BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 14-1297-EL-SSO

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Typical Bill Assumptions: Ohio Edison Company

Base Assumption: All rate and rider prices are as of July 1, 2014, except as noted below. All prices are expressed in dollars/kWh except the Rider DCR charge for GS (dollars per kW), GP (dollars per kW), and GSU (dollars per kVa) and the Rider EDR(d) charge (dollars per kVa).

	Period: ESP III								
	Rate	**RS**	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(1)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(2)	Delivery Capital Recovery Rider	$ 0.003621	$ 1.2847	$ 0.8679	$ 0.3624				
(3)	Residential Electric Heating Recovery Rider (RER2)	$ 0.002984							
(4)	Residential Generation Credit*	$ (0.008083)							

	Period: June 2016 - May 2017 (Year 1 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(5)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(6)	Retail Rate Stability Rider	$ 0.004558	$ 0.005720	$ 0.004715	$ 0.004044	$ 0.003694	$ -	$ -	$ 0.003597
(7)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(8)	Delivery Capital Recovery Rider	$ 0.004421	$ 1.5652	$ 1.0609	$ 0.4430				
(9)	Economic Development Rider								
(10)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(11)	(d) Transmission (Rate GT) Provision								
(12)	Credit					$ (0.013354)			
(13)	Charge					$ 6.00			
(14)	(e) Standard Charge Provision		$ 0.000660	$ 0.000645					
(15)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(16)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(17)	Alternative Energy Rider	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784
(18)	Residential Electric Heating Recovery Rider (RER2)	$ 0.002542							
(19)	Residential Generation Credit*	$ (0.005375)							

	Period: June 2017 - May 2018 (Year 2 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(20)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(21)	Retail Rate Stability Rider	$ 0.002875	$ 0.003608	$ 0.002974	$ 0.002551	$ 0.002330	$ -	$ -	$ 0.002269
(22)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(23)	Delivery Capital Recovery Rider	$ 0.005252	$ 1.8756	$ 1.2456	$ 0.5201				
(24)	Economic Development Rider								
(25)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(26)	(d) Transmission (Rate GT) Provision								
(27)	Credit					$ (0.008903)			
(28)	Charge					$ 4.00			
(29)	(e) Standard Charge Provision		$ 0.000660	$ 0.000645					
(30)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(31)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(32)	Alternative Energy Rider	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784
(33)	Residential Electric Heating Recovery Rider (RER2)	$ 0.002099							
(34)	Residential Generation Credit*	$ (0.002667)							

	Period: June 2018 - May 2019 (Year 3 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(35)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(36)	Retail Rate Stability Rider	$ 0.000284	$ 0.000356	$ 0.000294	$ 0.000252	$ 0.000230	$ -	$ -	$ 0.000224
(37)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(38)	Delivery Capital Recovery Rider	$ 0.006164	$ 2.2207	$ 1.4408	$ 0.6016				
(39)	Economic Development Rider								
(40)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(41)	(d) Transmission (Rate GT) Provision								
(42)	Credit					$ (0.004451)			
(43)	Charge					$2.00			
(44)	(e) Standard Charge Provision		$ 0.000660	$ 0.000645					
(45)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(46)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(47)	Alternative Energy Rider	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784	$ 0.000784
(48)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001664							
(49)	Residential Generation Credit*	$ -							

Notes
* Applicable only to RS - Electric Heating Customers for the period October 31 - March 31 for all kWh in excess of 1,250 kWhs consumed during each month. The price shown is annualized.

Typical Bill Assumptions: The Cleveland Electric Illuminating Company

Base Assumption: All rate and rider prices are as of July 1, 2014, except as noted below. All prices are expressed in dollars/kWh except the Rider DCR charge for GS (dollars per kW), GP (dollars per kW), and GSU (dollars per kW) and the Rider EDR(d) charge (dollars per kVa).

	Period: ESP III								
	Rate	**RS**	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(1)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(2)	Delivery Capital Recovery Rider	$ 0.006543	$ 2.9099	$ 1.1019	$ 0.7634				
(3)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001578							
(4)	Residential Generation Credit*	$ (0.006542)							

	Period: June 2016 - May 2017 (Year 1 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(5)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(6)	Retail Rate Stability Rider	$ 0.004702	$ 0.005735	$ 0.004443	$ 0.004353	$ 0.003546	$ -	$ -	$ 0.000927
(7)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(8)	Delivery Capital Recovery Rider	$ 0.007158	$ 3.1520	$ 1.2246	$ 0.8484				
(9)	Economic Development Rider								
(10)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(11)	(d) Transmission (Rate GT) Provision								
(12)	Credit					$ (0.013354)			
(13)	Charge					$ 6.00			
(14)	(e) Standard Charge Provision		$ 0.000627	$ 0.001111					
(15)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(16)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(17)	Alternative Energy Rider	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754
(18)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001209							
(19)	Residential Generation Credit*	$ (0.004333)							

	Period: June 2017 - May 2018 (Year 2 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(20)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(21)	Retail Rate Stability Rider	$ 0.002966	$ 0.003618	$ 0.002803	$ 0.002746	$ 0.002237	$ -	$ -	$ 0.000585
(22)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(23)	Delivery Capital Recovery Rider	$ 0.007839	$ 3.4607	$ 1.3354	$ 0.9252				
(24)	Economic Development Rider								
(25)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(26)	(d) Transmission (Rate GT) Provision								
(27)	Credit					$ (0.008903)			
(28)	Charge					$ 4.00			
(29)	(e) Standard Charge Provision		$ 0.000627	$ 0.001111					
(30)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(31)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(32)	Alternative Energy Rider	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754
(33)	Residential Electric Heating Recovery Rider (RER2)	$ 0.000839							
(34)	Residential Generation Credit*	$ (0.002125)							

	Period: June 2018 - May 2019 (Year 3 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(35)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(36)	Retail Rate Stability Rider	$ 0.000293	$ 0.000357	$ 0.000277	$ 0.000271	$ 0.000221	$ -	$ -	$ 0.000058
(37)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(38)	Delivery Capital Recovery Rider	$ 0.008441	$ 3.7386	$ 1.4307	$ 0.9912				
(39)	Economic Development Rider								
(40)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(41)	(d) Transmission (Rate GT) Provision								
(42)	Credit					$ (0.004451)			
(43)	Charge					$2.00			
(44)	(e) Standard Charge Provision		$ 0.000627	$ 0.001111					
(45)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(46)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(47)	Alternative Energy Rider	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754	$ 0.000754
(48)	Residential Electric Heating Recovery Rider (RER2)	$ 0.000484							
(49)	Residential Generation Credit*	$ -							

Notes
* Applicable only to RS - Electric Heating Customers for the period October 31 - March 31 for all kWhs consumed during each month. The price shown is annualized.

Typical Bill Assumptions: The Toledo Edison Company

Base Assumption: All rate and rider prices are as of July 1, 2014, except as noted below. All prices are expressed in dollars/kWh except the Rider DCR charge for GS (dollars per kW), GP (dollars per kW), and GSU (dollars per kVa) and the Rider EDR(d) charge (dollars per kVa).

	Period: ESP III								
	Rate	**RS**	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(1)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(2)	Delivery Capital Recovery Rider	$ 0.005381	$ 1.9735	$ 0.8000	$ 0.2139				
(3)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001429							
(4)	Residential Generation Credit (RGC 1)*	$ (0.004375)							
(5)	Residential Generation Credit (RGC 2)**	$ (0.006958)							

	Period: June 2016 - May 2017 (Year 1 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(6)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(7)	Retail Rate Stability Rider	$ 0.004776	$ 0.005852	$ 0.004976	$ 0.003953	$ 0.003489	$ -	$ -	$ 0.002082
(8)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(9)	Delivery Capital Recovery Rider	$ 0.005953	$ 2.1933	$ 0.8791	$ 0.2350				
(10)	Economic Development Rider								
(11)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(12)	(d) Transmission (Rate GT) Provision								
(13)	Credit					$ (0.013354)			
(14)	Charge					$ 6.00			
(15)	(e) Standard Charge Provision		$ 0.000323	$ 0.001409					
(16)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(17)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(18)	Alternative Energy Rider	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725
(19)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001346							
(20)	Residential Generation Credit (RGC 1)*	$ (0.002875)							
(21)	Residential Generation Credit (RGC 2)**	$ (0.004625)							

	Period: June 2017 - May 2018 (Year 2 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(22)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(23)	Retail Rate Stability Rider	$ 0.003013	$ 0.003692	$ 0.003139	$ 0.002494	$ 0.002201	$ -	$ -	$ 0.001313
(24)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(25)	Delivery Capital Recovery Rider	$ 0.006587	$ 2.4477	$ 0.9580	$ 0.2561				
(26)	Economic Development Rider								
(27)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(28)	(d) Transmission (Rate GT) Provision								
(29)	Credit					$ (0.008903)			
(30)	Charge					$ 4.00			
(31)	(e) Standard Charge Provision		$ 0.000323	$ 0.001409					
(32)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(33)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(34)	Alternative Energy Rider	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725
(35)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001262							
(36)	Residential Generation Credit (RGC 1)*	$ (0.001375)							
(37)	Residential Generation Credit (RGC 2)**	$ (0.002292)							

	Period: June 2018 - May 2019 (Year 3 of ESP IV)								
		RS	**GS**	**GP**	**GSU**	**GT**	**STL**	**POL**	**TRF**
(38)	Line Extension Cost Recovery Rider	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(39)	Retail Rate Stability Rider	$ 0.000298	$ 0.000365	$ 0.000310	$ 0.000246	$ 0.000217	$ -	$ -	$ 0.000130
(40)	Demand Side Management and Energy Efficiency Rider (DSE1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(41)	Delivery Capital Recovery Rider	$ 0.007143	$ 2.6798	$ 1.0228	$ 0.2734				
(42)	Economic Development Rider								
(43)	(c) Non-Residential Credit Provision					$ -	$ -	$ -	$ -
(44)	(d) Transmission (Rate GT) Provision								
(45)	Credit					$ (0.004451)			
(46)	Charge					$2.00			
(47)	(e) Standard Charge Provision		$ 0.000323	$ 0.001409					
(48)	(g) Infrastructure Improvement Provision	$ -	$ -	$ -	$ -	$ -			
(49)	(i) Automaker Charge Provision	$ -	$ -	$ -	$ -				
(50)	Alternative Energy Rider	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725	$ 0.000725
(51)	Residential Electric Heating Recovery Rider (RER2)	$ 0.001184							
(52)	Residential Generation Credit (RGC 1)*	$ -							
(53)	Residential Generation Credit (RGC 2)**	$ -							

Notes

* Applicable only to RS - Electric Heating Customers for the period October 31 - March 31 for all kWhs in excess of 2,000 consumed during each month. The price shown is annualized.

** Applicable only to RS - Apartment Rate Customers for the period October 31 - March 31 for the first 2,000 kWhs consumed during each month. The price shown is annualized.

