fewer problems than the rest of California, as did the other western states. By mid-2001—in the wake of one bankrupt utility, even higher wholesale prices, and rolling black-outs—skeptics blamed deregulation for putting California in a perilous position.

The Role of Restructuring

Much of the blame for California's electricity crisis attaches to the state's restructuring plan—but not to its objective, electricity deregulation. The state's plan gained political support on the basis of what turned out to be faulty assumptions. It then played a role in turning market stresses—high demand for electricity and limited production capacity—in the summer of 2000 and beyond into a full-blown crisis, in which California's major utilities could not buy enough power to supply their customers. But deregulation itself did not fail; rather, it was never achieved.

The restructuring plan did not remove sufficient barriers on both the supply and demand sides of the market to allow competition to work—in part because it was not designed to. Neither the state legislature and Public Utility Commission (PUC), which framed the plan, nor the Federal Energy Regulatory Commission, which approved it, envisioned the immediate or full deregulation of the electricity market covered by the plan. Instead, retail prices were to be frozen during an interim period. After that, the PUC would continue to oversee how much the utilities could charge their retail customers for generating or distributing electricity.

In addition, the market outside the restructuring plan mostly remains regulated. The California PUC has no authority over municipal utilities in the state, utilities in neighboring states, federal power agencies, or interstate transmission companies. All of those entities are still subject to local and federal controls. The continuing regulation of utilities in other parts of California and in neighboring states contributed indirectly to California's supply problems by limiting how much power those utilities were able or willing to sell outside their traditional service areas.

Even without restructuring, California's electric utilities would have faced a difficult challenge in meeting the demand for power and holding down prices in 2000. But at several key points during the unfolding crisis, features of the restructuring plan limited the responsiveness of the supply and demand sides of the electricity market.

Consequently, wholesale electricity prices were higher than they probably would have been in either a traditionally regulated market or a more fully deregulated market.

On the supply side, the plan's freeze on retail prices left the three big utilities in a financial shambles when wholesale prices in the spot market—where those utilities were acquiring nearly half of their power—rose above the freeze level. The plan made the utilities particularly dependent on that market in two ways: it encouraged them to sell their fossil-fuel generating capacity, and it discouraged them from signing new long-term supply contracts that could have protected them from adverse movements in prices.

Faced with a universal-service requirement (they could not unilaterally drop customers) and with a negative cash flow on nearly half of their sales, the utilities saw their losses mount. Lenders downgraded their creditworthiness, thus raising their costs for new borrowing. Moreover, independent power generators were able to push up wholesale prices further and even withdrew supplies when it looked as though the utilities might not be able to pay for their purchases. That happened in part because elements of the plan's auction system for the spot market appear to have created strong incentives for suppliers to bid strategically in a way that raised wholesale prices. Some generators may also have withheld supplies at certain times to boost prices even more.

On the demand side, two problems coincided. Extreme weather and strong economic growth put stress on the market by increasing the use of power. At the same time, the freeze on retail prices magnified the impact of that stress on wholesale prices by eliminating incentives for consumers to conserve power. Even a small drop in electricity use—like the decline that occurred in San Diego when the price freeze there was temporarily lifted—would have been enough to let the state avoid some of the disruptions it has faced.

The State's Response

The developments in California's electricity market and the failure of the state's restructuring plan provoked a political crisis. At the direction of the governor, the state began taking steps in January 2001 to help secure future electricity supplies and stabilize wholesale prices. The state has assumed a new role in purchasing wholesale power on behalf of private utilities. It is also moving toward establishing a state-owned utility that, in addition to buying power, would own an extensive transmission grid and build new generating plants. Moreover, the state has abandoned the retail price freeze, raising rates to ensure that consumers help cover its costs of buying power.

In addition, the state has negotiated long-term contracts, lasting up to 20 years, with electricity suppliers. The potential cost of that intervention became apparent in the summer of 2001 when electricity prices in the spot market dropped in response to mild weather and lower demand, falling below the price the state was paying under its long-term contracts. If that situation persists, Californians could be committed to paying high electricity prices for many years to come—the prospect that led to restructuring in the first place.

Lessons for the Future

Market restructuring and concerns about electricity prices and supplies are still important issues in many parts of the country. This past summer, the California market returned to a semblance of normalcy because of slower economic growth, moderation in the extreme weather conditions that had boosted demand for electricity, and a decline in the high prices for natural gas that had inflated the cost of generating power. But the electricity market in the western United States is likely to remain vulnerable to new stresses (for example, water levels in streams used to generate hydropower remain low). Some observers have warned that the problems in California might appear in other states.

California responded to its immediate concerns about the availability of electricity and the volatility of prices by directly intervening in the market—a response that could prove costly to electricity consumers and taxpayers. Long-term solutions to California's electricity problems will most likely require three changes: removing barriers to the addition of generating capacity, eliminating bottlenecks in the electricity transmission system, and removing regulatory restrictions on the sale of power throughout the broad western market. Those actions would help make the supply of electricity more responsive to changes in prices. On the demand side, the prospects for successful restructuring would also improve if consumers faced the full costs of electricity and were better able to adjust their use of power in response to changing prices.

California's decision to restructure its electricity market came in response to changing federal regulation of such markets beginning in the 1970s and to criticism of the state's market in the early 1990s. Consensus developed about two issues: first, that regulated producers and markets delivered electricity at too high a price, and second, that the future prospects for business investment in California were being hurt because the state's electricity prices were higher than those in other western states.

Electricity prices were high in California partly because the regulated market, by assuring producers of a high rate of return on their investments, provided incentives to build too much generating capacity. Policymakers, however, considered such excess capacity a saving grace of the system when California's restructuring plan took effect. Capacity in excess of demand was a key to ensuring that wholesale prices would fall with competition.

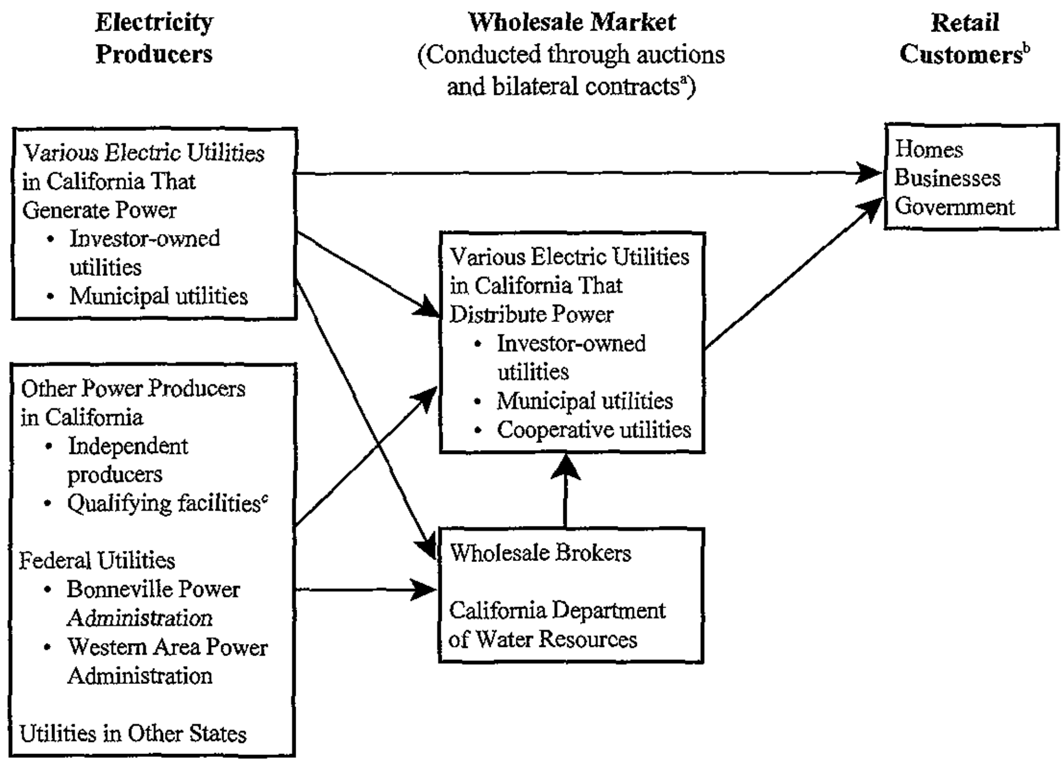
The plan required the state's three large investor-owned utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric—to sell part of their generating capacity. It also discouraged them from entering into long-term supply contracts with independent power producers. As a result, the utilities had to rely on the newly created spot wholesale market for about half of the electricity that their customers demanded.[1] (For more details about how the electricity market in California operates, see Figure 1.)

California's restructured electricity market functioned adequately at first, although hot, dry weather throughout the West in 1998 put pressure on the system (by increasing the demand for air conditioning and reducing the stream flows necessary for generating hydroelectric power).[2] By 2000, however, it was clear that capacity no longer comfortably exceeded demand. Since 1996, when the restructuring plan was enacted, generating capacity in California and the West had changed little, although the size of the population and the economy—which affect the demand for power—continued to increase. During the summer of 2000, the previous margin of electricity reserves was eroded by further increases in demand for electricity (because of economic and weather conditions) as well as by losses of hydropower capacity and other supply circumstances. In response, electricity prices rose to unheard-of levels. By 2001, utilities were facing bankruptcy, wholesale prices were continuing to rise, and customers were experiencing rolling blackouts. Skeptics about

1. In spot markets, transactions are made for immediate delivery (unlike futures markets, where transactions are made for delivery from one month to one year in the future).

2. For a discussion of early pressures on the electricity market, see California State Auditor, *Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Markets, Unsuccessful Oversight, and Uncontrollable Competitive Forces* (Sacramento: California State Auditor, March 2001).

FIGURE 1. WHO SELLS TO WHOM IN CALIFORNIA'S ELECTRICITY MARKET



SOURCE: Congressional Budget Office.

a. The California Independent System Operator conducts wholesale auctions of electricity. In addition, the California Power Exchange conducted such auctions until it was shut down in January 2001.

b. California's restructuring plan allowed customers to buy electricity directly from independent producers and brokers, but virtually all customers stayed with their traditional utility supplier as long as the freeze on prices remained in effect.

c. Producers who use renewable energy sources or cogeneration (waste heat from industrial processes) to make electricity.

the restructuring plan blamed it for placing California in a perilous position and for pushing up the cost of electricity in other western states as well.

