United States
Environmental Protection Agency

Air and Radiation
(6204J)

EPA #430-R-11-006
March 2011

Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule

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U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW (6204J)
Washington, D.C. 20460
(www.epa.gov/airmarkets)

March 2011

This report documents enhancements and updates that were made in EPA Base Case v4.10_PTox Mar2011[1] to provide capabilities required to perform modeling for the Proposed Toxics Rule. Specifically, the capability to model HCl emissions and controls was added. Existing coal units were given the option to burn natural gas by investing in a coal-to-gas retrofit. The cost and performance assumptions were updated for Activated Carbon Injection (ACI), the emission control particularly designated for mercury emission reductions. In addition, updates were made to the tables of state regulations and NSR and state settlements to reflect changes that had occurred since the previous base case

The current report takes the form of a supplement to the documentation report "Documentation for EPA Base Case v4.10 Using the Integrated Planning Model" (August 2010) that can be found on the web at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html. Exhibit 1 contains an abbreviated version of the table of contents of the v4.10 Documentation. Additions and changes found in this Documentation Supplement are shown in red.

[1] EPA Base Case v4.10_PTox Mar2011 refers to EPA's application of the Integrated Planning Model (IPM) of the U.S. power sector that was developed and used in analysis of the Proposed Toxics Rule. For brevity it is often referred to as v4.10_PTox in subsequent pages of this documentation supplement. IPM® is a registered trademark of ICF International.

Exhibit 1: Abbreviated table of contents for EPA Base Case v4.10 showing (in red) additions and changes covered in this Documentation Supplement

Documentation Supplement to Chapter 3 (“Power System Operation Assumptions”)

The tables of State Power Sector Regulations (Appendix 3-2), New Source Review Settlements (Appendix 3-3), and State Settlements (Appendix 3-4) were updated to reflect changes that had occurred since the provisions had been incorporated in EPA Base Case v4.10. The updated tables are included below.
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Appendix 3-2 State Power Sector Regulations included in EPA Base Case v4.10_PTox, Mar2011

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	0.02 lbs/MMBtu annual PPMDV for combined cycle EGUs which commenced operation after April 1, 2003	2003
Arizona	Title 18, Chapter 2, Article 7	Hg	90% removal of Hg content of fuel or 0.0087 lb/GWH-hr annual reduction for all non-cogen coal units > 25 MW	2017
California	CA Reclaim Market	NO_x	9.68 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	1994
		SO_2	4.292 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	
Colorado	40 C.F.R. Part 60	Hg	2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for Pawnee Station 1 and Rawhide Station 101 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 25 MW	2012
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	0.15 lbs/MMBtu rate limit in the winter season for all fossil units > 15 MW	2003
	Executive Order 19, RCSA 22a-198 & Connecticut General Statues (CGS) 22a-198	SO_2	0.33 lbs/MMBtu annual rate limit for all Title IV sources > 15 MW 0.55 lbs/MMBtu annual rate limit for all non-Title IV sources > 15 MW	
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal-fired units	2008
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW 0.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW	2009
	Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation	NO_x	0.125 lbs/MMBtu rate limit of NO_x annually for all coal and residual-oil fired units > 25 MW	2009
		SO_2	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units > 25 MW	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
		Hg	2012: 80% removal of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 25 MW	
Georgia	Multipollutant Control for Electric Utility Steam Generating Units	SCR, FGD, and Sorbent Injection Baghouse controls to be installed	The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates	Implementation from 2008 through 2015, depending on plant and control type
Illinois	Title 35, Section 217.706	NO_x	0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW	2004
	Title 35, Part 225, Subpart B: Control of Hg Emissions from Coal Fired Electric Generation Units	NO_x	0.11 lbs/MMBtu annual rate limit and ozone season rate limit for all Dynergy and Ameren coal steam units > 25 MW	2012
		SO_2	2013 & 2014: 0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW 2015 onwards: 0.25 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW	2013
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GW-hr annual reduction for all Ameren and Dynergy coal units > 25 MW	2015
	Title 35 Part 225; Subpart F: Combined Pollutant Standards	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units	2012
		SO_2	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all specified Midwest Gen coal steam units	2013
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all specified Midwest Gen coal steam units	2015
Kansas	NO_x Emission Reduction Rule, K.A.R. 28-19-713a.	NO_x	0.20 lbs/MMBtu annual rate limit for Quindaro Unit 2 and 0.26 lbs/MMBtu annual rate limit for Nearman Unit 1.	2012
Louisiana	Title 33 Part III - Chapter 22, Control of Emissions of Nitrogen Oxides	SO_2	1.2 lbs/MMBtu ozone season PPMDV for all single point sources that emit or have the potential to emit 5 tons or more of SO2 into the atmosphere	2005
	Title 33 Part III - Chapter 15, Emission Standards for Sulfur Dioxide	NO_x	Various annual rate limits depending on plant and fuel type for facilities within the Baton Rouge Nonattainment Area that collectively have the potential to emit 25 tons or more per year of NO_x or facilities within the Region of Influence that collectively have the potential to emit 50 tons or more per year of NO_x	2005
Maine	Chapter 145 NO_x Control Program	NO_x	0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr	2005
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
Maryland	Maryland Healthy Air Act	NO_x	3.6 MTons summer cap and 8.3 MTons annual cap for Mirant coal units 0.5 MTons summer cap and 1.4 MTons annual cap for Allegheny coal units 3.6 MTons summer cap and 8.03 MTons annual cap for Constellation coal units.	2009
		SO_2	2009 through 2012: 23.4 MTons annual cap for Constellation coal units, 24.2 MTons annual cap for Mirant Coal units, and 4.6 MTons annual cap for Allegheny coal units. 2013 onwards: 17.9 MTons annual cap for Constellation coal units, 18.5 MTons annual cap for Mirant Coal units, and 4.6 MTons annual cap for Allegheny coal units.	
		Hg	2010 through 2012: 80% removal of Hg content of fuel for Mirant, Allegheny, and Constellation coal steam units 2013 onwards: 90% removal of Hg content of fuel for Mirant, Allegheny, and Constellation coal steam units	
Massachusetts	310 CMR 7.29	NO_x	1.5 lbs/MWh annual GPS for Bayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	2006
		SO_2	3.0 lbs/MWh annual GPS for Bayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	
		Hg	2012: 85% removal of Hg content of fuel or 0.00000625 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor 2013 onwards: 95% removal of Hg content of fuel or 0.00000250 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	
Michigan	Part 15. Emission Limitations and Prohibitions - Mercury	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2015
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal units > 250 MW	2008
Missouri	10 CSR 10-6.350	NO_x	0.25 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Gasconade, Iron, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington and Wayne 0.18 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW the following counties: City of St. Louis, Franklin, Jefferson, and St. Louis 0.35 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Buchanan, Jackson, Jasper, Randolph, and any other county not listed	2004
Montana	Montana Mercury Rule Adopted 10/16/06	Hg	0.90 lbs/TBtu annual rate limit for all non-lignite coal units 1.50 lbs/TBtu annual rate limit for all lignite coal units	2010
New Hampshire	RSA 125-O: 11-18	Hg	80% reduction of aggregated Hg content of the coal burned at the facilities for Merrimack Units 1 & 2 and Schiller Units 4, 5, & 6	2012

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
	ENV-A2900 Multiple pollutant annual budget trading and banking program	NO_x	2.90 MTons summer cap for all fossil steam units > 250 MMBtu/hr operated at any time in 1990 and all new units > 15 MW 3.64 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	2007
		SO_2	7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	
New Jersey	N.J.A.C. 7:27-27.5, 27.6, 27.7, and 27.8	Hg	90% removal of Hg content of fuel annually for all coal-fired units 95% removal of Hg content of fuel annually for all MSW incinerator units	2007
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 1	NO_x	2009 - 2012 annual rate limits in lbs/MMBtu for the following technologies: Coal Boilers (Wet Bottom) - 1.0 for tangential and wall-fired, 0.60 for cyclone-fired Coal Boilers (Dry Bottom) - 0.38 for tangential, 0.45 for wall-fired, 0.55 for cyclone-fired Oil and/or Gas or Gas only: 0.20 for tangential, 0.28 for wall-fired, 0.43 for cyclone-fired 2013 & 2014 annual rate limits in lbs/MWh for the following technologies: All Coal Boilers: 1.50 for all Oil and/or Gas: 2.0 for tangential, 2.80 for wall-fired, 4.30 for cyclone-fired Gas only: 2.0 for tangential and wall-fired, 4.30 for cyclone-fired 2015 onward annual rate limits in lbs/MWh for the following technologies: All Coal Boilers: 1.50 for all Oil and/or Gas: 2.0 for fuel heavier than No. 2 fuel oil, 1.0 for No. 2 and lighter fuel oil Gas only: 1.0 for all	2009
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 4	NO_x	2.2 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 3.0 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 1.3 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 2.0 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007
New York	Part 237	NO_x	39.91 MTons non-ozone season cap for fossil fuel units > 25 MW	2004
	Part 238	SO_2	131.36 MTons annual cap for fossil fuel units > 25 MW	2005
	Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units	Hg	786 lbs annual cap through 2014 for all coal fired boiler or CT units >25 MW after Nov. 15, 1990. 0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after Nov.15 1990	2010
North Carolina	NC Clean Smokestacks Act: Statute 143-215.107D	NO_x	25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW	2007
		SO_2	2012: 100 MTons annual cap for Progress Energy coal plants > 25 MW and 150 MTons annual cap for Duke Energy coal plants > 25 MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80 MTons annual cap for Duke Energy coal plants > 25 MW	2009
Oregon	Oregon Administrative Rules, Chapter 345, Division 24	CO_2	675 lbs/MWh annual rate limit for new combustion turbines burning natural gas with a CF >75% and all new non-base load plants (with a CE <= 75%) emitting CO_2	1997

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
	Oregon Utility Mercury Rule - Existing Units	Hg	90% removal of Hg content of fuel reduction or 0.6 lbs/TBtu limitation for all existing coal units >25 MW	2012
	Oregon Utility Mercury Rule - Potential Units	Hg	25 lbs rate limit for all potential coal units > 25 MW	2009
Pacific Northwest	Washington State House Bill 3141	CO_2	$1.45/Mton cost (2004$) for all new fossil-fuel power plant	2004
Texas	Senate Bill 7 Chapter 101	SO_2	273.95 MTons cap of SO_2 for all grandfathered units built before 1971 in East Texas Region	2003
		NO_x	Annual cap for all grandfathered units built before 1971 in MTons: 84.48 in East Texas, 18.10 in West Texas, 1.06 in El Paso Region	
	Chapter 117	NO_x	East and Central Texas annual rate limits in lbs/MMBtu for units that came online before 1996: Gas fired units: 0.14 Coal fired units: 0.165 Stationary gas turbines: 0.14	2007
			Dallas/Fort Worth Area annual rate limit for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system except for CT and CC units online after 1992: 0.033 lbs/MMBtu or 0.50 lbs/MWh output or 0.0033 lbs/MMBtu on system wide heat input weighted average for large utility systems 0.06 lbs/MMBtu for small utility systems	
			Houston/Galveston region annual Cap and Trade (MECT) for all fossil units: 17.57 MTons	
			Beaumont-Port Arthur region annual rate limits for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system: 0.10 lbs/MMBtu	
Utah	R307-424 Permits: Mercury Requirements for Electric Generating Units	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2013
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	Annual rate limits in lbs/MMBtu for coal fired boilers > 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2009: 0.15, 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	2009
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall fired: 2009: 0.20; 2013 onwards: 0.17 in 2013 Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2009: 0.20; 2013 onwards: 0.15 Fluidized bed: 2009: 0.15; 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.41 Biologically derived fuel CTs between 25 and 49 MW: 0.15	
			Annual rate limits for CCs in lbs/MMBtu: Natural gas CCs > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.18 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19	
	Chapter NR 446. Control of Mercury Emissions	Hg	2012 through 2014: 40% reduction in total Hg emissions for all coal-fired units in electric utilities with annual Hg emissions > 100 lbs 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 150 MW 80% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 25 MW	2010

Notes:

Updates to the EPA Base Case v4.10_PTox from EPA Base Case 4.10 include the following:

1) An update of the modeling of SO_2 rate limits in Connecticut

2) An update of the modeling of the effective dates of various controls on units in Georgia

3) Addition of two Kansas State Law unit-specific constraints

4) An update of the modeling of NO_x rate limits in Louisiana

5) An update of the modeling of the NO_x annual and summer caps and SO_2 annual cap in Maryland

6) An update of the modeling of the NO_x rate limits in New Jersey

Appendix 3-3 New Source Review (NSR) Settlements in EPA Base Case v4.10_PTox, Mar2011

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Alabama Power																	
James H. Miller	Alabama	Units 3 & 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	With 45 days of settlement entry, APC must retire 7,538 SO_2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO_2 emission allowances outside of the APC system	1/1/21	http://www.epa.gov/compliance/resources/cases/civil/caa/alabamapower.html
Minnkota Power Cooperative																	
Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO_2/year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If Unit 3 is not operational by 12/31/2015, then beginning 1/01/2014, the plant wide emission shall not exceed 8,500.																	
Milton R. Young	Minnesota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD		Plant will surrender 4,346 allowances for each year 2012 – 2015, 8,693 allowances for years 2016 – 2018, 12,170 allowances for year 2019, and 14,886 allowances/year thereafter if Units 1 – 3 are operational by 12/31/2015. If only Units 1 and 2 are operational by12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade NO_x allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		http://www.epa.gov/compliance/resources/cases/civil/caa/minnkota.html
		Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/07		0.03	Before 2008				
SIGECO																	
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/sigecofb.html
		Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04										
		Unit 3			Improve and continuously	95%	06/30/04	Operate Existing	0.1	09/01/03	Install and continuously	0.015	06/30/07				

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
					operate existing FGD (shared by Units 2 and 3)			SCR Continuously			operate a Baghouse						
PSEG FOSSIL																	
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/pseglic.html
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06				
Mercer	New Jersey	Units 1 & 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.13	05/01/06							
TECO																	
Big Bend	Florida	Units 1 & 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/teco.html
		Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	Install SCR	0.1	05/01/09							
		Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07							
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04													
WEPCO																	
WEPCO shall comply with the following system wide average NO_x emission rates and total NO_x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17, 400 tons. For SO_2 emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.																	http://www.epa.gov/compliance/resources/cases/civil/c

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			aa/wepco.html
		Units 5 & 6						Install and operate low NO_x burners		12/31/03							
		Units 7 & 8						Operate existing low NO_x burners		12/31/05	Install Baghouse						
		Unit 9						Operate existing low NO_x burners		12/31/06	Install Baghouse						
Pleasant Prairie	Wisconsin	1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/06	Install and continuously operate SCR (or approved tech)	0.1	12/31/06							
		2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03							
Oak Creek	Wisconsin	Units 5 & 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							
		Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							
		Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							
Port Washington	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree													
Valley	Wisconsin	Boilers 1 – 4						Operate existing low NO_x burner		30 days after entry of consent decree							

VEPCO

The Total Permissible NOx Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 – 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year thereafter. Beginning 1/1/2013 they will have a system wide emission rate no greater than 0.15 lb/mmBtu.

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	01/01/05	Install and continuously operate SCR	0.11	01/01/08				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.			
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	01/01/13							
		Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12							
		Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11							
Chesapeake Energy	Virginia	Units 3 & 4						Install and continuously operate SCR	0.1	01/01/13							
Clover	Virginia	Units 1 & 2			Improve FGD	95% or 0.13	09/01/03										
Possum Point	Virginia	Units 3 & 4	Retire and repower to natural gas	05/02/03													
Santee Cooper																	
Santee Cooper shall comply with the following system wide averages for NO_x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO_2 emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.																	http://www.epa.gov/compliance/resources/cases/civil/caa/santeecooper.html
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			
		Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and Continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07							
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04							
		Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04							
		Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08							
		Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08							
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more		06/25/04							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
								stringent technology									
		Unit 2						Operate low NO_x burner or more stringent technology		05/01/04							
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		06/25/04							
Ohio Edison																	
Ohio Edison shall achieve reductions of 2,483 tons NO_x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1 – 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO_x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO_2 by 12/31/2010.																	http://www.epa.gov/compliance/resources/cases/civil/caa/ohioedison.html
No later than 8/11/2005, Ohio Edison shall install and operate low NO_x burners on Sammis Units 1 - 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO_x emissions from Sammis Units 1 – 5.																	
W.H. Sammis Plant	Ohio	Unit 1			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/mmBtu	12/31/08	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO_2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO_2. For calendar year 2006 through 2017, Ohio Edison may accumulate SO_2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO_2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO_2 allowances.			
		Unit 2			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/mmBtu	12/31/08	Operate existing SNCR continuously	0.25	02/15/06							
		Unit 3			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/mmBtu	12/31/08	Operate low NO_x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 10/31/07							
		Unit 4			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/mmBtu	06/30/09	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07							
		Unit 5			Install Flash Dryer Absorber or ECO[2] (or approved equiv. control tech)	50% removal or 1.1 lb/mmBtu	06/29/09	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	03/31/08							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
					& operate continuously												
		Unit 6			Install FGD[3] (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/mmBtu	06/30/11	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10				
		Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/mmBtu	06/30/11	Operate existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10				
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05										
		Unit 2			Upgrade existing FGD	95%	12/31/06										
		Unit 3			Upgrade existing FGD	95%	10/31/07										
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06							
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal.	12/31/11													
		Unit 5		12/31/11													
Mirantl[1,6]																	
System-wide NO_x Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NO_x Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008 – 2009; 5,200 tons 2010 thereafter. Beginning on 5/1/2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lb/mmBtu NO_x.																	
Potomac River Plant	Virginia	Unit 1															http://www.epa.gov/compliance/resources/cases/civil/caa/mirant.html
		Unit 2															
		Unit 3						Install low NO_x burners (or more effective tech) &		05/01/04							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
								operate continuously									
		Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							
		Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							
Morgantown Plant	Maryland	Unit 1						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/07							
		Unit 2						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/08							
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO_2 Allowances equal to the amount by which the SO_2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO_2 emissions allowed under this Section XVIII.			
		Unit 2			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10										
Illinois Power																	
System-wide NOx Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO2 Emission Annual Caps: 66,300 tons 2005 – 2006; 65,000 tons 2007; 62,000 tons 2008 – 2010; 57,000 tons 2011; 49,500 tons 2012; 29,000 tons 2013 onward.																	
Baldwin	Illinois	Units 1 & 2			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10	By year end 2008, Dynergy will surrender 12,000 SO_2 emission allowances, by year end 2009 it will surrender			http://www.epa.gov/compliance/resources/cases/civil/caa/illinoispower.html

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
		Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO_x burners	0.12 until 12/30/12; 0.1 from 12/31/12	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10	18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.			
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lb/mmBtu until 12/30/2012; 0.1 lb/mmBtu from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Bag-house: 0.015 lb/mmBtu ; For ESP: 0.03 lb/mmBtu	For Baghouse: 12/31/12; For ESP: 12/31/05				
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				
		Unit 2				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				
Vermilion	Illinois	Units 1 & 2				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10				
Wood River	Illinois	Units 4 & 5				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				
Kentucky Utilities Company																	
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO_x boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO_2 allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO_x allowances must be surrendered through 2020.	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		http://www.epa.gov/compliance/resources/cases/civil/caa/kucompany.html
Salt River Project Agricultural Improvement and Power District (SRP)																	
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO_x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD	Beginning in 2012, all surplus SO_2 allowances for both Coronado and Springerville Unit 4 must be	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of		http://www.epa.gov/compliance/resources/cases/civil/caa/srp.html

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO												Reference
			Action	Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	
					FGD.								installation)	surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the consent decree.	complying with the Consent Decree do not earn credits.		
		Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO_x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)				
American Electric Power																	
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO_x and SO_2 allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO_x allowances relative to the CAIR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO_x and SO_2 earns supercompliance allowances.		http://www.epa.gov/compliance/resources/cases/civil/caa/americanelectricpower1007.html
						450,000	2010		96,000	2009							
						450,000	2011		92,500	2010							
						420,000	2012		92,500	2011							
						350,000	2013		85,000	2012							
						340,000	2014		85,000	2013							
						275,000	2015		85,000	2014							
						260,000	2016		75,000	2015							
						235,000	2017		72,000	2016 and thereafter							
						184,000	2018										
						174,000	2019 and thereafter										
At least 600MW from various units	West Virginia	Sporn 1 – 4	Retire, retrofit, or re-power	12/31/18													
	Virginia	Clinch River 1 – 3															
	Indiana	Tanners Creek 1 – 3															

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
	West Virginia	Kammer 1 – 3															
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08							-
		Unit 2			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09							-
		Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08							-
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
		Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09							-
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09				-
		Unit 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09				-
		Unit 3			Install and continuously operate FGD		12/31/12	Install and continuously operate SCR		01/01/09							-
Clinch River	Virginia	Units 1 – 3				Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO_x burners		Date of entry							-
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry													-
		Unit 2	Retire, retrofit, or re-power	Date of entry													-
		Unit 3	Retire, retrofit, or re-power	12/31/12													-
		Unit 4			Install and continuously operate		12/31/10	Install and continuously operate SCR		12/31/10							-

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
					FGD												
		Unit 5			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry							-
		Unit 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry							-
Gavin	Ohio	Unit 1			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							-
		Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							-
Glen Lyn	Virginia	Units 1 – 3															-
		Units 5, 6			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	01/01/10	Continuously operate over-fire air		Date of entry							-
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
Mitchell	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							-
		Unit 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							-
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/08							-
Muskingum River	Ohio	Units 1 – 4	Retire, retrofit, or re-power	12/31/15													-
		Unit 5			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/08	Continuously operate ESP	0.03	12/31/02				-
Picway	Ohio	Unit 9						Continuously operate low NO_x burners		Date of entry							-

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Rockport	Indiana	Unit 1			Install and continuously operate FGD		12/31/17	Install and continuously operate SCR		12/31/17							-
		Unit 2			Install and continuously operate FGD		12/31/19	Install and continuously operate SCR		12/31/19							-
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13													-
Tanners Creek	Indiana	Units 1 – 3			Burn only coal with no more than 1.2 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
		Unit 4			Burn only coal with no more than 1.2% sulfur content annual average		Date of entry	Continuously operate over-fire air		Date of entry							-
East Kentucky Power Cooperative Inc.																	
By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO_x controls at Cooper 2 by 12/31/2012 and SO_2 controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.																	
System-wide					System-wide 12-month rolling tonnage limits apply	12-month rolling limit (tons)	Start of 12-month cycle	All units must operate low NO_x boilers	12-month rolling limit (tons)	Start of 12-month cycle	PM control devices must be operated continuously system-wide, ESPs must be optimized within 270 days of entry date, or EKPC may choose to submit a PM Pollution Control Upgrade Analysis.	0.03	1 year from entry date	All surplus SO_2 allowances must be surrendered each year, beginning in 2008.	SO_2 and NO_x allowances may not be used to comply with the Consent Decree. NO_x allowances that would become available as a result of compliance with the Consent Decree may not be sold or traded. SO_2 and NO_x allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to supercompliance may be sold or traded.		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html
						57,000	10/01/08		11,500	01/01/08							
						40,000	07/01/11		8,500	01/01/13							
						28,000	01/01/13		8,000	01/01/15							

Company and Plant	State	Unit	Settlement Actions: Retire/Repower – Action	Retire/Repower – Effective Date	SO_2 control – Equipment	SO_2 control – Percent Removal or Rate	SO_2 control – Effective Date	NO_x Control – Equipment	NO_x Control – Rate	NO_x Control – Effective Date	PM or Mercury Control – Equipment	PM or Mercury Control – Rate	PM or Mercury Control – Effective Date	Allowance Retirement – Retirement	Allowance Restriction – Restriction	Effective Date	Reference
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry							
		Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating	60 days after entry							
Dale Plant	Kentucky	Unit 1						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08				EKPC must surrender 1,000 NO_x allowances immediately under the ARP, and 3,107 under the NO_x SIP Call. EKPC must also surrender 15,311 SO_2 allowances.		Date of entry	http://www.epa.gov/compliance/resources/cases/civil/caa/eastkentuckypower-dale0907.html
		Unit 2						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08							
		Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012													
		Unit 4															
Cooper	Kentucky	Unit 1															
		Unit 2			If EKPC opts to install controls rather than retiring Dale, it must	95% or 0.10		If EKPC elects to install controls, it must continuously operate SCR	0.08 (or 90% if non-SCR technology is used)	12/31/12							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
					install and continuously operate FGD or equiv. technology			or install equiv. technology									
Nevada Power Company																	
Beginning 1/1/2010, combined NO_x emissions from Units 5,6,7, and 8 must be no more than 360 tons per year.																	
Clark Generating Station	Nevada	Unit 5	Units may only fire natural gas					Increase water injection immediately, then install and operate ultra-low NO_x burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180 tons combined	5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)					Allowances may not be used to comply with the Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html
		Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 7							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 8							5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)							
Dayton Power & Light																	
Non-EPA Settlement of 10/23/2008																	
Stuart Generating Station	Ohio	Station -wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO_2 to SO_3 conversion rate greater than 0.5%	0.17 station-wide	30 days after entry		0.030 lb per unit	07/31/09		NO_x and SO_2 allowances may not be used to comply with the monthly rates specified in the Consent Decree.		Courtlink document provided by EPA in email
									0.17 station-wide	60 days after entry date							
						82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12	Install rigid-type electro-des in each unit's ESP		12/31/15				
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	07/01/12							
									0.10 station-wide	12/31/14							
PSEG FOSSIL, Amended Consent Decree of November 2006																	

Company and Plant	State	Unit	Settlement Actions: Retire/Repower – Action	Retire/Repower – Effective Date	SO_2 control – Equipment	SO_2 control – Percent Removal or Rate	SO_2 control – Effective Date	NO_x Control – Equipment	NO_x Control – Rate	NO_x Control – Effective Date	PM or Mercury Control – Equipment	PM or Mercury Control – Rate	PM or Mercury Control – Effective Date	Allowance Retirement – Retirement	Allowance Restriction – Restriction	Effective Date	Reference
Kearny	New Jersey	Unit 7	Retire unit	01/01/07										Allowances allocated to Kearny, Hudson, and Mercer may only be used for the operational needs of those units, and all surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO_x Allowances and 8,568 SO_2 Allowances not already allocated to or generated by the units listed here. Kearny allowances must be surrendered with the shutdown of those units.			http://www.epa.gov/compliance/resources/decrees/amended/psegfossil-amended-cd.pdf
		Unit 8	Retire unit	01/01/07													
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10				
						Annual Cap (tons)	Year		Annual Cap (tons)	Year							
						5,547	2007		3,486	2007							
						5,270	2008		3,486	2008							
						5,270	2009		3,486	2009							
						5,270	2010		3,486	2010							
Mercer	New Jersey	Units 1 &2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10				
Westar Energy																	
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO2 and an annual rate limit of 0.07 lbs/MMBtu starting 2012 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO2 of no greater than 0.070 lb/MMBtu.			Units 1-3 must continuously operate Low NOx Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.180 lb/MMBtu. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.080 lb/MMBtu. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lb/MMBtu Plant-Wide 12-Month Rolling Average Emission Rate and 9.6 MTons annual cap for NOx by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lb/MMBtu PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lb/MMBtu PM Emissions Rate						
Duke Energy																	
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012													
		Units 2 & 4			Install Dry sorbent injection technology	80%	1/1/2012										

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
American Municipal Power																	
Gorsuch Station	Ohio	Units 2 & 3	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)														http://amppartners.org/newsroom/amp-to-retire-gorsuch-generating-station/
		Units 1 & 4															
Hoosier Energy Rural Electric Cooperative																	
Ratts	Indiana	Units 1 & 2						Install & continually operate SNCRS	0.25	12/31/2011	Continuously operate ESP			Annually surrender any NOx and SO2 allowances that Hoosier does not need in order to meet its regulatory obligations			http://www.epa.gov/compliance/resources/cases/civil/caa/hoosier.html
Merom	Indiana	Unit 1			Continusly run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12						
		Unit 2			Continusly run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014				Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13						

Notes:

1) Updates to the EPA Base Case v4.10_PTox from EPA Base Case 4.10 include the additions of the American Municipal Power settlement, the Hoosier Energy Rural Electric Cooperative settlement, a modification to the control requirements on the Mercer plant under the PSEG Fossil settlement, and an update to the SO_2 emission modeling on Jeffrey Energy Center as part of the Westar settlement.