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I. Estimated Rider RRS

Line	Description	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source / Calculation
1	Estimated Rider RRS (¢ / kWh)	0.5398	0.3672	0.1943	-0.2020	-0.3569	-0.3785	-0.3069	-0.3351	-0.2495	-0.4329	-0.3385	-0.5042	-0.5018	-0.6622	-0.4994	-0.1937	Attachment JMS-4
2	Monthly kWh	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	Assumption
3	Estimated Monthly Rider RRS	$4.05	$2.75	$1.46	($1.52)	($2.68)	($2.84)	($2.30)	($2.51)	($1.87)	($3.25)	($2.54)	($3.78)	($3.76)	($4.97)	($3.75)	($1.45)	Line 1 x Line 2 / 100

II. Estimated Energy and Capacity Charges

Line	Description	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source / Calculation
4	Energy Price ($ / MWH)	REDACTED - CONFIDENTIAL [redacted]																Rose Attachment II
5	Capacity Price ($ / KW-yr)	REDACTED - CONFIDENTIAL [redacted]																Rose Attachment III
6	Capacity Price ($ / MWh)	REDACTED - CONFIDENTIAL [redacted]																REDACTED - CONFIDENTIAL
7	Energy & Capacity Price ($ / MWH)	$61.94	$56.80	$64.62	$72.44	$82.55	$84.23	$85.51	$87.16	$90.49	$94.27	$98.10	$102.07	$106.14	$110.48	$114.54	$119.37	Line 4 + Line 6
8	Energy & Capacity Price (¢ / kWH)	6.1936	5.6796	6.4624	7.2436	8.2546	8.4231	8.5507	8.7157	9.0487	9.4270	9.8102	10.2067	10.6137	11.0478	11.4541	11.9367	Line 7 / 10
9	Monthly kWh	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	Assumption
10	Estimated Monthly Energy and Capacity Charges	$46.45	$42.60	$48.47	$54.33	$61.91	$63.17	$64.13	$65.37	$67.87	$70.70	$73.58	$76.55	$79.60	$82.86	$85.91	$89.53	Line 8 x Line 9 / 100

III. Rider RRS Impact on Generation Portion of Customer's Bill

Line	Description	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Source / Calculation
11	Estimated Monthly Rider RRS	$4.05	$2.75	$1.46	($1.52)	($2.68)	($2.84)	($2.30)	($2.51)	($1.87)	($3.25)	($2.54)	($3.78)	($3.76)	($4.97)	($3.75)	($1.45)	Line 3
12	Estimated Monthly Energy and Capacity Charges	$46.45	$42.60	$48.47	$54.33	$61.91	$63.17	$64.13	$65.37	$67.87	$70.70	$73.58	$76.55	$79.60	$82.86	$85.91	$89.53	Line 10
13	Estimated Energy and Capacity Charge with Rider RRS	$50.50	$45.35	$49.92	$52.81	$59.23	$60.33	$61.83	$62.85	$65.99	$67.46	$71.04	$72.77	$75.84	$77.89	$82.16	$88.07	Line 11 + Line 12
14	Percentage Reduction to Generation Portion of Bill	8.7%	6.5%	3.0%	-2.8%	-4.3%	-4.5%	-3.6%	-3.8%	-2.8%	-4.6%	-3.5%	-4.9%	-4.7%	-6.0%	-4.4%	-1.6%	Line 11 / Line 12

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OVEC Revenues
Page 1
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	OVEC	PY 16/17	PY 17/18	PY 18/19	PY 19/20	PY 20/21	PY 21/22	PY 22/23	PY 23/24	PY 24/25	PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30	PY 30/31	
(1)	Cleared MW Capacity (MW)	[redacted]															(A)
(2)	Capacity Rate ($ / MW-Day)																(B)
(3)	Total Capacity Revenues ($M)																L.(1) x L.(2) x 365

	OVEC	2016 (Jun - Dec)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031 (Jan - May)	
(4)	Calendar Capacity Revenues ($M)	[redacted]																5/12 x L.(3)$_{1st\ PY}$ + 7/12 x L.(3)$_{2nd\ PY}$
(5)	Facility Generation (GWHs)																	(C)
(6)	Energy Rate ($ / MWH)																	(D)
(7)	Total Energy Revenues ($M)																	L.(5) x L.(6)
(8)	Ancillary Revenues																	(E)
(9)	Other Revenues																	(F)

Sources:
(A) - PJM eRPM data for auctions that have occurred; FES forecast for future projections.
(B) - PJM RPM website for auctions that have occurred; Witness Rose forecast for future projections.
(C) - FE Dispatch Model
(D) - Witness Rose Forecast; Implied rate based on results of dispatch model
(E) & (F) - OVEC provided forecast

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OVEC Expenses
Page 2
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		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
	OVEC																	
(1)	Facility Generation (GWHs)	[redacted]																(A)
(2)	Fuel & Reagent Rate ($/MWh)																	(B)
(3)	Total Fuel Expense ($M)																	L.(1) x L.(2)
(4)	Total O&M Expense																	(C)
(5)	Total Fuel and O&M Expense																	L.(3) + L.(4)

Sources:
(A) - FE Dispatch Model
(B) - Witness Rose Forecast; Implied rate based on results of dispatch model

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Davis-Besse Revenues

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	Davis-Besse	**PY 16/17**	**PY 17/18**	**PY 18/19**	**PY 19/20**	**PY 20/21**	**PY 21/22**	**PY 22/23**	**PY 23/24**	**PY 24/25**	**PY 25/26**	**PY 26/27**	**PY 27/28**	**PY 28/29**	**PY 29/30**	**PY 30/31**	
(1)	Cleared MW Capacity (MW)	[redacted]															(A)
(2)	Capacity Rate ($ / MW-Day)	[redacted]															(B)
(3)	Total Capacity Revenues ($M)	[redacted]															L.(1) x L.(2) x 365

	Davis-Besse	**2016 (Jun - Dec)**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031 (Jan - May)**	
(4)	Calendar Capacity Revenues ($M)	[redacted]																5/12 x $L.(3)_{1st\ PY}$ + 7/12 x $L.(3)_{2nd\ PY}$
(5)	Facility Generation (GWHs)	[redacted]																(C)
(6)	Energy Rate ($ / MWH)	[redacted]																(D)
(7)	Total Energy Revenues ($M)	[redacted]																L.(5) x L.(6)
(8)	Ancillary Revenues	[redacted]																(E)
(9)	Other Revenues	[redacted]																(F)

Sources:
(A) - PJM eRPM data for auctions that have occurred; FES forecast for future projections.
(B) - PJM RPM website for auctions that have occurred; Witness Rose forecast for future projections.
(C) - FE Dispatch Model
(D) - Witness Rose Forecast; Implied rate based on results of dispatch model
(E) - FES internal forecast projection; FE Dispatch Model
(F) - FES internal forecast projection; FE Dispatch Model

Workpapers - JJL
Davis-Besse Expenses
Page 4
CONFIDENTIAL WORKING PAPERS

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Davis-Besse																	
(1) Facility Generation (GWHs)	[redacted]																(A)
(2) Fuel & Reagent Rate ($/MWh)	[redacted]																(B)
(3) Total Fuel Expense ($M)	[redacted]																L.(1) x L.(2)
(4) Labor	[redacted]																(C)
(5) Dues, Fees, & Licenses	[redacted]																(D)
(6) Lease/Rental Costs	[redacted]																(E)
(7) General Business & Travel	[redacted]																(F)
(8) Materials & Equipment	[redacted]																(G)
(9) Professional & Contractor	[redacted]																(H)
(10) Uncollectible Expense	[redacted]																(I)
(11) Other	[redacted]																(J)
(12) Other Deductions	[redacted]																(K)
(13) Construction Overheads	[redacted]																(L)
(14) State Reimbursed Programs	[redacted]																(M)
(15) Pension & OPEB	[redacted]																(N)
(16) Sale Lease-back Expense	[redacted]																(O)
(17) Service Company Expense	[redacted]																(P)
(18) Property Taxes	[redacted]																(Q)
(19) Insurance	[redacted]																(R)
(20) General Taxes	[redacted]																(S)
(21) Depreciation	[redacted]																(T)
(22) Accretion Expense	[redacted]																(U)
(23) Total O&M Expense	[redacted]																L.(4) thru L.(22)
(24) Total Fuel and O&M Expense	[redacted]																L.(3) + L.(23)

Sources:
(A) & (B) - FE Dispatch Model
(C) thru (U) - FES internal forecast

	Sammis	PY 16/17	PY 17/18	PY 18/19	PY 19/20	PY 20/21	PY 21/22	PY 22/23	PY 23/24	PY 24/25	PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30	PY 30/31	
(1)	Cleared MW Capacity (MW)	[redacted]															(A)
(2)	Capacity Rate ($ / MW-Day)																(B)
(3)	Total Capacity Revenues ($M)																L.(1) x L.(2) x 365

	Sammis	2016 (Jun - Dec)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031 (Jan - May)	
(4)	Calendar Capacity Revenues ($M)	[redacted]																$5/12 \times L.(3)_{1st\ PY} + 7/12 \times L.(3)_{2nd\ PY}$
(5)	Facility Generation (GWHs)																	(C)
(6)	Energy Rate ($ / MWH)																	(D)
(7)	Total Energy Revenues ($M)																	L.(5) x L.(6)
(8)	Ancillary Revenues																	(E)
(9)	Other Revenues																	(F)

Sources:
(A) - PJM eRPM data for auctions that have occurred; FES forecast for future projections.
(B) - PJM RPM website for auctions that have occurred; Witness Rose forecast for future projections.
(C) - FE Dispatch Model
(D) - Witness Rose Forecast; Implied rate based on results of dispatch model
(E) - FES internal forecast projection; FE Dispatch Model
(F) - FES internal forecast projection; FE Dispatch Model

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Sammis																	
(1) Facility Generation (GWHs)	[redacted]																(A)
(2) Fuel & Reagent Rate ($/MWh)																	(B)
(3) Total Fuel Expense ($M)																	L.(1) x L.(2)
(4) Labor																	(C)
(5) Dues, Fees, & Licenses																	(D)
(6) Lease/Rental Costs																	(E)
(7) General Business & Travel																	(F)
(8) Materials & Equipment																	(G)
(9) Professional & Contractor																	(H)
(10) Uncollectible Expense																	(I)
(11) Other																	(J)
(12) Other Deductions																	(K)
(13) Construction Overheads																	(L)
(14) State Reimbursed Programs																	(M)
(15) Pension & OPEB																	(N)
(16) Sale Lease-back Expense																	(O)
(17) Service Company Expense																	(P)
(18) Property Taxes																	(Q)
(19) Insurance																	(R)
(20) General Taxes																	(S)
(21) Depreciation																	(T)
(22) Accretion Expense																	(U)
(23) Total O&M Expense																	L.(4) thru L.(22)
(24) Total Fuel and O&M Expense																	L.(3) + L.(23)

Sources:
(A) & (B) - FE Dispatch Model
(C) thru (U) - FES internal forecast

COMPETITIVELY SENSITIVE CONFIDENTIAL

Workpapers - JJL
Davis-Besse Rate Base
Page 7
CONFIDENTIAL WORKING PAPERS

	Dec 31, 2013	Dec 31, 2014	Dec 31, 2015	May 30, 2016	Dec 31, 2016	Dec 31, 2017	Dec 31, 2018	Dec 31, 2019	Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Dec 31, 2023	Dec 31, 2024	Dec 31, 2025	Dec 31, 2026	Dec 31, 2027	Dec 31, 2028	Dec 31, 2029	Dec 31, 2030	May 30, 2031	
Davis-Besse																					
(1) Beginning Net Plant In-Service	[redacted]																				L.(4)$_{prev}$
(2) Annual CapEx In-Service																					(A)
(3) Annual Depreciation																					(B)
(4) End Balance - Net Plant In-Service																					L.(1) thru (L.3)
(5) Accum. Deferred Taxes																					(C)
(6) Service Co. Net Plant In-Service																					(D)
(7) Fleet Corp Support Plant In-Service																					(E)
(8) Capitalized Fuel																					(F)
(9) Materials and Supplies																					(G)
(10) Total Rate Base																					L.(4) thru L.(9)

Sources:
(A) & (B) - FES Internal Forecast
(C) - FE Tax Department Forecast
(D) thru (G) - FES Internal Forecast

Workpapers - JJL
Sammis Rate Base
Page 8
CONFIDENTIAL WORKING PAPERS

	Dec 31, 2013	Dec 31, 2014	Dec 31, 2015	May 30, 2016	Dec 31, 2016	Dec 31, 2017	Dec 31, 2018	Dec 31, 2019	Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Dec 31, 2023	Dec 31, 2024	Dec 31, 2025	Dec 31, 2026	Dec 31, 2027	Dec 31, 2028	Dec 31, 2029	Dec 31, 2030	May 30, 2031	
Sammis																					
(1) Beginning Net Plant In-Service	[redacted]																				L.(4)$_{prev}$
(2) Annual CapEx In-Service	[redacted]																				(A)
(3) Annual Depreciation	[redacted]																				(B)
(4) End Balance - Net Plant In-Service	[redacted]																				L.(1) thru (L.3)
(5) Accum. Deferred Taxes	[redacted]																				(C)
(6) Service Co. Net Plant In-Service	[redacted]																				(D)
(7) Fleet Corp Support Plant In-Service	[redacted]																				(E)
(8) Capitalized Fuel	[redacted]																				(F)
(9) Materials and Supplies	[redacted]																				(G)
(10) Total Rate Base	[redacted]																				L.(4) thru L.(9)

Sources:
(A) & (B) - FES Internal Forecast
(C) - FE Tax Department Forecast
(D) thru (G) - FES Internal Forecast

STAUB

WORKPAPERS

Daily Treasury Rates Historical Average: 1999-2014	
1-Year	2.22%
10-Year	3.92%
15-Year*	4.18%
30-Year	4.44%