Before Restructuring

California's electricity market is part of a larger, interconnected electricity grid called the Western Interconnect. The Interconnect comprises 11 western states (as well as parts of western Canada and northern Mexico) that effectively constitute one large market for electricity. What happens to supply or demand in one part of the region will influence prices in the other parts. For example, changes in the capacity to generate hydroelectric power—the cheapest source of electricity—in Washington

State can affect the supply of electricity available to all power-importing states in the Interconnect.

California is a net importer of power from its neighbors. In 1996, the state's utilities sold about 20 percent more electricity to their customers than was generated by local plants.[3] Typically, however, the state's utilities and independent power producers also sell to other states, and in certain seasons, the net flow of power is out of California.

For years, electricity prices were much higher in California than in neighboring states. In 1996, the average price to California households and businesses was 9.5 cents per kilowatt hour (kWh)—75 percent more than the average price in the 10 other western states.[4] A big part of that difference resulted from the greater availability of cheap hydropower in other parts of the West. California's policymakers could not alter the allocation of western hydropower, which depends on nature (the location of rivers) and federal policy (regional preferences in the sale of federal hydropower). But they could address two other factors that caused high prices: the structure of California's market (regulated monopolies) and state policies to support alternative energy. The fact that the state's utilities were facing increasing market pressure from independent power producers gave policymakers an extra impetus to do something about high prices.

<u>Inefficiencies of Regulated Monopolies</u>. Before restructuring, California's electricity was supplied by a mixture of large private utilities (owned by investors) and municipal power companies (owned by cities and counties). About 70 percent of Californians were customers of the state's three large investor-owned utilities.

To varying degrees, those utilities were vertically integrated, meaning that they were involved in all phases of their industry, controlling much of the generation, transmission, and distribution of electricity in their respective service areas.[5] They also functioned as regulated monopolies, meaning that each was the only utility that could operate in its service area, though with certain restrictions. The state's Public Utility Commission (PUC) approved the retail prices that those private utilities could charge for electricity and oversaw the reliability of their service. The Federal Energy Regu-

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3. Energy Information Administration, *Electric Power Annual 1996*, vol. 1, DOE/EIA-0348(96)/1 (August 1997), Tables 9 and 23, and *Electric Power Annual 1996*, vol. 2, DOE/EIA-0348(96)/2 (February 1998), Table 63.

4. Energy Information Administration, *Electric Power Annual 1996*, vol. 2, Table 6.

5. Transmission is the movement of power over high-voltage lines from generators to local utilities. Local distribution systems then carry that power over low-voltage lines to households and businesses. Before restructuring, San Diego Gas and Electric had the lowest level of vertical integration of the three large utilities. It purchased about half of the power that it sold (rather than generating that power itself).

latory Commission (FERC) was responsible for approving the wholesale prices that electricity producers could charge utilities for power and the rates that utilities could charge for the use of their transmission lines.

Under traditional regulation, the private utilities were allowed to charge prices that recovered their costs of production and gave investors a large enough return to attract ample capital for the utilities. Economists have long pointed out that such regulation encouraged utilities to overinvest in electricity-generating capacity because the cost of additional capacity could be more than covered by higher electricity prices. Indeed, in the mid-1990s, California's private utilities had much more generating capacity than they needed to supply their customers.

The Cost of Supporting Renewable Energy and Cogeneration. Another factor that contributed to high electricity prices in California before restructuring was federal and state policies that ordered utilities to buy electricity generated from alternative energy sources. The federal Public Utilities Regulatory Policy Act of 1978 required utilities to purchase all of the power generated by smaller producers known as qualifying facilities. Those producers generate electricity from renewable sources of energy (such as wind power) or as a by-product of manufacturing (a process called cogeneration). The 1978 law let the individual states set the prices that the utilities would pay for power generated from those sources.

Initially, California's PUC decided that the price for power from qualifying facilities should reflect the cost of the most expensive source of electricity—nuclear power. That decision was a boon to renewable-energy producers and cogenerators in the state, who could produce electricity much more cheaply than that. In 1995 (the last year for which data are available), California utilities paid an average of 12.3 cents per kWh for electricity from qualifying facilities, compared with only 4.2 cents per kWh for power from other sources.[6] As a result, electricity from qualifying facilities grew from less than 1 percent of the state's total generation in 1980 to about 20 percent in 1996.[7] That increasing reliance on alternative energy sources pushed up the average cost of power for utilities. But because regulators allowed the utilities to pass along the full cost of that power, their customers ended up bearing the brunt of the higher costs.

Competition from Independent Power Producers. California's large private utilities had little incentive to try to reduce their high costs so long as their customers (both retail customers and the municipal and cooperative utilities that purchased wholesale

6. Energy Information Administration, *Renewable Energy 1998: Issues and Trends*, DOE/EIA-0628(98) (March 1999), Table 9.

7. Energy Information Administration, *Renewable Energy 2000: Issues and Trends*, DOE/EIA-0628(2000) (February 2001), Table 6.

power from them) had little ability to choose other suppliers. Much of the momentum to restructure California's electricity market resulted from federal policies that supported the emergence of an independent power industry and gave the utilities' wholesale customers greater flexibility to shop for lower-cost supplies. Retail customers in the industrial sector also put pressure on the utilities because they had increasing incentives to switch to natural gas (and generate their own electricity) or relocate to regions with lower electricity prices.

One of the most important changes in federal policy was the Energy Policy Act of 1992, which encouraged the entry of new independent producers into electricity markets around the nation. Those independent firms increasingly sold power directly to municipal and cooperative utilities and worked with large industrial customers to develop cogeneration capabilities, which permitted those customers to supply part of their own power needs and sell excess power to the utilities. (Independent producers —many of which generate electricity from natural gas—and small producers that use renewable energy or cogeneration are known collectively as nonutilities; they are not generally subject to price regulations or universal-service requirements.) The 1992 federal law also provided incentives for utilities to spin off affiliated but unregulated independent power businesses. In addition, it gave independent producers open access to the utilities' transmission systems.

Before independents entered the market, California utilities had not faced competition. The utilities' high costs of generating power, as well as the costs of their long-term contracts with qualifying facilities, could be passed on to customers without financial harm to themselves. As competition spread, however, those generating plants and contracts increasingly became liabilities for the utilities; they eventually became known as stranded costs.[8] The utilities could not recoup those costs in a competitive market, where prices were expected to fall, unless regulators took some action, such as setting a floor for retail prices. Most of the potential stranded costs of California utilities resulted from long-term supply contracts. Any loss of wholesale customers or large retail customers to independent producers raised the prospect that the utilities' remaining customers would face even higher prices.[9]

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8. For a discussion of stranded costs, see Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs*, CBO Paper (October 1998).

9. Growing competition also threatened the utilities' ability to continue supporting state programs to promote energy conservation and renewable energy without raising prices for their remaining customers. Those programs include demand-side management (such as paying consumers to invest in efficient appliances), public benefit funds (which charge retail customers extra to pay for subsidies to renewable-energy producers), and renewable portfolio standards (which require utilities to supply a minimum percentage of their power from renewable sources).

The Restructuring Plan of 1996

Beginning in 1994, the California Public Utility Commission proposed a number of regulatory changes to the electricity market. Those changes—together with public law AB 1890, enacted in 1996—define the major elements of California's restructuring plan.

- The three large investor-owned utilities were required to divest themselves of at least half of their fossil-fuel-powered generating plants. (Fossil fuel includes natural gas, coal, and oil, but in California most of the fossil-fuel plants burn natural gas.)

- A nonprofit corporation, the Power Exchange (PX), was created to run wholesale electricity auctions, where the utilities were required to buy all of their power that was not coming from their own plants or from pre-existing contracts (primarily with qualifying facilities). That requirement effectively precluded the utilities from entering into long-term contracts with independent power producers because, until 1999, the PX did not sell such contracts.

- The utilities were also required to transfer control (though not ownership) of their transmission networks to another nonprofit corporation, the California Independent System Operator (CAISO).

- The restructuring plan froze retail prices for electricity until 2002 (or such time as the utilities recovered certain stranded costs).

- Finally, consumers were given a choice of continuing to buy power from their traditional utility or purchasing it from other suppliers—with the new supplier delivering power over the utility's distribution system and consumers being billed separately for power and distribution services. (Although many people believed that consumer choice was among the plan's most significant features, few customers actually switched suppliers while prices remained frozen.)

Sale of Generating Capacity. To promote wholesale competition among power generators, the plan required the state's three large private utilities to sell half of their fossil-fuel-powered generating capacity.[10] In the end, the utilities sold all of that capacity, although they kept virtually all of their hydropower and nuclear assets. The utilities also retained their long-term supply contracts with qualifying facilities,

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10. Energy Information Administration, *Electric Sales and Revenue 1999*, DOE/EIA-0540(99) (October 2000), Table 17.

although the plan gave them the resources to renegotiate the onerous pricing provisions of those contracts.

By September 2000, the effects of the required divestiture of generating assets were clearly visible. Power plants owned by the utilities provided just 28 percent of the electricity in the state's restructured power market, down from 40 percent the previous year. Meanwhile, the share from nonutilities in the state (independent power generators, including qualifying facilities) reached 58 percent, up from 40 percent in 1999.[11]

With that shift, the nonutilities assumed a more important role in determining prices in the new market. Under the plan's rules for wholesale auctions, wholesale electricity prices in the restructured market (like prices in other competitive markets) would be determined by the marginal cost—that is, the cost of the last and most expensive unit produced. Since divestiture, the utilities have generated their own electricity only from hydropower and nuclear power facilities. They usually operate those facilities to meet their base load requirements (the base level of their customers' demand for power, not counting daily and seasonal peaks in use) because of those facilities' low variable costs. The nonutilities, by contrast, generate most of their power from natural-gas-fired plants. Those plants also supply power for base load requirements, but they are especially important in meeting the increased requirements of peak periods. Thus, the contribution from gas-fired plants is critical in extreme market conditions such as those of 2000 and 2001, when demand rose to record levels and the utilities' supply from hydropower dropped. In those circumstances, the market price of electricity depends directly on the level of natural gas prices and the efficiency of operating gas-fired plants.