2) This summary table describes New Source Review settlement actions as they are represented in EPA Base Case. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.

3) Settlement actions for which the required emission limits will be effective by the time of the first mapped run year (before 1/1/2012) are built into the database of units used in EPA Base Case ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case, allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

4) Some control installations that are required by these NSR settlements have already been taken by the affected companies, even if deadlines specified in their settlement haven't occurred yet. Any controls that are already in place are built into EPA Base Case

5) If a settlement agreement requires installation of PM controls, then the controls are shown in this table and reflected in EPA Base Case. If settlement requires optimization or upgrade of existing PM controls, those actions are not included in EPA Base Case.

6) For units for which an FGD is modeled as an emissions constraint in EPA Base Case, EPA used the assumptions on removal efficiencies that are shown in the latest emission control technologies documentation

7) For units for which an FGD is hardwired in EPA Base Case, unless the type of FGD is specified in the settlement, EPA modeling assumes the most cost effective FGD (wet or dry) and corresponding 95% removal efficiency for wet and 90% for dry.

8) For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case, EPA assumed an emissions rate equal to 10% of the unit's uncontrolled rate, with a floor of .06 lb/MMBtu or used the emission limit if provided.

9) The applicable low NOx burner reduction efficiencies are shown in Table A 3-1:3 in the Base Case documentation materials.

10) EPA included in EPA Base Case the requirements of the settlements as they existed on January 1, 2011.

11) Some of the NSR settlements require the retirement of SO2 allowances. EPA estimated the amount of allowances to be retired from these settlements and adjusted the total Title IV allowances accordingly.

Appendix 3-4 State Settlements in EPA Base Case v4.10_PTox, Mar2011

Company and Plant	State	Unit	State Enforcement Actions													
			Retire/Repower		SO_2 control			NO_x Control			PM Control			Mercury Control		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date
AES																
Greenidge	New York	Unit 4			Install FGD	90%	09/01/07	Install SCR	0.15	09/01/07						
		Unit 3			Install BACT		12/31/09	Install BACT		12/31/09						
Westover	New York	Unit 8				90%	12/31/10	Install SCR	0.15	12/31/10						
		Unit 7			Install BACT		12/31/09	Install BACT		12/31/09						
Hickling	New York	Units 1 & 2			Install BACT		05/01/07	Install BACT		05/01/07						
Jennison	New York	Units 1 & 2			Install BACT		05/01/07	Install BACT		05/01/07						
Niagara Mohawk Power																
NRG shall comply with the below annual tonnage limitations for its Huntley and Dunkirk Stations: 2005 is 59,537 tons of SO_2 and 10,777 tons of NO_x, 2006 is 34,230 of SO_2 and 6,772 of NO_x, 2007 is 30,859 of SO_2 and 6,211 of NO_x, 2008 is 22,733 tons of SO_2																
Huntley	New York	Units 63 – 66	Retire	Before 2008												
Public Service Co. of NM																
San Juan	New Mexico	Unit 1			State-of-the-art technology	90%	10/31/08	State-of-the-art technology	0.3	10/31/08	Operate Baghouse and demister technology	0.015	12/31/09	Design activated carbon injection technology (or comparable tech)		12/31/09
		Unit 2					03/31/09			03/31/09			12/31/09			12/31/09
		Unit 3					04/30/08			04/30/08			04/30/08			04/30/08
		Unit 4					10/31/07			10/31/07			10/31/07			10/31/07
Public Service Co of Colorado																
Comanche	Colorado	Units 1 & 2			Install and operate FGD	0.1 lb/mmBtu combined average	07/01/09	Install low-NO_x emission controls	0.15 lb/mmBtu combined average	07/01/09				Install sorbent injection technology		07/01/09
		Unit 3			Install and operate FGD	0.1 lb/mmBtu		Install and operate SCR	0.08		Install and operate a fabric filter dust collection system	0.013		Install sorbent injection technology		Within 180 days of start-up
Rochester Gas & Electric																
Russell Plant	New York	Units 1 – 4	Retire all units													
Mirant New York																
Lovett Plant	New York	Unit 1	Retire	05/07/07												
		Unit 2	Retire	04/30/08												

Note: The TVA settlement with North Carolina was removed from this table to reflect the July 26, 2010 ruling by the U.S. Court of Appeals, Fourth Circuit Court reversing the settlement.

Documentation Supplement to Chapter 5 (“Emission Control Technologies”)

Chapter 5 covers a number of new capabilities incorporated in EPA Base Case v4.10_PTox. Section 5.3 presents features added to give existing coal units the option to burn natural gas by investing in a coal-to-gas retrofit. Section 5.4.3 describes the comprehensive update of the cost and performance assumptions for activated carbon injection (ACI) for mercury control. Section 5.5 describes the assumptions in v4.10_PTox related to hydrogen chloride (HCl) emission rate and control assumptions. This includes defining the removal rates for existing and new generating units and for wet and dry FGD (section 5.5.3.1). It also involves adding dry sorbent injection (DSI) and fabric filters (sections 5.5.3.2 and 5.5.4 respectively) as retrofit control technologies for HCl removal and developing associated cost and performance assumptions.

These changes and additions are presented in full below:

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5. Emission Control Technologies

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5.3 Coal-to-Gas conversions[2]

In EPA Base Case v4.10_PTox existing coal plants are given the option to burn natural gas in addition to coal by investing in a coal-to-gas retrofit. There are two components of cost in this option: Boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main transmission line. These two components of cost and their associated performance implications are discussed in the following sections.

5.3.1 Boiler Modifications For Coal-To-Gas Conversions

Enabling natural gas firing in a coal boiler typically involves installation of new gas burners and modifications to the ducting, windbox (i.e., the chamber surrounding a burner through which pressurized air is supplied for fuel combustion), and possibly to the heating surfaces used to transfer energy from the exiting hot flue gas to steam (referred to as the “convection pass”). It may also involve modification of environmental equipment. Engineering studies are performed to assess operating characteristics like furnace heat absorption and exit gas temperature; material changes affecting piping and components like superheaters, air (re)heaters, economizers, and recirculating fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

The following table summarizes the cost and performance assumptions for such boiler modifications as incorporated in Base Case v4.10_PTox. The values in the table were developed by EPA’s engineering staff based on technical papers3 and discussions with industry engineers familiar with such projects. They were designed to be applicable across the existing coal fleet.

[2] As discussed here coal-to-gas conversion refers to the modification of an existing boiler to allow it to fire natural gas. It does not refer to the addition of a gas turbine to an existing boiler cycle, the replacement of a coal boiler with a new natural gas combined cycle plant, or to the gasification of coal for use in a natural gas combustion turbine.

[3] For an example see Babcock and Wilcox’s White Paper MS-14 “Natural Gas Conversions of Exiting Coal-Fired Boilers” 2010 (www.babcock.com/library/tech-utility.html#14).

Table 5-11 Cost and Performance Assumptions for Coal-to-Gas Retrofits

Factor	Description	Notes
Applicability:	Existing pulverized coal (PC) fired and cyclone boiler units of a size greater than 25 MW:	Not applicable for fluidized bed combustion (FBC) and stoker boilers.
Capacity Penalty:	None	The furnace of a boiler designed to burn coal is oversized for natural gas, and coal boilers include equipment, such as coal mills, that are not needed for gas. As a result, burning gas should have no impact on net power output.
Heat Rate Penalty:	+ 5%	When gas is combusted instead of coal, the stack temperature is lower and the moisture loss to stack is higher. This reduces efficiency, which is reflected in an increase in the heat rate.
Incremental Capital Cost:	PC units: $/kW = 250*(75/MW)^0.35 Cyclone units: $/kW = 350*(75/MW)^0.35	The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system modifications. <u>Example for 50 MW PC unit:</u> $/kW = 250*(75/50)^0.35 = 288
Incremental Fixed O&M:	-(0.33)*31.1*(75/MW)^0.1	Due to reduced needs for operators, maintenance materials, and maintenance staff when natural gas combusted, FOM costs decrease by 33%.
Incremental Variable O&M:	= (0.25)*1.74*(75/MW)^0.2	Due to reduced waste disposal and miscellaneous other costs, VOM costs decrease by 25%.
Fuel Cost:	Natural gas	To obtain natural gas the unit incurs the cost of extending lateral pipeline spurs from the boiler to the local transmission mainline. See section 5.3.2.
NOx emission rate:	50% of existing coal unit NOx emission rate, with a floor of 0.05 lbs/MMBtu	The 0.05 lbs/MMBtu floor is the same as the NOx rate floor for new retrofit SCR on units burning subbituminous coal
SO2 emissions:	Zero	

5.3.2 Natural Gas Pipeline Requirements For Coal-To-Gas Conversions

For every individual coal boiler in the U.S., EPA tasked the gas team at ICF International to determine the miles and associated cost of extending pipeline laterals from each boiler to the interstate natural gas pipeline system.

To develop these costs the following principles were applied:

- For each boiler, gas volume was estimated based on size and heat rate.
- Direct distance to the closest pipeline was calculated. (The analysis only considered mainlines with diameters that were 16 inches or greater. The lateral distance represented the shortest distance – "as the crow flies" – between the boiler and the mainline.)
- Gas volume (per day) of the initial lateral was not allowed to exceed more than 10 percent of the estimated capacity of the mainline.
- The mainline capacities were estimated from the pipe's diameter using the Weymouth equation[4].
- If the gas requirement exceeded 10 percent of the estimated capacity of the mainline, the cost of a second lateral to connect to the next closest mainline was calculated.
- This procedure was repeated until the entire capacity required for the boiler was reached.
- Diameters of each lateral were then calculated using the Weymouth equation based on their required capacities.
- The cost of all the laterals was calculated based on the pipeline diameter and mileage required. Thus, the final pipeline cost for each boiler was based on the total miles of laterals required.

Figure 5-1 shows the calculations performed.

Figure 5-1 Calculations Performed in Costing Lateral Pipeline Requirement

<u>Mainline Flow Capacity, Q_m (million cubic feet per day)</u>
$Q_m = 0.06745 * d^{2.667}$, where d is the diameter of the mainline in inches

<u>Required Capacity of Lateral/s for Each Boiler, Q_l (million cubic feet per day)</u>
Q_l = (Boiler Capacity * Heat Rate *24) / 1,030,000, where Boiler Capacity is in MW and the Heat Rate is in Btu/kWh

<u>Diameter of Each Lateral, D (inches)</u>
$D = (14.83 * Q_l)^{0.37495}$, where each lateral's capacity may not exceed 10% of the mainline capacity to which the lateral connects

<u>Cost per Lateral, C ($)</u>
C = 60,000 *D * Number of Miles

Note: The above calculations assume a pipeline cost of $60,000 per inch-mile based on recently completed projects.

[4] The Weymouth equation in classical fluid dynamics is used in calculating compressible gas flow as a function of pipeline diameter and friction factors. It is used for pipe sizing.

There are several points to note about the approach. First, for relatively large boilers or in cases where the closest mainline has a relatively small diameter, multiple laterals are required to connect the boiler to the interstate gas transmission grid. This assures that each individual boiler will not become a relatively large portion of a pipelines' transmission capacity. It also reflects real-world practices where larger gas-fired power plants typically have multiple laterals connecting them to different mainlines. This increases the reliability of their gas supply and provides multiple options for gas purchase allowing them to capture favorable prices from multiple sources of gas supply at different points in time.

Second, expansion of mainlines was not included in the boiler specific pipeline cost, because the integrated gas model within IPM already includes corridor expansion capabilities. However, if in future IPM runs, multiple converted boilers are concentrated on a single pipeline along a corridor that includes multiple pipelines, a further assessment may be required to make sure that the mainline expansion is not being understated due to modeled efficiencies that may not actually be available in the field.

Figures 5-2 through 5-7 summarize the results of the pipeline costing procedure described above. They provide histograms of the number of laterals required per boiler (Figure 5-2), miles of pipeline required per boiler (Figure 5-3), diameters of the laterals in inches (Figure 5-4), total inch-miles of laterals required per boiler (Figure 5-5), total cost to each boiler in million$ (Figure 5-6), and cost (in $) per kW of boiler capacity (Figure 5-7). Table 5-12 gives a consolidated overview of the information in these figures by showing the minimum, maximum, average, and median values that appear in the figures. Table 5-13 ("Cost of Building Pipelines to Coal Plants") shows the pipeline costing results for each qualifying existing coal fired unit represented in EPA Base Case v4.10_PTox.