Source: Federal Reserve Board (H.15 Schedules)
http://www.federalreserve.gov/releases/h15/data.htm
* Interpolated average of 10-Year and 30-Year Rates

ROSE

WORKPAPERS

PUBLIC VERSION

Return to TOC

Zonal Coincident Peak Demand and Energy Assumptions

Gross Peak Demand (MW)

Year	PJM RTO	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	DOM	EKPC
2014	**157,281**	2,644	6,989	4,021	6,111	2,895	8,493	2,830	6,602	7,034	10,216	406	190	22,567	8,476	12,791	22,272	3,309	5,340	2,861	19,431	1,803
2015	**160,259**	2,694	7,089	4,090	6,236	2,965	8,663	2,914	6,666	7,154	10,334	409	193	22,926	8,641	12,937	22,833	3,404	5,432	2,913	19,936	1,830
2016	**162,468**	2,728	7,151	4,141	6,316	3,015	8,773	2,976	6,705	7,242	10,416	412	196	23,148	8,758	13,013	23,156	3,460	5,484	2,948	20,584	1,846
2017	**164,195**	2,750	7,252	4,184	6,369	3,061	8,881	3,025	6,729	7,319	10,470	413	198	23,323	8,841	13,083	23,447	3,503	5,533	2,976	20,978	1,860
2018	**165,480**	2,765	7,333	4,219	6,393	3,091	8,973	3,060	6,755	7,371	10,500	413	200	23,467	8,903	13,116	23,646	3,532	5,563	2,998	21,308	1,874
2019	**166,899**	2,777	7,414	4,255	6,456	3,127	9,053	3,100	6,793	7,439	10,549	415	201	23,597	8,965	13,172	23,878	3,564	5,604	3,016	21,642	1,882
2020	**168,592**	2,796	7,483	4,295	6,510	3,168	9,140	3,143	6,861	7,507	10,604	417	203	23,752	9,049	13,253	24,197	3,600	5,659	3,041	22,015	1,899
2021	**170,026**	2,815	7,535	4,330	6,554	3,205	9,225	3,185	6,894	7,571	10,649	418	205	23,920	9,126	13,310	24,415	3,636	5,695	3,061	22,369	1,908
2022	**171,216**	2,828	7,576	4,357	6,597	3,240	9,297	3,221	6,915	7,628	10,683	419	206	24,024	9,187	13,339	24,606	3,667	5,727	3,079	22,700	1,920
2023	**172,541**	2,840	7,623	4,388	6,636	3,277	9,377	3,259	6,926	7,688	10,723	420	208	24,158	9,261	13,393	24,805	3,701	5,764	3,100	23,064	1,930
2024	**173,728**	2,853	7,674	4,424	6,672	3,310	9,447	3,292	6,951	7,743	10,754	420	209	24,318	9,323	13,429	25,011	3,737	5,801	3,118	23,298	1,944
2025	**175,079**	2,868	7,718	4,455	6,716	3,346	9,522	3,329	7,010	7,806	10,794	421	210	24,460	9,391	13,506	25,261	3,774	5,845	3,138	23,552	1,957
2026	**176,383**	2,882	7,759	4,488	6,763	3,384	9,599	3,366	7,041	7,866	10,837	422	212	24,602	9,465	13,567	25,491	3,813	5,884	3,162	23,811	1,969
2027	**177,684**	2,901	7,798	4,518	6,804	3,423	9,681	3,403	7,067	7,928	10,884	424	214	24,779	9,537	13,634	25,708	3,854	5,926	3,182	24,044	1,975
2028	**178,835**	2,918	7,835	4,545	6,849	3,460	9,762	3,436	7,070	7,987	10,921	425	215	24,901	9,608	13,671	25,888	3,890	5,963	3,203	24,301	1,987
2029	**180,016**	2,933	7,871	4,576	6,872	3,493	9,843	3,465	7,093	8,041	10,959	425	216	25,099	9,682	13,718	26,046	3,931	5,986	3,226	24,538	2,003
2030	**181,274**	2,949	7,910	4,607	6,912	3,531	9,925	3,500	7,114	8,101	11,001	426	218	25,261	9,756	13,772	26,246	3,971	6,022	3,248	24,791	2,015
2031	**182,542**	2,966	7,949	4,638	6,951	3,569	10,008	3,535	7,135	8,161	11,042	427	219	25,425	9,831	13,825	26,448	4,012	6,058	3,271	25,046	2,026
2032	**183,819**	2,983	7,988	4,669	6,991	3,607	10,091	3,571	7,156	8,222	11,084	428	221	25,589	9,906	13,879	26,651	4,053	6,094	3,294	25,304	2,038
2033	**185,106**	2,999	8,027	4,700	7,032	3,646	10,175	3,607	7,177	8,283	11,127	429	222	25,755	9,982	13,933	26,855	4,095	6,130	3,316	25,565	2,050
2034	**186,403**	3,016	8,067	4,732	7,072	3,686	10,260	3,643	7,198	8,345	11,169	430	224	25,921	10,058	13,988	27,062	4,136	6,167	3,339	25,829	2,062
2035	**187,710**	3,033	8,106	4,764	7,113	3,726	10,345	3,679	7,219	8,407	11,211	431	225	26,089	10,135	14,042	27,269	4,179	6,204	3,363	26,095	2,074
Last 5 Years (2025-2029) Growth Rate	**0.7%**	0.6%	0.5%	0.7%	0.6%	1.1%	0.8%	1.0%	0.3%	0.7%	0.4%	0.2%	0.7%	0.6%	0.8%	0.4%	0.8%	1.0%	0.6%	0.7%	1.0%	0.6%
2014-2029 Growth Rate	**0.9%**	0.7%	0.8%	0.9%	0.8%	1.3%	1.0%	1.4%	0.5%	0.9%	0.5%	0.3%	0.9%	0.7%	0.9%	0.5%	1.0%	1.2%	0.8%	0.8%	1.6%	0.7%

Source: Table B-10, February 2014 Revised PJM 2014 Load Forecast. http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx

Data for post 2029 (not provided by PJM ISO) reflect average growth rates from the 5 last years (2025-2029) of the forecast.

Net Energy (GWh)

Year	PJM RTO	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	DOM	EKPC
2014	**832,247**	11,329	34,619	19,580	24,621	16,517	42,891	19,174	32,791	42,645	47,276	1,568	1,088	137,450	50,933	70,831	107,405	17,892	28,180	15,315	99,880	10,262
2015	**847,743**	11,510	34,984	19,871	25,112	16,918	43,836	19,879	33,124	43,467	47,885	1,582	1,109	139,332	51,869	71,558	110,231	18,478	28,582	15,598	102,496	10,322
2016	**863,762**	11,682	35,379	20,171	25,578	17,298	44,714	20,507	33,519	44,262	48,497	1,594	1,132	141,104	52,773	72,265	112,829	18,939	28,970	15,869	106,273	10,407
2017	**870,847**	11,740	35,705	20,304	25,780	17,506	45,219	20,874	33,665	44,646	48,679	1,597	1,142	141,656	53,096	72,369	114,151	19,176	29,124	15,990	108,014	10,414
2018	**878,209**	11,799	36,054	20,453	25,967	17,714	45,714	21,207	33,857	45,064	48,869	1,599	1,154	142,364	53,484	72,598	115,388	19,356	29,284	16,107	109,728	10,449
2019	**884,188**	11,840	36,330	20,576	26,117	17,881	46,137	21,488	34,019	45,380	49,015	1,604	1,163	142,834	53,804	72,681	116,424	19,484	29,407	16,191	111,347	10,466
2020	**894,896**	11,934	36,676	20,789	26,392	18,167	46,761	21,903	34,300	45,965	49,418	1,613	1,177	144,133	54,438	73,281	118,110	19,777	29,681	16,366	113,479	10,536
2021	**901,010**	12,000	36,823	20,928	26,600	18,353	47,133	22,191	34,434	46,284	49,613	1,613	1,183	144,528	54,766	73,466	119,192	19,966	29,826	16,450	115,115	10,546
2022	**908,770**	12,059	37,057	21,071	26,799	18,580	47,603	22,525	34,615	46,703	49,861	1,619	1,194	145,335	55,203	73,751	120,474	20,193	30,009	16,571	116,965	10,583
2023	**915,559**	12,114	37,211	21,205	26,974	18,780	48,027	22,828	34,771	47,076	50,033	1,623	1,204	145,990	55,594	73,918	121,628	20,387	30,163	16,674	118,749	10,610
2024	**923,919**	12,199	37,514	21,393	27,191	19,022	48,552	23,174	35,024	47,554	50,291	1,628	1,216	147,001	56,115	74,253	123,003	20,611	30,375	16,804	120,332	10,667
2025	**928,033**	12,216	37,565	21,469	27,296	19,180	48,847	23,402	35,085	47,799	50,378	1,629	1,220	147,319	56,358	74,351	123,858	20,779	30,462	16,870	121,281	10,669
2026	**934,742**	12,268	37,703	21,592	27,477	19,402	49,277	23,704	35,230	48,192	50,585	1,630	1,230	148,096	56,762	74,654	125,077	21,019	30,636	16,986	122,524	10,698
2027	**941,672**	12,326	37,841	21,718	27,666	19,631	49,716	24,015	35,371	48,596	50,799	1,633	1,240	148,938	57,179	74,960	126,288	21,273	30,813	17,104	123,841	10,724
2028	**951,106**	12,420	38,104	21,912	27,942	19,901	50,318	24,365	35,627	49,122	51,167	1,641	1,254	150,164	57,763	75,383	127,754	21,574	31,076	17,266	125,565	10,788
2029	**955,549**	12,453	38,146	21,981	28,077	20,066	50,632	24,571	35,696	49,370	51,241	1,641	1,261	150,651	58,043	75,480	128,588	21,771	31,173	17,337	126,575	10,796
2030	**962,571**	12,513	38,293	22,111	28,276	20,294	51,088	24,872	35,850	49,771	51,459	1,644	1,271	151,496	58,472	75,765	129,798	22,026	31,353	17,456	127,934	10,828
2031	**969,651**	12,573	38,440	22,242	28,476	20,524	51,549	25,177	36,005	50,175	51,678	1,647	1,282	152,345	58,904	76,051	131,020	22,285	31,535	17,575	129,308	10,860
2032	**976,791**	12,634	38,588	22,373	28,677	20,757	52,013	25,486	36,161	50,582	51,898	1,650	1,293	153,199	59,340	76,338	132,254	22,546	31,717	17,696	130,697	10,892
2033	**983,989**	12,695	38,736	22,505	28,880	20,993	52,482	25,798	36,318	50,993	52,119	1,653	1,303	154,058	59,778	76,626	133,499	22,810	31,901	17,817	132,100	10,925
2034	**991,248**	12,756	38,885	22,638	29,085	21,231	52,955	26,115	36,475	51,407	52,341	1,656	1,314	154,922	60,220	76,915	134,755	23,078	32,085	17,939	133,519	10,957
2035	**998,566**	12,817	39,034	22,772	29,291	21,472	53,433	26,435	36,633	51,824	52,563	1,659	1,325	155,791	60,665	77,206	136,024	23,348	32,271	18,062	134,952	10,989
Last 5 Years (2025-2029) Growth Rate	**0.7%**	0.5%	0.4%	0.6%	0.7%	1.1%	0.9%	1.2%	0.4%	0.8%	0.4%	0.2%	0.8%	0.6%	0.7%	0.4%	0.9%	1.2%	0.6%	0.7%	1.1%	0.3%
2014-2029 Growth Rate	**0.9%**	0.6%	0.6%	0.8%	0.9%	1.3%	1.1%	1.7%	0.6%	1.0%	0.5%	0.3%	1.0%	0.6%	0.9%	0.4%	1.2%	1.3%	0.7%	0.8%	1.6%	0.3%

Source: Table E-1, February 2014 Revised PJM 2014 Load Forecast. http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx

Data for post 2029 (not provided by PJM ISO) reflect average growth rates from the 5 last years (2025-2029) of the forecast.