The Power Exchange. Most of the wholesale exchange of electricity between independent producers and the investor-owned utilities took place in a new market, under the aegis of the PX. Those utilities were required to buy power in that market. From 1998 until its termination in January 2001, the PX ran several different auctions, matching supply and demand and setting prices. Sellers submitted bids in the form of a supply schedule (how much they would supply at various prices), and buyers submitted bids in the form of a demand schedule (how much they would buy at various prices).

Initially, the PX conducted auctions only for power to be dispatched in each hour of the next day (the day-ahead market). Later, it added a block-forward market,

11. Data from the Energy Information Administration on existing capacity and planned additions to capacity for electric utilities and nonutilities are available at www.eia.doe.gov. In both 1999 and 2000, the rest of the market's electricity came from power generators in other states, including federally owned sources (such as the Bonneville Power Administration), and from municipal utilities in California. Much of that additional supply was generated from hydropower.

which allowed bids for blocks of hours for each day of the month, for one to six months in the future. In both types of auctions, the lowest-bid supplies were awarded first, but the price paid for all supplies was based on the last and most expensive unit of power sold (the marginal cost of supply in the market at that time).

The PX was shut down in January 2001 after its two largest customers, Pacific Gas and Electric and Southern California Edison, defaulted on payments for power they had purchased through the PX. At that time, sellers stopped offering electricity in PX auctions for fear of not being paid, and the exchange suspended participation by the two utilities. Much of the business formerly conducted through the PX moved to the CAISO or was replaced by direct contracts with the state government.

The California Independent System Operator. The plan's other new institution, the CAISO, took over the task of coordinating supply and demand in the state's electricity transmission system—a job that had formerly been done by the private utilities that owned the transmission lines. Electricity transmission requires the continuous balance of power supply with consumer use (or load): too much or not enough power at any moment can crash the entire system. The vertically integrated utilities that owned the lines had managed that balancing task. But with open access to transmission lines, there was concern that the utilities would give preference in scheduling to power from their own generators. A primary goal for the CAISO was to ensure nondiscriminatory access.

Besides scheduling power supplies from various sources for the next day (consistent with projections of next-day demand), the CAISO is responsible for acquiring access to additional supplies to meet unanticipated surges in demand or losses of generation. To that end, the CAISO operates a real-time market—an auction for acquiring power supplies in the next hour, separate from the auctions formerly run by the PX. (That real-time auction enables the CAISO to buy what the restructuring plan expected would be the small amounts of power necessary to balance the system.) To ensure adequate reserves and avoid the need for last-minute purchases, the CAISO conducts another auction for the provision of standby capacity. It can also forgo its auctions altogether by contracting with suppliers bilaterally in so-called out-of-market purchases. The CAISO then bills the utilities that distribute the electricity for its purchases on their behalf.

As carried out by the Public Utility Commission, the restructuring plan limited the ability of utilities to make long-term deals with independent power producers (other than qualifying facilities) by requiring them to buy all of the power they needed but did not generate themselves in the PX and CAISO markets. The restriction on long-term contracting effectively prohibited the utilities from participating in futures markets for electricity. That restriction, which was formulated as part of the 1996 plan, was eased somewhat in later actions. In 1999, the PX added the block-forward market to let utilities buy hourly blocks of power one to six months in advance. And in 2000, the PUC eased the limits on bilateral long-term contracts and futures trading.

One reason that California's restructuring plan restricted long-term contracts was to help ensure a competitive wholesale market by forcing a large share of power sales into the new PX and CAISO auctions. The plan's framers feared that if such contract arrangements were allowed, they would let the utilities maintain some degree of vertical control over independent producers and effectively thwart the goal of divestiture.

Retail Price Freeze. The plan mandated a reduction and freeze in the retail price of electricity. That provision had two goals. One was to allay consumers' fears that restructuring would force them to pay higher prices. The other was to assure the utilities that retail prices would not drop too much relative to wholesale prices, so they would be able to pay off their stranded costs. Accordingly, prices were supposed to be frozen at a level 10 percent below the 1996 level. The freeze was to last until 2002 or until the utilities had paid off their stranded costs—whichever came first.

As it turned out, however, the reduction in prices for consumers was close to zero because the state effectively loaned the utilities the present value of the 10 percent reduction for their immediate use in paying off stranded costs and then required them to repay that loan from a surcharge on customers' bills.[12] The remaining funds to repay stranded costs were to come from the utilities' sales of fossil-fuel-powered generating plants and from the difference between the retail price and the wholesale price that would be set in the new competitive marketplace.

Consumer Choice. Finally, to help ensure that electricity users would ultimately see the benefits of lower wholesale prices, consumers were immediately given the option to purchase their power directly from a retailing generator (or reselling middleman) of their choosing or to continue buying it from the utility that distributes the power.[13] Framers of the plan expected that when the plan was fully implemented (by 2002 at the latest), the retail price of electricity would reflect the wholesale price—what it cost for whichever producer customers had selected as their power source to generate

12. To make it easier for utilities to renegotiate contracts with qualifying facilities, the restructuring plan gave utilities the right to receive a stream of income from ratepayers—paid as a special surcharge on customers' power bills. In a process known as securitization, the utilities turned that right over to a state infrastructure bank in exchange for a cash payment. The state infrastructure bank then issued bonds that are backed by that stream of income. Unlike the case with debt that the utilities could issue themselves, income from those bonds is exempt from state taxes.

13. Following the lead of deregulation in natural gas and telephone service, the owners of the distribution network (which still held a monopoly) were allowed to charge a distribution fee for delivering power to those customers. The fee could include charges for other services and for state programs.

electricity. However, very few customers exercised their option to sign up with new suppliers until California directed the utilities to raise retail prices in March 2001.

Market Developments from 1996 Through 2001

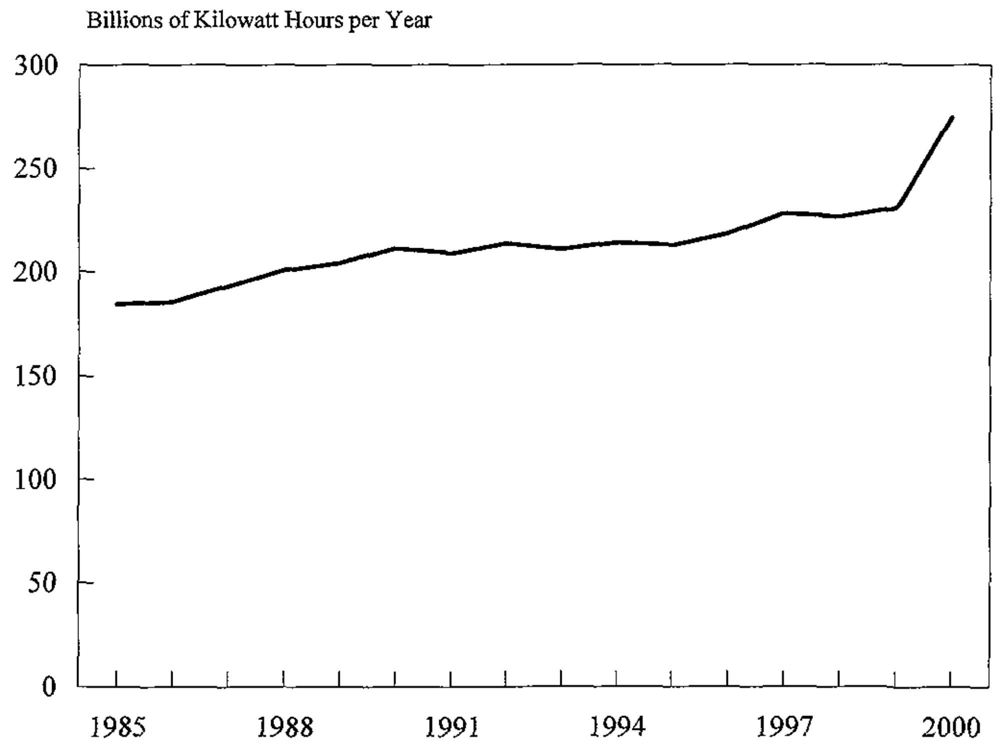
California's electricity crisis was precipitated by a convergence of long-term trends and special circumstances that created a scarcity of power and put upward pressure on electricity prices, not just in California but throughout the West. Several events are especially important to understanding the stress on electricity markets in the region. Strong economic growth in California and extreme weather throughout the West in the summer of 2000 pushed the demand for electricity to record levels. The excess generating capacity of the early 1990s had almost disappeared by that time, especially for peaking capacity (the generating capacity needed to meet the demand for electricity when it is highest). The amount of water flow in streams used to generate hydropower fell in 2000 from the high levels of 1999. And natural gas prices increased sharply, making it difficult to use gas to meet the increased demand for electricity or to replace hydropower without raising prices. In those tight market conditions, some characteristics of California's restructuring plan caused wholesale prices to rise well above what they might have been under the old regulated system or under a better restructuring plan.

Growth in Demand for Power Because of Economic Expansion. Increases in electricity consumption track increases in real (inflation-adjusted) personal income. In California, real personal income grew at an annual rate of 3.2 percent from 1994 through 1998, with a corresponding increase in electricity consumption of 1.5 percent a year.[14] In 2000, however, personal income in California grew by 9.3 percent, which contributed to a surge in demand for electricity (see Figure 2). That unexpected jump in demand put substantial upward pressure on prices.

Under normal circumstances, neighboring states in the Western Interconnect might have responded by selling more power to California utilities, which might have lessened the effect of strong demand on electricity prices. But their capacity to sell to California was strained as well. Those states had to accommodate their own growth in electricity consumption. For example, between 1994 and 1998, Arizona's electricity use grew by 3.8 percent a year, and Nevada's grew by 6.5 percent a year, rates much higher than the 1.5 percent annual growth that California experienced during those years.

14. See Bureau of Economic Analysis, "Regional Accounts Data," available at www.bea.doc.gov/bea/regional/data.htm. Real annual growth in 2000 was estimated by the Congressional Budget Office using BEA data for income and deflators for gross state product.

FIGURE 2. ELECTRICITY CONSUMPTION IN CALIFORNIA, 1985-2000



SOURCE: Congressional Budget Office based on data from Energy Information Administration, *Electric Power Annual*, vol. 1, DOE/EIA-0348/1 (various issues), Table A21.