Figure 5-2

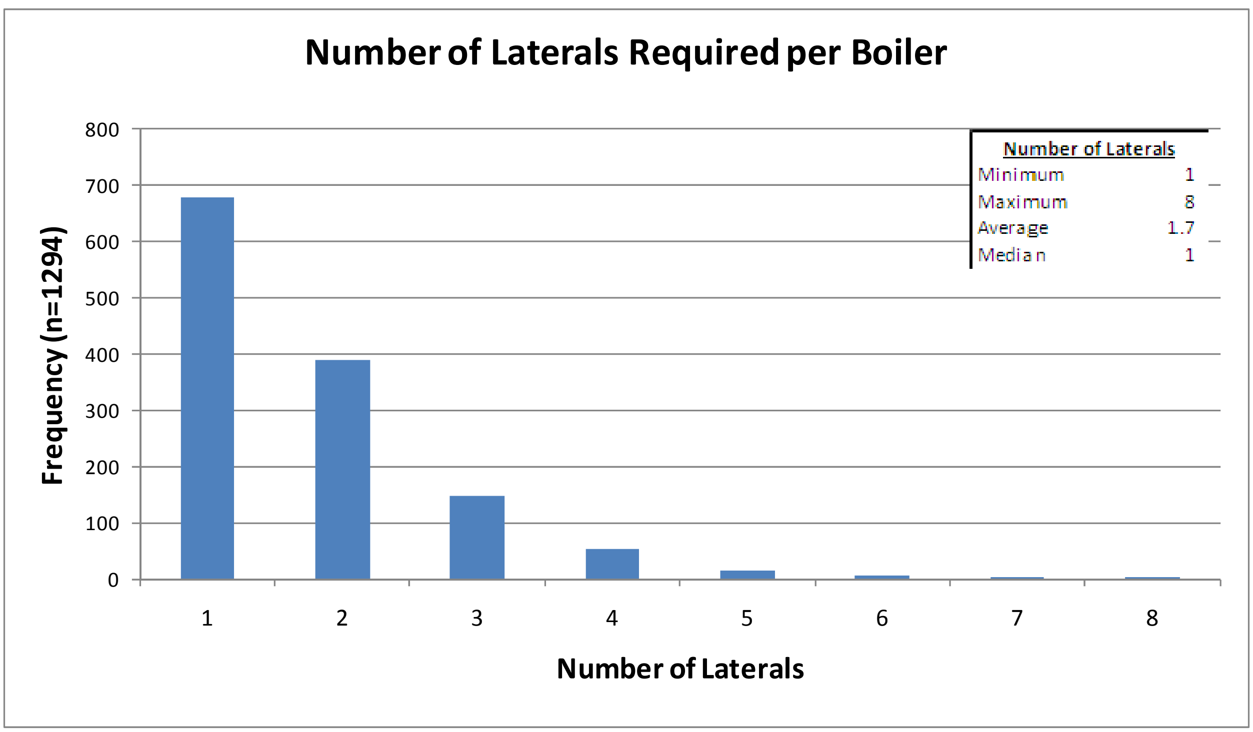

Figure 5-3

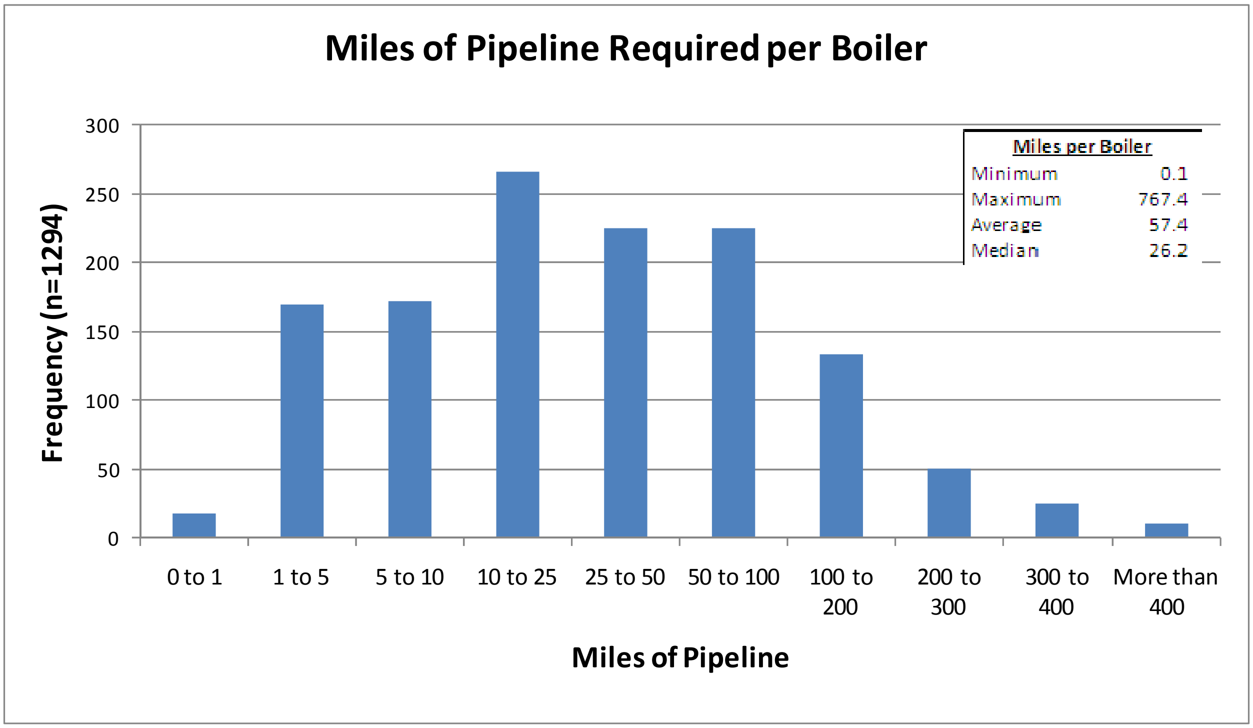

Figure 5-4

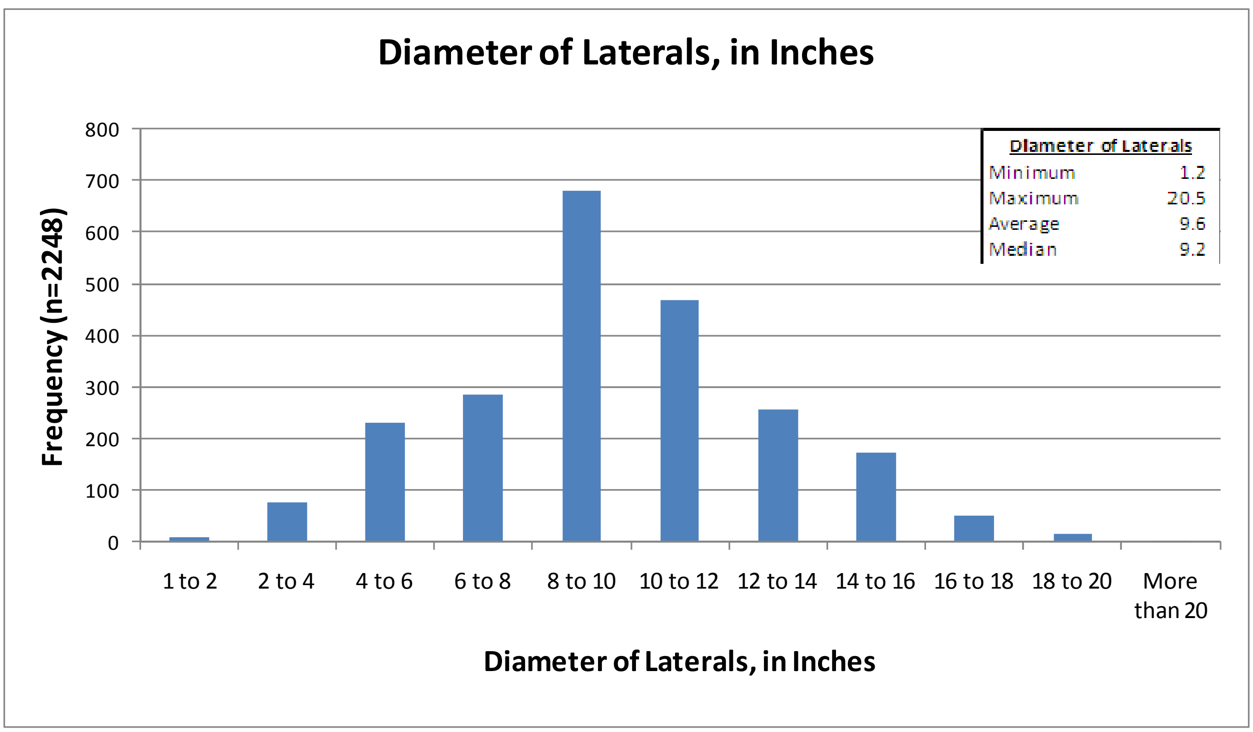

Figure 5-5

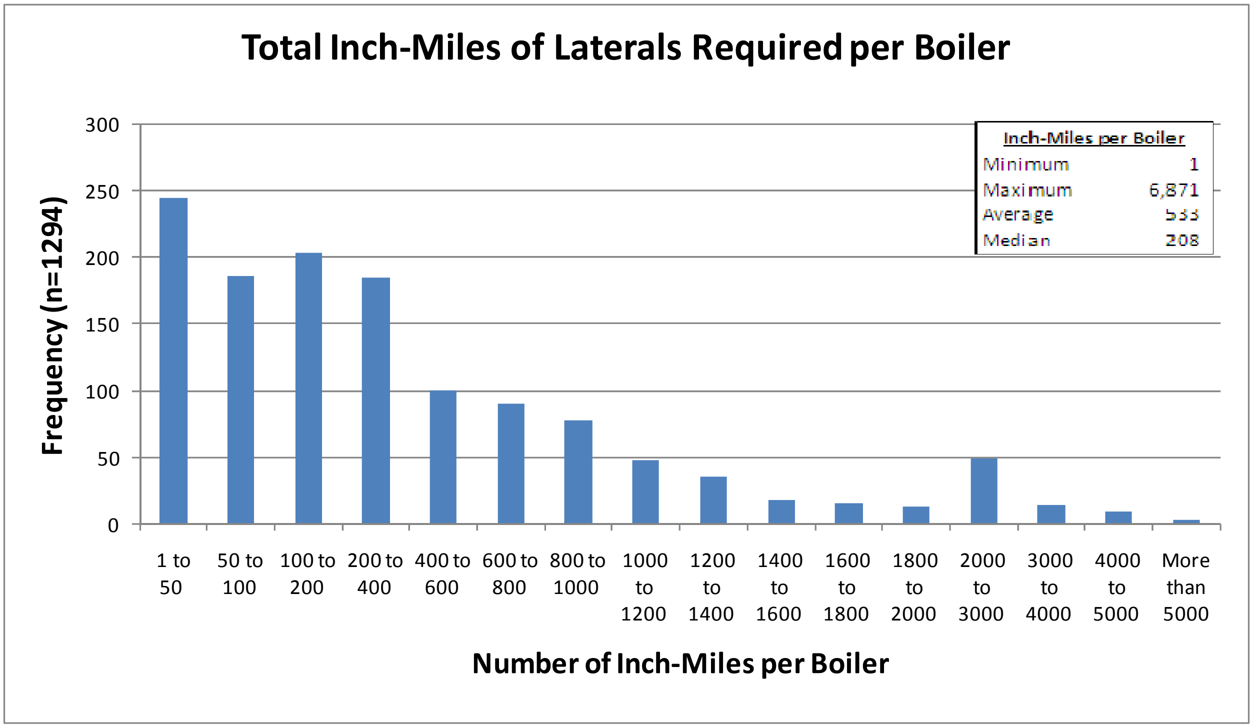

Figure 5-6

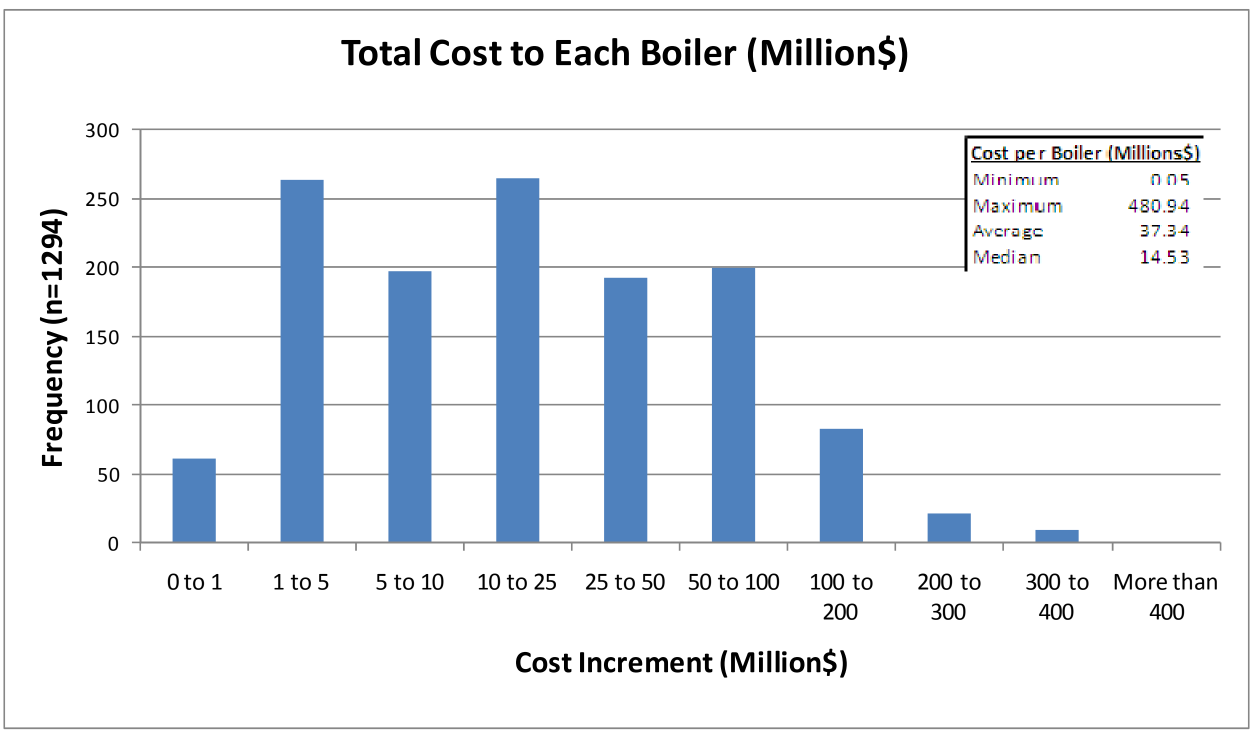

Figure 5-7

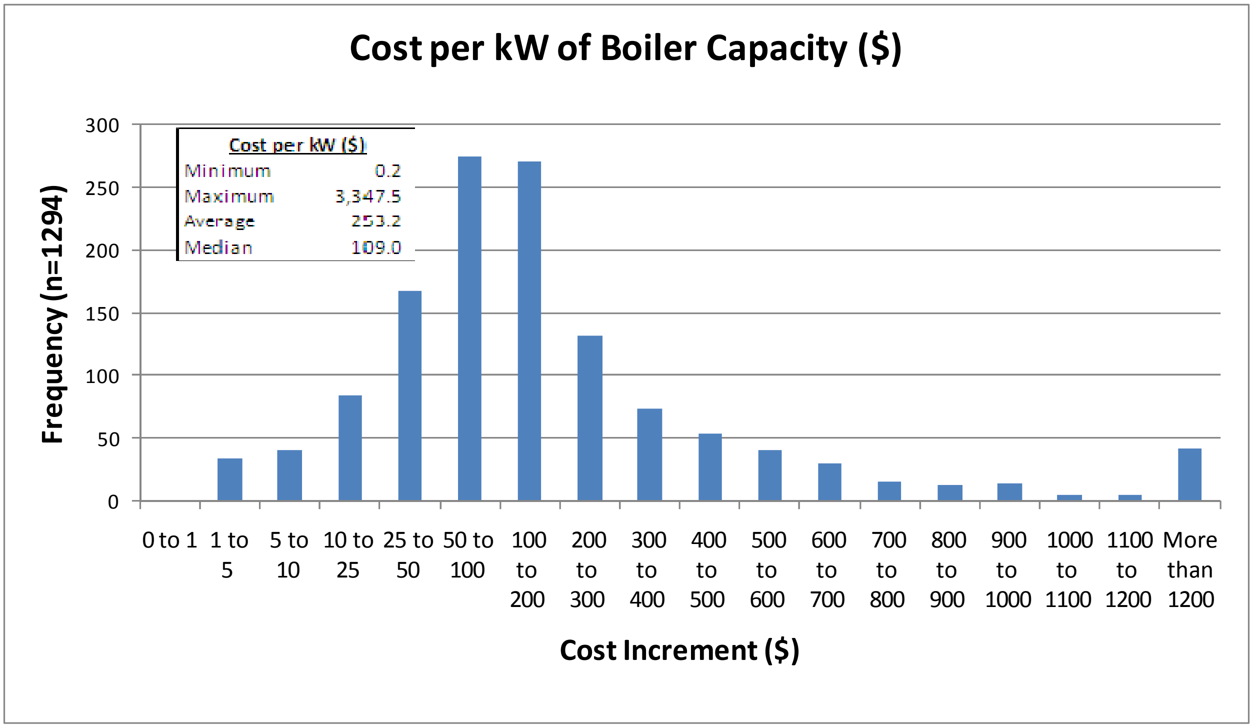
Cost per kW of Boiler Capacity ($)
Cost per kW ($)
Minimum 0.2
Maximum 3,347.5
Average 253.2
Median 109.0
Frequency (n=1294)
300
250
200
150
100
50
0
0 to 1
1 to 5
5 to 10
10 to 25
25 to 50
50 to 100
100 to 200
200 to 300
300 to 400
400 to 500
500 to 600
600 to 700
700 to 800
800 to 900
900 to 1000
1000 to 1100
1100 to 1200
More than 1200
Cost Increment ($)

Table 5-13 Cost of Building Pipelines to Coal Plants

UniqueID_Final	Plant Name	State	Coal Boiler Capacity (MW)	Number of Laterals Required	Miles of New Pipeline Required to Hook Up Unit (miles)	Total Cost of New Pipeline ($)	Cost of New Pipeline per KW of Coal Capacity ($/kW)
3_B_1	Barry	AL	138	1	1	856,526	6
3_B_2	Barry	AL	137	1	1	854,527	6
3_B_3	Barry	AL	249	2	8	5,243,996	21
3_B_4	Barry	AL	362	2	8	6,578,846	18
3_B_5	Barry	AL	750	3	19	16,808,021	22
7_B_1	Gadsden	AL	64	1	29	16,488,170	258
7_B_2	Gadsden	AL	66	1	29	16,913,408	256
8_B_10	Gorgas	AL	690	2	68	64,804,607	94
8_B_6	Gorgas	AL	108	1	8	5,481,155	51
8_B_7	Gorgas	AL	109	1	8	5,362,968	49
8_B_8	Gorgas	AL	165	1	8	5,940,132	36
8_B_9	Gorgas	AL	175	1	8	6,126,314	35
10_B_1	Greene County	AL	254	1	7	6,058,364	24
10_B_2	Greene County	AL	243	1	7	6,006,273	25
26_B_1	E C Gaston	AL	254	1	23	20,296,423	80
26_B_2	E C Gaston	AL	256	1	23	20,549,257	80
26_B_3	E C Gaston	AL	254	1	23	20,403,517	80
26_B_4	E C Gaston	AL	256	1	23	20,416,837	80
26_B_5	E C Gaston	AL	861	3	163	157,432,294	183
47_B_1	Colbert	AL	177	1	0	373,331	2
47_B_2	Colbert	AL	177	1	0	373,331	2
47_B_3	Colbert	AL	177	1	0	373,331	2
47_B_4	Colbert	AL	173	1	0	370,044	2

47_B_5	Colbert	AL	459	2	4	3,524,413	8
50_B_1	Widows Creek	AL	111	2	165	76,835,602	692
50_B_2	Widows Creek	AL	111	2	165	76,835,602	692
50_B_3	Widows Creek	AL	111	2	165	77,445,655	698
50_B_4	Widows Creek	AL	111	2	165	77,445,655	698
50_B_5	Widows Creek	AL	111	2	165	73,708,744	664
50_B_6	Widows Creek	AL	111	2	165	73,708,744	664
50_B_7	Widows Creek	AL	473	3	253	156,623,156	331
50_B_8	Widows Creek	AL	464	2	165	138,258,079	298
51_B_1	Dolet Hills	LA	650	4	32	24,784,949	38
56_B_1	Charles R Lowman	AL	86	1	17	11,062,025	129
56_B_2	Charles R Lowman	AL	238	2	44	30,585,021	129
56_B_3	Charles R Lowman	AL	238	2	44	30,950,390	130
59_B_1	Platte	NE	100	1	26	17,550,190	176
60_B_1	Whelan Energy Center	NE	77	1	8	4,771,943	62
60_B_2	Whelan Energy Center	NE	220	1	8	6,543,326	30
87_B_1	Escalante	NM	247	2	11	5,066,695	21
108_B_SGU1	Holcomb	KS	360	4	46	26,657,544	74
113_B_1	Cholla	AZ	110	1	28	18,947,152	172
113_B_2	Cholla	AZ	275	1	28	26,244,568	95
113_B_3	Cholla	AZ	271	1	28	26,736,227	99
113_B_4	Cholla	AZ	380	2	58	47,225,178	124
126_B_4	H Wilson Sundt Generating Station	AZ	156	1	4	3,325,760	21
127_B_1	Oklaunion	TX	690	8	560	324,667,985	471
130_B_1	Cross	SC	620	2	240	224,907,896	363
130_B_2	Cross	SC	540	2	240	216,115,742	400
130_B_3	Cross	SC	580	2	240	217,804,475	376
130_B_4	Cross	SC	600	2	240	214,338,942	357
136_B_1	Seminole	FL	658	3	153	123,762,396	188
136_B_2	Seminole	FL	658	3	153	122,186,247	186

160_B_2	Apache Station	AZ	175	1	2	1,297,559	7
160_B_3	Apache Station	AZ	175	1	2	1,277,332	7
165_B_1	GRDA	OK	490	6	296	174,657,509	356
165_B_2	GRDA	OK	520	7	415	208,730,810	401
207_B_1	St Johns River Power Park	FL	626	3	212	196,013,308	313
207_B_2	St Johns River Power Park	FL	626	4	477	307,121,204	491
298_B_LIM1	Limestone	TX	831	7	325	193,623,209	233
298_B_LIM2	Limestone	TX	858	7	325	200,701,756	234
384_B_71	Joliet 29	IL	259	2	2	1,347,435	5
384_B_72	Joliet 29	IL	259	2	2	1,162,657	4
384_B_81	Joliet 29	IL	259	2	2	1,248,834	5
384_B_82	Joliet 29	IL	259	2	2	1,162,657	4
462_B_55	W N Clark	CO	18	1	40	14,508,820	824
462_B_59	W N Clark	CO	25	1	40	16,328,260	656
465_B_3	Arapahoe	CO	47	1	9	4,410,931	94
465_B_4	Arapahoe	CO	121	2	86	42,752,979	353
469_B_1	Cherokee	CO	115	2	74	33,550,262	292
469_B_2	Cherokee	CO	120	2	74	33,924,698	283
469_B_3	Cherokee	CO	165	2	74	43,357,353	263
469_B_4	Cherokee	CO	388	2	74	67,384,584	174
470_B_1	Comanche	CO	366	2	151	139,124,028	380
470_B_2	Comanche	CO	370	2	151	139,986,886	378
470_B_3	Comanche	CO	750	4	463	332,375,688	443
477_B_5	Valmont	CO	199	1	19	14,716,699	74
492_B_5	Martin Drake	CO	46	1	13	6,642,383	144
492_B_6	Martin Drake	CO	77	2	127	33,893,437	440
492_B_7	Martin Drake	CO	131	2	127	64,243,979	490
525_B_H1	Hayden	CO	205	2	78	48,661,086	237
525_B_H2	Hayden	CO	300	3	123	81,937,859	273
527_B_1	Nucla	CO	100	2	43	11,535,802	115

564_B_1	Stanton Energy Center	FL	440	2	31	28,104,431	64
564_B_2	Stanton Energy Center	FL	446	2	31	27,959,515	63
568_B_BHB3	Bridgeport Station	CT	372	3	43	28,557,342	77
593_B_3	Edge Moor	DE	86	2	14	6,706,484	78
593_B_4	Edge Moor	DE	174	2	14	7,908,368	45
594_B_3	Indian River Generating Station	DE	153	1	65	48,452,569	317
594_B_4	Indian River Generating Station	DE	405	2	144	88,686,140	219
602_B_1	Brandon Shores	MD	643	2	46	42,283,145	66
602_B_2	Brandon Shores	MD	643	2	46	42,934,049	67
628_B_1	Crystal River	FL	379	2	80	64,036,264	169
628_B_2	Crystal River	FL	491	2	80	67,687,999	138
628_B_4	Crystal River	FL	722	2	80	37,187,321	52
628_B_5	Crystal River	FL	721	2	80	35,020,225	49
641_B_4	Crist	FL	78	1	6	3,592,115	46
641_B_5	Crist	FL	78	1	6	3,517,484	45
641_B_6	Crist	FL	302	2	31	24,092,073	80
641_B_7	Crist	FL	472	2	31	30,704,144	65
642_B_1	Scholz	FL	49	1	13	6,456,489	132
642_B_2	Scholz	FL	49	1	13	6,716,660	137
643_B_1	Lansing Smith	FL	162	1	22	17,226,194	106
643_B_2	Lansing Smith	FL	195	1	22	18,788,587	96
645_B_BB01	Big Bend	FL	391	2	25	18,006,544	46
645_B_BB02	Big Bend	FL	391	2	25	17,980,144	46
645_B_BB03	Big Bend	FL	364	2	25	19,260,622	53
645_B_BB04	Big Bend	FL	447	2	25	20,775,229	46
663_B_B2	Deerhaven Generating Station	FL	228	1	12	10,065,696	44
667_B_1	Northside Generating Station	FL	275	3	205	97,644,692	355
667_B_2	Northside Generating Station	FL	275	3	205	110,541,549	402
676_B_3	C D McIntosh Jr	FL	342	1	0	52,953	-
703_B_1BLR	Bowen	GA	713	2	83	83,854,057	118

703_B_2BLR	Bowen	GA	718	2	83	85,497,920	119
703_B_3BLR	Bowen	GA	902	3	212	165,111,996	183
703_B_4BLR	Bowen	GA	929	3	212	168,510,330	181
708_B_1	Hammond	GA	112	1	42	27,538,206	246
708_B_2	Hammond	GA	112	1	42	27,345,875	244
708_B_3	Hammond	GA	112	1	42	27,384,522	245
708_B_4	Hammond	GA	510	2	110	102,098,030	200
709_B_1	Harllee Branch	GA	266	2	60	43,475,590	163
709_B_2	Harllee Branch	GA	325	2	60	47,552,004	146
709_B_3	Harllee Branch	GA	509	2	60	57,310,793	113
709_B_4	Harllee Branch	GA	507	2	60	57,554,933	114
710_B_MB1	Jack McDonough	GA	258	1	8	6,833,915	26
710_B_MB2	Jack McDonough	GA	259	1	8	6,833,915	26
727_B_3	Mitchell	GA	96	1	67	39,746,899	414
728_B_Y1BR	Yates	GA	99	1	9	6,092,955	62
728_B_Y2BR	Yates	GA	105	1	9	6,250,791	60
728_B_Y3BR	Yates	GA	112	1	9	6,402,249	57
728_B_Y4BR	Yates	GA	135	1	9	6,719,015	50
728_B_Y5BR	Yates	GA	137	1	9	6,756,893	49
728_B_Y6BR	Yates	GA	352	2	23	17,743,087	50
728_B_Y7BR	Yates	GA	355	2	23	17,648,076	50
733_B_1	Kraft	GA	48	1	2	861,799	18
733_B_2	Kraft	GA	52	1	2	851,601	16
733_B_3	Kraft	GA	102	1	2	1,099,326	11
753_B_ST	Crisp Plant	GA	10	1	67	20,321,021	2,032
856_B_1	E D Edwards	IL	112	2	61	13,738,422	123
856_B_2	E D Edwards	IL	273	2	61	46,425,546	170
856_B_3	E D Edwards	IL	364	3	125	85,921,187	236
861_B_01	Coffeen	IL	340	3	103	68,710,560	202
861_B_02	Coffeen	IL	560	3	103	82,715,063	148

863_B_05	Hutsonville	IL	76	2	67	18,023,856	237
863_B_06	Hutsonville	IL	77	1	25	14,411,276	187
864_B_05	Meredosia	IL	203	1	18	15,177,107	75
867_B_7	Crawford	IL	213	1	19	16,157,648	76
867_B_8	Crawford	IL	319	2	43	31,027,338	97
874_B_5	Joliet 9	IL	314	2	2	1,666,759	5
876_B_1	Kincaid Generation LLC	IL	584	2	11	8,272,242	14
876_B_2	Kincaid Generation LLC	IL	584	2	11	8,186,657	14
879_B_51	Powerton	IL	385	2	66	60,857,425	158
879_B_52	Powerton	IL	385	2	66	59,892,609	156
879_B_61	Powerton	IL	385	2	66	60,703,641	158
879_B_62	Powerton	IL	385	2	66	59,892,609	156
883_B_17	Waukegan	IL	100	1	15	10,038,571	100
883_B_7	Waukegan	IL	328	2	38	29,029,637	89
883_B_8	Waukegan	IL	361	2	38	30,956,775	86
884_B_1	Will County	IL	151	1	4	3,163,672	21
884_B_2	Will County	IL	148	1	4	3,225,873	22
884_B_3	Will County	IL	251	2	16	6,254,012	25
884_B_4	Will County	IL	510	3	27	19,264,080	38
886_B_19	Fisk Street	IL	326	2	50	37,297,455	114
887_B_1	Joppa Steam	IL	167	1	1	868,817	5
887_B_2	Joppa Steam	IL	167	1	1	868,052	5
887_B_3	Joppa Steam	IL	167	1	1	866,518	5
887_B_4	Joppa Steam	IL	167	1	1	865,749	5
887_B_5	Joppa Steam	IL	167	1	1	874,899	5
887_B_6	Joppa Steam	IL	167	1	1	867,286	5
889_B_1	Baldwin Energy Complex	IL	624	3	106	79,181,733	127
889_B_2	Baldwin Energy Complex	IL	629	3	106	81,560,802	130
889_B_3	Baldwin Energy Complex	IL	629	3	106	83,884,301	133
891_B_9	Havana	IL	487	2	74	66,810,686	137

892_B_1	Hennepin Power Station	IL	81	1	14	8,519,227	105
892_B_2	Hennepin Power Station	IL	240	1	14	12,775,378	53
897_B_1	Vermilion	IL	84	1	9	5,387,282	64
897_B_2	Vermilion	IL	213	1	9	7,794,565	37
898_B_4	Wood River	IL	105	1	1	414,232	4
898_B_5	Wood River	IL	383	2	50	31,960,057	83
963_B_31	Dallman	IL	86	2	9	2,538,463	30
963_B_32	Dallman	IL	87	2	9	3,674,986	42
963_B_33	Dallman	IL	199	2	9	6,103,905	31
963_B_4	Dallman	IL	200	2	9	5,241,841	26
976_B_123	Marion	IL	120	1	2	1,159,953	10
976_B_4	Marion	IL	170	2	5	3,301,244	19
981_B_3	State Line	IN	187	1	17	13,401,529	72
981_B_4	State Line	IN	303	1	17	16,050,991	53
983_B_1	Clifty Creek	IN	217	2	73	46,944,665	216
983_B_2	Clifty Creek	IN	217	2	73	46,314,833	213
983_B_3	Clifty Creek	IN	217	2	73	46,115,920	213
983_B_4	Clifty Creek	IN	217	2	73	46,015,513	212
983_B_5	Clifty Creek	IN	217	2	73	45,451,394	209
983_B_6	Clifty Creek	IN	217	2	73	45,812,745	211
988_B_U1	Tanners Creek	IN	145	2	34	16,615,136	115
988_B_U2	Tanners Creek	IN	145	2	34	15,923,309	110
988_B_U3	Tanners Creek	IN	200	2	34	20,702,486	104
988_B_U4	Tanners Creek	IN	500	2	34	29,541,774	59
990_B_50	Harding Street	IN	109	2	19	8,909,894	82
990_B_60	Harding Street	IN	109	2	19	8,885,172	82
990_B_70	Harding Street	IN	435	2	19	15,879,585	37
991_B_3	Eagle Valley	IN	43	1	7	3,124,071	73
991_B_4	Eagle Valley	IN	56	1	7	3,485,879	62
991_B_5	Eagle Valley	IN	62	1	7	3,503,708	57