Return to TOC

Zonal Demand Response and Energy Efficiency (MW)

Demand Response (MW)

Year	PJM RTO	DR as % of Peak	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	DOM	EKPC
2014	**14,118**	**9.0%**	205	1,341	392	444	398	831	438	893	1,300	964	31	0	1,635	887	956	1,536	232	55	222	1,360	0
2015	**14,833**	**9.3%**	208	1,142	434	350	349	802	526	867	1,155	796	21	0	1,684	936	1,764	1,698	197	279	245	1,382	0
2016	**12,408**	**7.6%**	172	937	440	223	314	531	432	664	998	631	10	0	1,377	685	1,812	1,236	247	304	143	1,121	133
2017	**10,975**	**6.7%**	135	791	370	159	299	480	357	608	686	388	3	0	1,426	929	1,020	1,478	209	192	161	1,141	140
2018	**11,062**	**6.7%**	135	800	373	160	302	485	361	611	691	390	3	0	1,435	935	1,023	1,491	211	193	163	1,159	141
2019	**11,157**	**6.7%**	136	809	376	162	305	489	366	614	697	391	3	0	1,443	942	1,027	1,505	213	195	164	1,177	142
2020	**11,270**	**6.7%**	137	816	380	163	309	494	371	620	704	393	3	0	1,452	951	1,033	1,525	215	197	165	1,198	143
2021	**11,366**	**6.7%**	138	822	383	164	313	499	376	623	710	395	3	0	1,463	959	1,038	1,539	217	198	166	1,217	144
2022	**11,444**	**6.7%**	139	827	385	165	316	502	380	625	715	396	3	0	1,469	965	1,040	1,551	219	199	167	1,235	145
2023	**11,532**	**6.7%**	139	832	388	166	320	507	384	626	721	398	3	0	1,477	973	1,044	1,564	221	200	168	1,255	145
2024	**11,612**	**6.7%**	140	837	391	167	323	511	388	628	726	399	3	0	1,487	980	1,047	1,577	223	202	169	1,267	146
2025	**11,703**	**6.7%**	140	842	394	168	327	515	393	634	732	400	3	0	1,496	987	1,053	1,592	226	203	170	1,281	147
2026	**11,791**	**6.7%**	141	847	397	169	330	519	397	637	737	402	3	0	1,504	994	1,058	1,607	228	205	171	1,295	148
2027	**11,877**	**6.7%**	142	851	399	170	334	523	401	639	743	404	3	0	1,515	1,002	1,063	1,621	230	206	173	1,308	149
2028	**11,953**	**6.7%**	143	855	402	171	338	528	405	639	749	405	3	0	1,523	1,009	1,066	1,632	233	207	174	1,322	150
2029	**12,033**	**6.7%**	144	859	404	172	341	532	409	641	754	407	3	0	1,535	1,017	1,070	1,642	235	208	175	1,335	151
2030	**12,117**	**6.7%**	144	863	407	173	345	536	413	643	760	408	4	0	1,545	1,025	1,074	1,655	237	209	176	1,349	152
2031	**12,202**	**6.7%**	145	867	410	174	348	541	417	645	765	410	4	0	1,555	1,033	1,078	1,667	240	211	177	1,362	153
2032	**12,287**	**6.7%**	146	871	413	175	352	545	421	647	771	411	4	0	1,565	1,041	1,082	1,680	242	212	179	1,376	154
2033	**12,373**	**6.7%**	147	876	415	176	356	550	425	649	777	413	4	0	1,575	1,049	1,087	1,693	245	213	180	1,391	154
2034	**12,460**	**6.7%**	148	880	418	177	360	555	430	651	782	414	4	0	1,585	1,057	1,091	1,706	247	214	181	1,405	155
2035	**12,547**	**6.7%**	149	884	421	178	364	559	434	653	788	416	4	0	1,595	1,065	1,095	1,719	250	216	182	1,419	156

Energy Efficiency (MW)

Year	PJM RTO	EE as % of Peak	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	AEP	APS	ATSI	COMED	DAY	DEOK	DLCO	DOM	EKPC
2014	**822**	**0.5%**	1	118	7	2	4	7	4	43	10	5	0	0	9	6	3	546	4	0	3	52	0
2015	**923**	**0.6%**	1	104	16	0	3	15	3	56	14	11	0	0	214	1	45	422	2	5	4	7	0
2016	**1,117**	**0.7%**	2	125	21	5	10	12	10	84	30	12	0	0	119	14	197	427	13	5	4	28	0
2017	**1,339**	**0.8%**	1	124	29	7	13	25	13	104	36	18	0	0	136	10	142	583	49	18	11	21	1
2018	**1,350**	**0.8%**	1	125	29	7	13	25	13	105	36	18	0	0	137	10	142	590	50	18	11	21	1
2019	**1,360**	**0.8%**	1	126	29	7	13	25	13	105	36	18	0	0	137	10	143	595	50	18	11	21	1
2020	**1,376**	**0.8%**	1	127	30	7	13	26	14	106	37	18	0	0	139	11	144	604	51	18	11	22	1
2021	**1,386**	**0.8%**	1	128	30	7	13	26	14	107	37	18	0	0	139	11	144	609	51	18	11	22	1
2022	**1,397**	**0.8%**	1	128	30	7	14	26	14	107	37	18	0	0	140	11	145	616	52	18	11	22	1
2023	**1,407**	**0.8%**	1	129	30	7	14	26	14	108	38	18	0	0	140	11	145	622	52	18	11	23	1
2024	**1,421**	**0.8%**	1	130	31	7	14	27	14	108	38	18	0	0	141	11	146	629	53	18	11	23	1
2025	**1,427**	**0.8%**	1	130	31	8	14	27	14	109	38	18	0	0	142	11	146	633	53	18	11	23	1
2026	**1,438**	**0.8%**	1	131	31	8	14	27	15	109	38	18	0	0	142	11	146	639	54	18	11	23	1
2027	**1,449**	**0.8%**	1	131	31	8	14	27	15	109	39	18	0	0	143	11	147	645	55	19	11	24	1
2028	**1,463**	**0.8%**	1	132	31	8	15	28	15	110	39	18	0	0	144	11	148	653	55	19	11	24	1
2029	**1,470**	**0.8%**	1	132	31	8	15	28	15	110	39	19	0	0	145	11	148	657	56	19	11	24	1
2030	**1,481**	**0.8%**	1	133	32	8	15	28	15	111	40	19	0	0	146	11	149	663	57	19	12	25	1
2031	**1,492**	**0.8%**	1	133	32	8	15	28	16	111	40	19	0	0	147	11	149	670	57	19	12	25	1
2032	**1,504**	**0.8%**	1	134	32	8	15	29	16	112	40	19	0	0	147	12	150	676	58	19	12	25	1
2033	**1,515**	**0.8%**	1	134	32	8	15	29	16	112	41	19	0	0	148	12	150	682	59	19	12	25	1
2034	**1,526**	**0.8%**	1	135	32	8	16	29	16	113	41	19	0	0	149	12	151	689	59	19	12	26	1
2035	**1,538**	**0.8%**	1	135	33	8	16	29	16	113	41	19	0	0	150	12	151	695	60	19	12	26	1

Notes: The numbers represent the sum of auction cleared demand response and energy efficiency resources.
[1] 2014/2015, 2015/2016, 2016/2017, 2017/2018: Cleared DSM inclusion in capacity auctions based on PJM auction results.
[2] Starting with the 2014/2015 auction Energy efficiency was introduced and ILR resources are counted as DR resources.
[3] 2018 onwards DR and EE are assumed to increase at the rate of increase in Peak demand and Energy demand respectively.

Return to TOC

Reserve Margin Target Levels (%)

Year	PJM
2015	15.7%
2016	15.7%
2017	15.7%
2018-2035	15.8%

Source:

Reserve margins for the 2015 to 2017 period reflect the Internal Reserve Margin (IRM) from the PJM Reserve Requirement Study, October 2013.
The 2018-2035 period reflects the 11-year forecast average (2013-2023) from the PJM Reserve Requirement Study, October 2013.

Return to TOC

Gas Price Assumptions

Henry Hub Gas Price Projection

Year	Henry Hub (2013$/MMBtu)	Henry Hub (Nom$/MMBtu)
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]
Average	[redacted]	[redacted]

Basis Differentials excl Fuel tax and LDC (2013$/MMBtu)

Year	ATSI
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]
2039	[redacted]
2040	[redacted]
2041	[redacted]
2042	[redacted]
2043	[redacted]
2044	[redacted]
Average	[redacted]

Delivered Gas Prices incl Fuel tax and LDC (2013$/MMBtu)

Year	ATSI
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]
2039	[redacted]
2040	[redacted]
2041	[redacted]
2042	[redacted]
2043	[redacted]
2044	[redacted]
Average	[redacted]

Notes:

[1] 2015, and 2016 prices are based on OTCGH futures for trade dates 4/18/2014 to 5/18/2014 as reported by SNL Financial.

[2] 2018-2044 prices reflect ICF's fundamentals forecast as of April 2014. 2017 is a transition year between futures and ICF fundamentals.

[3] The gas hubs used for historical and futures data are shown below.

Region	Gas Hub
ATSI	9.4% Dominion S, 3.1% Texas Gas Zone 1, 37.5% Chicago, 50% Michcon Detroit CG

[4] The LDC and taxes assumed are shown below.

Region	LDC (2013$/MMBtu)	Taxes (%)
ATSI	0.16	0%

[5] OTCGH forward Henry Hub prices averaged for trade dates 4/18/2014 and 5/18/2014 are shown below.

Commodity Price - OTCGH Futures		
Year	Henry Hub (2013$/MMBtu)	Henry Hub (Nom$/MMBtu)
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
Average 2015-2021	[redacted]	[redacted]

Source: SNL

[6] Assumed inflation post-2013 is 2.1% annually.

Return to TOC

Representative Minemouth Coal Prices (2013$)

Minemouth (2013$/ton)					
	Northern Appalachia	Central Appalachia	Powder River Basin	Illinois Basin	Northern Appalachia
Sulfur; Heat Content	3.5 lbs SO2/MMBtu; 25.5 MMBtu/ton	1.67 lbs SO2/MMBtu; 24.5 MMBtu/ton	0.8 lbs SO2/MMBtu; 17.6 MMBtu/ton	6.0 lbs SO2/MMBtu; 22.1 MMBtu/ton	4.5 lbs SO2/MMBtu; 25 MMBtu/ton
2014	[redacted]				
2016					
2018					
2023					
2030					
2033					

Minemouth (2013$/MMBtu)					
	Northern Appalachia	Central Appalachia	Powder River Basin	Illinois Basin	Northern Appalachia
Sulfur; Heat Content	3.5 lbs SO2/MMBtu; 25.5 MMBtu/ton	1.67 lbs SO2/MMBtu; 24.5 MMBtu/ton	0.8 lbs SO2/MMBtu; 17.6 MMBtu/ton	6.0 lbs SO2/MMBtu; 22.1 MMBtu/ton	4.5 lbs SO2/MMBtu; 25 MMBtu/ton
2014	[redacted]				
2016					
2018					
2023					
2030					
2033					

Notes:
[1] Coal prices delivered to plant vary by source, location, and transportation option(s).
[2] Coal prices are solved dynamically within the model and may be slighter different from those reported above

Representative Coal Transportation Rates

Transportation Mode	Origin	Destination	Rate 2013$/Ton-Mile
Rail	Wyoming	Eastern Ohio	[redacted]
	Wyoming	Illinois	
	Wyoming	Texas	
	Illinois	Florida	
	Illinois	Tennessee	
	Pennsylvania	Maryland	
	Pennsylvania	Ohio	
	Rockies	Alabama	
	Rockies	Kentucky and Tennessee	
Barge			
Truck			

Return to TOC

PJM Firm Builds

Fuel Type	Plant Name	ISO Zone Name	2013	2014	2015	2016	2017	Total (2013-2016)
Biomass	South Boston Energy Project	DOM	50					50
	Altavista	DOM		51				51
	Hopewell	DOM		51				51
		DOM		51				51
Total Biomass			50	153	0	0	0	203
Fuel Cell	Bloom Energy Center	DPL-N	15	12				27
Total Fuel Cell			15	12	0	0	0	27
Hydro	Willow Island Hydroelectric Units 1 & 2	APS			35			35
	Cannelton Ohio River Units 1, 2, 3	KY		84				84
	Meldahl Hydroelectric Project	KY		105				105
	Holtwood Units 18,19	PPL	132					132
Total Hydro			132	189	35	0	0	356
Landfill Gas	Ciba CHP Facility	DOM			30			30
Total Landfill			0	0	30	0	0	30
Gas	Nelson Energy Center	COMED		543				543
	Warren County CC	DOM			1,300			1,300
	Newark	PSEG-N			625			625
	West Deptford Energy Center (LS-Power) CC	AE	194	565				758
	CPV Woodbridge Energy Center CC	JCPL			660			660
	Garrison Energy Center CC	DPL-S			309			309
	Brunswick County CC	DOM				1,360		1,360
	Moxie Liberty	PENELEC				850		850
Total Natural Gas			194	1,108	2,894	2,210	0	6,405
Solar	Green Energy Capital Solar	PPL		11				11
	Grand Ridge Solar Farm	COMED	20					20
	DeSapio No 2 Solar Farm	JPL-W	3					3
	Rockford Solar Partners					17		17
	Red Lion Fuell Cell		11					11
	McKee City Solar	AE		2				2
	Warfield II Solar			20				20
	PA Solar Park			11				11
Total Solar			34	43	0	17	0	94
Wind	Harmony Wind	APS	80					80
	Beech Ridge Energy			50				50
	Hardin Wind Farm		300					300
	Wlidcat	AEP	200					200
	Patton	PECO	30					30
Total Wind			610	50	0	0	0	660
Total	`		1,035	1,554	2,959	2,227	0	7,775

ICF considers projects firm if the plant is under construction or meets two of the following four criteria:
(1) Fully permitted
(2) Fully financed
(3) PPA for more than 50% of output

Notes:

Given the September 30th 2013, Maryland District Court's decision that found the contract associated with CPV's Charles County project illegal and given that the unit has not received financing or started construction ICF does not include the Charles County project as firm.