Extreme Temperatures in Western States. Electricity consumption is also highly dependent on local weather conditions, which affect the demand for cooling in the summer and heating in the winter. For example, the California Energy Commission estimates that if summer temperatures are 5 degrees Fahrenheit higher than normal, California's electricity demand rises by 8.5 percent.[15] In a broad region such as that covered by the Western Interconnect, usually when one area is having extreme weather, such as sustained high temperatures, other areas will be experiencing moderate weather. As a result, regional demand for electricity tends to be more stable than local demand. Across the far western states, utilities have traditionally counted on a pattern of peak demand during the winter in the north (Oregon and Washington) and peak demand during the summer in the south (California, Arizona, and Nevada).

When unusually high or low temperatures occur throughout a broad area, however, demand for electricity in the region can rise significantly. In the summer of

15. California Energy Commission, *High Temperatures & Electricity Demand—An Assessment of Supply Adequacy in California: Trends & Outlook* (Sacramento: California Energy Commission, July 1999).

1998, such a coincidence of high temperatures occurred in California and the Southwest. As a result, California several times declared Stage 2 alerts, which authorized the disruption of interruptible service (service for those customers who pay less in exchange for being cut off in times of shortage). Those weather conditions represented the most extreme coincidence of regional temperatures since 1985 and were thought to be an isolated occurrence. But in the summer of 2000, they happened again, as temperatures stayed high for several periods all across California, Arizona, and New Mexico. Demand for electricity in California was 14 percent greater that summer than in the summer of 1999. Moreover, California's neighbors (which otherwise could have sent excess supply to the state) were experiencing high demand, too.

Weather conditions also had a constricting effect on the supply of power. The far northwestern states experienced earlier-than-normal winter temperatures in the fall of 2000, so little transition existed between summer and winter demand peaks for the entire western region. Because of that short transition, independent producers that had run aging gas-fueled generators at high capacity through the summer were not able to service those units fully during the normal autumn downtime. The result was added maintenance problems with natural gas facilities during the winter months.

Problems with Generating Capacity. The large, unexpected increase in electricity demand in 2000 came at an especially bad time, for two reasons. First, construction of generating capacity in the West had not kept pace with the long-term growth of demand. And second, unusually high levels of existing capacity in California—at times, nearly 10 percent of the state's generating capacity—were idle for maintenance and other reasons.

Between 1995 and 1999, generating capacity in the West remained essentially the same. Data from the Energy Information Administration on capacity at the region's electric utilities and nonutilities present a combined picture of the stagnation in capacity in the West (see Table 1).

When the restructuring debate began in California, the state had a large and costly reserve of generating capacity. But the state's early concern that high capacity led to high year-round prices, plus local opposition to new generating plants and an uncertain investment climate, contributed to a halt in construction of new facilities. (Uncertainty about market restructuring was probably not a major cause of that halt, since a similar lack of investment activity existed in surrounding states that did not restructure.) As California's reserve margin for electricity generation diminished in the late 1990s, it became more and more costly to boost local production to meet short-term increases in demand.

Besides limited capacity, the poor physical condition of existing generators heightened the western states' vulnerability to a severe market disruption in the face of higher demand in 2000. The California Energy Commission reported that in 1999,

TABLE 1. ELECTRICITY-GENERATING CAPACITY IN THE WESTERN STATES, 1995–1999 (In megawatts)

	1995	1996	1997	1998	1999
Electric Utilities (WSCC)	129,751	131,292	129,232	116,159	107,832
Nonutilities (Mountain and Pacific)	16,617	17,408	16,985	29,672	40,096
Total	146,368	148,700	146,217	145,831	147,928

SOURCE: Energy Information Administration, *Electric Power Annual 1999*, vol. 2, DOE/EIA-0348(99)/2 (October 2000), Tables 34 and 53.

NOTE: WSCC is the Western Systems Coordinating Council region (excluding Canada and Mexico) of the North American Electric Reliability Council. Nonutilities are independent electricity producers as well as some small producers (known as qualifying facilities) that use renewable energy sources or cogeneration to produce electricity. Mountain and Pacific are regions of the Census Bureau; figures for those regions include small amounts of generating capacity in Hawaii and Alaska.

about 60 percent of the state's oil- and gas-fired generating units—capacity that was critical for meeting peak-period demand—were at least 30 years old.[16] In part because of the maintenance demands of older equipment, a larger-than-usual share of the existing capacity in California was idle at the outset of the summer 2000 crisis.[17] Planned outages in April 2000 idled about 8,800 megawatts of capacity—nearly a fifth of the state's total. All but about 1,000 megawatts of that capacity came back on line in the next few months, but unplanned outages grew over the summer, reaching about 3,400 megawatts by August. During the subsequent winter crisis, unplanned outages in the state hovered around 4,000 megawatts, or about 10 percent of total generating capacity.[18]

The consequences of strong growth in demand, little growth in capacity, and idled generators show up in data on peak reserve margins. Traditionally, utilities have tried to maintain a large enough reserve of untapped capacity to meet peak-period

16. Ibid.

17. Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, Part I (November 1, 2000), Figure 2-12.

18. Federal Energy Regulatory Commission, *Report on Plant Outages in the State of California* (February 1, 2001), Figure 2.

demand (both seasonal and daily peaks).[19] With growing demand and idled capacity, peak reserve margins in California and the western region were already at historical lows before the summer of 2000.[20] In 1997 (the last year reported), the reserve margin in California and southern Nevada was only 7.8 percent, down from 14.3 percent in 1995 (just before California's restructuring plan was enacted). Those estimates are based on regional demand levels that do not assume a coincidence of extreme weather across states, such as occurred in 1998 and again in the summer of 2000.[21] As a result, they probably overestimate the actual ability of the western power market to meet demand in such circumstances. Since then, reserve margins have continued to shrink.

Problems with Hydropower Supplies and Natural Gas Prices. Electricity supplies in the West in the summer of 2000 were constrained and increasingly expensive because of several interrelated factors involving the supply of hydropower and the price of natural gas. Stream flows returned to normal levels in the western coastal states (from the high levels of 1999) and dropped below normal levels in the mountain states, reducing the region's capacity to generate electricity from hydropower. (In effect, the West had benefited from conditions that were especially favorable to hydropower in 1999, which had masked the problems of California's restructuring plan.) That reduction in hydropower forced the region to rely on more costly sources of electricity, particularly natural-gas-powered facilities owned by independent generators. At the same time, natural gas prices across the country began to climb toward record levels.

In 1999, the California Energy Commission estimated that the western states had just enough reserve generating capacity to accommodate another summer like that of 1998. In other words, regional demand could be met by fully utilizing all available capacity, assuming that stream levels across the West were, on average, at normal levels. That estimate also assumed that utilities would need to restrict sales to some customers with interruptible service, as they had in 1998. But in 2000, electricity generation from hydropower was lower across the western states than it had been in 1998, so noninterruptible service was threatened, too. In California, net generation from hydropower in 2000 dropped 13 percent from the above-normal level

19. Reserve requirements are set by the North American Electric Reliability Council. Membership in the council is voluntary.

20. California Energy Commission, *High Temperatures & Electricity Demand,* Table III-1.

21. Energy Information Administration, *Electric Power Monthly,* DOE/EIA-0226 (various issues), Tables 45 and 47. Although the North American Electric Reliability Council, which includes California utilities, does not require members to maintain a reserve margin (which includes allowances for scheduled maintenance and forced outages), it does require an operating margin of 5 percent to 7 percent, which could translate into a 15 percent reserve margin.

TABLE 2. NET ELECTRICITY GENERATION FROM HYDROPOWER AND NATURAL GAS IN 11 WESTERN STATES, FIRST NINE MONTHS OF 1999 AND 2000
(In millions of kilowatt hours)

	Hydropower		Natural Gas	
	1999	2000	1999	2000
Electric Utilities	154,020	126,955	29,846	35,995
Nonutilities	3,130	5,231	69,365	102,510
Total	157,150	132,186	99,211	138,505

SOURCE: Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(2001/01) (January 2001), Tables 10 and 65.

NOTE: Nonutilities are independent electricity producers as well as some small producers (known as qualifying facilities) that use renewable energy sources or cogeneration to produce electricity.

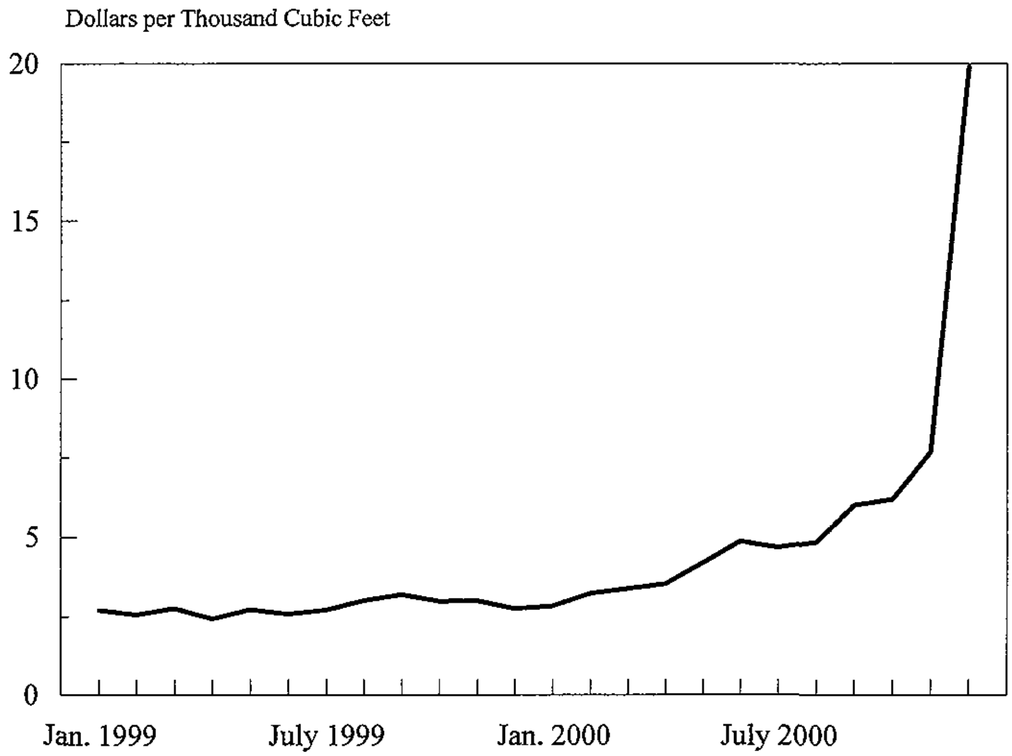
of 1999.[22] For the other western states, total hydropower production fell by 18 percent in 2000. In particular, Washington, Oregon, and Idaho—which the previous year had depended on hydropower for about 85 percent of their electricity generation (and had sent much of that power to California)—had to replace that low-cost energy with electricity from more expensive sources.