991_B_6	Eagle Valley	IN	99	1	7	4,193,428	42
994_B_1	Petersburg	IN	232	3	49	21,334,190	92
994_B_2	Petersburg	IN	435	3	49	37,186,537	85
994_B_3	Petersburg	IN	540	3	49	41,499,639	77
994_B_4	Petersburg	IN	545	3	49	41,426,794	76
995_B_7	Bailly	IN	160	1	6	4,734,708	30
995_B_8	Bailly	IN	320	1	6	6,131,745	19
996_B_11	Dean H Mitchell	IN	110	1	9	6,215,826	57
996_B_4	Dean H Mitchell	IN	125	1	9	6,467,171	52
996_B_5	Dean H Mitchell	IN	125	1	9	6,298,738	50
996_B_6	Dean H Mitchell	IN	125	1	9	6,290,529	50
997_B_12	Michigan City	IN	469	2	30	23,673,656	50
1001_B_1	Cayuga	IN	479	2	17	14,422,589	30
1001_B_2	Cayuga	IN	473	2	17	14,501,320	31
1008_B_1	R Gallagher	IN	140	2	68	37,331,906	267
1008_B_2	R Gallagher	IN	140	2	68	37,021,229	264
1008_B_3	R Gallagher	IN	140	2	68	37,073,612	265
1008_B_4	R Gallagher	IN	140	2	68	37,331,906	267
1010_G_1	Wabash River	IN	85	1	18	9,993,513	118
1010_G_1A	Wabash River	IN	189	1	18	13,544,723	72
1010_B_2	Wabash River	IN	85	1	18	10,865,630	128
1010_B_3	Wabash River	IN	85	1	18	10,562,318	124
1010_B_4	Wabash River	IN	85	1	18	10,734,687	126
1010_B_5	Wabash River	IN	95	1	18	10,957,573	115
1010_B_6	Wabash River	IN	318	2	36	27,172,030	85
1012_B_2	F B Culley	IN	90	2	17	7,809,213	87
1012_B_3	F B Culley	IN	270	2	17	12,236,461	45
1024_B_5	Crawfordsville	IN	11	1	17	4,869,930	459
1024_B_6	Crawfordsville	IN	13	1	17	4,869,930	387
1032_B_5	Logansport	IN	17	1	33	12,027,095	729

1032_B_6	Logansport	IN	22	1	33	13,630,519	620
1037_B_2	Peru	IN	20	1	35	13,581,293	679
1037_B_5	Peru	IN	12	1	35	11,360,979	947
1040_B_1	Whitewater Valley	IN	35	1	15	6,598,822	190
1040_B_2	Whitewater Valley	IN	63	1	15	8,261,808	132
1043_B_1SG1	Frank E Ratts	IN	122	2	21	10,457,087	86
1043_B_2SG1	Frank E Ratts	IN	121	2	21	10,319,734	85
1046_B_1	Dubuque	IA	35	1	5	2,208,889	62
1046_B_5	Dubuque	IA	30	1	5	1,972,563	65
1046_B_6	Dubuque	IA	13	1	5	1,467,704	111
1047_B_2	Lansing	IA	11	1	55	17,428,351	1,542
1047_B_3	Lansing	IA	37	1	55	26,822,979	733
1047_B_4	Lansing	IA	261	1	55	51,934,638	199
1048_B_2	Milton L Kapp	IA	211	1	12	10,197,479	48
1058_B_2	Sixth Street	IA	14	1	26	8,461,946	622
1058_B_3	Sixth Street	IA	14	1	26	8,917,212	656
1058_B_4	Sixth Street	IA	14	1	26	8,917,212	656
1058_B_5	Sixth Street	IA	14	1	26	8,917,212	656
1073_B_1	Prairie Creek	IA	9	1	27	7,326,935	805
1073_B_2	Prairie Creek	IA	10	1	27	7,746,242	759
1073_B_3	Prairie Creek	IA	42	1	27	12,682,328	305
1073_B_4	Prairie Creek	IA	125	1	27	18,508,829	149
1077_B_1	Sutherland	IA	31	1	13	5,431,663	178
1077_B_2	Sutherland	IA	31	1	13	5,478,150	176
1077_B_3	Sutherland	IA	82	1	13	7,308,613	89
1081_B_7	Riverside	IA	3	1	9	1,543,342	617
1081_B_8	Riverside	IA	3	1	9	1,543,342	617
1081_B_9	Riverside	IA	130	1	9	6,507,714	50
1082_B_1	Walter Scott Jr. Energy Center	IA	45	1	7	3,490,912	78
1082_B_2	Walter Scott Jr. Energy Center	IA	88	1	7	4,579,541	52

1082_B_3	Walter Scott Jr. Energy Center	IA	690	2	20	19,594,759	28
1082_B_4	Walter Scott Jr. Energy Center	IA	800	3	100	83,501,145	104
1091_B_1	George Neal North	IA	135	1	6	4,137,763	31
1091_B_2	George Neal North	IA	300	2	94	56,762,413	189
1091_B_3	George Neal North	IA	515	2	94	92,812,290	180
1104_B_1	Burlington	IA	209	1	56	48,751,365	233
1122_B_7	Ames Electric Services Power Plant	IA	33	1	9	4,306,424	130
1122_B_8	Ames Electric Services Power Plant	IA	70	1	9	5,719,317	82
1131_B_6	Streeter Station	IA	19	1	11	4,085,397	216
1131_B_7	Streeter Station	IA	36	1	11	5,297,932	148
1167_B_7	Muscatine Plant #1	IA	22	1	15	6,025,405	276
1167_B_8	Muscatine Plant #1	IA	35	1	15	7,448,934	213
1167_B_9	Muscatine Plant #1	IA	147	1	15	11,166,673	76
1175_B_6	Pella	IA	15	1	34	11,121,998	741
1175_B_7	Pella	IA	13	1	34	10,691,186	835
1217_B_1	Earl F Wisdom	IA	38	1	5	2,119,776	57
1218_B_1	Fair Station	IA	23	1	13	4,940,202	211
1218_B_2	Fair Station	IA	41	1	13	5,861,900	143
1239_B_39	Riverton	KS	38	1	5	2,600,912	68
1239_B_40	Riverton	KS	54	1	5	2,860,706	53
1241_B_1	La Cygne	KS	724	2	38	34,344,062	47
1241_B_2	La Cygne	KS	682	2	38	33,970,202	50
1250_B_3	Lawrence Energy Center	KS	48	1	5	2,464,647	51
1250_B_4	Lawrence Energy Center	KS	110	1	5	3,255,157	30
1250_B_5	Lawrence Energy Center	KS	366	2	41	33,321,767	91
1252_B_10	Tecumseh Energy Center	KS	129	1	20	14,251,148	110
1252_B_9	Tecumseh Energy Center	KS	74	1	20	12,396,350	168
1295_B_1	Quindaro	KS	72	1	0	291,231	4
1295_B_2	Quindaro	KS	111	1	0	350,406	3
1353_B_BSU1	Big Sandy	KY	260	2	13	9,325,001	36

1353_B_BSU2	Big Sandy	KY	800	3	28	22,413,123	28
1355_B_1	E W Brown	KY	94	1	11	6,988,397	74
1355_B_2	E W Brown	KY	160	1	11	8,028,683	50
1355_B_3	E W Brown	KY	422	2	27	22,420,126	53
1356_B_1	Ghent	KY	475	2	72	62,221,800	131
1356_B_2	Ghent	KY	469	2	72	60,732,185	129
1356_B_3	Ghent	KY	478	2	72	61,354,347	128
1356_B_4	Ghent	KY	478	2	72	61,336,293	128
1357_B_4	Green River	KY	68	1	23	13,703,486	202
1357_B_5	Green River	KY	95	1	23	14,284,315	150
1361_B_5	Tyrone	KY	71	1	29	16,305,568	230
1363_B_4	Cane Run	KY	155	2	69	40,785,891	263
1363_B_5	Cane Run	KY	168	2	69	42,701,837	254
1363_B_6	Cane Run	KY	240	3	118	64,697,971	270
1364_B_1	Mill Creek	KY	303	3	128	82,282,642	272
1364_B_2	Mill Creek	KY	301	3	128	82,811,245	275
1364_B_3	Mill Creek	KY	391	3	128	91,832,381	235
1364_B_4	Mill Creek	KY	477	3	128	98,648,172	207
1374_B_1	Elmer Smith	KY	132	1	6	4,260,976	32
1374_B_2	Elmer Smith	KY	261	1	6	5,968,374	23
1378_B_1	Paradise	KY	616	3	122	71,081,976	115
1378_B_2	Paradise	KY	602	2	73	60,900,519	101
1378_B_3	Paradise	KY	977	3	122	112,779,002	115
1379_B_1	Shawnee	KY	133	1	7	4,919,734	37
1379_B_10	Shawnee	KY	124	1	7	5,111,900	41
1379_B_2	Shawnee	KY	134	1	7	4,937,195	37
1379_B_3	Shawnee	KY	134	1	7	4,937,195	37
1379_B_4	Shawnee	KY	134	1	7	4,937,195	37
1379_B_5	Shawnee	KY	134	1	7	4,937,195	37
1379_B_6	Shawnee	KY	134	1	7	4,937,195	37

1379_B_7	Shawnee	KY	134	1	7	4,937,195	37
1379_B_8	Shawnee	KY	134	1	7	4,937,195	37
1379_B_9	Shawnee	KY	134	1	7	4,937,195	37
1381_B_C1	Kenneth C Coleman	KY	150	1	13	9,632,325	64
1381_B_C2	Kenneth C Coleman	KY	150	1	13	9,632,325	64
1381_B_C3	Kenneth C Coleman	KY	155	1	13	9,753,637	63
1382_B_H1	HMP&L Station Two Henderson	KY	153	2	8	4,675,164	31
1382_B_H2	HMP&L Station Two Henderson	KY	159	2	8	4,777,427	30
1383_B_R1	Robert A Reid	KY	65	1	2	1,099,308	17
1384_B_1	Cooper	KY	116	1	32	20,622,529	178
1384_B_2	Cooper	KY	225	1	32	26,316,589	117
1385_B_1	Dale	KY	27	1	4	1,766,472	65
1385_B_2	Dale	KY	27	1	4	1,773,806	66
1385_B_3	Dale	KY	75	1	4	2,378,590	32
1385_B_4	Dale	KY	75	1	4	2,378,590	32
1393_B_6	R S Nelson	LA	550	3	9	8,013,893	15
1552_B_1	C P Crane	MD	200	2	45	28,572,945	143
1552_B_2	C P Crane	MD	200	2	45	28,389,222	142
1554_B_2	Herbert A Wagner	MD	135	1	22	16,819,534	125
1554_B_3	Herbert A Wagner	MD	324	1	22	21,800,677	67
1570_B_11	R Paul Smith Power Station	MD	87	2	27	13,234,070	152
1570_B_9	R Paul Smith Power Station	MD	28	1	12	4,785,577	171
1571_B_1	Chalk Point LLC	MD	341	1	1	1,452,650	4
1571_B_2	Chalk Point LLC	MD	342	1	1	1,453,966	4
1572_B_1	Dickerson	MD	182	2	9	5,429,574	30
1572_B_2	Dickerson	MD	182	2	9	5,421,348	30
1572_B_3	Dickerson	MD	182	2	9	5,454,113	30
1573_B_1	Morgantown Generating Plant	MD	624	3	99	65,209,623	105
1573_B_2	Morgantown Generating Plant	MD	620	3	99	62,360,586	101
1606_B_1	Mount Tom	MA	144	1	15	10,827,679	75

1619_B_1	Brayton Point	MA	244	3	85	44,147,316	181
1619_B_2	Brayton Point	MA	244	3	85	44,233,074	181
1619_B_3	Brayton Point	MA	612	5	218	146,022,447	239
1626_B_1	Salem Harbor	MA	82	1	1	383,498	5
1626_B_2	Salem Harbor	MA	80	1	1	379,893	5
1626_B_3	Salem Harbor	MA	150	1	1	480,620	3
1695_B_4	B C Cobb	MI	156	2	90	51,000,180	327
1695_B_5	B C Cobb	MI	156	2	90	50,689,290	325
1702_B_1	Dan E Karn	MI	255	1	49	42,287,400	166
1702_B_2	Dan E Karn	MI	260	1	49	42,567,978	164
1710_B_1	J H Campbell	MI	260	3	188	105,151,164	404
1710_B_2	J H Campbell	MI	355	3	188	123,228,381	347
1710_B_3	J H Campbell	MI	825	3	188	159,177,335	193
1720_B_7	J C Weadock	MI	151	1	48	34,952,956	231
1720_B_8	J C Weadock	MI	151	1	48	34,990,691	232
1723_B_1	J R Whiting	MI	102	1	14	8,960,245	88
1723_B_2	J R Whiting	MI	102	1	14	8,960,245	88
1723_B_3	J R Whiting	MI	124	1	14	9,608,933	77
1731_B_1	Harbor Beach	MI	103	2	144	65,999,089	641
1732_B_10	Marysville	MI	42	1	9	4,558,011	109
1732_B_11	Marysville	MI	42	1	9	4,558,011	109
1732_B_12	Marysville	MI	42	1	9	4,558,011	109
1732_B_9	Marysville	MI	42	1	9	4,558,011	109
1733_B_1	Monroe	MI	770	3	63	51,067,983	66
1733_B_2	Monroe	MI	785	3	63	51,099,864	65
1733_B_3	Monroe	MI	795	3	63	51,321,409	65
1733_B_4	Monroe	MI	775	3	63	50,810,782	66
1740_B_2	River Rouge	MI	241	2	21	14,040,402	58
1740_B_3	River Rouge	MI	272	3	43	18,325,670	67
1743_B_1	St Clair	MI	151	1	1	821,585	5

1743_B_2	St Clair	MI	154	1	1	819,061	5
1743_B_3	St Clair	MI	160	1	1	833,199	5
1743_B_4	St Clair	MI	151	1	1	818,216	5
1743_B_6	St Clair	MI	312	1	1	1,020,896	3
1743_B_7	St Clair	MI	440	2	3	1,888,087	4
1745_B_16	Trenton Channel	MI	53	1	7	3,518,012	67
1745_B_17	Trenton Channel	MI	53	1	7	3,656,788	70
1745_B_18	Trenton Channel	MI	53	1	7	3,459,862	66
1745_B_19	Trenton Channel	MI	53	1	7	3,400,035	65
1745_B_9A	Trenton Channel	MI	536	2	28	24,802,480	46
1769_B_5	Presque Isle	MI	88	2	310	134,703,955	1,531
1769_B_6	Presque Isle	MI	88	2	310	134,119,117	1,524
1769_B_7	Presque Isle	MI	85	2	310	142,818,725	1,680
1769_B_8	Presque Isle	MI	85	2	310	137,993,296	1,623
1769_B_9	Presque Isle	MI	85	2	310	137,993,296	1,623
1771_B_1	Escanaba	MI	13	1	100	33,520,946	2,579
1771_B_2	Escanaba	MI	13	1	100	33,520,946	2,579
1825_B_3	J B Sims	MI	73	1	50	28,170,957	387
1830_B_3	James De Young	MI	11	1	58	17,149,007	1,633
1830_B_4	James De Young	MI	21	1	58	21,967,043	1,072
1830_B_5	James De Young	MI	27	1	58	25,680,113	951
1831_B_1	Eckert Station	MI	40	1	24	11,844,286	296
1831_B_2	Eckert Station	MI	42	1	24	12,088,759	289
1831_B_3	Eckert Station	MI	41	1	24	12,054,339	298
1831_B_4	Eckert Station	MI	69	1	24	14,020,209	203
1831_B_5	Eckert Station	MI	69	1	24	14,438,857	210
1831_B_6	Eckert Station	MI	67	1	24	14,126,816	211
1832_B_1	Erickson Station	MI	152	1	22	16,549,274	109
1843_B_2	Shiras	MI	20	1	141	51,087,933	2,620
1843_B_3	Shiras	MI	41	1	141	67,829,244	1,654

1866_B_5	Wyandotte	MI	24	1	3	1,197,065	50
1866_B_7	Wyandotte	MI	24	1	3	1,148,547	48
1866_B_8	Wyandotte	MI	24	1	3	1,273,346	53
1891_B_1	Syl Laskin	MN	55	1	20	10,946,407	199
1891_B_2	Syl Laskin	MN	55	1	20	10,946,407	199
1893_B_1	Clay Boswell	MN	69	1	51	28,426,438	412
1893_B_2	Clay Boswell	MN	69	1	51	27,994,647	406
1893_B_3	Clay Boswell	MN	351	3	305	209,904,664	599
1893_B_4	Clay Boswell	MN	525	3	305	259,254,414	494
1904_B_3	Black Dog	MN	94	1	15	9,442,803	100
1904_B_4	Black Dog	MN	165	1	15	11,307,091	69
1915_B_1	Allen S King	MN	610	3	109	98,379,962	161
1943_B_2	Hoot Lake	MN	60	1	31	16,991,480	284
1943_B_3	Hoot Lake	MN	84	1	31	19,334,908	230
1961_B_NEPP	Austin Northeast	MN	29	1	10	4,487,238	153
1979_B_1	Hibbing	MN	10	1	14	3,643,086	357
1979_B_2	Hibbing	MN	10	1	14	3,643,086	357
1979_B_3	Hibbing	MN	10	1	14	3,585,412	352
2008_B_1	Silver Lake	MN	9	1	43	12,680,825	1,364
2008_B_2	Silver Lake	MN	14	1	43	14,336,096	1,010
2008_B_3	Silver Lake	MN	24	1	43	16,834,510	693
2008_B_4	Silver Lake	MN	59	1	43	23,408,712	395
2018_B_7	Virginia	MN	10	1	6	1,757,260	181
2018_B_9	Virginia	MN	10	1	6	1,733,461	179
2022_B_3	Willmar	MN	20	1	12	4,429,040	217
2049_B_4	Jack Watson	MS	230	1	1	1,059,090	5
2049_B_5	Jack Watson	MS	476	2	26	22,151,655	47
2062_B_H1	Henderson	MS	11	1	2	599,246	54
2062_B_H3	Henderson	MS	18	1	2	715,923	40
2076_B_1	Asbury	MO	213	3	141	76,776,545	360

2079_B_5A	Hawthorn	MO	563	2	39	40,971,852	73
2080_B_1	Montrose	MO	170	2	59	36,622,937	215
2080_B_2	Montrose	MO	164	2	59	36,044,913	220
2080_B_3	Montrose	MO	176	2	59	36,984,154	210
2094_B_1	Sibley	MO	54	1	12	6,050,087	112
2094_B_2	Sibley	MO	54	1	12	5,930,500	110
2094_B_3	Sibley	MO	401	2	41	34,896,137	87
2098_B_5	Lake Road	MO	14	1	3	1,202,124	83
2098_B_6	Lake Road	MO	97	1	3	2,454,909	25
2103_B_1	Labadie	MO	597	2	88	86,771,052	145
2103_B_2	Labadie	MO	594	2	88	84,880,112	143
2103_B_3	Labadie	MO	612	2	88	85,776,583	140
2103_B_4	Labadie	MO	612	2	88	85,099,994	139
2104_B_1	Meramec	MO	122	2	63	27,322,272	224
2104_B_2	Meramec	MO	120	2	63	25,433,774	212
2104_B_3	Meramec	MO	269	2	63	49,292,459	183
2104_B_4	Meramec	MO	347	3	143	95,551,056	275
2107_B_1	Sioux	MO	497	2	53	36,171,805	73
2107_B_2	Sioux	MO	497	2	53	36,171,805	73
2123_B_6	Columbia	MO	25	1	11	4,577,245	187
2123_B_7	Columbia	MO	25	1	11	4,001,683	163
2132_B_1	Blue Valley	MO	21	1	10	3,657,281	174
2132_B_2	Blue Valley	MO	21	1	10	3,657,281	174
2132_B_3	Blue Valley	MO	51	1	10	5,626,006	110
2144_B_4	Marshall	MO	5	1	16	3,494,867	713
2144_B_5	Marshall	MO	16	1	16	5,547,190	347
2161_B_1	James River Power Station	MO	21	1	46	17,279,505	823
2161_B_2	James River Power Station	MO	21	1	46	17,279,505	823
2161_B_3	James River Power Station	MO	41	1	46	22,905,772	559
2161_B_4	James River Power Station	MO	56	1	46	24,300,389	434

2161_B_5	James River Power Station	MO	97	2	120	55,733,835	575
2167_B_1	New Madrid	MO	580	2	41	38,953,400	67
2167_B_2	New Madrid	MO	580	2	41	39,162,023	68
2168_B_MB1	Thomas Hill	MO	175	1	11	9,239,564	53
2168_B_MB2	Thomas Hill	MO	275	1	11	10,753,692	39
2168_B_MB3	Thomas Hill	MO	670	2	44	35,713,178	53
2169_B_1	Chamois	MO	17	1	36	12,968,063	763
2169_B_2	Chamois	MO	49	1	36	18,027,617	368
2171_B_1	Missouri City	MO	19	1	17	6,359,232	335
2171_B_2	Missouri City	MO	19	1	17	6,359,232	335
2187_B_2	J E Corette Plant	MT	158	1	150	117,905,332	746
2240_B_6	Lon Wright	NE	15	1	3	877,700	59
2240_B_7	Lon Wright	NE	20	1	3	1,018,837	51
2240_B_8	Lon Wright	NE	85	1	3	1,624,218	19
2277_B_1	Sheldon	NE	105	1	12	8,230,098	78
2277_B_2	Sheldon	NE	120	1	12	8,683,755	72
2291_B_1	North Omaha	NE	79	1	15	9,059,759	115
2291_B_2	North Omaha	NE	111	1	15	10,288,311	93
2291_B_3	North Omaha	NE	111	1	15	10,236,486	92
2291_B_4	North Omaha	NE	138	2	31	14,642,191	106
2291_B_5	North Omaha	NE	224	2	31	20,708,445	92
2324_B_1	Reid Gardner	NV	110	1	3	1,972,018	18
2324_B_2	Reid Gardner	NV	110	1	3	1,993,430	18
2324_B_3	Reid Gardner	NV	110	1	3	2,016,780	18
2324_B_4	Reid Gardner	NV	225	1	3	2,524,264	11
2364_B_1	Merrimack	NH	113	1	30	20,672,673	184
2364_B_2	Merrimack	NH	320	2	60	43,651,526	136
2367_B_4	Schiller	NH	48	1	3	1,393,557	29
2367_B_6	Schiller	NH	48	1	3	1,344,635	28
2378_B_1	B L England	NJ	129	2	94	52,365,737	406

2378_B_2	B L England	NJ	155	2	94	55,367,158	357
2384_B_8	Deepwater	NJ	80	1	9	5,464,709	68
2403_B_2	PSEG Hudson Generating Station	NJ	608	4	43	28,685,847	47
2408_B_1	PSEG Mercer Generating Station	NJ	324	2	20	14,828,819	46
2408_B_2	PSEG Mercer Generating Station	NJ	324	2	20	14,394,239	44
2434_B_10	Howard Down	NJ	23	1	22	9,263,690	403
2442_B_1	Four Corners	NM	170	1	4	2,915,795	17
2442_B_2	Four Corners	NM	170	1	4	2,923,662	17
2442_B_3	Four Corners	NM	220	1	4	3,300,614	15
2442_B_4	Four Corners	NM	760	4	65	48,280,480	64
2442_B_5	Four Corners	NM	760	4	65	48,390,171	64
2451_B_1	San Juan	NM	322	2	20	11,031,400	34
2451_B_2	San Juan	NM	320	2	20	11,210,066	35
2451_B_3	San Juan	NM	495	3	38	25,969,488	52
2451_B_4	San Juan	NM	506	3	38	25,016,173	49
2468_G_5	Raton	NM	7	1	21	5,429,391	787
2480_B_3	Danskammer Generating Station	NY	133	1	13	9,015,718	68
2480_B_4	Danskammer Generating Station	NY	236	2	33	21,202,511	90
2526_B_11	AES Westover	NY	22	1	3	1,274,492	58
2526_B_12	AES Westover	NY	22	1	3	1,289,755	59
2526_B_13	AES Westover	NY	84	1	3	2,031,559	24
2527_B_6	AES Greenidge LLC	NY	106	1	4	2,599,972	25
2535_B_1	AES Cayuga	NY	152	1	14	10,586,859	70
2535_B_2	AES Cayuga	NY	153	1	14	10,609,438	69
2549_B_67	C R Huntley Generating Station	NY	190	2	9	5,176,646	27
2549_B_68	C R Huntley Generating Station	NY	190	2	9	5,176,646	27
2554_B_1	Dunkirk Generating Station	NY	75	1	7	3,811,141	51
2554_B_2	Dunkirk Generating Station	NY	75	1	7	3,833,477	51
2554_B_3	Dunkirk Generating Station	NY	185	2	33	13,407,977	72
2554_B_4	Dunkirk Generating Station	NY	185	2	33	13,487,072	73