Similarly on October 11 2013, New Jersey District Court also found the contracts associated with the CPV's Woodbridge and the Hess's Newark ES projects illegal. ICF assumes Newark Energy Center as firm build because the project has recieved financing and we also assume CPV Woodbridge as firm because the project has received financing and is currently under construction.

PJM Firm Retirements (MW)

Methodology for Firm Retirements:

Not all announced retirements are consided as firm. For PJM ISO, ICF considers for firm retirements units that have filed for deactivation request and their request have been reviewed and approved by PJM ISO. Units that have announced retirements (such as C. P. Crane) but have not filed deactivation requests are not included as firm. Most likely these units will retire in our model based on the economics.

PJM Regions	2014	2015	2016	2017	Total
AE	158	209	0	0	367
AP	0	0	0	0	0
AEP	0	5,408	0	0	5,408
APS	0	0	0	0	0
ATSI	0	885	0	0	885
BGE	118	0	76	0	194
ComEd	0	0	0	0	0
Dayton	0	277	0	0	277
DEOK	0	652	0	0	652
DOM	900	0	0	0	900
DPL	0	0	0	34	34
DUQ	0	0	0	125	125
EKPC	0	193	0	0	193
JCPL	0	470	0	0	470
MetEd	401	0	0	0	401
PECO	0	0	0	0	0
PenElec	0	597	0	0	597
PEPCO	0	0	0	1,224	1,224
PSEG	184	1,987	0	0	2,171
PPL	0	382	0	0	382
Total	**1,761**	**11,060**	**76**	**1,383**	**14,280**

Unit	Capacity	Trans Zone	Age (Years)	Projected Deactivation Date	PJM Reliability Status
Kearny9	21	PSEG	43	5/1/2015	Reliability Analysis complete - impacts identified, however impacts resolved with the interconnection of projects T41 and T42 which are in-service.
Chesapeake 1	111	DOM	58	12/31/2014	Reliability Analysis complete. Impacts identified. Upgrades expected to be completed by June 2015.
Chesapeake 2	111	DOM	56	12/31/2014	Reliability Analysis complete. Impacts identified. Upgrades expected to be completed by June 2015.
Chesapeake 3	147	DOM	52	12/31/2014	Reliability Analysis complete. Impacts identified. Upgrades expected to be completed by June 2016. On 10/11/12 generator submitted an updated deactivation request changing the deactivation date to 12/31/14. Reliability analysis complete. Previously identified baseline upgrades are still needed to be completed by June 2015. In addition a new reliability issue was identified and a previously identified baseline upgrade will need to be accelerated and completed by June 2015. It is expected that the Chesapeake 3 generating unit will deactivate on December 31, 2014.

Chesapeake 4	207	DOM	49	12/31/2014	Reliability Analysis complete. Impacts identified. Upgrades expected to be completed by June 2016. On 10/11/12 generator submitted an updated deactivation request changing the deactivation date to 12/31/14. Reliability analysis complete. Previously identified baseline upgrades are still needed to be completed by June 2015. In addition a new reliability issue was identified and a previously identified baseline upgrade will need to be accelerated and completed by June 2015. It is expected that the Chesapeake 4 generating unit will deactivate on December 31, 2014.
Yorktown 1	159	DOM	54	12/31/2014	Reliability Analysis complete. Impacts identified. Upgrades expected to be completed by June 2015.
Bergen 3	21	PSEG	44	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
Burlington 8	21	PSEG	44	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
National Park 1	21	PSEG	42	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
Mercer 3	115	PSEG	44	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
Sewaren 6	111	PSEG	46	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
Ashtabula 5	244	ATSI	53	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will continue to operate as upgrades to transmission system are constructed - estimated till June 1, 2015. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Eastlake 1	132	ATSI	58	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will continue to operate as upgrades to transmission system are constructed - estimated till June 1, 2015. See posting - FE Generator Deactivation Study Results and Required Upgrades.

Eastlake 2	132	ATSI	58	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will continue to operate as upgrades to transmission system are constructed - estimated till June 1, 2015. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Eastlake 3	132	ATSI	57	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will continue to operate as upgrades to transmission system are constructed - estimated till June 1, 2015. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Lake Shore 18	245	ATSI	49	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will continue to operate as upgrades to transmission system are constructed - estimated till June 1, 2015. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Walter C Beckjord 5	238	DEOK	49	4/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014
Walter C Beckjord 6	414	DEOK	42	4/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014
Portland 1	158	MetEd	53	6/1/2014	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled. On May 15, 2013 NRG submitted an updated deactivation notice with an effective deactivation date of 6/1/2014. New reliability analysis complete. Impacts identified and upgrades expected to be completed by new deactivation date (June 1, 2014).

Portland 2	243	MetEd	49	6/1/2014	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled. On May 15, 2013 NRG submitted an updated deactivation notice with an effective deactivation date of 6/1/2014. New reliability analysis complete. Impacts identified and upgrades expected to be completed by new deactivation date (June 1, 2014).
Glen Gardner CT 1	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 2	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 3	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 4	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 5	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 6	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 7	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Glen Gardner CT 8	20	JCPL	40	5/1/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Shawville 1	122	PenElec	57	4/16/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.

Shawville 2	125	PenElec	58	4/16/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Shawville 3	175	PenElec	52	4/16/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Shawville 4	175	PenElec	51	4/16/2015	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled.
Clinch River 3	230	AEP	50	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Glen Lyn 5	90	AEP	67	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Glen Lyn 6	235	AEP	54	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Kammer 1	200	AEP	53	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Kammer 2	200	AEP	53	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Kammer 3	200	AEP	53	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Kanawha River 1	200	AEP	58	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Kanawha River 2	200	AEP	58	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Muskingum River 1	190	AEP	58	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Muskingum River 2	190	AEP	57	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Muskingum River 3	205	AEP	54	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Muskingum River 4	205	AEP	53	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Picway 5	95	AEP	56	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Sporn 1	145	AEP	62	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Sporn 2	145	AEP	61	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.

Sporn 3	145	AEP	60	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Sporn 4	145	AEP	60	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Tanner Creek 1	145	AEP	61	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Tanner Creek 2	145	AEP	59	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Tanner Creek 3	198	AEP	57	6/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2015.
Sewaren 1	104	PSEG	63	6/1/2015	Reliability Analysis complete. No impacts expected with PSEG contemplating re-use of Capacity Rights for a new generation project
Sewaren 2	118	PSEG	63	6/1/2015	Reliability Analysis complete. No impacts expected with PSEG contemplating re-use of Capacity Rights for a new generation project
Sewaren 3	107	PSEG	62	6/1/2015	Reliability Analysis complete. No impacts expected with PSEG contemplating re-use of Capacity Rights for a new generation project
Sewaren 4	124	PSEG	60	6/1/2015	Reliability Analysis complete. No impacts expected with PSEG contemplating re-use of Capacity Rights for a new generation project
Cedar 1	44	AE	39	5/31/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015.
Cedar 2	22	AE	39	5/31/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015.
Deepwater 1	78	AE	53	5/31/2014	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015. On Sept 4, 2013 PJM received an updated deactivation notice indicating the Deepwater units would now be deactivated on May 31, 2014. Updated reliability analysis complete. One impact identified and expected to be completed before June 1, 2014.
Deepwater 6	80	AE	57	5/31/2014	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015. On Sept 4, 2013 PJM received an updated deactivation notice indicating the Deepwater units would now be deactivated on May 31, 2014. Updated reliability analysis complete. One impact identified and expected to be completed before June 1, 2014.
Missouri Ave CT B	20	AE	42	5/31/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015.

Missouri Ave CT C	20	AE	43	5/31/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015.
Missouri Ave CT D	20	AE	43	5/31/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2015.
Hutchings 1	53	Dayton	63	6/1/2015	Reliability Analysis Complete. No impacts identified.
Hutchings 2	50	Dayton	63	6/1/2015	Reliability Analysis Complete. No impacts identified.
Burlington 9 GT	184	PSEG	40	6/1/2014	Reliability Analysis complete. Impacts identified and not expected to be completed till June 2015. Upgrades identified are already identified baseline upgrades with a June 2015 expected in-service date. Transmission owners cannot commit to completing these upgrades by June 2014. In addition, generator is affected by the conversion of the interconnect sub to 230 kV which is a required baseline upgrade and scheduled to be completed by June 2014.
Yorktown 2	165	Dom	53	12/31/2014	Reliability analysis complete. No new reliability impacts identified. Previously identified baseline upgrades are still needed to be completed prior to June 2015. Yorktown 2 is expected to deactivate as scheduled on December 31, 2014.
Riverside 6	118	BGE	42	6/1/2014	Reliability Analysis complete. No impacts identified.
Essex 12 (#121)	46	PSEG	41	5/31/2015	Reliability analysis complete. No impacts with Capacity Interconnection rights re-used in interconnection project(s) T107, X3-004, and / or Y2-019.
Essex 12 (#122)	46	PSEG	41	5/31/2015	Reliability analysis complete. No impacts with Capacity Interconnection rights re-used in interconnection project(s) T107, X3-004, and / or Y2-019.
Essex 12 (#123)	46	PSEG	41	5/31/2015	Reliability analysis complete. No impacts with Capacity Interconnection rights re-used in interconnection project(s) T107, X3-004, and / or Y2-019.
Essex 12 (#124)	46	PSEG	41	5/31/2015	Reliability analysis complete. No impacts with Capacity Interconnection rights re-used in interconnection project(s) T107, X3-004, and / or Y2-019.
BL England Diesel(s) {IC1, IC	8	AE	51	10/1/2015	No reliability impacts - with request to transfer CIRs to Y1-001.
Hutchings 3	59	Dayton	62	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Hutchings 5	58	Dayton	60	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Hutchings 6	57	Dayton	59	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Burlington 11 #111	46	PSEG	40	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.

Burlington 11 #112	46	PSEG	40	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Burlington 11 #113	46	PSEG	40	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Burlington 11 #114	46	PSEG	40	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 1 #11	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 1 #12	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 1 #13	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 1 #14	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 2 #21	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 2 #22	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 2 #23	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 2 #24	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 3 #31	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 3 #32	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 3 #33	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Edison 3 #34	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 10 #101	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 10 #102	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 10 #103	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 10 #104	42	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 11 #111	46	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.

Essex 11 #112	46	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 11 #113	46	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Essex 11 #114	46	PSEG	41	6/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by June 1, 2015.
Middle Energy Center 1	19	AE	42	5/31/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Middle Energy Center 2	20	AE	42	5/31/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Middle Energy Center 3	36	AE	41	5/31/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Werner CT C1	53	JCPL	40	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Werner CT C2	53	JCPL	40	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Werner CT C3	53	JCPL	40	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Werner CT C4	53	JCPL	40	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Gilbert CT C1	23	JCPL	42	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Gilbert CT C2	25	JCPL	42	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Gilbert CT C3	25	JCPL	42	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Gilbert CT C4	25	JCPL	42	5/1/2015	Reliability analysis complete. Impacts identified and expected to be resolved by May 2015.
Muskingum River 5	600	AEP	45	6/1/2015	Reliability analysis complete. One impact identified. Upgrade expected to be completed in 2nd quarter 2015. Unit can deactivate as planned.
Tanners Creek 4	500	AEP	49	6/1/2015	Reliability analysis complete. One impact identified. Upgrade expected to be completed in 2nd quarter 2015. Unit can deactivate as planned.
Sunbury 3	94	PPL	62	6/1/2015	Reliability analysis complete. Impacts identified. Upgrades and interim operating measures expected to be completed in 2nd quarter 2015. In addition requested to re-use CIRs for project Z1-090.
Sunbury 1	80	PPL	64	6/1/2015	Reliability analysis complete. Impacts identified. Upgrades and interim operating measures expected to be completed in 2nd quarter 2015. In addition requested to re-use CIRs for project Z1-090.