That loss of supply from inside and outside California put further upward pressure on electricity prices in the state and the region. As the demand for electricity increased relative to the supply in the summer of 2000, the western market turned increasingly to producers with natural-gas-fired generating plants (see Table 2). At the same time, the high cost of producing electricity from natural gas became greater still. The prices that electricity producers paid for natural gas had remained fairly stable—in the range of $2 to $3 per thousand cubic feet (mcf)—since the wholesale gas market was deregulated in 1986. Starting in April 2000, however, those prices rose significantly above $3 per mcf, reaching $4.90 per mcf by August (see Figure 3).[23]

22. Data for 1999 and the first 10 months of 2000 come from Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(2001/01) (January 2001), Table 11.

23. An increase of $1 per thousand cubic feet in the price of natural gas translates into an increase of $20 per megawatt hour in the cost of producing electricity; see Federal Energy Regulatory Commission, "Notice of Proxy Price for February Wholesale Transactions in the California Wholesale Electric Market," Docket No. EL00-95-018, available at www.ferc.gov/electric/bulkpower/feb_proxy.PDF.

FIGURE 3. PRICES THAT CALIFORNIA UTILITIES PAID FOR NATURAL GAS, JANUARY 1999 THROUGH DECEMBER 2000



SOURCE: Congressional Budget Office based on data from Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (various issues), Table 24.

The increase in natural gas prices was itself related to developments in the electricity market. Natural gas exploration and development lagged in the past decade because of relatively low prices for oil and gas, which meant that there was little excess capacity to absorb the increase in demand for gas in 2000 that resulted from the demand for electricity. Thus, that higher electricity demand most likely played a role in raising natural gas prices. Support for that view comes from the fact that prices paid for natural gas at the wellhead did not start increasing until June 2000, whereas prices for gas delivered to utilities were already rising two months earlier. Some observers contend that gas marketers actively restrained the supply of natural gas to California in order to push up prices. Evidence for such actions is not apparent, however—the average monthly prices that local distribution companies in the state paid for gas in the past year were not significantly out of line with prices in high-cost cities in the Northeast and the South.[24]

24. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (June 2001), Table 20.

Another factor that made supplying electricity from natural gas even more costly was the environmental controls that California adopted to carry out the federal Clean Air Act and its amendments. In particular, electricity producers and other industries in California that burn fossil fuels are required to hold credits for the right to emit nitrogen oxides (NO_x), a by-product of fossil-fuel combustion.[25] Buying NO_x credits represents a cost to producers who exceed the legal standard for NO_x emissions, generally reflecting their avoided cost of acquiring cleaner fuels or investing in technology to reduce emissions. The increased use of natural gas in mid-2000 meant that more credits had to be purchased. As a result, the price of the credits leaped from $4,000 per ton of emissions to more than $45,000 per ton during that year. For a natural-gas-fired turbine that emits two pounds of NO_x for each megawatt hour (mWh) of electricity it generates, credit prices at that level add about $45 per mWh to the cost of electricity.[26]

Cumulative Effects. By early 2001, California's restructuring plan was seen by virtually all observers as a failure. The rolling blackouts that occurred during the first few months of the year provided dramatic evidence of that failure—as did the soaring wholesale prices for electricity and the worsening financial condition of the large utilities that were subject to the plan. The prices that utilities paid for power to supply both the southern and northern California markets had generally been below $40 per mWh in the spring of 1998. Two years later those prices started rising dramatically, reaching a monthly average of more than $250 per mWh by the end of 2000 (see Figure 4). Although a precise total is difficult to determine, the press frequently reported that between the onset of the crisis and the first quarter of 2001, the three utilities lost a total of $12 billion to $14 billion. In April, Pacific Gas and Electric declared bankruptcy, claiming debts of $8.9 billion.

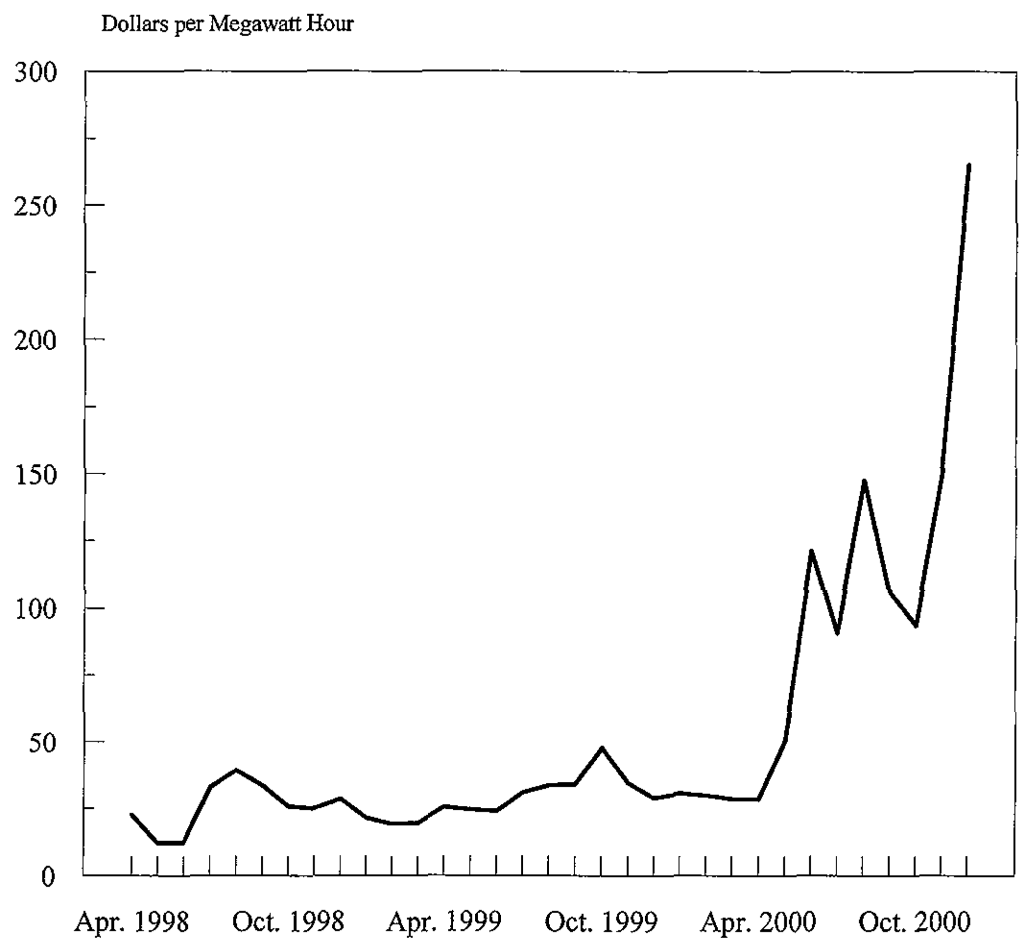
WHAT ROLE DID THE RESTRUCTURING PLAN PLAY?

When California's plan was enacted, the expectation of falling or (at worst) stable wholesale prices was the political glue that held together the conflicting interests who formulated and agreed to the plan. However, aspects of that plan—combined with

25. The goal of the NO_x credit program is to minimize the total cost of attaining a national standard for NO_x emissions. It requires the operator of a fossil-fuel-fired plant that emits NO_x in excess of the standard to purchase credits from other operators that generate extra credits by emitting NO_x in an amount below the standard. For more information about the NO_x program, see Congressional Budget Office, *Federalism and Environmental Protection: Case Studies for Drinking Water and Ground-Level Ozone* (November 1997), and *Factors Affecting the Relative Success of EPA's NO_x Cap-and-Trade Program*, CBO Paper (June 1998).

26. Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets*, Part I.

FIGURE 4. AVERAGE PRICES THAT UTILITIES PAID FOR ELECTRICITY IN THE CALIFORNIA POWER EXCHANGE'S DAY-AHEAD AUCTIONS, APRIL 1998 THROUGH DECEMBER 2000



SOURCE: Congressional Budget Office based on data for the northern and southern regions from the California Energy Commission (available at www.energy.ca.gov/electricity/wepr/monthly_day_ahead_prices.html).

limits on electricity supplies within the state and the rest of the West that were beyond the reach of the plan—amplified upward pressures on wholesale prices.

Analysts point to three features of the restructuring plan that go a long way in explaining how the stresses of extreme market conditions in the summer of 2000 pushed California's utilities into debt and led to supply disruptions in the state. Those features are the freeze on retail prices, the restriction on long-term contracts, and the design of the PX and CAISO markets. The first two features created a financial disaster for the investor-owned utilities when wholesale electricity prices began to rise. The third feature exacerbated those financial problems by letting independent producers avoid limits on wholesale prices and, perhaps, by enabling them to exercise their market power to raise prices even further. However, the restructuring plan did not and could not alter all of the western power market, much of which remained regulated by other states and the federal government.

The Price Freeze

Initially, the freeze on the price that retail customers could be charged for electricity acted as a price floor. The idea was that if wholesale prices fell (which they were expected to do), retail prices would not fall along with them. That would help maintain the utilities' cash flows, although it would also keep consumers from enjoying the benefits of competition at the wholesale level. In the summer of 2000, however, wholesale prices rose above the fixed retail price for a sustained period. When that happened, the freeze acted as a price ceiling: utilities could not pass on their rising costs to consumers.[27]

Not allowing retail prices to change with conditions in the wholesale market had three important effects. First, and critically, when wholesale prices rose, net cash flows for the investor-owned utilities fell, which made it impossible for them to continue distributing electricity profitably. Instead, they had to sell at a loss. Even though the utilities are required to meet all of their customers' needs for power, their financial difficulties have forced them to curtail service on several occasions (through brownouts and blackouts).[28] Second, the price freeze probably discouraged new retail sellers from entering the market. Third, the freeze diminished whatever incentive retail customers would otherwise have had to reduce their electricity use. Such a reduction could have helped dampen some of the upward pressure on wholesale prices.