2682_B_10	S A Carlson	NY	15	1	19	5,898,034	393
2682_B_12	S A Carlson	NY	15	1	19	5,960,664	397
2682_B_9	S A Carlson	NY	15	1	19	5,960,664	397
2706_B_1	Asheville	NC	191	1	53	42,245,167	221
2706_B_2	Asheville	NC	185	1	53	41,997,560	227
2708_B_5	Cape Fear	NC	144	1	67	48,101,001	334
2708_B_6	Cape Fear	NC	172	1	67	52,415,896	305
2709_B_1	Lee	NC	74	1	85	49,597,140	670
2709_B_2	Lee	NC	77	1	85	49,400,739	642
2709_B_3	Lee	NC	248	3	336	175,013,921	706
2712_B_1	Roxboro	NC	369	4	318	165,574,308	449
2712_B_2	Roxboro	NC	671	5	501	358,153,400	534
2712_B_3A	Roxboro	NC	353	4	318	179,209,965	508
2712_B_3B	Roxboro	NC	353	4	318	164,614,623	467
2712_B_4A	Roxboro	NC	349	4	318	192,495,589	552
2712_B_4B	Roxboro	NC	349	4	318	180,621,857	518
2713_B_1	L V Sutton	NC	93	2	333	159,333,256	1,713
2713_B_2	L V Sutton	NC	102	2	333	157,221,358	1,541
2713_B_3	L V Sutton	NC	403	4	767	480,939,460	1,193
2716_B_1	W H Weatherspoon	NC	48	1	119	60,915,952	1,269
2716_B_2	W H Weatherspoon	NC	49	1	119	61,084,751	1,247
2716_B_3	W H Weatherspoon	NC	76	1	119	69,786,937	918
2718_B_1	G G Allen	NC	162	1	15	11,286,661	70
2718_B_2	G G Allen	NC	162	1	15	11,275,688	70
2718_B_3	G G Allen	NC	260	1	15	13,258,122	51
2718_B_4	G G Allen	NC	275	1	15	13,456,826	49
2718_B_5	G G Allen	NC	265	1	15	13,399,377	51
2720_B_5	Buck	NC	38	1	10	4,763,840	127
2720_B_6	Buck	NC	38	1	10	4,763,840	127
2720_B_7	Buck	NC	38	1	10	4,763,840	125

2720_B_8	Buck	NC	128	1	10	6,775,198	53
2720_B_9	Buck	NC	128	1	10	6,799,947	53
2721_B_5	Cliffside	NC	550	2	126	78,126,677	142
2721_B_6	Cliffside	NC	800	3	267	156,413,590	196
2723_B_1	Dan River	NC	67	1	1	592,542	9
2723_B_2	Dan River	NC	67	1	1	586,647	9
2723_B_3	Dan River	NC	142	2	2	965,276	7
2727_B_1	Marshall	NC	378	2	85	54,785,142	145
2727_B_2	Marshall	NC	378	2	85	54,832,904	145
2727_B_3	Marshall	NC	657	2	85	58,667,715	89
2727_B_4	Marshall	NC	657	2	85	58,648,369	89
2732_B_10	Riverbend	NC	133	1	8	5,849,602	44
2732_B_7	Riverbend	NC	94	1	8	5,226,437	56
2732_B_8	Riverbend	NC	94	1	8	5,276,288	56
2732_B_9	Riverbend	NC	133	1	8	5,828,717	44
2790_B_B1	R M Heskett	ND	29	1	5	2,173,851	74
2790_B_B2	R M Heskett	ND	76	1	5	3,036,810	40
2817_B_1	Leland Olds	ND	221	1	26	23,149,954	105
2817_B_2	Leland Olds	ND	448	2	59	50,234,609	112
2823_B_B1	Milton R Young	ND	250	1	23	21,246,210	85
2823_B_B2	Milton R Young	ND	455	2	52	44,411,133	98
2824_B_1	Stanton	ND	130	1	26	18,738,173	144
2824_B_10	Stanton	ND	57	1	26	13,452,251	234
2828_B_1	Cardinal	OH	600	3	58	44,899,302	75
2828_B_2	Cardinal	OH	600	3	58	46,258,050	77
2828_B_3	Cardinal	OH	630	3	58	49,434,180	78
2830_B_1	Walter C Beckjord	OH	94	1	7	4,025,382	43
2830_B_2	Walter C Beckjord	OH	94	1	7	3,957,346	42
2830_B_3	Walter C Beckjord	OH	128	1	7	4,404,241	34
2830_B_4	Walter C Beckjord	OH	150	1	7	4,620,484	31

2830_B_5	Walter C Beckjord	OH	238	1	7	5,566,075	23
2830_B_6	Walter C Beckjord	OH	414	2	39	13,252,021	32
2832_B_6	Miami Fort	OH	163	2	31	15,320,273	94
2832_B_7	Miami Fort	OH	500	2	31	26,978,826	54
2832_B_8	Miami Fort	OH	500	2	31	26,795,622	54
2835_B_7	Ashtabula	OH	244	3	147	73,712,911	302
2836_B_10	Avon Lake	OH	96	2	94	49,628,104	517
2836_B_12	Avon Lake	OH	640	4	251	192,073,460	300
2837_B_1	Eastlake	OH	132	2	121	68,778,521	521
2837_B_2	Eastlake	OH	132	2	121	68,275,329	517
2837_B_3	Eastlake	OH	132	2	121	67,409,064	511
2837_B_4	Eastlake	OH	240	3	187	98,897,850	412
2837_B_5	Eastlake	OH	597	3	187	146,553,511	245
2838_B_18	Lake Shore	OH	245	2	110	81,148,527	331
2840_B_3	Conesville	OH	165	2	17	5,179,593	31
2840_B_4	Conesville	OH	780	3	36	34,479,228	44
2840_B_5	Conesville	OH	375	2	17	13,898,446	37
2840_B_6	Conesville	OH	375	2	17	13,806,685	37
2843_B_9	Picway	OH	95	1	2	1,213,631	13
2848_B_H-1	O H Hutchings	OH	58	1	3	1,541,919	27
2848_B_H-2	O H Hutchings	OH	55	1	3	1,489,428	27
2848_B_H-3	O H Hutchings	OH	63	1	3	1,528,214	24
2848_B_H-4	O H Hutchings	OH	63	1	3	1,503,725	24
2848_B_H-5	O H Hutchings	OH	63	1	3	1,575,322	25
2848_B_H-6	O H Hutchings	OH	63	1	3	1,578,597	25
2850_B_1	J M Stuart	OH	597	2	33	34,998,663	59
2850_B_2	J M Stuart	OH	597	2	33	34,359,197	58
2850_B_3	J M Stuart	OH	597	2	33	33,709,140	56
2850_B_4	J M Stuart	OH	597	2	33	34,791,509	58
2861_B_1	Niles	OH	108	1	16	10,610,699	98

2861_B_2	Niles	OH	108	1	16	10,537,680	98
2864_B_7	R E Burger	OH	156	1	1	1,036,633	7
2864_B_8	R E Burger	OH	156	1	1	1,058,515	7
2866_B_1	W H Sammis	OH	180	1	12	9,298,987	52
2866_B_2	W H Sammis	OH	180	1	12	9,339,857	52
2866_B_3	W H Sammis	OH	180	1	12	9,257,816	51
2866_B_4	W H Sammis	OH	180	1	12	9,232,966	51
2866_B_5	W H Sammis	OH	300	2	30	18,766,521	63
2866_B_6	W H Sammis	OH	600	4	69	46,052,387	77
2866_B_7	W H Sammis	OH	600	4	69	46,307,383	77
2872_B_1	Muskingum River	OH	190	1	4	3,481,788	18
2872_B_2	Muskingum River	OH	190	1	4	3,456,143	18
2872_B_3	Muskingum River	OH	205	1	4	3,526,616	17
2872_B_4	Muskingum River	OH	205	1	4	3,427,273	17
2872_B_5	Muskingum River	OH	585	2	18	15,822,798	27
2876_B_1	Kyger Creek	OH	217	1	17	13,759,604	63
2876_B_2	Kyger Creek	OH	217	1	17	13,822,283	64
2876_B_3	Kyger Creek	OH	217	1	17	13,822,283	64
2876_B_4	Kyger Creek	OH	217	1	17	13,874,156	64
2876_B_5	Kyger Creek	OH	217	1	17	13,801,443	64
2878_B_1	Bay Shore	OH	136	2	29	15,670,335	115
2878_B_2	Bay Shore	OH	138	2	29	16,166,545	117
2878_B_3	Bay Shore	OH	142	2	29	16,107,455	113
2878_B_4	Bay Shore	OH	215	2	29	18,700,991	87
2908_G_10	Lake Road	OH	25	1	45	17,869,176	715
2908_G_11	Lake Road	OH	85	2	110	47,569,837	560
2908_G_8	Lake Road	OH	25	1	45	17,869,176	715
2908_G_9	Lake Road	OH	25	1	45	17,869,176	715
2914_G_3	Dover	OH	8	1	13	3,409,244	426
2914_B_4	Dover	OH	15	1	13	4,595,500	302

2917_B_8	Hamilton	OH	33	1	4	1,882,521	57
2917_B_9	Hamilton	OH	51	1	4	2,128,420	42
2935_B_10	Orrville	OH	13	1	20	6,488,346	503
2935_B_11	Orrville	OH	13	1	20	6,488,346	503
2935_B_12	Orrville	OH	30	1	20	7,899,993	266
2935_B_13	Orrville	OH	23	1	20	7,178,704	312
2936_B_3	Painesville	OH	11	1	58	16,231,647	1,546
2936_B_4	Painesville	OH	22	1	58	22,301,632	1,037
2936_B_5	Painesville	OH	22	1	58	20,902,148	972
2937_B_4	Piqua	OH	12	1	17	5,411,688	436
2937_B_5	Piqua	OH	12	1	17	5,296,940	427
2937_B_6	Piqua	OH	20	1	17	6,429,290	321
2942_B_5	St Marys	OH	6	1	26	6,320,195	1,090
2942_B_6	St Marys	OH	9	1	26	7,005,188	778
2943_B_1	Shelby Municipal Light Plant	OH	12	1	3	1,019,872	85
2943_B_2	Shelby Municipal Light Plant	OH	12	1	3	1,041,965	87
2943_G_4	Shelby Municipal Light Plant	OH	7	1	3	866,280	124
2952_B_4	Muskogee	OK	511	4	136	96,829,197	190
2952_B_5	Muskogee	OK	522	4	136	96,922,416	186
2952_B_6	Muskogee	OK	515	4	136	95,749,179	186
2963_B_3313	Northeastern	OK	450	3	57	44,740,461	99
2963_B_3314	Northeastern	OK	450	3	57	44,806,701	100
3098_B_1	Elrama	PA	94	1	3	2,086,921	22
3098_B_2	Elrama	PA	94	1	3	2,099,683	22
3098_B_3	Elrama	PA	103	1	3	2,164,661	21
3098_B_4	Elrama	PA	174	2	11	5,496,850	32
3113_B_1	Portland	PA	157	1	10	7,355,187	47
3113_B_2	Portland	PA	243	1	10	8,616,408	35
3115_B_1	Titus	PA	81	1	11	6,152,979	76
3115_B_2	Titus	PA	81	1	11	6,188,668	76

3115_B_3	Titus	PA	81	1	11	6,164,913	76
3118_B_1	Conemaugh	PA	850	3	44	28,478,143	34
3118_B_2	Conemaugh	PA	850	3	44	28,478,143	34
3122_B_1	Homer City Station	PA	620	2	10	9,077,095	15
3122_B_2	Homer City Station	PA	614	2	10	8,978,074	15
3122_B_3	Homer City Station	PA	650	2	10	9,207,237	14
3130_B_1	Seward	PA	261	1	2	1,629,448	6
3130_B_2	Seward	PA	261	1	2	1,668,097	6
3131_B_1	Shawville	PA	122	1	10	7,200,797	59
3131_B_2	Shawville	PA	125	1	10	7,294,959	58
3131_B_3	Shawville	PA	175	1	10	8,071,310	46
3131_B_4	Shawville	PA	175	1	10	8,071,310	46
3136_B_1	Keystone	PA	850	3	19	16,645,580	20
3136_B_2	Keystone	PA	850	3	19	16,488,634	19
3138_B_3	New Castle	PA	94	1	3	1,719,550	18
3138_B_4	New Castle	PA	98	1	3	1,670,431	17
3138_B_5	New Castle	PA	134	1	3	1,966,212	15
3140_B_1	PPL Brunner Island	PA	344	2	7	4,613,100	13
3140_B_2	PPL Brunner Island	PA	397	2	7	5,127,900	13
3140_B_3	PPL Brunner Island	PA	754	3	34	29,273,420	39
3149_B_1	PPL Montour	PA	750	3	99	78,561,631	105
3149_B_2	PPL Montour	PA	750	3	99	78,561,631	105
3152_B_1A	Sunbury Generation LP	PA	40	1	26	12,190,368	309
3152_B_1B	Sunbury Generation LP	PA	40	1	26	12,190,368	309
3152_B_2A	Sunbury Generation LP	PA	40	1	26	12,190,368	309
3152_B_2B	Sunbury Generation LP	PA	40	1	26	12,190,368	309
3152_B_3	Sunbury Generation LP	PA	87	1	26	16,356,969	188
3152_B_4	Sunbury Generation LP	PA	128	1	26	18,917,854	148
3161_B_2	Eddystone Generating Station	PA	309	3	13	7,788,797	25
3178_B_1	Armstrong Power Station	PA	172	1	11	8,120,940	47

3178_B_2	Armstrong Power Station	PA	171	1	11	8,105,917	47
3179_B_1	Hatfields Ferry Power Station	PA	530	2	8	7,227,186	14
3179_B_2	Hatfields Ferry Power Station	PA	530	2	8	7,194,169	14
3179_B_3	Hatfields Ferry Power Station	PA	530	2	8	7,304,351	14
3181_B_33	Mitchell Power Station	PA	277	3	27	11,206,077	40
3251_B_1	H B Robinson	SC	176	1	87	66,202,863	376
3264_B_1	W S Lee	SC	100	1	1	878,755	9
3264_B_2	W S Lee	SC	100	1	1	876,154	9
3264_B_3	W S Lee	SC	170	1	1	1,039,925	6
3280_B_CAN1	Canadys Steam	SC	105	2	210	94,419,328	899
3280_B_CAN2	Canadys Steam	SC	116	2	210	98,698,195	851
3280_B_CAN3	Canadys Steam	SC	175	2	210	125,031,058	714
3287_B_MCM1	McMeekin	SC	125	1	71	47,542,812	380
3287_B_MCM2	McMeekin	SC	125	1	71	48,485,566	388
3295_B_URQ3	Urquhart	SC	94	2	107	34,257,609	364
3297_B_WAT1	Wateree	SC	350	2	200	149,254,789	426
3297_B_WAT2	Wateree	SC	350	2	200	147,815,608	422
3298_B_WIL1	Williams	SC	615	2	259	213,418,201	347
3317_B_1	Dolphus M Grainger	SC	85	1	158	94,743,575	1,115
3317_B_2	Dolphus M Grainger	SC	85	1	158	95,251,225	1,121
3319_B_3	Jefferies	SC	153	1	99	74,184,083	485
3319_B_4	Jefferies	SC	153	1	99	73,960,402	483
3325_B_1	Ben French	SD	22	1	108	40,426,126	1,872
3393_B_1	Allen Steam Plant	TN	245	2	33	21,938,571	90
3393_B_2	Allen Steam Plant	TN	245	2	33	21,938,571	90
3393_B_3	Allen Steam Plant	TN	245	2	33	21,938,571	90
3396_B_1	Bull Run	TN	881	3	204	205,971,347	234
3399_B_1	Cumberland	TN	1,232	3	81	80,248,498	65
3399_B_2	Cumberland	TN	1,233	3	81	80,283,958	65
3403_B_1	Gallatin	TN	222	1	2	1,928,621	9

3403_B_2	Gallatin	TN	222	1	2	1,928,621	9
3403_B_3	Gallatin	TN	260	1	2	2,058,185	8
3403_B_4	Gallatin	TN	260	1	2	2,058,185	8
3405_B_1	John Sevier	TN	176	2	139	78,136,455	444
3405_B_2	John Sevier	TN	176	2	139	78,136,455	444
3405_B_3	John Sevier	TN	176	2	139	78,136,455	444
3405_B_4	John Sevier	TN	176	2	139	78,136,455	444
3406_B_1	Johnsonville	TN	106	1	19	12,724,426	120
3406_B_10	Johnsonville	TN	141	1	19	13,566,786	96
3406_B_2	Johnsonville	TN	106	1	19	12,724,426	120
3406_B_3	Johnsonville	TN	106	1	19	12,724,426	120
3406_B_4	Johnsonville	TN	106	1	19	12,724,426	120
3406_B_5	Johnsonville	TN	106	1	19	12,342,977	116
3406_B_6	Johnsonville	TN	106	1	19	12,342,977	116
3406_B_7	Johnsonville	TN	141	1	19	13,566,786	96
3406_B_8	Johnsonville	TN	141	1	19	13,566,786	96
3406_B_9	Johnsonville	TN	141	1	19	13,566,786	96
3407_B_1	Kingston	TN	134	2	97	36,622,679	273
3407_B_2	Kingston	TN	134	2	97	36,622,679	273
3407_B_3	Kingston	TN	134	2	97	36,622,679	273
3407_B_4	Kingston	TN	134	2	97	36,622,679	273
3407_B_5	Kingston	TN	175	2	97	51,649,364	295
3407_B_6	Kingston	TN	175	2	97	51,649,364	295
3407_B_7	Kingston	TN	175	2	97	51,649,364	295
3407_B_8	Kingston	TN	175	2	97	51,649,364	295
3407_B_9	Kingston	TN	175	2	97	51,649,364	295
3470_B_WAP5	W A Parish	TX	645	3	6	2,686,937	4
3470_B_WAP6	W A Parish	TX	650	3	6	2,974,589	5
3470_B_WAP7	W A Parish	TX	565	2	1	1,132,402	2
3470_B_WAP8	W A Parish	TX	600	2	1	1,192,947	2

3497_B_1	Big Brown	TX	575	2	13	5,824,349	10
3497_B_2	Big Brown	TX	575	2	13	5,447,670	9
3644_B_1	Carbon	UT	67	1	7	3,779,914	56
3644_B_2	Carbon	UT	105	2	67	27,882,639	266
3775_B_1	Clinch River	VA	235	3	164	88,926,102	378
3775_B_2	Clinch River	VA	235	3	164	89,731,011	382
3775_B_3	Clinch River	VA	235	3	164	88,097,986	375
3776_B_51	Glen Lyn	VA	45	1	17	8,772,437	195
3776_B_52	Glen Lyn	VA	45	1	17	8,772,437	195
3776_B_6	Glen Lyn	VA	235	2	49	32,250,863	137
3788_B_1	Potomac River	VA	88	1	10	6,569,511	75
3788_B_2	Potomac River	VA	88	1	10	6,137,038	70
3788_B_3	Potomac River	VA	102	1	10	6,137,038	60
3788_B_4	Potomac River	VA	102	1	10	6,195,082	61
3788_B_5	Potomac River	VA	102	1	10	6,252,233	61
3796_B_3	Bremo Bluff	VA	71	1	13	7,856,735	111
3796_B_4	Bremo Bluff	VA	156	1	13	9,809,996	63
3797_B_3	Chesterfield	VA	100	1	5	3,093,281	31
3797_B_4	Chesterfield	VA	166	2	55	25,405,927	153
3797_B_5	Chesterfield	VA	310	3	142	88,732,353	286
3797_B_6	Chesterfield	VA	658	4	229	159,656,669	243
3803_B_1	Chesapeake	VA	111	2	116	56,744,698	511
3803_B_2	Chesapeake	VA	111	2	116	59,262,250	534
3803_B_3	Chesapeake	VA	156	2	116	66,253,664	425
3803_B_4	Chesapeake	VA	217	3	228	109,196,341	503
3809_B_1	Yorktown	VA	159	2	120	61,769,959	388
3809_B_2	Yorktown	VA	164	2	120	63,285,654	386
3845_B_BW21	Transalta Centralia Generation	WA	703	2	158	162,043,992	231
3845_B_BW22	Transalta Centralia Generation	WA	703	2	158	162,043,992	231
3935_B_1	John E Amos	WV	800	3	33	25,455,486	32

3935_B_2	John E Amos	WV	800	3	33	25,525,621	32
3935_B_3	John E Amos	WV	1,300	4	76	54,359,572	42
3936_B_1	Kanawha River	WV	205	2	21	10,004,729	49
3936_B_2	Kanawha River	WV	205	2	21	9,969,552	49
3938_B_11	Philip Sporn	WV	150	2	28	16,300,090	109
3938_B_21	Philip Sporn	WV	150	2	28	16,052,044	107
3938_B_31	Philip Sporn	WV	150	2	28	15,982,920	107
3938_B_41	Philip Sporn	WV	150	2	28	15,866,234	106
3938_B_51	Philip Sporn	WV	450	2	28	25,116,859	56
3942_B_1	Albright	WV	73	2	20	5,946,953	81
3942_B_2	Albright	WV	73	2	20	5,946,953	81
3942_B_3	Albright	WV	137	2	20	10,607,955	77
3943_B_1	Fort Martin Power Station	WV	552	2	22	20,856,287	38
3943_B_2	Fort Martin Power Station	WV	555	2	22	20,871,288	38
3944_B_1	Harrison Power Station	WV	652	5	89	62,842,593	96
3944_B_2	Harrison Power Station	WV	642	5	89	62,955,955	98
3944_B_3	Harrison Power Station	WV	651	5	89	62,590,340	96
3945_B_7	Rivesville	WV	46	2	32	12,443,114	271
3945_B_8	Rivesville	WV	91	2	32	16,219,574	178
3946_B_1	Willow Island	WV	54	1	3	1,914,114	35
3946_B_2	Willow Island	WV	181	2	24	16,815,933	93
3947_B_1	Kammer	WV	210	1	1	488,386	2
3947_B_2	Kammer	WV	210	1	1	488,025	2
3947_B_3	Kammer	WV	210	1	1	488,025	2
3948_B_1	Mitchell	WV	800	3	5	4,385,284	5
3948_B_2	Mitchell	WV	800	3	5	4,375,301	5
3954_B_1	Mt Storm	WV	524	4	152	85,613,330	163
3954_B_2	Mt Storm	WV	524	4	152	86,726,251	166
3954_B_3	Mt Storm	WV	521	3	92	74,902,071	144
3992_B_7	Blount Street	WI	22	1	29	11,189,692	500

3992_B_8	Blount Street	WI	49	1	29	13,913,394	284
3992_B_9	Blount Street	WI	48	1	29	13,824,500	287
4041_B_5	South Oak Creek	WI	261	2	45	30,655,617	117
4041_B_6	South Oak Creek	WI	264	2	45	30,967,962	117
4041_B_7	South Oak Creek	WI	298	2	45	33,064,085	111
4041_B_8	South Oak Creek	WI	312	2	45	33,486,899	107
4042_B_1	Valley	WI	70	1	5	3,047,663	44
4042_B_2	Valley	WI	70	1	5	3,047,663	44
4042_B_3	Valley	WI	70	1	5	3,026,671	43
4042_B_4	Valley	WI	70	1	5	3,026,671	43
4050_B_3	Edgewater	WI	76	1	30	17,941,613	236
4050_B_4	Edgewater	WI	321	2	84	55,804,908	174
4050_B_5	Edgewater	WI	414	3	174	100,511,909	243
4054_B_1	Nelson Dewey	WI	107	2	58	29,322,978	275
4054_B_2	Nelson Dewey	WI	111	2	58	29,643,798	267
4072_B_5	Pulliam	WI	49	1	10	5,081,019	105
4072_B_6	Pulliam	WI	72	2	118	19,051,451	266
4072_B_7	Pulliam	WI	88	2	118	36,909,371	420
4072_B_8	Pulliam	WI	133	2	118	59,324,062	445
4078_B_1	Weston	WI	62	1	73	42,302,848	682
4078_B_2	Weston	WI	86	2	204	76,891,284	894
4078_B_3	Weston	WI	338	4	535	305,939,828	905
4078_B_4	Weston	WI	519	4	535	357,497,756	689
4125_B_5	Manitowoc	WI	2	1	28	3,801,699	2,534
4125_B_6	Manitowoc	WI	18	1	28	9,652,063	536
4125_B_7	Manitowoc	WI	18	1	28	9,262,060	515
4125_B_8	Manitowoc	WI	21	1	28	9,726,975	472
4125_B_9	Manitowoc	WI	30	1	28	11,236,889	375
4127_B_5	Menasha	WI	7	1	10	2,268,040	329
4127_B_B23	Menasha	WI	9	1	10	2,770,899	326