Sunbury 2	80	PPL	64	6/1/2015	Reliability analysis complete. Impacts identified. Upgrades and interim operating measures expected to be completed in 2nd quarter 2015. In addition requested to re-use CIRs for project Z1-090.
Sunbury 4	128	PPL	60	6/1/2015	Reliability analysis complete. Impacts identified. Upgrades and interim operating measures expected to be completed in 2nd quarter 2015. In addition requested to re-use CIRs for project Z1-090.
AES Beaver Valley	125	DUQ	26	6/1/2017	Reliability analysis complete. Impacts identified. Upgrades and interim operating measures expected to be completed in 2nd quarter 2017.
Riverside 4	76	BGE	62	6/1/2016	Reliability analysis complete. No issues identified.
Dickerson 1	182	PEPCO	54	5/31/2017	Reliability analysis complete. Impacts identified. Upgrades expected to be completed in 2nd quarter of 2017.
Dickerson 2	182	PEPCO	53	5/31/2017	Reliability analysis complete. Impacts identified. Upgrades expected to be completed in 2nd quarter of 2017.
Dickerson 3	182	PEPCO	51	5/31/2017	Reliability analysis complete. Impacts identified. Upgrades expected to be completed in 2nd quarter of 2017.
Chalk Point 1	337	PEPCO	49	5/31/2017	Reliability analysis complete. Impacts identified. Upgrades expected to be completed in 2nd quarter of 2017.
Chalk Point 2	341	PEPCO	48	5/31/2017	Reliability analysis complete. Impacts identified. Upgrades expected to be completed in 2nd quarter of 2017.
Big Sandy 2	800	AEP	44	6/1/2015	Reliability analysis underway.
McKee 1	17	DPL	52	5/31/2017	Reliability analysis complete. No impacts identified.
McKee 2	17	DPL	52	5/31/2017	Reliability analysis complete. No impacts identified.
Dale 1	23	EKPC	59	4/16/2015	Reliability analysis complete. No impacts identified.
Dale 2	23	EKPC	59	4/16/2015	Reliability analysis complete. No impacts identified.
Dale 3	74	EKPC	56	4/16/2015	Reliability analysis complete. No impacts identified.
Dale 4	73	EKPC	53	4/16/2015	Reliability analysis complete. No impacts identified.

Source : PJM Future Deactivation Requests as of 05.05.2014 [http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx]

Return to TOC

Recent PJM Retirements

PJM Regions	2010	2011	2012	2013	2014	Total (2010-2014)
ACE	17	0	0	0	0	17
AE	0	0	23	0	129	152
AEP	189	0	605	0	0	794
AP		0	458	1,949	0	2,407
APS	0	0	593	0	0	593
ATSI	0	94	1,549	0	0	1,643
CE	299	0	0	0	0	299
ComEd	0	0	1,373	0	0	1,373
Dayton	0	0	0	62	0	62
DEOK	0	0	119	0	150	269
DOM	140	101	0	3	0	244
DPL	89	90	0	170	0	349
DUQ	0	30	460	0	0	490
MetEd	0	0	0	243	0	243
PE	0	426	0	0	0	426
PE	0	201	309	0	0	510
PECO	0	0	0	169	0	169
PenElec	0	0	0	31	0	31
PEP	0	0	1,272	0	0	1,272
PPL	0	0	16	8	0	24
PS	0	383	0	0	0	383
PSEG	7	0	250	0	0	257
Total	**741**	**1,325**	**7,027**	**2,635**	**279**	**12,007**

Unit	Capacity (MW)	Trans Zone	Age (Years)	Requested Deactivation Date	Actual Deactivation Date	PJM Reliability Status
Indian River 2	89	DPL	48	5/1/2010	5/1/2010	Reliability issue identified and resolved
Howard M. Down (Vineland) Unit 9	17	ACE	49	8/28/2010	8/28/2010	Reliability analysis complete - impacts identified - generator has elected to deactivate as requested
INGENCO Richmond Plant	3	DOM	18	8/31/2010	8/31/2010	Reliability analysis complete - no impacts identified
North Branch	74	DOM	18	7/5/2010	8/1/2010	Reliability analysis complete - no impacts identified
Hall Branch (aka Altavista)	63	DOM	19	9/6/2010	10/13/2010	Reliability analysis complete - impacts identified - generator has elected to deactivate as requested
Gorsuch	189	AEP	59	12/15/2010	11/11/2010	Reliability analysis complete - impacts identified - generator has elected to deactivate as requested
Baleville Landfill	3.8	PSEG	9	2/22/2011	12/22/2010	Reliability analysis complete - no impacts identified
Kingsland Landfill	2.8	PSEG	11	2/22/2011	12/22/2010	Reliability analysis complete - no impacts identified
Will County 1	151	CE	55	9/1/2010	12/30/2010	Potential reliability issues identified - can be resolved by summer 2011
Will County 2	148	CE	55	9/1/2010	12/30/2010	Potential reliability issues identified - can be resolved by summer 2011
Kitty Hawk GT1	18	DOM	39	4/19/2011	3/15/2011	Reliability analysis complete - no impacts identified
Kitty Hawk GT2	16	DOM	39	4/19/2011	3/15/2011	Reliability analysis complete - no impacts identified

Chesapeake 8	17.5	DOM	41	4/19/2011	3/15/2011	Reliability analysis complete - no impacts identified
Chesapeake 9	16.9	DOM	41	4/19/2011	3/15/2011	Reliability analysis complete - no impacts identified
Chesapeake 10	16.9	DOM	41	4/19/2011	3/15/2011	Reliability analysis complete - no impacts identified
Chesapeake 7	16	DOM	40	7/28/2012	4/8/2011	Reliability analysis complete - no impacts identified
Indian River 1	90	DPL	50	5/1/2011	5/1/2011	Reliability issues identified and expected to be resolved by 5/1/2011
Brunot Island 1B	15	DUQ	39	7/19/2011	6/1/2011	Reliability analysis complete - no impacts identified. Interconnection request submitted to re-start unit in 4th quarter 2015.
Brunot Island 1C	15	DUQ	39	7/19/2011	6/1/2011	Reliability analysis complete - no impacts identified. Interconnection request submitted to re-start unit in 4th quarter 2015.
Cromby 1	144	PE	55	5/31/2011	5/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted - Necessary upgrades completed
Eddystone 1	279	PE	49	5/31/2011	5/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted - Necessary upgrades completed
Cromby Diesel	2.7	PE	43	5/31/2011	5/31/2011	Reliability analysis complete - no impacts identified
Burger 3	94	ATSI	61	9/1/2011	9/1/2011	Reliability Analysis complete. Impacts identified. TO plans to complete all required upgrades by June 1, 2013. Gen owner elected to deactivate unit as requested on 9/1/2011.
Cromby 2	201	PE	54	5/31/2011	12/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted - Necessary upgrades completed
Hudson 1	383	PS	39	12/7/2004	12/8/2011	PJM has determined that Hudson 1 is no longer needed for reliability purposes effective December 7, 2011.
Sporn 5	440	AEP	49	12/31/2010	2/13/2012	Reliability analysis complete - no impacts identified. AEP received approval from Ohio PUC to deactivate unit. AEP informed PJM on 2/13/2012. Unit deactivated.
State Line 3	197	ComEd	55	4/1/2012	3/25/2012	Reliability Analysis complete for April 1, 2012 deactivation date - no impacts identified. Potential re-use of CIRs in interconnection project Y3-063.
State Line 4	318	ComEd	49	4/1/2012	3/25/2012	Reliability Analysis complete for April 1, 2012 deactivation date - no impacts identified. Potential re-use of CIRs in interconnection project Y3-063.
Viking Energy NUG	16	PPL	21	3/1/2012	3/31/2012	Reliability Analysis complete - no impacts identified
Walter C Beckjord 1	94	DEOK	59	5/1/2012	5/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 1, 2012
Buzzard Point East Banks 1, 2, 4-8	112	PEP	39	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Buzzard Point West Banks 1-8	128	PEP	39	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Eddystone 2	309	PE	49	5/31/2011	5/31/2012	Reliability analysis complete - Reliability Impacts identified - Results posted

Niles 2	108	ATSI	58	6/1/2012	6/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Unit deactivated on June 1, 2012.
Elrama 1	93	DUQ	59	6/1/2012	6/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Unit deactivated on June 1, 2012. Potential re-use of CIRs in interconnection project Y3-042.
Elrama 2	93	DUQ	59	6/1/2012	6/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Unit deactivated on June 1, 2012. Potential re-use of CIRs in interconnection project Y3-042.
Elrama 3	103	DUQ	57	6/1/2012	6/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Unit deactivated on June 1, 2012. Potential re-use of CIRs in interconnection project Y3-042.
Kearny 10	122	PSEG	39	6/1/2012	6/1/2012	Kearny 10 deactivated and capacity rights re-used on new interconnection project
Kearny 11	128	PSEG	40	6/1/2012	6/1/2012	Kearny 11 deactivated and capacity rights re-used on new interconnection project
Benning 15	275	PEP	39	5/31/2012	7/17/2012	Benning 15 deactivated - required system upgrades completed.
Benning 16	275	PEP	35	5/31/2012	7/17/2012	Benning 16 deactivated - required system upgrades completed.
Crawford 8	319	ComEd	50	12/31/2014 (no later than)	8/24/2012	Reliability Analysis Complete. No impacts identified.
Fisk Street 19	326	ComEd	52	12/31/2012 (no later than)	8/30/2012	Reliability Analysis Complete. No impacts identified.
Crawford 7	213	ComEd	53	12/31/2014 (no later than)	8/28/2012	Reliability Analysis Complete. No impacts identified.
Vineland 10	23	AE	41	9/1/2012	9/1/2012	Reliability Analysis complete - no impacts for deactivation Sept. 2012. Previously identified baseline upgrade completed as scheduled (summer 2012).
Armstrong 1	172	AP	53	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Armstrong 2	171	AP	52	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.

Bay Shore 2	138	ATSI	53	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades. Interconnection project Z1-030 requests to re-use capacity rights (CIRs) from Bay Shore U2, U3 and U4.
Bay Shore 3	142	ATSI	48	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades. Interconnection project Z1-030 requests to re-use capacity rights (CIRs) from Bay Shore U2, U3 and U4.
Bay Shore 4	215	ATSI	43	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades. Interconnection project Z1-030 requests to re-use capacity rights (CIRs) from Bay Shore U2, U3 and U4.
Eastlake 4	240	ATSI	55	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Eastlake 5	597	ATSI	39	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.

R Paul Smith 3	28	AP	64	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.
R Paul Smith 4	87	AP	43	9/1/2012	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues. Unit will deactivate as scheduled. See posting - FE Generator Deactivation Study Results and Required Upgrades.
Albright 1	73	APS	59	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Albright 2	73	APS	59	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Albright 3	137	APS	57	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Rivesville 5	35	APS	68	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Rivesville 6	86	APS	60	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Willow Island 1	51	APS	63	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.