Financial Problems for Utilities. The price freeze affected the wholesale market for electricity in ways that hurt the investor-owned utilities. As the financial condition of those utilities deteriorated (from having to operate at a loss), some producers demanded higher prices to sell power to the utilities to compensate for the risk that they would not get paid. Those fears proved to be realistic; the utilities stopped payments to the CAISO and to small independent generators or cogenerators of electricity. Some generators, such as those producing electricity from hydroelectric facilities, reportedly refused to sell to California utilities at any price until credit concerns could

27. As noted earlier, the freeze was intended to last until the three large investor-owned utilities recovered their stranded costs or until 2002 (whichever came first). In the summer of 2000, the freeze still applied to customers of two utilities, Pacific Gas and Electric and Southern California Edison. The freeze for customers of San Diego Gas and Electric had been lifted on July 1, 1999 (although it was reimposed later).

28. Brownouts involve decreasing the level of power supplied to customers (reducing the voltage); blackouts involve turning off power completely.

be resolved.[29] (Their reluctance was part of what prompted the state to assume responsibility for purchasing power on its own.) In addition, the large California utilities operate distribution systems for natural gas, and the severe fall in their electricity earnings jeopardized their ability to buy natural gas for resale to independent power generators.[30]

Fewer Retail Sellers. More subtly, the price freeze probably also discouraged some generators and marketers of electricity from selling power directly to retail customers in California. If the price faced by consumers who stayed with their traditional utility had tracked the wholesale price of power (even with various surcharges) rather than being frozen, the resulting variation in prices would have left room for retailers to offer fixed-price contracts to attract risk-averse consumers. Those alternative retailers would have been free to sign long-term contracts with suppliers or engage in other hedging activities to minimize the risk they faced in offering fixed prices to their customers—activities that the restructuring plan did not allow California's private utilities to pursue.

Little Incentive for Conservation. The retail price freeze also diminished the incentives for consumers to conserve electricity. The ability of consumers to greatly reduce electricity use on short notice is small relative to their total consumption. But relative to the size of the power disruptions that California has experienced so far, the ability to conserve could be significant. Reserve margins of less than 1.5 percent will trigger rolling blackouts; in the blackouts of March 2001, about 5 percent of California's households and businesses experienced a loss of service, which lasted for less than two hours. Even a very small percentage reduction in consumption could have helped avert such interruptions of service.

In San Diego, where retail customers briefly faced market prices in the summer of 2000, evidence suggests that higher prices caused a decline in power use. A doubling of retail prices led to a drop in demand of between 2.2 percent and 7.6 percent, depending on the hour of the day.[31] By September 2000, legislators had

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29. The U.S. Secretary of Energy (first William Richardson and then Spencer Abraham) has required generators to sell to the California market. The Secretary derives the authority to do that from section 202(c) of the Federal Power Act. If California utilities are ultimately unable to pay for electricity that the federal government requires generators to sell to them, it is unclear who will be responsible for those losses.

30. The U.S. Secretary of Energy has required natural gas suppliers to deliver to Pacific Gas and Electric. The Secretary derives the authority to do that from section 302 of the Natural Gas Policy Act and section 101(c) of the Defense Production Act.

31. James Bushnell and Erin Mansur, *The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego*, Working Paper PWP-082 (Berkeley, Calif.: University of California Energy Institute, Program on Workable Energy Regulation, April 2001), available at www.ucei.berkeley.edu/ucei/PDF/pwp082.pdf.

responded to public pressure by reducing and refreezing retail prices in San Diego, so customers there had no further incentive to curb their demand for electricity. Indeed, the opposite may have occurred, since consumers increased their use when prices dropped.

Although consumers' ability to reduce power consumption in response to higher prices is limited in the short term, it increases in the longer term. When they are faced with the full cost of electricity, residential customers have an incentive to buy energy-saving appliances, add insulation to their homes, or switch from electric to gas-fired appliances. Industrial customers can not only purchase energy-efficient equipment but also add their own power-generating facilities or even cogeneration facilities that harness waste heat from their industrial processes.

A price freeze that keeps consumers' costs low retards such reductions in the demand for electricity. By protecting consumers from price volatility, a freeze can also dampen their incentive to invest in the ability to alter electricity purchases on short notice—such as by owning auxiliary petroleum- or gas-fired generators—or even to sign up for interruptible service with their utility. The absence of a consumer response to price changes places a greater burden on suppliers to adjust to shifting market conditions.

The Restrictions on Long-Term Contracts

California's Public Utility Commission generally interpreted the restructuring plan as incompatible with allowing the utilities to contract for long-term power supplies outside the PX (until its termination) and the CAISO. That restriction applied to two types of long-term arrangements: contracts that the utilities made in the futures market and contracts in which the independent producers that had purchased the utilities' generating assets agreed to supply the utilities with a certain amount of electricity in the future.[32]

The PUC's opposition to long-term contracts was consistent with the plan's emphasis on creating a competitive wholesale market and giving that market a big role in determining the wholesale price of electricity. Indeed, in California, the spot market ended up supplying about half of the utilities' demand for power, on average, compared with only about 10 percent to 20 percent in other restructured service

32. The PX requested and was granted authority by the Federal Energy Regulatory Commission in several instances to offer forward contracts, including contracts for the block-forward market. Later, the PUC permitted the investor-owned utilities to participate in those new PX markets, although it limited the amount of power they could buy for future delivery. The PUC also reserved the right to review contracted prices for future reasonableness, so those new contracts did not effectively help the utilities guarantee a price for future delivery.

areas, such as Pennsylvania, New Jersey, Maryland, and the New England states.[33] California's reliance on spot-market purchases was even greater during periods of peak demand. But the utilities could not defend themselves against increases in wholesale prices by using their traditional recourse to self-supply or other risk-management strategies. The rationale for discouraging long-term contracting, like that for the retail price freeze, rested in large part on the assumption that available generating capacity would remain large enough to keep wholesale prices low.

Historically, California's big private utilities had not faced significant risk of adverse price movements caused by changes in supply or demand. In collaboration with the PUC, the utilities maintained a high margin of reserve capacity, which was included in their rate base and thus paid for by customers. (A high reserve margin contributes to reliability of service for consumers by making disruptions of service less likely in the event that generating units are unexpectedly idled or load increases.) Under the restructuring plan, by contrast, the new reliance on spot-market purchases and the retail price freeze made the utilities subject for the first time to the risk of financial loss if wholesale prices rose. Their ability to limit that type of risk was sharply curtailed by the plan's restrictions on the use of long-term supply contracts and futures markets and by the requirement that they sell much of their power-generating capacity.

It is not clear that the utilities recognized their new exposure to market risks or that they would have acted to reduce that exposure if they had been allowed to do so. Some accounts suggest that initially, the utilities did not want to sign long-term, fixed-price contracts because long-term prices were generally higher than the spot prices they were paying in the PX and CAISO auctions and they were trying to maximize cash flow to recover their stranded costs.

Had the utilities been able to enter into long-term contracts that guaranteed their future cost or supply of electricity, such arrangements would have helped diminish the shortage of power-generating capacity—and thus reduced the upward pressures on prices. Such long-term guarantees would have encouraged independent generators to build new capacity and would have improved the utilities' financial position, so generators might not have charged higher prices as compensation for the risk of nonpayment by the utilities.

Because the investor-owned utilities were not able to protect themselves from the risk of adverse movements in wholesale prices and because retail prices were frozen, consumers were exposed to the risk of losing service. Furthermore, the plan's heavy reliance on the spot market to meet peak-period demand potentially gave independent generators a great deal of power over that market.

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33. California State Auditor, *Energy Deregulation*, p. 24.

Flawed Auction Markets, Price Caps, and Market Power

The spot market for electricity created by California's restructuring plan comprised the PX and CAISO auctions, the rules governing those auctions, and oversight by the FERC. Prices in spot markets for electricity can change quickly and dramatically because both the short-term demand for electricity and (without a large reserve margin) the short-term supply are not very responsive to changes in price. In other words, in a tight market, only a very large price increase can produce the combined responses in demand and supply that are necessary to avoid a supply shortage.

As with many features of California's plan, the spot market might have worked better if a sufficient reserve of peaking capacity had existed, as was assumed when the plan took effect. Not only did the potential for large price increases grow as the reserve margin disappeared, but some analysts believe that features of the market's design contributed to even larger price increases. Those analysts point to the design of the PX and CAISO auctions, the price caps established for the CAISO market, and the withholding of supplies during certain periods.[34]

The design of the auction systems may have given individual sellers an opportunity to engage in strategic bidding to secure higher prices.[35] Sellers in the PX auctions submitted bids in the form of a supply schedule; the markets' operators then scheduled power generation by those individual sellers, from the lowest-cost to the highest, until all of the demand to be met by the auction had been satisfied. In the CAISO auctions, sellers submit single-price bids, subject to a price cap that may be lifted during emergencies. In both markets, the price paid to all successful bidders reflects the cost of the last and most expensive increment of supply from the highest bidder. Some analysts believe that the PX system gave sellers an incentive to submit supply schedules with relatively low prices (reflecting actual costs) for most of their sales and very high prices (exceeding costs) for the last units of power offered. The idea was that sellers expected sometimes to be awarded that top price for all of their sales but never risked not selling the bulk of their power.

The CAISO established price caps to eliminate the temporary spikes in prices that can occur during periods of peak demand. Those caps may have served as a focal point when sellers set the top price in their supply bids. That is, the existence of caps

34. For a discussion of competition in the California market, see Severin Borenstein, James Bushnell, and Frank Wolak, *Diagnosing Market Power in California's Restructured Wholesale Electricity Market*, Working Paper No. 7868 (Cambridge, Mass.: National Bureau of Economic Research, September 2000).

35. For a discussion of how the auctions and price caps operate, see California State Auditor, *Energy Deregulation*.

in the CAISO market may have encouraged bidding in the CAISO and PX markets at higher prices.[36]

The caps probably did not achieve their goal of effectively restraining prices. The CAISO had discretion to lift its caps altogether if it believed that a supply shortage was imminent. If sellers withheld supply in the day-ahead market—so that it looked to the CAISO as though a real-time shortfall was imminent—the CAISO was more likely to lift its caps. Indeed, independent power producers reportedly avoided the caps by selling some power to municipal utilities in California and to utilities outside the state for resale to the CAISO, since out-of-market sales by those utilities to the CAISO were never subject to caps.