4127_B_B24	Menasha	WI	15	1	10	3,373,140	233
4140_B_B1	Alma	WI	18	1	57	19,767,691	1,123
4140_B_B2	Alma	WI	18	1	57	19,767,691	1,123
4140_B_B3	Alma	WI	21	1	57	21,221,307	1,006
4140_B_B4	Alma	WI	51	1	57	28,803,600	565
4140_B_B5	Alma	WI	77	1	57	33,564,993	436
4143_B_1	Genoa	WI	356	2	142	98,844,475	277
4150_B_5	Neil Simpson	WY	15	1	22	7,681,834	526
4151_B_1	Osage	WY	10	1	73	22,120,867	2,190
4151_B_2	Osage	WY	10	1	73	22,120,867	2,190
4151_B_3	Osage	WY	10	1	73	22,120,867	2,190
4158_B_BW41	Dave Johnston	WY	106	1	8	5,447,933	51
4158_B_BW42	Dave Johnston	WY	106	1	8	5,440,496	51
4158_B_BW43	Dave Johnston	WY	220	1	8	7,155,406	33
4158_B_BW44	Dave Johnston	WY	330	1	8	8,291,718	25
4162_B_1	Naughton	WY	160	1	36	27,629,118	173
4162_B_2	Naughton	WY	210	1	36	30,459,162	145
4162_B_3	Naughton	WY	330	3	186	95,198,954	288
4259_B_1	Endicott Station	MI	50	1	16	8,147,501	163
4271_B_B1	John P Madgett	WI	398	2	138	97,551,759	245
4941_B_1	Navajo	AZ	750	3	348	312,653,688	417
4941_B_2	Navajo	AZ	750	3	348	311,741,926	416
4941_B_3	Navajo	AZ	750	3	348	308,739,092	412
6002_B_1	James H Miller Jr	AL	684	2	73	72,453,897	106
6002_B_2	James H Miller Jr	AL	687	2	73	72,325,000	105
6002_B_3	James H Miller Jr	AL	687	2	73	72,389,499	105
6002_B_4	James H Miller Jr	AL	688	2	73	72,163,306	105
6004_B_1	Pleasants Power Station	WV	639	2	31	34,629,535	54
6004_B_2	Pleasants Power Station	WV	639	2	31	34,511,038	54
6009_B_1	White Bluff	AR	815	3	30	29,247,265	36

6009_B_2	White Bluff	AR	825	3	30	29,904,002	36
6016_B_1	Duck Creek	IL	335	2	80	65,045,755	194
6017_B_1	Newton	IL	557	2	32	21,256,386	38
6017_B_2	Newton	IL	569	2	32	21,218,914	37
6018_B_2	East Bend	KY	600	3	81	60,069,860	100
6019_B_1	W H Zimmer	OH	1,300	4	129	110,317,488	85
6021_B_C1	Craig	CO	428	3	62	43,725,334	102
6021_B_C2	Craig	CO	428	3	62	44,007,279	103
6021_B_C3	Craig	CO	418	3	62	43,820,042	105
6030_B_1	Coal Creek	ND	554	2	85	58,252,800	105
6030_B_2	Coal Creek	ND	560	2	85	78,618,531	140
6031_B_2	Killen Station	OH	615	2	36	32,401,966	53
6034_B_1	Belle River	MI	698	4	115	57,929,531	83
6034_B_2	Belle River	MI	698	4	115	65,882,626	94
6041_B_1	H L Spurlock	KY	315	2	43	34,299,690	109
6041_B_2	H L Spurlock	KY	509	2	43	43,854,659	86
6041_B_3	H L Spurlock	KY	268	2	43	31,686,751	118
6041_B_4	H L Spurlock	KY	268	2	43	30,443,356	114
6052_B_1	Wansley	GA	891	3	205	125,379,945	141
6052_B_2	Wansley	GA	892	3	205	125,632,090	141
6055_B_2B1	Big Cajun 2	LA	580	2	3	2,561,145	4
6055_B_2B2	Big Cajun 2	LA	575	2	3	2,555,499	4
6055_B_2B3	Big Cajun 2	LA	588	2	3	2,531,971	4
6061_B_1	R D Morrow	MS	180	1	8	6,731,374	37
6061_B_2	R D Morrow	MS	180	1	8	6,804,328	38
6064_B_N1	Nearman Creek	KS	229	2	36	19,542,070	85
6065_B_1	Iatan	MO	651	2	23	23,906,085	37
6068_B_1	Jeffrey Energy Center	KS	730	2	89	85,285,064	117
6068_B_2	Jeffrey Energy Center	KS	730	2	89	86,254,355	118
6068_B_3	Jeffrey Energy Center	KS	730	2	89	88,473,899	121

6071_B_1	Trimble County	KY	383	3	142	97,287,993	254
6071_B_2&3	Trimble County	KY	760	3	142	115,264,482	152
6073_B_1	Victor J Daniel Jr	MS	514	2	6	5,020,082	10
6073_B_2	Victor J Daniel Jr	MS	514	2	6	5,000,070	10
6076_B_1	Colstrip	MT	307	2	261	184,856,344	602
6076_B_2	Colstrip	MT	307	2	261	184,856,344	602
6076_B_3	Colstrip	MT	740	2	261	288,152,024	389
6076_B_4	Colstrip	MT	740	2	261	288,152,024	389
6077_B_1	Gerald Gentleman	NE	665	2	33	32,410,571	49
6077_B_2	Gerald Gentleman	NE	700	2	33	31,478,432	45
6082_B_1	AES Somerset LLC	NY	681	6	278	170,834,291	251
6085_B_14	R M Schahfer	IN	431	2	36	31,648,586	73
6085_B_15	R M Schahfer	IN	472	2	36	32,892,605	70
6085_B_17	R M Schahfer	IN	361	2	36	29,462,210	82
6085_B_18	R M Schahfer	IN	361	2	36	29,060,625	81
6089_B_B1	Lewis & Clark	MT	52	1	19	10,381,544	198
6090_B_1	Sherburne County	MN	762	4	230	186,587,670	245
6090_B_2	Sherburne County	MN	752	4	230	181,960,628	242
6090_B_3	Sherburne County	MN	936	4	230	209,343,996	224
6094_B_1	Bruce Mansfield	PA	830	5	83	68,945,809	83
6094_B_2	Bruce Mansfield	PA	830	5	83	68,639,498	83
6094_B_3	Bruce Mansfield	PA	830	5	83	67,538,385	81
6095_B_1	Sooner	OK	535	5	237	138,736,724	259
6095_B_2	Sooner	OK	540	5	237	148,708,188	275
6096_B_1	Nebraska City	NE	646	2	45	44,246,688	68
6096_B_2	Nebraska City	NE	663	2	17	15,623,098	24
6098_B_1	Big Stone	SD	470	2	75	63,989,316	136
6101_B_BW91	Wyodak	WY	335	3	207	123,430,969	368
6106_B_1SG	Boardman	OR	585	3	292	156,464,937	267
6113_B_1	Gibson	IN	630	3	73	64,635,948	103

6113_B_2	Gibson	IN	628	3	73	64,690,650	103
6113_B_3	Gibson	IN	628	3	73	64,157,149	102
6113_B_4	Gibson	IN	622	3	73	64,544,530	104
6113_B_5	Gibson	IN	620	3	73	65,515,933	106
6124_B_1	McIntosh	GA	157	2	174	98,023,860	626
6136_B_1	Gibbons Creek	TX	462	2	8	6,109,161	13
6137_B_1	A B Brown	IN	245	3	51	27,652,839	113
6137_B_2	A B Brown	IN	245	3	51	27,652,839	113
6138_B_1	Flint Creek	AR	528	6	303	183,956,789	348
6139_B_1	Welsh	TX	528	2	26	23,265,057	44
6139_B_2	Welsh	TX	528	2	26	22,953,307	43
6139_B_3	Welsh	TX	528	2	26	22,977,196	44
6146_B_1	Martin Lake	TX	750	4	16	13,579,347	18
6146_B_2	Martin Lake	TX	750	4	16	13,422,881	18
6146_B_3	Martin Lake	TX	750	4	16	13,196,821	18
6147_B_1	Monticello	TX	565	2	27	25,810,168	46
6147_B_2	Monticello	TX	565	2	27	25,648,477	45
6147_B_3	Monticello	TX	750	3	41	37,072,040	49
6155_B_1	Rush Island	MO	604	4	218	158,885,720	263
6155_B_2	Rush Island	MO	604	4	218	153,186,703	254
6165_B_1	Hunter	UT	430	2	94	81,186,634	189
6165_B_2	Hunter	UT	430	2	94	81,003,689	188
6165_B_3	Hunter	UT	460	2	94	83,041,697	181
6166_B_MB1	Rockport	IN	1,300	4	142	138,145,250	106
6166_B_MB2	Rockport	IN	1,300	4	142	138,981,337	107
6170_B_1	Pleasant Prairie	WI	617	3	72	55,255,225	90
6170_B_2	Pleasant Prairie	WI	617	3	72	55,822,411	90
6177_B_U1B	Coronado	AZ	395	2	132	108,847,521	276
6177_B_U2B	Coronado	AZ	390	2	132	105,111,801	270
6178_B_1	Coleto Creek	TX	632	4	26	21,145,534	33

6179_B_1	Fayette Power Project	TX	598	5	98	65,108,619	109
6179_B_2	Fayette Power Project	TX	598	5	98	64,482,723	108
6179_B_3	Fayette Power Project	TX	445	4	64	44,478,896	100
6180_B_OG1	Oak Grove	TX	800	6	190	85,241,342	107
6180_B_OG2	Oak Grove	TX	800	6	190	85,241,342	107
6181_B_1	J T Deely	TX	385	2	30	27,795,726	72
6181_B_2	J T Deely	TX	385	2	30	27,756,673	72
6183_B_SM-1	San Miguel	TX	391	3	62	45,994,741	118
6190_B_2	Rodemacher	LA	523	2	27	25,318,899	48
6190_B_3A	Rodemacher	LA	330	1	5	5,011,157	15
6190_B_3B	Rodemacher	LA	330	1	5	5,011,157	15
6193_B_061B	Harrington	TX	347	4	42	22,996,183	66
6193_B_062B	Harrington	TX	347	4	42	24,424,959	70
6193_B_063B	Harrington	TX	347	4	42	24,863,255	72
6194_B_171B	Tolk	TX	535	2	24	21,681,861	41
6194_B_172B	Tolk	TX	545	2	24	21,315,741	39
6195_B_1	Southwest Power Station	MO	178	3	224	115,261,948	648
6204_B_1	Laramie River Station	WY	565	4	154	86,961,102	154
6204_B_2	Laramie River Station	WY	570	4	154	83,331,016	146
6204_B_3	Laramie River Station	WY	570	4	154	92,413,957	162
6213_B_1SG1	Merom	IN	507	2	65	62,606,265	123
6213_B_2SG1	Merom	IN	493	2	65	64,220,141	130
6225_B_1	Jasper 2	IN	14	1	3	866,561	62
6238_B_1A	Pearl Station	IL	22	1	6	2,112,513	96
6248_B_1	Pawnee	CO	505	2	13	8,921,462	18
6249_B_1	Winyah	SC	295	1	130	121,732,828	413
6249_B_2	Winyah	SC	295	1	130	122,722,703	416
6249_B_3	Winyah	SC	295	1	130	121,333,096	411
6249_B_4	Winyah	SC	270	1	130	120,256,266	445
6250_B_1A	Mayo	NC	371	4	320	194,458,700	524

6250_B_1B	Mayo	NC	371	4	320	194,458,700	524
6254_B_1	Ottumwa	IA	673	2	116	87,704,788	130
6257_B_1	Scherer	GA	837	3	233	241,767,423	289
6257_B_2	Scherer	GA	843	3	233	243,015,931	288
6257_B_3	Scherer	GA	875	3	233	247,595,035	283
6257_B_4	Scherer	GA	850	3	233	243,874,806	287
6264_B_1	Mountaineer	WV	1,300	3	50	51,914,394	40
6469_B_B1	Antelope Valley	ND	450	2	59	50,262,299	112
6469_B_B2	Antelope Valley	ND	450	2	59	50,577,883	112
6481_B_1SGA	Intermountain Power Project	UT	900	3	233	158,299,880	176
6481_B_2SGA	Intermountain Power Project	UT	900	3	233	158,299,880	176
6639_B_G1	R D Green	KY	231	2	8	5,747,905	25
6639_B_G2	R D Green	KY	233	2	8	5,770,269	25
6641_B_1	Independence	AR	836	4	47	37,254,469	45
6641_B_2	Independence	AR	842	4	47	37,171,856	44
6648_B_4	Sandow	TX	545	4	107	74,584,612	137
6664_B_101	Louisa	IA	745	2	59	61,830,763	83
6705_B_1	Warrick	IN	136	2	17	9,509,125	70
6705_B_2	Warrick	IN	136	2	17	9,523,228	70
6705_B_3	Warrick	IN	136	2	17	9,537,272	70
6705_B_4	Warrick	IN	300	2	17	12,924,387	43
6761_B_101	Rawhide	CO	272	2	18	12,342,549	45
6768_B_1	Sikeston Power Station	MO	233	2	36	23,625,426	101
6772_B_1	Hugo	OK	440	2	67	58,910,578	134
6823_B_W1	D B Wilson	KY	420	2	49	36,972,967	88
7030_B_U1	Twin Oaks Power One	TX	152	2	13	5,921,171	39
7030_B_U2	Twin Oaks Power One	TX	153	2	13	6,858,395	45
7097_B_BLR1	J K Spruce	TX	555	3	58	44,996,468	81
7097_B_BLR2	J K Spruce	TX	750	3	58	48,312,157	64
7210_B_COP1	Cope	SC	420	2	177	152,775,716	364

7213_B_1	Clover	VA	431	4	280	187,989,514	436
7213_B_2	Clover	VA	434	5	431	217,508,623	501
7242_G_1CA	Polk	FL	123	1	1	689,955	6
7242_G_1CT	Polk	FL	132	1	1	708,828	5
7286_B_1	Richard Gorsuch	OH	50	1	5	2,652,682	53
7286_B_2	Richard Gorsuch	OH	50	1	5	2,652,682	53
7286_B_3	Richard Gorsuch	OH	50	1	5	2,652,682	53
7286_B_4	Richard Gorsuch	OH	50	1	5	2,652,682	53
7343_B_4	George Neal South	IA	632	2	94	100,888,536	160
7504_B_2	Neil Simpson II	WY	80	1	23	13,829,794	173
7537_B_1A	North Branch	WV	37	1	10	4,456,718	120
7537_B_1B	North Branch	WV	37	1	10	4,315,178	117
7549_B_1	Milwaukee County	WI	3	1	5	1,001,342	303
7549_B_2	Milwaukee County	WI	3	1	5	958,082	290
7549_B_3	Milwaukee County	WI	3	1	5	958,082	290
7652_B_D-1	US DOE Savannah River Site (D Area)	SC	20	1	30	10,455,104	533
7652_B_D-2	US DOE Savannah River Site (D Area)	SC	20	1	30	10,455,104	533
7652_B_D-3	US DOE Savannah River Site (D Area)	SC	20	1	30	10,455,104	533
7652_B_D-4	US DOE Savannah River Site (D Area)	SC	20	1	30	10,455,104	533
7737_B_B001	Cogen South	SC	90	1	82	50,925,685	566
7790_B_1-1	Bonanza	UT	468	5	75	40,737,592	87
7902_B_1	Pirkey	TX	675	2	4	4,246,866	6
8023_B_1	Columbia	WI	555	4	306	219,530,738	396
8023_B_2	Columbia	WI	559	4	306	214,992,053	385
8042_B_1	Belews Creek	NC	1,115	3	122	76,553,763	69
8042_B_2	Belews Creek	NC	1,115	3	122	76,537,100	69
8066_B_BW71	Jim Bridger	WY	530	2	3	2,411,220	5
8066_B_BW72	Jim Bridger	WY	530	2	3	2,418,842	5
8066_B_BW73	Jim Bridger	WY	530	2	3	2,404,606	5
8066_B_BW74	Jim Bridger	WY	530	2	3	2,417,759	5

8069_B_1	Huntington	UT	445	2	68	63,247,668	142
8069_B_2	Huntington	UT	450	2	68	63,434,031	141
8102_B_1	General James M Gavin	OH	1,310	3	52	49,730,161	38
8102_B_2	General James M Gavin	OH	1,300	3	52	49,430,685	38
8219_B_1	Ray D Nixon	CO	208	2	130	91,347,020	439
8222_B_B1	Coyote	ND	427	2	59	50,345,130	118
8223_B_1	Springerville	AZ	400	2	170	137,893,456	345
8223_B_2	Springerville	AZ	400	2	170	137,336,825	343
8223_B_3	Springerville	AZ	400	2	170	142,795,380	357
8223_B_4	Springerville	AZ	400	2	170	131,249,797	328
8224_B_1	North Valmy	NV	254	3	420	246,905,695	972
8224_B_2	North Valmy	NV	268	3	420	262,664,147	980
8226_B_1	Cheswick	PA	580	3	30	23,108,254	40
10002_B_CFB	ACE Cogeneration Facility	CA	101	1	55	36,115,023	357
10003_B_BLR3	Trigen Colorado Energy	CO	8	1	17	4,224,070	521
10003_B_BLR4	Trigen Colorado Energy	CO	8	1	17	4,224,070	521
10003_B_BLR5	Trigen Colorado Energy	CO	8	1	17	4,462,765	551
10030_B_COGEN1	NRG Energy Center Dover	DE	16	1	41	13,762,699	860
10043_B_B01	Logan Generating Plant	NJ	219	3	7	3,257,942	15
10071_B_1A	Cogentrix Virginia Leasing Corporation	VA	19	1	53	18,675,110	973
10071_B_1B	Cogentrix Virginia Leasing Corporation	VA	19	1	53	17,966,383	936
10071_B_1C	Cogentrix Virginia Leasing Corporation	VA	19	1	53	17,966,383	936
10071_B_2A	Cogentrix Virginia Leasing Corporation	VA	19	1	53	18,675,110	973
10071_B_2B	Cogentrix Virginia Leasing Corporation	VA	19	1	53	17,966,383	936
10071_B_2C	Cogentrix Virginia Leasing Corporation	VA	19	1	53	17,966,383	936
10075_B_1	Taconite Harbor Energy Center	MN	65	1	77	43,873,377	675
10075_B_2	Taconite Harbor Energy Center	MN	67	1	77	44,056,543	658
10075_B_3	Taconite Harbor Energy Center	MN	68	1	77	44,508,992	655
10113_B_CFB1	John B Rich Memorial Power Station	PA	40	1	22	10,166,547	254
10113_B_CFB2	John B Rich Memorial Power Station	PA	40	1	22	9,865,959	247

10143_B_ABB01	Colver Power Project	PA	110	2	16	7,296,841	66
10151_B_BLR1A	Grant Town Power Plant	WV	40	1	14	6,230,377	156
10151_B_BLR1B	Grant Town Power Plant	WV	40	1	14	6,068,111	152
10207_B_1	Hercules Missouri Chemical Works	MO	6	1	3	668,369	117
10207_B_2	Hercules Missouri Chemical Works	MO	6	1	3	668,369	117
10207_B_3	Hercules Missouri Chemical Works	MO	6	1	3	668,369	117
10333_B_1	Central Power & Lime	FL	139	1	5	3,407,144	25
10343_B_SG-101	Foster Wheeler Mt Carmel Cogen	PA	43	1	22	10,975,235	255
10367_B_CB1302	East Third Street Power Plant	CA	20	1	4	1,397,893	72
10368_B_CB1302	Loveridge Road Power Plant	CA	19	1	3	1,250,255	66
10369_B_CB1302	Wilbur West Power Plant	CA	19	1	2	644,904	34
10370_B_CB1302	Wilbur East Power Plant	CA	19	1	3	1,043,072	55
10371_B_CB1302	Nichols Road Power Plant	CA	19	1	3	1,298,925	68
10373_B_CB1302	Hanford	CA	25	1	22	8,730,145	352
10377_B_1A	Cogentrix Hopewell	VA	18	1	10	3,417,788	188
10377_B_1B	Cogentrix Hopewell	VA	18	1	10	3,531,133	194
10377_B_1C	Cogentrix Hopewell	VA	18	1	10	3,417,788	188
10377_B_2A	Cogentrix Hopewell	VA	18	1	10	3,531,133	194
10377_B_2B	Cogentrix Hopewell	VA	18	1	10	3,417,788	188
10377_B_2C	Cogentrix Hopewell	VA	18	1	10	3,417,788	188
10378_B_1A	Primary Energy Southport	NC	18	1	173	59,585,090	3,347
10378_B_1B	Primary Energy Southport	NC	18	1	173	57,630,632	3,238
10378_B_1C	Primary Energy Southport	NC	18	1	173	57,630,632	3,238
10378_B_2A	Primary Energy Southport	NC	18	1	173	59,585,090	3,347
10378_B_2B	Primary Energy Southport	NC	18	1	173	57,630,632	3,238
10378_B_2C	Primary Energy Southport	NC	18	1	173	57,630,632	3,238
10379_B_1A	Primary Energy Roxboro	NC	19	1	24	8,355,164	447
10379_B_1B	Primary Energy Roxboro	NC	19	1	24	8,092,596	433
10379_B_1C	Primary Energy Roxboro	NC	19	1	24	8,092,596	433
10380_B_A BLR	Elizabethtown Power LLC	NC	16	1	129	42,742,982	2,671

10380_B_B BLR	Elizabethtown Power LLC	NC	16	1	129	42,742,982	2,671
10382_B_UNIT1	Lumberton	NC	16	1	118	39,366,830	2,460
10382_B_UNIT2	Lumberton	NC	16	1	118	39,366,830	2,460
10384_B_1A	Edgecombe GenCo	NC	29	1	36	14,989,978	519
10384_B_1B	Edgecombe GenCo	NC	29	1	36	14,534,809	503
10384_B_2A	Edgecombe GenCo	NC	29	1	36	14,989,978	519
10384_B_2B	Edgecombe GenCo	NC	29	1	36	14,534,809	503
10464_B_E0001	Black River Generation	NY	18	1	27	9,340,465	510
10464_B_E0002	Black River Generation	NY	18	1	27	8,971,022	490
10464_B_E0003	Black River Generation	NY	18	1	27	8,971,022	490
10477_B_P1	Wisconsin Rapids Pulp Mill	WI	11	1	80	22,287,032	1,990
10477_B_P2	Wisconsin Rapids Pulp Mill	WI	11	1	80	22,287,032	1,990
10495_B_6	Rumford Cogeneration	ME	43	1	24	11,293,272	266
10495_B_7	Rumford Cogeneration	ME	43	1	24	10,978,023	258
10566_B_BOIL1	Chambers Cogeneration LP	NJ	131	2	17	9,093,687	69
10566_B_BOIL2	Chambers Cogeneration LP	NJ	131	2	17	9,238,900	71
10601_G_GEN1	BP Wilmington Calciner	CA	29	1	3	1,039,284	36
10603_B_031	Ebensburg Power	PA	50	1	4	2,168,090	44
10641_B_B1	Cambria Cogen	PA	44	1	3	1,426,559	32
10641_B_B2	Cambria Cogen	PA	44	1	3	1,388,167	32
10670_B_AAB001	AES Deepwater	TX	140	2	0	184,032	1
10671_B_1A	AES Shady Point	OK	80	1	3	1,973,180	25
10671_B_1B	AES Shady Point	OK	80	1	3	1,965,567	25
10671_B_2A	AES Shady Point	OK	80	1	3	1,973,180	25
10671_B_2B	AES Shady Point	OK	80	1	3	1,965,567	25
10672_B_CBA	Cedar Bay Generating LP	FL	83	1	20	11,321,540	136
10672_B_CBB	Cedar Bay Generating LP	FL	83	1	20	11,679,195	140
10672_B_CBC	Cedar Bay Generating LP	FL	83	1	20	11,679,195	140
10675_B_A	AES Thames	CT	91	1	26	15,600,819	172
10675_B_B	AES Thames	CT	91	1	26	15,682,088	173