Willow Island 2	138	APS	51	9/1/2012	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013. Thus generator can be allowed to deactivate as scheduled on 9/1/2012 assuming all upgrades are still on track to be completed as scheduled.
Niles 1	109	ATSI	58	6/1/2012	10/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Evaluating options. Unit to be kept in service until October 1, 2012, pending analysis of outages required to implement required system upgrades. Unit deactivated on Oct. 1, 2012. Potential Re-use of cap rights from Niles 1 in interconnection project Z1-034
Elrama 4	171	DUQ	51	6/1/2012	10/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Evaluating options. Unit to be kept in service until October 1, 2012, pending analysis of outages required to implement required system upgrades. Unit deactivated on Oct. 1, 2012. Potential re-use of CIRs in interconnection project Y3-042.
Potomac River 1-5	482	PEP	62	10/1/2012	10/1/2012	Reliability Analysis complete - no impacts identified. Units deactivated on Oct. 1, 2012.
SMART Paper	25	DEOK	50	8/10/2012	10/8/2012	Reliability Analysis Complete. No impacts identified. Unit deactivated.
Conesville 3	165	AEP	49	12/31/2012	12/31/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Generator has deactivated as planned on December 31, 2012.
Schuylkill 1	166	PECO	54	2/1/2013	1/1/2013	Reliability analysis complete - no impacts identified. Unit deactivated on 1/1/13.
Schuylkill Diesel	3	PECO	45	2/1/2013	1/1/2013	Reliability analysis complete - no impacts identified. Unit deactivated on 1/1/13.
Hutchings 4	62	Dayton	61	6/1/2013	6/1/2013	Reliability Analysis Complete. No impacts identified. Unit deactivated on 6/1/2013.
Ingenco Petersburg Plant	2.9	DOM	20	5/31/2013	5/31/2013	Reliability analysis complete - no impacts identified. Unit deactivated on 5/31/13.
Titus 1	81	MetEd	61	4/16/2015 9/1/2013	9/1/2013	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled. On May 15, 2013 NRG submitted an updated deactivation notice with an effective deactivation date of 9/1/2013. New reliability analysis complete and impacts identified and upgrades cannot be completed by new deactivation date. Generation owner has informed PJM that Titus will deactivate as scheduled on 9/1/2013. Unit deactivated on 9/1/2013.

Titus 2	81	MetEd	60	4/16/2015 9/1/2013	9/1/2013	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled. On May 15, 2013 NRG submitted an updated deactivation notice with an effective deactivation date of 9/1/2013. New reliability analysis complete and impacts identified and upgrades cannot be completed by new deactivation date. Generation owner has informed PJM that Titus will deactivate as scheduled on 9/1/2013. Unit deactivated on 9/1/2013.
Titus 3	81	MetEd	58	4/16/2015 9/1/2013	9/1/2013	Reliability Analysis complete - impacts identified - upgrades and operating procedures expected to be in place by May 2015 to allow generators to deactivate as scheduled. On May 15, 2013 NRG submitted an updated deactivation notice with an effective deactivation date of 9/1/2013. New reliability analysis complete and impacts identified and upgrades cannot be completed by new deactivation date. Generation owner has informed PJM that Titus will deactivate as scheduled on 9/1/2013. Unit deactivated on 9/1/2013.
Piney Creek NUG	31	PenElec	20	4/12/2013	4/12/2013	PJM was informed on 6/25/13 that unit had ceased operations on 4/12/13 and was being decommissioned starting on 6/13/13. PJM determined that this was not a PJM generator since it was operating under a State Tariff. However, since the unit was a capacity resource, and in both the Planning and Operations models, PJM has completed Reliability analysis and identified impacts. Solution is an already identified baseline upgrade with a June 2014 expected in-service date. Interim operating procedures are being discussed for implementation.
Koppers Co. IPP	8	PPL	23	9/30/2013	9/30/2013	Reliability analysis complete. No impacts identified.
Hatfield's Ferry 1	530	AP	43	10/9/2013	10/9/2013	Detailed reliability studies complete. The impacts to the transmission system from the unit deactivation can be mitigated through the completion of required baseline upgrades and the implementation of temporary operating measures in the interim period. Unit not required for system reliability and may deactivate as requested. Unit deactivated on 10/9/2013.

Hatfield's Ferry 2	530	AP	42	10/9/2013	10/9/2013	Detailed reliability studies complete. The impacts to the transmission system from the unit deactivation can be mitigated through the completion of required baseline upgrades and the implementation of temporary operating measures in the interim period. Unit not required for system reliability and may deactivate as requested. Unit deactivated on 10/9/2013.
Hatfield's Ferry 3	530	AP	41	10/9/2013	10/9/2013	Detailed reliability studies complete. The impacts to the transmission system from the unit deactivation can be mitigated through the completion of required baseline upgrades and the implementation of temporary operating measures in the interim period. Unit not required for system reliability and may deactivate as requested. Unit deactivated on 10/9/2013.
Mitchell 2	82	AP	63	10/9/2013	10/9/2013	Detailed reliability studies complete. The impacts to the transmission system from the unit deactivation can be mitigated through the completion of required baseline upgrades and the implementation of temporary operating measures in the interim period. Unit not required for system reliability and may deactivate as requested. Unit deactivated on 10/9/2013.
Mitchell 3	277	AP	49	10/9/2013	10/9/2013	Detailed reliability studies complete. The impacts to the transmission system from the unit deactivation can be mitigated through the completion of required baseline upgrades and the implementation of temporary operating measures in the interim period. Unit not required for system reliability and may deactivate as requested. Unit deactivated on 10/9/2013.
Indian River 3	170	DPL	40	12/31/2013	12/31/2013	Reliability analysis complete - reliability impacts identified and expected to be resolved before unit is deactivated. Unit deactivated on 12/31/13.
Mad River CTs A & B	0	ATSI	41	1/9/2014	1/9/2014	Reliability analysis complete. Two impacts identified. Upgrades expected to be completed in 2015. Operating measures in place in interim period. Unit can deactivate as scheduled. O MW capacity rights, but 50 MW (total) energy. Unit deactivated 1/9/2014.
Modern Power Landfill NUG	0	MetEd	15	4/8/2014	2/3/2014	Reliability analysis complete - no impacts identified. Unit deactivated 2/3/2014. Unit is 0 MW capacity, 6 MW energy resource.

Walter C Beckjord 4	150	DEOK	53	4/1/2015 4/16/2014	2/17/2014	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014. Upgrades complete. On January 16, 2014 Beckjord U4 submitted an updated deactivation notice with an April 16, 2014 deactivation date. Reliability analysis complete for April 2014 deactivation date and no impacts identified. Unit deactivated on Feb. 17, 2014.
BL England Unit 1	129	AE	50	5/1/2014	5/1/2014	Reliability analysis complete. No reliability impacts - with request to transfer CIRs to Y1-001. Unit deactivated 5/1/2014.

Source : PJM PJM Generator Deactivations as of 05.02.2014 [http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx]

Return to TOC

ICF Base Case New Plant Capital Costs (2013$/summer kW-yr) - ATSI & AEP/Dayton

2013$/kW-Yr	Fossil Prime Movers - AEP/Dayton	
Year	CT	CC
2015		
2016		
2017	701	1,062
2018	701	1,062
2019	701	1,062
2024	701	1,062
2028	701	1,062
2029	701	1,062
2035	701	1,062
2036	701	1,062
2037	701	1,062

2013$/kW-Yr	Renewable Prime Movers - AEP/Dayton				
Year	Onshore Wind Step 1	Onshore Wind Step 2	Onshore Wind Step 3	Solar PV-Utility Scale	Solar PV-DG
2015	1,778	2,133	2,666	2,180	2,202
2016	1,760	2,112	2,640	2,137	2,158
2018	1,726	2,071	2,589	2,404	2,428
2023	1,643	1,971	2,464	2,650	2,676
2030	1,465	1,759	2,198	2,301	2,324
2037	1,333	1,600	2,000	2,144	2,166

Notes:

(1) The capital costs projections provided in above tables represent ICF's view of the future capital costs. For modeling purposes, for CC and CT technologies, we assume a single flat real capital cost price based on 2017 projections. ICF assumes there will be boom and bust cycles around capital costs however it is hard to predict the exact timing of these cycles.

(2) CC builds are allowed only in 2017 onwards due to lead time limitations
(4) Wind and Solar builds are allowed from 2015 onwards
(5) When appropriate, capital costs are adjusted for summer weather and altitude conditions.
(6) Above we show costs in dollars per summer kW.

Wind Capital Costs:

[1] Wind capital costs are divided into three steps to reflect various terrain characteristics, resources degradation and other resource constraints.
[2] AEO wind classes 3-6 have been incorporated into IPM with separate capital costs
[3] IPM includes the effect of the federal PTC as defined under current policy. The PTC is avialable for qualifying resources that commence construction before the end of 2013.

Return to TOC

New Plant Heat Rates (Btu/KWh)

	Combined Cycle	Combustion Turbine	Jet Engine (CT - LMS 100)
2015			8,600
2016		10,905	8,600
2017		10,905	8,600
2018	6,800	10,905	8,600
2020	6,800	10,905	8,600
2025	6,500	10,905	8,600
2030	6,400	10,905	8,600
2035	6,400	10,905	8,600

Notes: Annual average, HHV, degraded, full load.

Return to TOC

ICF New Plant Proxy Financing Assumptions for PJM - AEP/Dayton

Utility/Merchant Ratio:	100% Merchant	Adjusted	Adjusted	Adjusted	100% Merchant
Technology Type	**Combustion Turbine**	**Combined Cycle/Cogen**	**Wind & Renewables**	**Retrofits Utility**	**Combined Cycle/Cogen**
Input Assumptions					
Debt Life (years)		20	15	15	20
Book Life (years)	30	30	20	15	30
Nominal After Tax					
Equity Rate (%)	13.3%	10.8%	10.8%	10.8%	13.3%
Equity Ratio (%)	45%	45%	45%	45%	45%
Nominal Pre-Tax					
Debt Rate (%)	7.8%	5.8%	5.8%	5.8%	7.8%
Debt Ratio (%)	55%	55%	55%	55%	55%
Income Tax Rate (%)	37.6%	37.6%	37.6%	37.6%	37.6%
Inflation (%)	2.1%	2.1%	2.1%	2.1%	2.1%
Property Tax and Insurance (%)	0.97%	0.97%	0.97%	0.97%	0.97%
Output					
Real Levelized Fixed Charge Rate (%)	**12.1%**	**9.7%**	**9.4%**	**12.6%**	**11.9%**
Nominal After tax Weighted Average Cost of Capital (%)	8.66%	6.85%	6.85%	6.85%	8.66%
Real Weighted Average Cost of Capital (%)	6.43%	4.65%	4.65%	4.65%	6.43%

Notes:

(1) Financing assumptions are important because the annual costs of capital investment are a function of both financing costs and capital costs. In equilibrium in the long-term, an important driver of scarcity or capacity prices is the annual costs of new entry, i.e., entry by a new natural gas-fired combined cycle.

We have calculated the merchant cost of equity requirement to be approximately 13.3 percent. ICF has assessed the required rate of return for new entrants using the Capital Asset Pricing Model (CAPM). ICF assumes that the required return on equity for new entrants without long-term fixed price contracts (i.e., without long-term power sales contracts of 10 years or longer) is equal to that of publicly traded Independent Power Producer (IPPs) (e.g., NRG, Calpine, and Dynegy). ICF uses observable securities prices over a five-year period and concludes that at a 55 percent debt share, the required rate of return on equity is 13.3 percent (nominal). This leads to a nominal after-tax weighted average cost of capital (WACC) of approximately 8.7percent (nominal).

However, for purposes of equilibrium capacity / scarcity price calculations, we use a lower equity rate of 10.8 percent to calculate the cost of new entry (CONE) than does PJM. This is consistent with our historical observation of market conditions that result in lower capacity prices relative to true merchant CONE. Thus, ICF is assuming that new generic non-firm units without contracts and generic existing units will not earn in equilibrium their required rate of return. This reflects several factors including temporary discounts of equipment costs, temporary periods of low financing costs, use of brownfield sites, greater economies of scale, imperfections in the power markets (e.g., price caps and market intervention) and the availability, in some cases, of traditional utility financing and long term power purchase agreements (e.g. industrial hosts contracting for power).