It is also possible that individual sellers tacitly colluded to withhold supplies in order to push prices above competitive levels. Taking advantage of the designs of the auction system and price caps (to bid prices that exceeded costs) would enable those suppliers to realize above-market prices and profits from withholding supplies. However, evidence about how much, if any, capacity was withheld for competitive rather than legitimate operational reasons is unclear. Academic and legal debate continues over the extent to which the price increases of the past year resulted from exercises of market power by electricity generators. Discussions about whether specific laws have been broken focus on the Federal Power Act and its requirement that wholesale electricity rates be "just and reasonable," as well as on general antitrust statutes that prohibit price fixing.

Regulated Power Markets in California and the Rest of the West

Another way in which California's restructuring plan helped turn the market stresses of mid-2000 into a crisis was by not adequately taking into account how dependent the state's large investor-owned utilities were on other utilities, both inside and outside California. The legislation that authorized the plan did not require all utilities in the state to participate in the new market, and California law of course did not govern other states' utilities or federal power agencies. The three private utilities covered by the plan buy only a small part of their electricity from those sources; but at the critical margin, constraints on the flow of power into the new wholesale market probably influenced the source and cost of the last kilowatt hour of power, which determined the price for all of the electricity sold in the market.

36. From the buyers' perspective, the price cap in the CAISO auction would have represented the maximum price they would want to pay in the PX auction. If the PX price ever exceeded the CAISO price, buyers would reduce their demand bids in the PX auction and allow the CAISO to make purchases on their behalf.

Specifically, the restructuring plan did not include 38 municipal and cooperative utilities (most notably the Los Angeles and Sacramento municipal utility districts). It also did not cover three small investor-owned utilities in the state. Together, those excluded utilities account for about 30 percent of direct retail sales of electricity in California. The state's municipal utilities did not want to join the restructured electricity market for at least two reasons. First, they did not have the same high exposure to stranded costs that the private utilities did, and hence, they did not need the state's plan to recover those costs. Second, they receive a federal tax preference that could have been jeopardized if they had sold too much power, under the plan, to other utilities (see Box 2).

Other constraints on the flow of power to the wholesale market include various types of regulations, such as the regional-preference and average-cost-pricing rules of the utilities outside the restructuring plan and regulations that impede the regional transmission of electricity.

Regional-Preference Rules. Power from utilities outside California has not been completely free to flow in response to price signals in the state's wholesale market. Those utilities (like municipally owned and cooperative producers within the state) are required to meet the power demands of their service areas before exporting power to other markets, even if wholesale prices are higher elsewhere. Similar regional-preference rules make it difficult for more power to flow to California from the federally owned Bonneville Power Administration and Western Area Power Administration. Those agencies supply about 10 percent of the California market, on average—mainly through sales to municipal and cooperative utilities. But most of their relatively inexpensive hydropower goes to municipal utilities, cooperatives, and industrial customers in the northwestern states.[37]

The regional-preference rules of local utilities and federal power agencies have the effect of impeding energy flows across the western states largely because the customers of that power do not have full rights to its use. In particular, they do not have the right to resell the power on their own or to receive compensation if the utility sells it elsewhere. That restriction has weakened somewhat in the past year, with

37. The Bonneville Power Administration (BPA) may sell excess power at higher rates outside the region and does sell some power to California's municipal utilities. The Western Area Power Administration (WAPA) sells to municipal utilities and cooperatives throughout the West at prices established under terms similar to those for the BPA. The subsidies implicit in federal rate-setting and the reliance on hydropower cause federal rates to be much lower than prices from nonfederal producers. Although the BPA and WAPA are not free to sell to investor-owned utilities in California, both agencies engage in power swaps with those utilities, dispatching federal power today to be repaid with California utility power at a later date.

BOX 2.
MUNICIPAL UTILITIES AND THE FEDERAL TAX EXEMPTION FOR STATE AND LOCAL BONDS

Many local governments operate electric utilities, generally known as municipal utilities (or munis). The munis engage primarily in retail distribution, buying power from others and selling it to homes and businesses in their service areas. But some munis, including the Sacramento Municipal Utility District (SMUD) and the Los Angeles Water and Power District (LAWPD), also generate their own power.

The munis, like other state and local government entities, commonly issue bonds to pay for construction. The interest on such bonds is generally exempt from federal taxation. As a consequence, bondholders are willing to accept a reduced interest rate, and the munis can borrow at favorable rates. Federal policy favors the munis in other ways, too: by exempting their income from federal taxation and by giving them preferential access to low-cost federal power.

Federal restrictions on the use of the munis' borrowed funds have made California's munis reluctant to sell power to the state's investor-owned utilities for fear of losing the tax exemption on their bonds. The federal government limits the use of tax-exempt bonds in financing public facilities in order to prevent state and local officials from using the proceeds to make favorable loans to private businesses. Section 141 of the Internal Revenue Code generally allows no more than 10 percent of bond proceeds to be used by a private business if that business is receiving favorable electricity rates or is outside a muni's traditional service area. That private-use restriction applies over the life of a bond issue, and violation can result in the interest income becoming taxable retroactively.

Participation by munis in a restructured electricity market could violate the private-use rule and trigger taxation of interest payments on their bonds.[1] One example relates to munis' power sales. Selling power to utilities outside a muni's service area, if that power was generated by or transmitted over facilities financed with tax-exempt bonds that have not been paid off, could violate section 141. A second example relates to power distribution for others. Allowing investor-owned utilities to use a muni's distribution facilities that were financed with tax-exempt bonds that are still outstanding could also violate section 141. In 1999, the SMUD and LAWPD made about 15 percent of their power sales to other utilities. However, that electricity was generated at debt-free facilities (no longer subject to the private-use rule), was sold in short-term spot markets consistent with Internal Revenue Service regulations, or fit under the allowable limits on private use.

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1. See Dennis Zimmerman, *Electricity Restructuring and Tax-Exempt Bonds: Economic Analysis of Legislative Proposals*, Report RL30411 (Congressional Research Service, January 20, 2000).

some suppliers offering to pay large customers not to take power (as part of their programs for demand-side management) and others granting sale rights.[38]

Average-Cost Pricing. A common feature of power regulation in the United States is that a regulated provider of electricity sets a price that reflects its average costs. All of the utilities outside California's restructured market generally adhere to that pricing rule. However, average-cost pricing reduces incentives for the customers of those utilities to limit their consumption when power costs rise. Such conservation would help free up supplies that could be sold on the wholesale market.

Although some of those utilities have been forced to buy increasingly expensive power in the wholesale market to compensate for high demand and lost hydropower capacity, price increases to their local customers have been held down by the continuing low costs of the power they generate themselves or buy from the federal government. As with regional preferences, the problem here lies not just with average-cost pricing but with the rights to the power: customers would have full incentives to conserve in the face of rising spot prices if they could resell that power in the wholesale market.

Transmission Bottlenecks. Other types of regulation, related to the construction of transmission lines and the pricing of transmission services, also impede the flow of electricity from regions where it can be produced at the lowest cost to regions where consumers value it the most. Individual transmission systems are generally part of broad power grids that connect many states. For that reason, transmission services and rates are regulated by the federal government. (Only in Texas, where transmission is entirely within the state, is there no federal role.) Decisions about the construction and siting of transmission lines, however, are primarily a local affair. With the growth of nonutility suppliers and wholesale competition, power is moving across transmission lines in directions and volumes that the utilities that designed the systems did not envision. Those new flows have created bottlenecks in the delivery of power.

The building of new transmission capacity to remove bottlenecks is limited by two factors: the extent of local control over construction decisions and the way in which transmission services are priced. Requests for permission to build transmission lines must come from local utilities, which are state-franchised monopolies, and must be approved by local regulators. Investments that create opportunities for outside utilities or independent power producers to compete in a local market or that appear

38. A notable example is Kaiser Aluminum, which buys electricity from the Bonneville Power Administration. Kaiser chose to shut down its aluminum operations until the fall of 2001 (when its current contract with BPA expires) in order to resell its cheap BPA power to California. The BPA is acting as Kaiser's marketing agent, selling most of the power at full market prices minus a small marketing fee. Kaiser employees continue to be paid during the shutdown.

primarily to benefit other communities may be suspect. The siting of transmission lines is also dependent on local approval and environmental considerations.

The regulation of prices for transmission services may also mute economic signals about when and where to add new capacity. Most transmission lines in the United States are owned by private utilities or the federal government. The principal regulatory agency for private lines is the FERC, which sets prices for transmission on the basis of a utility's average systemwide cost of building and operating transmission lines, a fair market return on the utility's investment, and its current operating costs. The federal power agencies (such as the Bonneville Power Administration) are largely self-regulating. They set their own systemwide transmission rates on the basis of historical capital costs and current operating costs. The average-cost-pricing rules used by the FERC and the federal agencies do not provide incentives to add capacity to congested parts of the transmission grid.

CALIFORNIA'S RESPONSE: A NEW ROLE FOR STATE GOVERNMENT

A broad goal of restructuring in California was to secure the benefits of competition for electricity consumers in two ways: by breaking up the vertically integrated, state-regulated monopolies to create more wholesale suppliers, and by giving retail customers the chance to choose their power producer. However, the state's response to the crisis and its efforts to secure adequate electricity supplies and control volatile wholesale prices are leaving California with a new market structure.

The new market differs from the old regulated-monopoly system, from the interim restructuring plan, and from the competitive ideal that the state was working toward. Beginning in January 2001, the governor, the California legislature, and the Public Utility Commission acted to give the state a long-term role in buying wholesale power on behalf of private utilities. Lawmakers are also moving toward establishing a new state-owned utility that would not only buy power but also own and operate the transmission systems of the state's private utilities and build and operate new generating plants. The state has effectively abandoned the freeze on retail electricity prices, raising rates to help cover its costs of buying power.

The New Purchasing Agency

The California agency now charged with purchasing electricity is the Department of Water Resources (DWR). That department has become one of the largest buyers of electricity in the country. It has reportedly signed contracts that cover 90 percent of the wholesale purchasing requirements of the state's three large investor-owned utilities—or about one-third of California's total power use. In addition, a new agency, the California Consumer Power and Conservation Authority, will acquire generating capacity to supplement the state's supplies and sell the power it generates to the DWR. A new state bureaucracy will also be needed to manage much of California's transmission grid if the state is successful in taking over the transmission lines of the three large utilities.