10676_B_2	AES Beaver Valley Partners Beaver	PA	43	1	4	2,100,058	49
10676_B_3	AES Beaver Valley Partners Beaver	PA	43	1	4	2,159,729	50
10676_B_4	AES Beaver Valley Partners Beaver	PA	43	1	4	2,159,729	50
10676_B_5	AES Beaver Valley Partners Beaver	PA	17	1	4	1,520,200	89
10678_B_BLR1	AES Warrior Run Cogeneration Facility	MD	180	1	13	10,326,468	57
10684_B_BLR25	Argus Cogen Plant	CA	25	1	55	20,748,431	830
10684_B_BLR26	Argus Cogen Plant	CA	25	1	55	20,748,431	830
10743_B_CFB1	Morgantown Energy Facility	WV	25	1	12	4,578,240	183
10743_B_CFB2	Morgantown Energy Facility	WV	25	1	12	4,417,517	177
10768_B_CFB	Rio Bravo Jasmin	CA	33	1	29	12,560,352	381
10769_B_CFB	Rio Bravo Poso	CA	33	1	9	4,078,042	124
10771_B_1	Hopewell	VA	32	1	10	4,433,144	141
10771_B_2	Hopewell	VA	32	1	10	4,433,144	141
10773_B_1	Altavista Power Station	VA	32	1	7	3,025,687	96
10773_B_2	Altavista Power Station	VA	32	1	7	3,025,687	96
10774_B_1	Southampton Power Station	VA	63	1	21	11,523,948	183
10774_B_2	Southampton Power Station	VA	37	1	21	9,507,426	260
10784_B_BLR1	Colstrip Energy LP	MT	35	1	136	60,677,814	1,734
10849_B_BLR1	Silver Bay Power	MN	36	1	53	23,127,868	642
10849_B_BLR2	Silver Bay Power	MN	69	1	53	29,467,498	427
50012_B_BLR4	Alloy Steam Station	WV	38	1	16	6,888,251	181
50030_B_1A	Nelson Industrial Steam and Operating	LA	107	2	7	2,705,642	25
50030_B_2A	Nelson Industrial Steam and Operating	LA	106	2	7	2,679,457	25
50039_B_1	Kline Township Cogen Facility	PA	50	1	27	13,837,247	277
50130_B_BLR1	G F Weaton Power Station	PA	56	1	3	1,630,715	29
50130_B_BLR2	G F Weaton Power Station	PA	56	1	3	1,630,715	29
50202_B_1	WPS Power Niagara	NY	53	1	3	1,434,035	27
50368_G_TG1	Cornell University Central Heat	NY	1	1	3	268,863	269
50368_G_TG2	Cornell University Central Heat	NY	5	1	3	542,420	102
50388_B_K1	Phillips 66 Carbon Plant	CA	10	1	1	197,169	20

50388_B_K2	Phillips 66 Carbon Plant	CA	10	1	1	197,169	20
50397_B_1PB035	P H Glatfelter	PA	9	1	7	1,841,605	212
50397_B_3PB033	P H Glatfelter	PA	4	1	7	1,493,030	373
50397_B_4PB034	P H Glatfelter	PA	9	1	7	1,874,010	208
50397_B_5PB036	P H Glatfelter	PA	36	1	7	3,138,015	87
50410_B_10	Chester Operations	PA	36	1	0	165,409	5
50611_B_031	WPS Westwood Generation LLC	PA	30	1	9	3,969,914	132
50651_B_1	Trigen Syracuse Energy	NY	11	1	8	2,211,538	199
50651_B_2	Trigen Syracuse Energy	NY	11	1	8	2,243,056	202
50651_B_3	Trigen Syracuse Energy	NY	11	1	8	2,243,056	202
50651_B_4	Trigen Syracuse Energy	NY	11	1	8	2,243,056	202
50651_B_5	Trigen Syracuse Energy	NY	11	1	8	2,243,056	202
50651_G_GEN2	Trigen Syracuse Energy	NY	11	1	8	2,211,538	201
50776_B_BLR1	Panther Creek Energy Facility	PA	42	1	22	10,108,238	244
50776_B_BLR2	Panther Creek Energy Facility	PA	42	1	22	10,224,344	246
50806_B_PB4	Stone Container Florence Mill	SC	75	1	122	69,382,961	928
50835_B_1	TES Filer City Station	MI	30	1	42	17,747,919	592
50835_B_2	TES Filer City Station	MI	30	1	42	17,141,107	571
50879_B_BLR1	Wheelabrator Frackville Energy	PA	45	1	21	10,414,793	234
50888_B_BLR1	Northampton Generating Company	PA	112	1	5	3,307,302	30
50931_B_BLR1	Yellowstone Energy LP	MT	28	1	149	65,987,299	2,400
50931_B_BLR2	Yellowstone Energy LP	MT	28	1	149	58,025,007	2,110
50951_B_1	Sunnyside Cogen Associates	UT	51	1	15	7,903,915	155
50974_B_UNIT 1	Scrubgrass Generating	PA	43	1	8	3,993,426	94
50974_B_UNIT 2	Scrubgrass Generating	PA	43	1	8	3,881,950	91
50976_B_AAB01	Indiantown Cogeneration LP	FL	330	2	4	3,323,473	10
52007_B_BLR1	Mecklenburg Power Station	VA	69	1	15	8,567,737	124
52007_B_BLR2	Mecklenburg Power Station	VA	69	1	15	8,567,737	124
52071_B_5A	Sandow 5	TX	300	2	32	23,260,335	78
52071_B_5B	Sandow 5	TX	300	2	32	23,260,335	78

54035_B_BLR1	Westmoreland Roanoke Valley I	NC	165	2	62	36,771,503	223
54081_B_1A	Cogentrix of Richmond	VA	26	1	8	3,050,662	116
54081_B_1B	Cogentrix of Richmond	VA	26	1	8	2,948,358	112
54081_B_2A	Cogentrix of Richmond	VA	26	1	8	3,050,662	116
54081_B_2B	Cogentrix of Richmond	VA	26	1	8	2,948,358	112
54081_B_3A	Cogentrix of Richmond	VA	21	1	8	2,820,983	132
54081_B_3B	Cogentrix of Richmond	VA	21	1	8	2,723,771	128
54081_B_4A	Cogentrix of Richmond	VA	21	1	8	2,820,983	132
54081_B_4B	Cogentrix of Richmond	VA	21	1	8	2,723,771	128
54144_B_BRBR1	Piney Creek Project	PA	33	1	16	6,808,383	209
54224_B_GEN6	Franklin Heating Station	MN	3	1	43	7,175,049	2,563
54238_B_N64514	Port of Stockton District Energy Fac	CA	22	1	3	997,963	45
54238_B_N64516	Port of Stockton District Energy Fac	CA	22	1	3	958,629	44
54304_B_1A	Birchwood Power	VA	239	1	29	25,665,810	107
54406_G_1	Capitol Heat and Power	WI	1	1	28	2,967,700	3,297
54406_G_2	Capitol Heat and Power	WI	1	1	28	2,967,700	2,968
54626_B_BL01	Mt Poso Cogeneration	CA	52	1	18	9,385,483	180
54634_B_1	St Nicholas Cogen Project	PA	88	1	24	14,921,531	170
54677_B_HRB	CII Carbon LLC	LA	23	1	1	409,816	18
54677_G_TG-2	CII Carbon LLC	LA	23	1	1	409,816	18
54755_B_BLR2	Westmoreland Roanoke Valley II	NC	44	1	9	4,516,042	103
54775_B_BLR10	University of Iowa Main Power Plant	IA	4	1	12	2,476,778	590
54775_B_BLR11	University of Iowa Main Power Plant	IA	4	1	12	2,476,778	590
54992_G_ST	Fellsway Development LLC	MA	0	1	4	345,520	1,728
55076_B_AA001	Red Hills Generating Facility	MS	220	1	6	5,085,298	23
55076_B_AA002	Red Hills Generating Facility	MS	220	1	6	5,209,367	24
55360_B_1	Two Elk Generating Station	WY	300	2	88	32,932,652	110
55479_B_3	Wygen 1	WY	70	1	22	12,384,742	177
55749_B_PC1	Hardin Generator Project	MT	109	1	113	76,683,994	706
55856_B_PC1	Prairie State Generating Company LLC	IL	800	3	102	75,746,741	95

55856_B_PC2	Prairie State Generating Company LLC	IL	800	3	102	75,746,741	95
56037_G_1	Fox Valley Energy Center	WI	7	1	12	2,829,794	435
56068_B_1	Elm Road Generating Station	WI	617	3	87	69,303,550	112
56068_B_2	Elm Road Generating Station	WI	617	3	87	69,303,550	112
56163_B_1	KUCC	UT	30	1	5	2,097,370	70
56163_B_2	KUCC	UT	30	1	5	2,097,370	70
56163_B_3	KUCC	UT	30	1	5	2,097,370	70
56163_B_4	KUCC	UT	65	1	5	2,599,586	40
56224_B_001	TS Power Plant	NV	200	2	279	166,191,132	831
56319_B_4	Wygen	WY	90	1	22	12,811,795	142
56319_B_5	Wygen	WY	100	1	22	13,317,187	133
56456_B_STG1	Plum Point Energy	AR	665	2	34	33,548,267	50
56671_B_1	Longview Power	WV	695	2	21	21,085,857	30
82794_C_1	ERCT_TX_Coal steam	TX	300	2	8	3,520,181	12
82821_B_1	Great River Energy Spiritwood Station	ND	99	1	14	8,403,970	85
82886_C_1	NWPE_WY_Coal steam	WY	422	3	212	111,573,136	264
82909_C_1	RFCO_IN_IGCC	IN	630	3	69	56,903,399	90
82916_C_1	RMPA_CO_Coal steam	CO	18	1	11	3,744,305	208
82932_C_1	SPPN_KS_Coal steam	KS	22	1	10	3,755,430	171
82934_C_1	SPPN_MO_Coal steam	MO	1,150	3	82	79,762,328	69
82998_B_CFB1	Virginia City Hybrid Energy Center	VA	293	3	168	99,750,208	341
82998_B_CFB2	Virginia City Hybrid Energy Center	VA	293	3	168	99,750,208	341

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5.4.3 Mercury Control Capabilities

EPA Base Case v4.10_PTox offers two options for meeting mercury reduction requirements: (1) combinations of SO_2, NO_X, and particulate controls which deliver mercury reductions as a co-benefit and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. These two options are discussed below.

Mercury Control through SO_2 and NO_X Retrofits

In EPA Base Case v4.10, units that install SO_2, NO_X, and particulate controls, reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used in the base case to capture the unregulated mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO_2, NO_X, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses") and particulate matter (PM) scrubbers). These same EMFs would be available in mercury policy runs to characterize the mercury reductions that can be achieved by retrofitting a unit with SCR, SO_2 scrubbers and particulate controls. The absence of a federal mercury emission reduction policy means that these controls appear in the base case in response to SO_2, NO_X, or particulate limits or state-level mercury emission requirements. However, in future model runs where mercury limits are present these same SO_2 and NO_X controls could be deliberately installed for mercury control if they provide the least cost option for meeting mercury policy limits.

Activated Carbon Injection (ACI)

The technology specifically designated for mercury control is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. In preparation for performing modeling of air toxics, a comprehensive update of ACI cost and performance assumptions was undertaken by Sargent & Lundy, the same engineering firm that developed the SO_2 and NO_X control assumptions used in EPA Base Case v4.10. The ACI update, whose elements are described below, incorporates the latest field experience through 2010.

Assuming a target of 90% removal from the level of mercury in the coal, three alternative ACI options were identified as providing the required rate of removal for all possible configurations of boiler, emission controls, and coal types used in the U.S. electric power sector. The three ACI options differed based on the type of particulate control device − electrostatic precipitator (ESP) or pre-existing or new fabric filter (also called a "baghouse"), i.e.,

- ACI with Existing ESP
- ACI with Existing Baghouse
- ACI with an Additional Full Baghouse (also referred to as Toxecon)

All three configurations assume the use of brominated ACI, where a small amount of bromine is chemically bonded to the powdered carbon which is injected into the flue gas stream. The use of brominated ACI exploits the discovery that by converting elemental mercury to oxidized mercury, halogens (like chlorine, iodine, and bromine) can make activated carbon more effective in capturing the mercury at the high temperatures found in industrial processes like power generation. The ionic mercury adheres to the activated carbon (and to fly ash and unburned carbon in the fuel gas) which can be removed efficiently from the flue gas by the particulate control device (ESP or fabric filter). In the third option listed above the additional baghouse is installed downstream of the pre-existing particulate matter device and the activated carbon is injected after the existing controls. This configuration allows the fly ash to be removed before the mercury controls to preserve its marketability.

The applicable ACI option depends on the coal type burned, its SO_2 content, the boiler and particulate control type and, in some instances, consideration of whether an SO_2 scrubber (FGD) system and SCR NO_x post-combustion control are present. Table 5-16 shows the ACI assignment scheme used in EPA Base Case v4.10_PTox to achieve 90% mercury removal.

Table 5-16. Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v4.10_PTox (Proposed Toxics Rule).

Air pollution controls				Bituminous Coal			Subbituminous Coal			Lignite Coal		
Burner Type	**Particulate Control Type**	**SCR System**	**FGD System**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acf)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acf)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acf)**
FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
FBC	Fabric Filter	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2

Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP without FGC	--	Dry FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	--	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Dry FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Fabric Filter	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2

Non-FBC	Fabric Filter	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Dry FGD	No	No	0	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

Non-FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

Non-FBC	PM Scrubber	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

Note: In the table above "Toxecon" refers to the option described as "ACI System with an Additional Baghouse" and "ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/million acfm" elsewhere in this chapter.

Methodology for Obtaining ACI Control Costs: For ACI systems the carbon feed rate dictates the size of the equipment and resulting costs. The feed rate in turn is a function of the required removal (in this case 90%) and the type of particulate control device. Engineering experience had established that a carbon feed rate of 5 pounds of carbon injected for every 1,000,000 actual cubic feet per minute (acfm) of flue gas would provide the stipulated 90% mercury removal rate for units shown in Table 5-16 as qualifying for ACI systems with existing ESP. For generating units with fabric filters a 2 pound per million acfm is required. Alternative sets of costs were developed for each of the three ACI options: ACI systems for units with existing ESPs, ACI for units with existing fabric filters (baghouses), and the combined cost of ACI plus an additional baghouse for units that either have no existing particulate control or that require ACI plus a baghouse in addition to their existing particulate control. There are various reasons that a combined ACI plus additional baghouse would be required. These include situations where the existing ESP cannot handle the additional particulate load associate with the ACI or where SO_3 injection is currently in use to condition the flue gas for the ESP. Another cause for combined ACI and baghouse is use of PRB coal whose combustion produces mostly elemental mercury, not ionic mercury, due to this coal's low chlorine content.

Capital Cost: Included in the installed capital cost of ACI are

- All equipment
- Installation
- Buildings
- Foundations
- Electrical

If an additional baghouse is required in combination with the ACI, specific installed capital costs include

- Duct work
- Foundations
- Structural steel
- Induced draft (ID) fan modifications or new booster fans
- Electrical modifications

For the combined ACI and fabric filter option a full size baghouse with an air-to-cloth (A/C) ratio of 4.0 is assumed, not a polishing baghouse with a 6.0 A/C ratio[5]. Table 5-17 shows the capital cost modules and the governing variables for ACI systems.

[5] The "air-to-cloth" (A/C) ratio is the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater area of the cloth required and the higher the cost for a given volumetric flow.

Table 5-17. Capital Cost Components and Their Governing Variables for ACI Systems

Module	Hg Removal Rate	Retrofit Difficulty (1 = average)	Particulate Capture Type (ESP or Baghouse)	Heat Rate (Btu/kWh)	Unit Size (MW)	Coal Type
ACI Injection - Carbon Feed Rate	X	X	X	X	X	
Additional Fabric Filter (if needed)		X		X	X	X

A bare installed total cost is calculated from the carbon feed rate based on the required removal rate, the particulate control, and the flue gas flow rate. The resulting bare installed total cost is increased by 15% to account for additional engineering and construction management costs, labor premiums, and contractor profits and fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. Since ACI systems are expected to be completed in less than a year, no Allowance for Funds used During Construction (AFUDC) is provided for ACI systems by themselves. However, if combined with an additional baghouse, 6% is added to account for Allowance for Funds used During Construction (AFUDC) which is premised on a 2-year project duration for the baghouse.

The cost resulting from these calculations is the capital cost factor (expressed in $/kW) that is used in EPA Base Case v4.10_PTox.

<u>Variable Operating and Maintenance Costs (VOM)</u>: These are the costs incurred in running an emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For ACI, Sargent & Lundy identified three components of VOM: (a) reagent use and unit costs, (b) waste production and disposal cost, (c) cost of additional power required to run the DSI control (often called the "parasitic load"). For the ACI in combination with fabric filter option, the VOM includes a fourth component: (d) the cost of filter bag and cage replacement. (With an assumption that the A/C ratio = 6.0, the bag and cage replacement cycles are 3 and 9 years respectively.)

For ACI carbon usage is a function of unit size and heat rate. The carbon waste production is equal to the carbon feed rate. To provide a conservative estimate, the costing analysis assumed that the carbon is captured in the same particulate collector as the fly ash, making it necessary for both the total fly ash and the carbon to be landfilled. Typical ash contents for each fuel were used to calculate a total fly ash production rate.

For purposes of modeling, the total VOM includes cost components (a), (b), and, where applicable, (d) as noted above. Component (c) – cost of additional power for the ACI system – is factored into IPM, not in the VOM value, but through capacity and heat rate penalties as described in the next paragraph.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the ACI system is represented through a reduction in the amount of electricity that is available for sale to the grid. For example in the option of a combined ACI system with an additional baghouse, if 0.65% of the unit's electrical generation is needed to operate the combined system, the generating unit's capacity is reduced by 0.65%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the ACI device), the unit's heat rate is scaled up such that a comparable reduction (0.65% in the previous example) in the new higher heat rate yields the original heat rate. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). As was the case for FGD in EPA Base Case v4.10, specific ACI heat rate and capacity penalties are calculated for each installation. For ACI, the site specific calculations take into account the additional power required for blowers for the injection system and, where an additional fabric filter is present, the power for the baghouse compressors.

Fixed Operating and Maintenance Costs (FOM): These are the annual costs of maintaining a unit. They represent expenses incurred regardless of the extent to which the emission control system is run. They are expressed in units of $ per kW per year. In calculating FOM Sargent & Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

- FOM for operations is based on the number of addition operators needed. For ACI one (1) additional operator is assumed to be needed.

- FOM for maintenance is a direct function of the ACI capital cost.

- FOM for administration is a function of the FOM for operations and maintenance.

Table 5-18 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties for the three ACI options represented in EPA Base Case v4.10_PTox (Proposed Toxics Rule). For each ACI option values are shown for an illustrative set of generating units with a representative range of capacities and heat rates.

Tables 1-3 in Appendix 5-3 contains illustration worksheets of the detailed calculations performed to obtain the capital, VOM, and FOM costs for examples of the three ACI options described in this section. The worksheets were developed by Sargent & Lundy[6].

[6] These worksheets were extracted from Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology* (Project 12301-009), October 2010. The complete report is available for review and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/.

Table 5-18. Illustrative Activated Carbon Injection (ACI) Costs for Representative Sizes and Heat Rates Under Assumptions in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
ACI System with an Existing ESP	9,000	0.12	0.12	2.76	32.06	0.13	12.60	0.05	8.16	0.03	6.13	0.03	4.53	0.02
ACI with a Sorbent Injection Rate of 5 lbs/million acfm	10,000	0.13	0.13	3.07	32.56	0.14	12.80	0.05	8.29	0.03	6.23	0.03	4.60	0.02
Assuming Bituminous Coal	11,000	0.14	0.14	3.38	33.04	0.14	12.99	0.05	8.41	0.04	6.32	0.03	4.67	0.02
ACI System with an Existing Baghouse	9,000	0.05	0.05	2.24	27.93	0.12	10.98	0.05	7.11	0.03	5.34	0.02	3.95	0.02
ACI with a Sorbent Injection Rate of 2 lbs/million acfm	10,000	0.05	0.05	2.49	28.37	0.12	11.16	0.05	7.23	0.03	5.43	0.02	4.01	0.02
Assuming Bituminous Coal	11,000	0.06	0.06	2.74	28.80	0.12	11.32	0.05	7.33	0.03	5.51	0.02	4.07	0.02
ACI System with an Additional Baghouse	9,000	0.65	0.65	0.50	240	0.91	182	0.69	162	0.61	150	0.57	139	0.53
ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/million acfm	10,000	0.65	0.66	0.54	259	0.98	197	0.75	176	0.67	163	0.62	151	0.57
Assuming Bituminous Coal	11,000	0.66	0.66	0.58	278	1.05	212	0.80	189	0.72	176	0.67	163	0.62

5.5 Hydrogen Chloride (HCl) Control Technologies

Consistent with other analysis performed for the Toxics Rule, hydrogen chloride (HCl) is used in EPA Base Case v4.10_PTox (Proposed Toxics Rule) as a surrogate for the acid gas hazardous air pollutants (HAPs). (See Toxics Rule preamble for a discussion of this topic.) The following sections describe how HCl emissions from coal are represented in IPM, the emission control technologies available for HCl removal, and the cost and performance characteristics of these technologies.

5.5.1 Chlorine Content of Fuels

HCl emissions from the power sector result from the chlorine content of the coal that is combusted by electric generating units. Data on chlorine content of coals had been collected as part EPA's 1999 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR 1999) described above in section 5.4.1 To provide the capability for EPA Base Case v4.10 to account for HCl emissions, this data had to be incorporated into the model. The procedures used for this are presented in the updated text in section 9.1.3 below.

5.5.2 HCl Removal Rate Assumptions for Existing and Potential Units

SO_2 emission controls on existing and new (potential) units provide the HCl reductions indicated in Table 5-19. New supercritical pulverized coal units (column 3) that the model builds include FGD (wet or dry) which is assumed to provide a 99% removal rates for HCl. For existing conventional pulverized coal units with pre-existing FGD (column 5), the HCl removal rate is 5% higher than the reported SO_2 removal rate up to a maximum of 99% removal. In addition, for fluidized bed combustion units (column 4) with no FGD and no fabric filter, the HCl removal rate is the same as the SO_2 removal rate up to a maximum of 95%. FBCs with fabric filters have an HCl removal rate of 95%.

When policies for controlling toxics emissions are modeled, it is assumed prior to performing a model run that the most cost effective default option for existing coal steam units with FGD would be to upgrade their FGDs to obtain at least 90% SO_2 removal and 99% HCl removal and then let the model determine if any further reductions are needed. The cost of the FGD Upgrade Adjustment, as it is called, is assumed to be $100/kW (in 2009$). It is applied in the model as an FOM cost adder[7].

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[7] The FGD Upgrade Adjustment is applied in the model as a FOM cost adder, where

FOM Adder = FGD Upgrade Adjustment X Capital Charge Rate
= $100/kW ($2009) X 11.3%
= $11.30/kW-yr ($2009)

Table 5-19. HCl Removal Rate Assumptions for Potential (New) and Existing Units in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

		Potential (New)	**Existing Units with FGD**		
			Base Case		**Policy Case**
Gas	**Controls ==>**	**Supercritical Pulverized Coal with Wet or Dry FGD**	**Fluidized Bed Combustion (FBC)**	**Conventional Pulverized Coal (CPC) with Wet or Dry FGD**	**Existing Coal Steam Units with FGD Upgrade Adjustment**
HCl	Removal Rate	99%	**Without fabric filter:** Same as reported SO_2 removal rate up to a maximum of 95% ——— **With fabric filter:** 95%	Reported SO_2 removal rate + 5% up to a maximum of 99%	If reported SO_2 removal < 90%, unit incurs cost to upgrade FGD, so that SO_2 removal is 90%. Then, the resulting HCl removal rate is 99% ——— If reported SO_2 removal is ≥ 90% and < 94%, then the unit incurs a cost to upgrade FGD and the HCl removal rate is 99%. (The SO_2 removal rate remains as reported.) ——— If the reported SO_2 removal rate is ≥ 94%, the unit incurs no upgrade cost and the HCl removal rate is 99%.

5.5.3 HCl Retrofit Emission Control Options

Table 5-20 Summary of HCl Emission Control Technology Assumptions in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

HCl Control Technology Options	Applicability
Limestone Forced Oxidation (LSFO) Scrubber	Base case and policy case
Lime Spray Dryer (LSD)	Base case and policy case
Dry Sorbent Injection (DSI)	Base case and policy case
Scrubber upgrade adjustment	To existing coal steam units with FGD in policy cases analyzed for Toxics Rulemaking

All the retrofit options for HCl emission control are summarized in Table 5-20. The scrubber upgrade adjustment was discussed above in 5.5.2. The other options are discussed in detail in the following sections.

5.5.3.1 Wet and Dry FGD

In addition to providing SO_2 reductions, wet scrubbers (Limestone Forced Oxidation, LSFO) and dry scrubbers (Lime Spray Dryer, LSD) reduce HCl as well. For both LSFO and LSD the HCl removal rate is assumed to be 99% with a floor of 0.0001 lbs/MMBtu. This is summarized in columns 2-5 of Table 5-21.

Table 5-21 Summary of Retrofit HCl (and SO_2) Emission Control Performance Assumptions in v4.10_PTox (Proposed Toxics Rule)
.