(2) The financial assumptions are consistent across all regions, with only income tax, property tax and insurance varying by region.
(3) We use the following MACRS depreciation schedule :
Combined Cycle - 20 years, Combustion Turbine - 15 years, and Wind - 5 years.
(4) The financing assumptions for CTs reflect merchant financing in contrast to lower cost financing assumed for CCs. This reflects the higher risks for CTS and the lesser likelihood that they will be contracted on similar terms as CCs

Return to TOC

Summary of Environmental Regulations Assumptions

Regulation	Timing
Maryland Healthy Air Act (MD HAA)	2009/2010 Phase I; 2012/2013Phase II
SO2 and NOx (CAIR/CAIR II)	2009/2010 Phase 1 (CAIR); 2015 Phase 2 (CAIR); 2018 CAIR II (CAIR Replacement)
Air Toxics (MATS)	2016
CCR (coal ash) Disposal	
CO2 (National)	2020
Water Intake (316b)	2025

Parameter	Current
MATS	Federal Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) standards consistent with those set by EPA in its final Air Toxics Rule, released December 21st, 2011.
	Units are required to meet the Hg and HCl standards in the final rule. For PM compliance, units are required to upgrade their ESP or install a FF based on EPA’s modeling assumptions for the final rule to meet the filterable PM standard.
	States with existing Hg rules proceed as planned, so long as they meet minimum requirement as defined by federal MACT
CO2	RGGI; Federal cap-and-trade CO2 program starting in 2020

Return to TOC

Environmental Regulations: SO2, NOx

	SO_2 Programs	NO_x Programs	
CAIR for SO_2 and NO_x (Through 2017)	25 States + DC Retirement ratio:	**Annual**	**Ozone Season**
	2015: 2.86:1 Existing Title IV for unaffected states	25 States + DC 2009: 1.522 million tons 2015: 1.268 million tons 200,000 ton Compliance Supplement Pool (CSP) in 2009	25 States + DC 2009: 0.568 million tons 2015-Onwards: 0.485 million tons (Banking from SIP Call allowed)
CAIR II for SO_2 and NO_x (2018-onwards)	25 States + DC State level emission budgets with intrastate trading only (see table below)	25 States + DC State level emission budgets with intrastate trading only (see table below)	

State	Annual SO2 Projected Budget 2018+ (tons)	Annual NOX Projected Budget 2018+ (tons)
Alabama	88,246	46,014
Delaware	12,550	2,778
District of Columbia	396	96
Florida	141,932	66,297
Georgia	119,312	44,214
Illinois	107,895	50,820
Indiana	142,575	72,623
Iowa	35,893	21,794
Kentucky	105,713	55,470
Louisiana	33,570	23,674
Maryland	39,590	18,483
Michigan	100,019	43,536
Minnesota	27,993	20,962
Mississippi	18,907	11,871
Missouri	76,840	39,914
New Jersey	18,139	8,446
New York	75,678	30,411
North Carolina	76,911	41,455
Ohio	186,771	72,445
Pennsylvania	154,554	66,033
South Carolina	32,071	21,775
Tennessee	76,841	33,982
Texas	179,730	120,676
Virginia	35,548	24,050
West Virginia	120,894	49,480
Wisconsin	48,868	27,173
Total	2,057,436	1,014,472

Return to TOC

Environmental Regulations: Air Toxics (HAPS)

Environmental Regulations	Programs	Start Year	ICF Treatment
Air Toxics (MATS) Regulations	State Level	Vary by State	Final state level programs.
	Air Toxics (MATS)	2016	Federal Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) standards consistent with those set by EPA in its final Air Toxics Rule, released December 21st, 2011. Units are required to meet the Hg and HCl standards in the final rule. For PM compliance, units are required to upgrade their ESP or install a FF based on EPA's modeling assumptions for the final rule to meet the filterable PM standard.

States with State Level Hg Regulations

State	Performance Standard	Alternate Regulation
CA	No	Considering a cap at current levels at existing sources.
CT	Yes	90% removal or 0.6 lb/Tbtu at the unit level by 7/2008.
DE	Yes	Unit-level regulation: Phase 1 (2009): 80% capture or rate limit of 1.0 lb/TBtu; Phase 2 (2013): 90% capture or rate limit
ID	No	
IL	Yes	0.008 lb Hg/GWh or 90% removal by 2009; Ameren, Dynegy: unit-level controls and plan-level reduction of 90% by 2012; Midwest Generation: 90% removal at all plants by 2009
MA	Yes	Facility-level: 85% Hg removal or 0.0075 lb/GWh by 2008 and 95% Hg removal or 0.0025 lb/GWh by 2012.
MD	Yes	Facility-level: Phase 1 (2010): 80% removal; Phase 2 (2013): 90% removal. Brandon Shores and Wagner are allowed to combine emissions
ME	Yes	Facility-level: limit of 50 lbs/yr; drops to 35 lb/yr in 2007 and 25 lb/yr in 2010
MI	Yes	Phase 1 (2010): CAMR levels; Phase 2 (2015): 90% reduction. System-wide averaging .
MN	Yes	90% removal for facilities over 500 MW; reductions required by 2010 for dry PM units and 2014 for wet PM units.
NH	Yes	Unit level: 80% removal via scrubber installation by 7/1/2013. SO2 emission credits for early Hg reductions.
NJ	Yes	Unit level: 90% removal or 3.0 mg/MWh by 2008; compliance extended to 2012 with multi-pollutant controls.
NM	No	Facility level: Adopts CAMR budgets; unused allowances (inc. new source set-aside) are retired annually.
NY	Yes	Facility level: Phase 1 (2010-2014): limits based on CAMR budget. Phase 2 (2015): limit of 0.6 lbs/MMBtu
PA	Yes	Unit level: 80% reduction by 2010, 90% reduction by 2015
VT	No	
WI	No	Facility level: Adopts CAMR standards & schedule.
RI	No	Only new sources will be subject to CAMR.
WA	Yes	Facility level: 2013: 0.008 lb/GWh (existing sources) and 0.0066 lb/GWh (new sources); plants must be in
OR	Yes	State standards (12/2006): 90% removal or 0.60 lb/TBtu by 7/2012 (one year extension possible).

Return to TOC

Environmental Regulations: National Carbon Policy

National CO2 (CAP & TRADE)		
Year	**National CO2 Expected Allowance Prices (2013$/Ton)**	**National CO2 Expected Allowance Prices (Nominal$/Ton)**
2015	0.0	[redacted]
2016	0.0	
2017	0.0	
2018	0.0	
2019	0.0	
2020	1.0	
2021	3.1	
2022	4.1	
2023	6.1	
2024	7.1	
2025	9.2	
2026	10.2	
2027	11.2	
2028	12.3	
2029	13.3	
2030	15.3	
2031	17.4	
2032	19.4	
2033	21.4	
2034	24.5	
2035	26.5	

Notes:
Inflation used beyond 2015 is 2.1% annually.

National CO2
[1] ICF assumes a charge on CO2 from the power sector beginning in 2020. The 2020 start date of the regulation reflects potential timing for existing unit New Source Performance Standards (NSPS) for GHGs. That being said, we believe that the issue of limiting CO2 emissions is one that will be revisited over time.

Return to TOC

Ash and Water Regulations

Water Intake Regulations	
Timing	2025
Once-through cooling systems	[1] Plants with once-through cooling in the following states must install cooling towers: CA, OR, WA, NJ, NY, MA [2] Plants with once-through cooling in other states must install a representative alternative compliance option, such as nets with fish handling, booms, velocity caps, etc.
Re-circulating systems with cooling pond/canal are exempted	

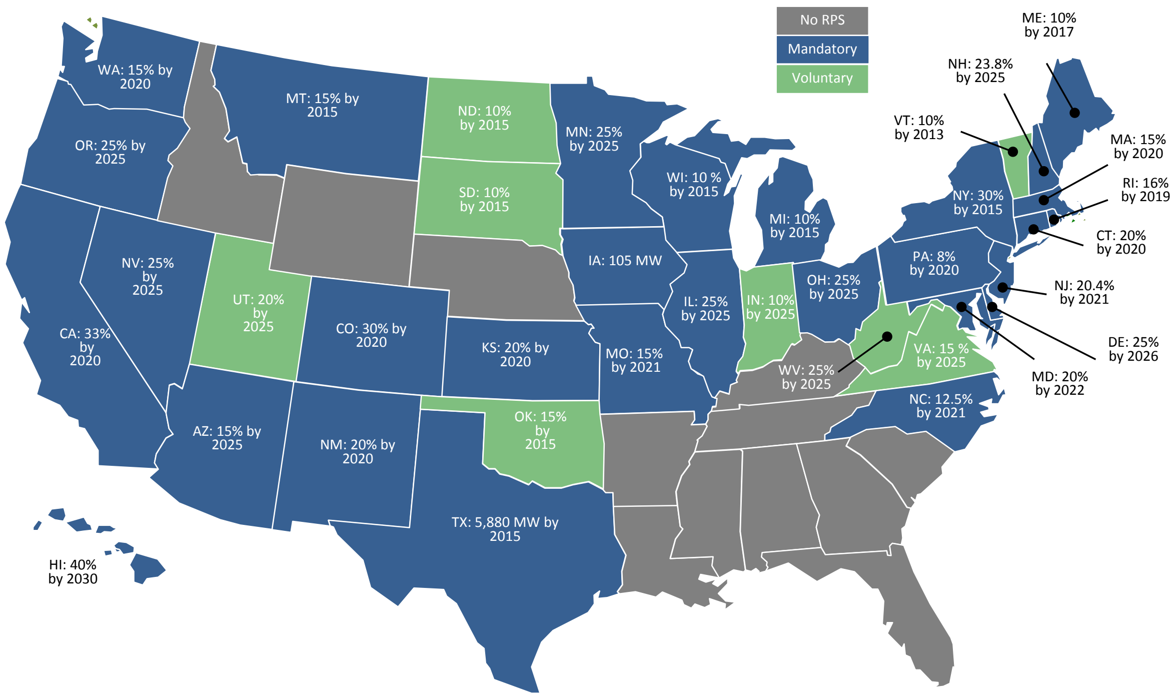
Ash Regulations	
Timing	2018
Units with surface-based impoundment	(1) Dry collection modifications (2) Close/cap ash pond (3) New wastewater treatment facilities
Units that landfill	Upgrade wastewater treatment facilities for scrubbed units only (in response to effluent guidelines)
Ash is not treated as hazardous	
Beneficial use of ash continues	

316(B) Timing

There are two pieces to 316(b) impingement and entrainment. Entrainment is the one that is more costly. Technologies to meet impingement requirements must be implemented as soon as possible, but no later than 8 years after the final rule is issued. Since the final rule was due in July 2013, this would put compliance in mid to late-2021. For the entrainment requirements, the timing is vague. Given that impingement is no later than 8 years, we assume slightly more time would be allowed for entrainment given that the controls are potentially more costly and more time consuming. Also for entrainment, existing facilities that withdraw more than 125 MGD will be requirement to conduct studies to determine whether and what site-specific controls, if any, would be required to reduce entrainment. This decision process will include public input. This would presumably add substantial time to the process.

Return to TOC

Renewable Portfolio Standards



Source: ICF

Note: With the recent signing of S.B. 310, Ohio's state RPS target has been reduced from 25% by 2025 to 12.5% by 2027. The older standard is currently reflected in the modeling.

Return to TOC

PJM Inter-Regional Transmission Expansion

Transmission Development	TRAIL	Susq-Roseland	North Central Reliability Project
Online Year	**2011-2012**	**2016**	**2014**
Affected Connections	AEP-APS APS-PEPCO APS-DOM PEPCO-BGE	WC-PSEGN	PSEGN

Notes:

Mt Storm – Doubs transmission rebuilding project:

Starting in 2012, and for the non-summer months, the APS to DOM transmission line will be set to pre-TRAIL levels in order to approximate the effect of the rebuild.

With the completion of the project in December of 2014, the APS to DOM line will be back up to TRAIL levels.

Key High Voltage ATSI Transmission Projects

PJM Upgrade ID	Description	ISA-In Service Date	Revised In Service Date	Projected In Service Date	Status	Percent Complete	State	Region	Transmission Owner	Cost Estimate	Location	Driver	Task	Display Service Date
b1282	Build Beaver - Hayes - Davis - Besse #2 345 kV line	1/6/2015	1/6/2014	1/6/2014	Under Construction	75	OH	PJM WEST	ATSI	34.65	Beaver - Besse	Load Delivery Voltage	Build	1/6/2014
b1283	Loop the Chamberlin - Mansfield 345 kV line into the Hanna 345 kV substation	1/6/2015	1/6/2014	1/6/2014	Under Construction	50	OH	PJM WEST	ATSI	8.1	Hanna	Load Delivery Voltage	Loop in	1/6/2014
b1922	Install a 2nd 345/138 kV transformer at the Bayshore station	1/6/2014		1/6/2014	Under Construction	40	OH	PJM WEST	ATSI	7.2	Bayshore	N-1-1 Voltage	Install	1/6/2014
b1924	Build a new Mansfield - Northfield ("Glen Willow") 345 kV line	1/6/2015		1/6/2015	Under Construction	30	OH	PJM WEST	ATSI	184.5	Mansfield/Northfield	Load Deliverability	Build	1/6/2015