California is planning the largest state or local bond issue in history—as high as $13.4 billion—in the fall of 2001 to finance its purchases of electricity and natural gas in 2001 and its acquisition of private transmission assets. Revenue from the sale of those bonds may also be used to help shore up the financial position of the private utilities. In the first seven months of 2001, the DWR spent about $9.5 billion from its general fund and from short-term borrowing to buy electricity and natural gas (recouping only about $1.5 billion from reselling that power to utilities). The agency made those purchases in the spot market for immediate delivery as well as in the markets for short- and long-term delivery, with signed contracts valued at over $45 billion. The contracts guarantee delivery for various periods, some as long as 20 years.

With the emergence of the DWR, the role of the state's private utilities and the PUC (which regulates those utilities) is diminishing. And with one large buyer replacing three utilities in the state's wholesale market, competition will most likely diminish as well. Those utilities may keep their nuclear and hydropower generating plants and their long-term supply contracts with qualifying facilities, but otherwise they will have a small presence in the wholesale market. Instead, the utilities will act as distributors of power purchased by the state, charging retail customers for the full cost of those purchases.

The future position of the state's independent power producers may also be in question. Not only are they facing fewer buyers, but their biggest customer, the state, may have the authority to seize their assets if it believes they are charging too much for electricity or restricting supplies. The California Senate passed a resolution in July 2001 indicating that it would support the governor in such a seizure.

In August, the PUC effectively yielded authority to the DWR to set retail electricity rates without public review in order to ensure sufficient revenues to cover its bond issue. (Both organizations are subject to direction from the governor's office, which appoints members to the PUC and selects managers of the DWR.) The PUC had already approved rate hikes in January and March to help cover the state's costs. In future, the state will direct the large private utilities to set rates that will repay expenses incurred in 2001 and cover the state's current costs of buying power. The state plans to secure its upcoming bond issue with those power revenues. The PUC will continue to oversee the part of the retail rate that covers the utilities' cost of generating electricity, having power purchased on their behalf, and distributing power. It is not clear which organization—the PUC, DWR, or a new agency—would decide what rates are necessary to finance operations of a future state-owned transmission grid.

Implications of the State's New Role

California's actions represent a blunt solution to the problems of insecure supply and volatile prices—a solution that ultimately may present the state with many of the same problems that restructuring was intended to solve. The goal of securing the benefits of competition appears to be farther away than ever. For example, tension exists between the state's need to raise rates to pay for the debt it incurred during the crisis and the right of ratepayers in a competitive market to contract with other power providers. In fact, since the rate hike of March 2001, some industrial customers have begun exercising their option to choose other suppliers. As a result, the state wants to rescind that option for all customers. The situation is similar to the one that prevailed before the crisis, when utilities with stranded costs opposed a rapid switch to a competitive system because it would leave them unable to recover those costs from ratepayers.

Two other factors that could make it harder to achieve the goal of competitive prices are the lack of transparency of state actions and the possibility of government subsidies to the state electricity business. In general, the state will not be subject to oversight in its rate setting. Electricity rates are supposed to cover financing costs, current power costs, and administrative costs. Because the state is actively concerned about security of supply, it may be putting too much emphasis on costly long-term contracts—much as the private utilities relied too heavily on risky spot-market purchases. Already, in July 2001, as demand and wholesale prices dropped with moderate weather in the West, the average cost of the state's power purchases ($133 per mWh) rose above the average price in the spot market ($82 per mWh).[39] Those and any future losses on power purchases will be passed on to consumers. Moreover, it is not clear what "administrative costs" of the state will find their way into retail electricity prices. With no oversight, California has already demonstrated its reluctance to publish information about the contracts it has signed or its costs of purchasing power and has released that information only under court order.

If the state cannot recover all of its electricity-related costs through retail prices, California taxpayers will have to make up the difference. In short, the state may be at risk of creating a major government-subsidized industry—an industry that private suppliers could be at a disadvantage in competing against.

39. California Department of Water Resources, "July Energy Costs Down Significantly" (press release, Sacramento, July 16, 2001), available at www.owe.water.ca.gov/newsreleases/2001/7-16-01energycosts.html.

LESSONS FOR FUTURE RESTRUCTURING EFFORTS

California's problems have occurred at a time when many other states are restructuring, or are debating the merits of restructuring, their electricity markets. The experience of California suggests several lessons for those states about both the supply and demand sides of electricity markets. In particular, if markets rather than regulation are to determine the price of power, prices must be allowed to respond when unanticipated disturbances occur—such as last year's very hot summer in the West. The supply and demand sides of the market together must be sufficiently robust to dampen such swings.

Supply-Side Lessons

The lessons for the supply side of the market are twofold. First, restructuring is more likely to succeed when more of the power in a market is free to respond to price signals. As California attempted to restructure, regulatory constraints limited the flow of power to the state's wholesale market from municipal utilities in California, from utilities in other states, and from federal power agencies. Second, utilities should be free to manage the risks of adverse price movements in that competitive environment by entering into long-term contracts. One lesson not to take from the California experience relates to the size of the reserve margin: building enough generating capacity to meet the demand for electricity under any scenario may not be cost-effective.

If restructuring is to allow supply to be more responsive to prices by moving power within the market, it must also address regulatory barriers to the construction and operation of transmission systems. A restructured market that works well will probably feature an immediate increase in the demand for transmission services, as communities increasingly acquire power from new sources in new locations not envisioned by the original designers of the transmission grid.[40] The regionwide costs of supplying electricity can drop if low-cost generators from some states in the region are able to provide more power than before. Moreover, the responsiveness of regionwide supply can improve if additional suppliers from part of the region are able to put more power into the grid to offset disruptions in supply locally or unexpected surges in demand elsewhere in the region. To realize those gains, however, consumers must be willing to accept a trade-off: the lower prices that result from access to out-of-state power supplies will sometimes rise when their state sends supplies to other parts of the region.

40. Any increase in the distance that power is transmitted will result in some additional transmission losses (about 9 percent of the electricity that leaves power plants is lost to heat transfer, which results from resistance in the power lines).

Making sure that transmission capacity does not limit the responsiveness of supply may require changing how transmission services are regulated and priced (to create appropriate incentives for new construction) and how new lines are approved. For example, some analysts have called for charging different, market-sensitive rates for transmission in different parts of the overall system—a practice known as node pricing—to provide greater incentives for construction to remove bottlenecks. The FERC believes that creating regional transmission organizations to operate large sections of the grid could help, too.[41]

Restructuring is also more likely to be successful if utilities are allowed to use standard risk-management tools. Letting utilities both enter into long-term contracts with suppliers at fixed prices and hedge through the futures market would help protect them from the financial difficulties that have plagued California's power distributors. It would also enable the utilities to offer greater price certainty to their customers (in place of a freeze on retail rates). That price certainty is important not just because it protects against high prices but because it creates a better climate for producers, distributors, and consumers.

Having a large reserve of generating capacity could ease the transition from a regulated to a competitive market structure. Indeed, if California had implemented its plan in the early 1990s, when the state's utilities still possessed more capacity than they needed, the market could have better handled the stresses that arose in the summer of 2000. That improved response could in turn have masked some of the faults of the restructuring plan.

Creating such a reserve as a matter of policy, however, is an expensive way to ensure price stability. One of the reasons that the state moved to a competitive market structure was to help reduce electricity prices by lowering the costs of the utilities' reserve capacity. In a competitive market, producers' investment in reserve capacity should be consistent with the amount of price stability (or, equivalently, supply security) that consumers are willing to pay for in the form of long-term supply contracts.

Demand-Side Lessons

California's freeze on retail rates inhibited the response of electricity users to the state's supply problems. Thus, it proved to be a major factor in the ensuing crisis. A simple lesson of that experience is that consumers need to face the real cost of electricity. Exposing consumers to price changes will induce them to increase their use of power when prices fall and curtail it when prices rise. When prices do not

41. See Federal Energy Regulatory Commission, "Regional Transmission Organization," Order No. 2000, *Federal Register*, vol. 65 (January 6, 2000), p. 809.

change along with costs, and when the amount of power demanded cannot respond to prices in that way, a greater adjustment must be made on the supply side of the market.

Price signals should encourage consumers not only to buy more or less power now but also to invest in the ability to adjust their future power use. Some of the same demand responsiveness that results from having consumers pay market prices may also be achieved if utilities either compensate customers for reducing their use or allow customers to resell power to others (in which case, a third party is paying them to reduce their use).

An important distinction exists between long- and short-term capabilities for lowering power use. In California, consumers have already responded over the years to high electricity prices by, among other things, adding thermal insulation to buildings, purchasing efficient appliances, and switching to natural gas. Those are long-term investments. Indeed, the state ranks among the lowest nationally in per capita use of electricity by households. However, electricity consumers—particularly households—have acquired few devices that would let them reduce electricity use on short notice, such as real-time meters (which would tell them when prices were changing), backup power supplies, or dual-fuel capabilities. One reason is that consumers do not usually face real-time prices (in particular, the full cost of generating electricity during peak-use times). Another reason is that although electricity prices in California have been high overall, they have historically been stable.

Some analysts believe that the supply adjustments and resulting price increases in California would have been much smaller if various techniques to manage demand had been in wide use before restructuring.[42] For example, several approaches can make real-time pricing easier, such as technologies that monitor electricity use and prices, and contracting arrangements with electricity suppliers that permit the customer (or a designated agent) to interrupt service when the price rises. In many cases, large industrial customers already have the capacity to monitor and adjust their demand in the face of rising prices and, in fact, do so. Successful restructuring may necessitate that residential and commercial customers acquire many of the same demand-management capabilities that industrial consumers have.

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42. See Stephen J. Rassenti, Vernon L. Smith, and Bart J. Wilson, *Demand-Side Bidding Will Control Market Power, and Decrease the Level and Volatility of Prices* (Tucson: Economic Science Laboratory, University of Arizona, February 2001); Severin Borenstein, *The Trouble with Electricity Markets (and Some Solutions)*, Working Paper PWP-081 (Berkeley, Calif.: University of California Energy Institute, Program on Workable Energy Regulation, January 2001), available at www.ucei.berkeley.edu/ucei/PDF/pwp081.pdf; and Paul Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector" (paper prepared for the Brookings-AEI Conference on Deregulation in Network Industries, December 10, 1999, revised February 17, 2000), available at http://econ-www.mit.edu/faculty/pjoskow/files/BrookingsV2.pdf.

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