Performance Assumptions	Limestone Forced Oxidation (LSFO)		Lime Spray Dryer (LSD)		Dry Sorbent Injection (DSI)[1]	
	SO_2	HCl	SO_2	HCl	SO_2	HCl
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	92% with a floor of 0.065 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	**With fabric filter:** 70% ––– **With an electrostatic percipitator[2]:** 50%	**With fabric filter:** 90% with a floor of 0.0001 lbs/MMBtu ––– **With an electrostatic percipitator[2]:** 60% with a floor of 0.0001 lbs/MMBtu
Capacity Penalty	-1.65%		-0.70%		-0.65%	
Heat Rate Penalty	1.68%		0.71%		0.65%	
Cost (2007$)	See Table 5-3 and 5-4		See Table 5-3 and 5-4		See Tables D and E	
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 2.0% Sulfur by Weight		Coals ≤ 2.0 lb/mmBtu of SO_2	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG		BA, BB, BD, BE, SA, SB, SD, LD, LE, and LG		BA, BB, BD, SA, SB, SD, and LD	

<u>Notes</u>
1. The cost and performance values shown in this table apply to existing units with pre-existing fabric filters or electrostatic precipitators. Units with neither ESP nor FF are assumed to have to install a fabric filter in order to qualify for the DSI retrofit.
2. The option to retrofit DSI on existing units with ESP was not offered in the runs performed for the current rulemaking.

5.5.3.2 Dry Sorbent Injection

Besides HCl reductions obtained from FGD, EPA Base Case v4.10_PTox includes dry sorbent injection (DSI), not previously included in the base case, as a retrofit option for achieving (in combination with a particulate control device) both SO_2 and HCl removal. In DSI for HCl reduction, a dry sorbent is injected into the flue gas duct where it reacts with the HCl and SO_2 in the flue gas to form a compound, which is then captured in a downstream fabric filter or electrostatic precipitator (ESP) and disposed of as waste. (A sorbent is a material that takes up another substance by either adsorption on its surface or absorption internally or in solution. A sorbent may also chemically react with another substance.) The sorbent assumed in the cost and performance characterization discussed in this section is trona, a sodium-rich material with major underground deposits found in Sweetwater County, Wyoming. Trona is typically delivered with an average particle size of 30 μm diameter, but can be reduced to about 15 μm through onsite in-line milling to increase its surface area and capture capability.

Removal rate assumptions: The removal rate assumptions for DSI are summarized in Table 5-21. The assumptions shown in the last two columns of Table 5-21 were derived from assessments by EPA engineering staff in consultation with Sargent & Lundy. As indicated in this table, the assumed SO2 removal rate for DSI + ESP is 50% and for DSI + fabric filter is 70%. The assumed HCl removal rate is 60% for DSI + ESP and 90% for DSI + fabric filter. (This is noted in the next-to-the-last column in Table 5-21.) Although the option to retrofit DSI on existing units with ESP is shown in Table 5-21 it was not offered in the runs performed for the current rulemaking.

Methodology for Obtaining DSI Control Costs: The engineering firm of Sargent & Lundy, whose analyses were used to update the cost of SO_2 and post-combustion NO_x controls in EPA Base Case , v4.10, performed similar engineering assessments of the cost of DSI retrofits with two alternative, associated particulate control devices, i.e., ESP and fabric filter (also called a "baghouse"). Their analysis of DSI noted that the cost drivers of DSI are quite different from those of wet or dry FGD. Whereas plant size and coal sulfur rates are key underlying determinants of FGD cost, sorbent feed rate and fly ash waste handling are the main drivers of the capital cost of DSI with plant size and coal sulfur rates playing a secondary role.

Sorbent feed rate determines the amount of sorbent required and the size and extensiveness of the DSI installation. The sorbent feed rate needed to achieve a specified percent SO_2 or HCl removal[8] is firstly a function of the flue gas SO_2 rate (which, in turn, is a function of the sulfur content of the coal burned, expressed in lbs of SO_2/mmBtu), the unit's size and heat rate, and the sorbent particle size (which determines whether in-line milling is needed). The sorbent feed rate is also a function of the residence time of the sorbent in the flue gas stream and the extent of mixing and penetration of the sorbent in the flue gas. Residence time, penetration, and mixing are largely dependent on the type of particulate control device use (electrostatic precipitator or fabric filter).

[8] For purposes of engineering calculations the percent removal is often translated into a corresponding "Normalized Stoichiometric Ratio" (NSR) associated with a particular percent removal, where the NSR is defined as

$$NSR = \left(\frac{moles\ of\ sobent\ inject}{moles\ of\ SO2\ in\ flue\ gas}\right) \Big/ (theoretical\ moles\ of\ sorbent\ required)$$

In EPA Base Case v4.10_PTox the DSI sorbent feed rate and variable O&M costs are based on assumptions that a fabric filter and in-line trona milling are used, and that the SO2 removal rate is 60%. The corresponding HCl removal effect is assumed to be 90%, based on information from Solvay Chemicals (H. Davidson, *Dry Sorbent Injection for Multi-pollutant Control Case Study*, CIBO IECT VIII, August, 2010).

The cost of fly ash waste handling, the other key contributor to DSI cost, is a function of the type of particulate capture device and the flue gas SO_2 rate (which, as noted above, is itself a function of the sulfur content of the coal and the unit's size and heat rate). Fly ash waste handling costs are also a function of the ash content and the higher heating value (HHV) of the coal. The governing variables of the key capital cost components of DSI are presented in Table 5-22.

Table 5-22. Capital Cost Components and Their Governing Variables for HCl Removal with DSI.

Module	Retrofit Difficulty (1 = average)	Particulate Capture Type (ESP or Baghouse)	Sorbent Particle Size Require-ment (milled or unmilled)	Heat Rate (Btu/ kWh)	SO2 Rate of coal (lb/ MMBtu)	Ash Content of Coal (percent)	Higher Heating Value (HHV) of Coal (Btu/lb)	Unit Size (MW)
Sorbent Feed Handling	X		X	X	X			X
Fly Ash Waste Handling	X	X		X		X	X	X

Once the key variables for the two DSI modules are identified, they are used to derive costs for each base module component. These costs are then summed to obtain total bare module costs. The base installed cost for DSI includes

- All equipment
- Installation
- Buildings
- Foundations
- Electrical
- Average retrofit difficulty
- In-line milling equipment is assumed to be included

This total is increased by 15% to account for additional engineering and construction management costs, labor premiums, and contractor profits and fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. Since DSI installations are expected to be completed in less than a year, no Allowance for Funds used During Construction (AFUDC) is provided for DSI. The cost resulting from these calculations is the capital cost factor (expressed in $/kW) that is used in EPA Base Case v4.10_PTox.

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running an emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For DSI, Sargent & Lundy identified three components of VOM: (a) costs for sorbent usage, (b) costs associated with waste production and disposal, (c) cost of additional power required to run the DSI control (often called the "parasitic load"). For DSI, sorbent usage is a function of the "Normalized Stoichiometric Ratio" and SO_2 feed rate. As noted above the feed rate is a function of the SO_2 rate of the coal and the unit's size and heat rate.

Total waste production involves the production of both reacted and unreacted sorbent and fly ash. Sorbent waste is a function of the sorbent feed rate with an adjustment for excess sorbent feed. Use of DSI makes the fly ash unsalable, which means that any fly ash produced must be landfilled along with the reacted and unreacted sorbent waste. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for the total waste stream for the VOM analysis.

For purposes of modeling, the total VOM includes the first two component costs noted in the previous paragraph, i.e., the costs for sorbent usage and the costs associated with waste production and disposal,. The last component – cost of additional power – is factored into IPM, not in the VOM value, but through a capacity and heat rate penalty as described in the next paragraph.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the DSI is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 0.65% of the unit's electrical generation is needed to operate DSI, the generating unit's capacity is reduced by 0.65%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the DSI device), the unit's heat rate is scaled up such that a comparable reduction (0.65% in the previous example) in the new higher heat rate yields the original heat rate. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). As was the case for FGD in EPA Base Case v4.10, specific DSI heat rate and capacity penalties are calculated for each installation. For DSI the installation specific calculations take into account the additional power required by air blowers for the injection system, drying equipment for the transport air, and in-line milling equipment, if required.

Fixed Operating and Maintenance Costs (FOM): These are the annual costs of maintaining an emission control. They represent expenses incurred regardless of the extent to which the emission control system is run. They are expressed in units of $ per kW per year. In calculating FOM Sargent & Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

- FOM for operations is based on the number of operators needed which is a function of the size (i.e., MW capacity) of the generating unit. In general for DSI two (2) additional operators are assumed to be needed.

• FOM for maintenance is a direct function of the DSI capital cost.

• FOM for administration is a function of the FOM for operations and maintenance.

Table 5-23 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties of a DSI retrofit for an illustrative and representative set of generating units with the capacities and heat rates indicated.

Illustration worksheets of the detailed calculations performed to obtain the capital, VOM, and FOM costs for an example DSI appear in Appendix 5-4. The worksheets were developed by Sargent & Lundy[9].

[9]These worksheets were extracted from Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies: Complete Dry Sorbent Injection Cost Development Methodology* (Project 12301-007), May 2010. The complete report is available for review and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/.

Table 5-23. Illustrative Dry Sorbent Injection (DSI) Costs for Representative Sizes and Heat Rates Under Assumptions in EPA Base Case v4.10_PTox (Proposed Toxics Rule) .

Control Type	Heat Rate (Btu/ kWh)	SO2 Rate (lb/ MMBtu)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/ kWh)	Capacity (MW)									
						100		300		500		700		1000	
						Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
DSI - FF	9,000	2.0	0.64	0.65	6.05	122	2.25	55	0.87	38	0.57	30	0.43	28	0.36
Assuming Bituminous Coal	10,000	2.0	0.71	0.72	6.72	125	2.28	57	0.89	40	0.58	31	0.43	31	0.38
	11,000	2.0	0.79	0.79	7.40	129	2.30	59	0.90	41	0.59	34	0.46	34	0.41
DSI - ESP	9,000	2.0	1.08	1.10	11.23	141	2.41	64	0.94	47	0.64	47	0.57	47	0.52
Assuming Bituminous Coal	10,000	2.0	1.20	1.22	12.47	145	2.44	66	0.96	52	0.68	52	0.61	52	0.56
	11,000	2.0	1.32	1.34	13.72	149	2.48	68	0.98	58	0.73	58	0.65	58	0.60

5.5.4 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option in EPA Base Case v4.10_PTox, but are accounted for as a cost adder where they are required for particulate matter (PM), mercury, or HCl emission control. In EPA Base Case v4.10_PTox, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit. In the v4.10_PTox policy case any unit that was retrofit by the model with DSI and did not have an existing fabric filter incurred the cost of installing a fabric filter. This cost was added to the DSI costs discussed in section 5.5.3.2. This section describes the methodology used by Sargent & Lundy to derive the cost of a fabric filter.

The engineering cost analysis is based on a pulse-jet fabric filter which collects particulate matter on a fabric bag and uses air pulses to dislodge the particulate from the bag surface and collect it in hoppers for removal via an ash handling system to a silo. This is a mature technology that has been operating commercially for more than 25 years. “Baghouse” and “fabric filters” are used interchangeably to refer to such installations.

Capital Cost: Two governing variables are used to derive the bare module capital cost of a fabric filter. The first of these is the “air-to-cloth” (A/C) ratio. The major driver of fabric filter capital cost, the A/C ratio is defined as the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater the area of the cloth required and the higher the cost for a given volumetric flow.

The other determinant of capital cost is the flue gas volumetric flow rate (in ACFM) which is a function of the type of coal burned and the unit’s size and heat rate.

The capital cost for fabric filters include:

- Duct work modifications,
- Foundations,
- Structural steel,
- Induced draft (ID) fan modifications or new booster fans, and
- Electrical modifications.

After the bare installed total capital cost is calculated, it is increased by 20% to account for additional engineering and construction management costs, labor premiums, and contractor profits and fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner’s home office costs, i.e., owner’s engineering, management, and procurement costs, and by another 6% to account for Allowance for Funds used During Construction (AFUDC) which is premised on a 2-year project duration.

The cost resulting from these calculations is the capital cost factor (expressed in $/kW). Fabric filter capital costs are implemented in EPA Base Case v4.10_PTox as an FOM adder. Plants that install fabric filters incur a total FOM charge which includes the true FOM associated with the fabric filter plus a capital cost FOM Adder derived by multiplying the capital cost by a capital charge rate of 11.3%, i.e.,

Total FOM = True FOM + Capital Cost FOM Adder

where the FOM Adder = Capital Cost X Capital Charge Rate = Capital Cost X 11.3%

In EPA Base Case v4.10_PTox the capital cost of a fabric filter is based on the use of a "polishing" fabric filter designed with A/C=6.0. This basis results in a capital cost that is at least 10% less than the cost of a design with A/C=4.0, and assumes that the existing ESP remains in place and active.

Variable Operating and Maintenance Costs (VOM): For fabric filters the VOM is strictly a function of the costs of the fabric filter bag and cage translated in a $/MWhr cost based on the filter and bag replacement cycle for a specified A/C ratio. For units whose A/C ratio = 6.0, the replacement cycle for the bag is 3 years and the cage is 9 years, whereas for units whose A/C ratio = 4.0, the bag and cage replacement cycles are 5 and 10 years respectively.

Capacity and Heat Rate Penalty: Conceptually, the capacity and heat rate penalties for fabric filters represent the amount of electrical power required to operate the baghouse and are calculated by the same procedure used when calculating the capacity and heat rate penalty for DSI as described in section 5.5.3.2. The resulting capacity and heat rate penalties are both 0.6%.

However, since fabric filters were not endogenously modeled as a retrofit option, but simply added to the DSI costs for generating units that do not have an existing baghouse, the capacity and heat rate penalties described here were not factored into the representation of fabric filters in EPA Base Case v4.10_PTox.

Fixed Operating and Maintenance Costs (FOM): Sargent & Lundy's engineering analysis indicated that no additional operations staff would be required for a baghouse. Consequently the FOM strictly includes two components:

- FOM for maintenance is a direct function of the DSI capital cost.

- FOM for administration is a function of the FOM for operations (which is zero) and maintenance.

Table 5-24 presents the capital, VOM, and FOM costs for fabric filters as represented in EPA Base Case v4.10_PTox for an illustrative set of generating units with a representative range of capacities and heat rates.

Worksheets illustrating the detailed calculations performed to obtain the capital, VOM, and FOM costs for two example fabric filters (A/C Ratio = 4.0 and A/C Ratio = 6.0) appear in Appendix 5-5. The worksheets were developed by Sargent & Lundy[10].

[10] These worksheets were extracted from Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology* (Project 12301-009), October 2010. The complete report is available for review and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/.

Table 5-24. Illustrative Fabric Filter (Baghouse) Costs for Representative Sizes and Heat Rates Under Assumptions in EPA Base Case v4.10_PTox (Proposed Toxics Rule) .

Coal Type	Heat Rate (Btu/ kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/ kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
Bituminous	9,000	0.60	0.60	0.15	188	0.8	153	0.6	139	0.6	130	0.6	122	0.5
	10,000				205	0.9	167	0.7	151	0.6	141	0.6	132	0.6
	11,000				221	0.9	180	0.8	163	0.7	153	0.6	143	0.6

Notes on Implementation

1. Plant specific fabric filter capital costs shown in this table are implemented in EPA Base Case v4.10_PTox as an FOM adder. Plants that install fabric filters incur a total FOM charge which includes the true FOM component shown in the above table plus a capital cost FOM Adder derived by multiplying the capital cost in the table above by a capital charge rate 11.3%, i.e.,

Total FOM = True FOM + Capital Cost FOM Adder

where the FOM Adder = Capital Cost X Capital Charge Rate = Capital Cost X 11.3%.

Plants that install fabric filters also incur the additional VOM costs shown in the above table.

2. Since the fabric filter costs were not endogenously modeled as a retrofit option, the capacity and heat rate penalties shown in the above table were not represented in the model.

Appendix 5-3 Example Cost Calculation Worksheets for Three Activated Carbon Injection (ACI) Options for Mercury Emission Control in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

Table 1. Example Complete Cost Estimate for an ACI System with an Existing ESP (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<— User Input
Retrofit Factor	B		1	<— User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<— User Input
Type of Coal	D		Bituminous	<— User Input
Existing FGD System	E		Wet FGD	<— User Input
Existing SCR	F		TRUE	<— User Input (Activated carbon may not be required. Co-benefit of SCR and FGD system should achieve 80% removal.)
Removal Less Than 80%?	G		FALSE	<— User Input
Existing PM Control	H		ESP	<— User Input
Baghouse Addition	J		Not Added	<— User Input for retrofit of an additional baghouse after the existing PM control.
Heat Input	K	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	L	(acfm)	2,068,902	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Carbon Feed Rate	M	(lb/hr)	621	= If Existing FGD, SCR, and removal is less than 80% then 0 else L*60*(If Baghouse then 2 else 5)/1000000 Based on 2 lb/MMacf for baghouse applications 5 lb/MMacf for ESP applications Flow determined downstream of an air preheater
Carbon Waste Rate	N	(lb/hr)	621	= M
Fly Ash Waste Rate	P	(ton/hr)	20.7	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Total Waste Rate	Q	(ton/hr)	21.0	Based on no beneficial uses for fly ash with activated carbon without an additional baghouse If J = True or G = True then 0 else P + N/2000
Aux Power	R	(%)	0.12	If J = True then 0.6 else 0 + (0.1*M/A) **Should be used for model input.**
Carbon Cost	S	($/ton)	1500	
Waste Disposal Cost	T	($/ton)	50	
Aux Power Cost	U	($/kWh)	0.06	
Bag Cost	V	($/bag)	80	
Cage Cost	W	($/cage)	30	
Operating Labor Rate	X	($/hr)	60	Labor cost including all benefits

			Example	Comments
Capital Cost Calculation				
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMC ($) =	1,360,000*B*(M^0.15)	$	3,542,000	Base ACI module includes all equipment from unloading to injection
BMB ($) =	If(J = Not Added then 0, J = 6.0 Air-to-Cloth then 422, J = 4.0 Air-to-Cloth then 476)*B*L^(	$	-	Base module for an additional baghouse including ID or booster fans, piping, ductwork, etc…
BMF ($) =	If there is a wet FGD, SCR, and capture is less than 80% then $500,000 else 0	$	-	Base module for wet FGD additive addition (as applicable)
BMA ($) =	If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then $1,000,000 else 0	$	-	Base module for coal additive addition (as applicable)
BM ($) =	BMC + BMB + BMF + BMA	$	3,542,000	Total Base module cost including retrofit factor
BM ($/KW) =			7	Base module cost per kW
Total Project Cost				
A1 = If baghouse addition then 10% else 5% of BM		$	177,000	Engineering and Construction Management costs
A2 = 5% of BM		$	177,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM		$	177,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	4,073,000	Capital, engineering and construction cost subtotal
CECC ($/KW) =			8	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	204,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = If baghouse addition then 6% else 0% of CECC + B1		$	-	AFUDC For ACI system only: 0% for less than 1 year engineering and construction cycle For additional baghouse: 6% for a 2 year engineering and construction cycle
C2 = If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 2500*A else 0		$	-	One time coal additive royalty fee (as applicable)
TPC ($) = CECC + B1 + B2 + C2		$	4,277,000	Total project cost
TPC ($/kW) =			9	Total project cost per kW
Fixed O&M Cost				
FOMO ($/kW-yr) = (0 additional operators)*2080*X/(A*1000)		$	-	Fixed O&M additional operating labor costs
FOMM ($/kW-yr) = BM*0.005/(B*A*1000)		$	0.04	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr) = 0.03*(FOMO+0.4*FOMM)		$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW-yr) = FOMO + FOMM + FOMA		$	0.04	Total Fixed O&M costs
Variable O&M Cost				
VOMR ($/MWh) = M*S/(2000*A)		$	0.93	Variable O&M costs for carbon sorbent
VOMW ($/MWh) = Q*T/A		$	2.10	Variable O&M costs for waste disposal that includes the carbon and the fly ash waste as applicable
VOMB ($/MWh) = If(J = Not Added then 0, J = 6.0 Air-to-Cloth then 0.094, J = 4.0 Air-to-Cloth then 0.105)*(V/3+W/9)		$	-	Variable O&M costs for bags and cages.
VOMF ($/MWh) = If there is a wet FGD, SCR, and capture is less than 80% then 115/A else 0		$	-	Variable O&M costs for wet FGD additive addition
VOMA ($/MWh) = If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 200/A else 0		$	-	Variable O&M costs for coal additive addition
VOM ($/MWh) = VOMR + VOMW + VOMB + VOMF + VOMC		$	3.04	

Table 2. Example Complete Cost Estimate for an ACI System with an Existing Baghouse (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Existing FGD System	E		Wet FGD	<--- User Input
Existing SCR	F		TRUE	<--- User Input (Activated carbon may not be required. Co-benefit of SCR and FGD system should achieve 80% removal.)
Removal Less Than 80%?	G		FALSE	<--- User Input
Existing PM Control	H		Baghouse	<--- User Input
Baghouse Addition	J		Not Added	<--- User Input for retrofit of an additional baghouse after the existing PM control.
Heat Input	K	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	L	(acfm)	2,066,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Carbon Feed Rate	M	(lb/hr)	248	= If Existing FGD, SCR, and removal is less than 80% then 0 else L*60*(if Baghouse then 2 else 5)/1000000 Based on 2 lb/MMacf for baghouse applications 5 lb/MMacf for ESP applications Flow determined downstream of an air preheater
Carbon Waste Rate	N	(lb/hr)	248	= M
Fly Ash Waste Rate	P	(ton/hr)	20.7	(A*C)* Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Total Waste Rate	Q	(ton/hr)	20.9	Based on no beneficial uses for fly ash with activated carbon without an additional baghouse If J = True or G = True then 0 else P + N/2000
Aux Power	R	(%)	0.05	If J = True then 0.6 else 0 + (0.1*M/A) **Should be used for model input.**
Carbon Cost	S	($/ton)	1500	
Waste Disposal Cost	T	($/ton)	50	
Aux Power Cost	U	($/kWh)	0.06	
Bag Cost	V	($/bag)	60	
Cage Cost	W	($/cage)	30	
Operating Labor Rate	X	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMC ($) = 1,380,000*B*(M^0.15)	$	3,087,000	Base ACI module includes all equipment from unloading to injection
BMB ($) = If J = Not Added then 0, J = 6.0 Air-to-Cloth then 422, J = 4.0 Air-to-Cloth then 476)*B*L^(	$	-	Base module for an additional baghouse including ID or booster fans, piping, ductwork, etc...
BMF ($) = If there is a wet FGD, SCR, and capture is less than 80% then $500,000 else 0	$	-	Base module for wet FGD additive addition (as applicable)
BMA ($) = If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then $1,000,000 else 0	$	-	Base module for coal additive addition (as applicable)
BM ($) = BMC + BMB + BMF + BMA	$	3,087,000	Total Base module cost including retrofit factor
BM ($/KW) =		6	Base module cost per kW
Total Project Cost			
A1 = If baghouse addition then 10% else 5% of BM	$	154,000	Engineering and Construction Management costs
A2 = 5% of BM	$	154,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	154,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	$	3,549,000	Capital, engineering and construction cost subtotal
CECC ($/kW) =		7	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	177,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = If baghouse addition then 6% else 0% of (CECC + B1)	$	-	AFUDC For ACI system only: 0% for less than 1 year engineering and construction cycle For additional baghouse: 6% for a 2 year engineering and construction cycle
C2 = If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 2500*A else 0	$	-	One time coal additive royalty fee (as applicable)
TPC ($) = CECC + B1 + B2 + C2	$	3,726,000	Total project cost
TPC ($/kW) =		7	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW-yr) = (0 additional operators)*2080*X/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW-yr) = BM*0.005/(B*A*1000)	$	0.03	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW-yr) = FOMO + FOMM + FOMA	$	0.03	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*S/(2000*A)	$	0.37	Variable O&M costs for carbon sorbent
VOMW ($/MWh) = Q*T/A	$	2.09	Variable O&M costs for waste disposal that includes the carbon and the fly ash waste as applicable
VOMB ($/MWh) = If J = Not Added then 0, J = 6.0 Air-to-Cloth then 0.004, J = 4.0 Air-to-Cloth then 0.005) (V/3+W/5)	$	-	Variable O&M costs for bags and cages
VOMF ($/MWh) = If there is a wet FGD, SCR, and capture is less than 80% then 110/A else 0	$	-	Variable O&M costs for wet FGD additive addition
VOMA ($/MWh) = If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 250/A else 0	$	-	Variable O&M costs for coal additive addition
VOM ($/MWh) = VOMR + VOMW + VOMB + VOMF + VOMC	$	2.46	

Table 5. Example Complete Cost Estimate for an ACI System with an Additional Baghouse (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Existing FGD System	E		Wet FGD	<--- User Input
Existing SCR	F		TRUE	<--- User Input (Activated carbon may not be required. Co-benefit of SCR and FGD system should achieve 80% removal.)
Removal Less Than 80%?	G		FALSE	<--- User Input
Existing PM Control	H		ESP	<--- User Input
Baghouse Addition	J		6.0 Air-to-Cloth	<--- User Input for retrofit of an additional baghouse after the existing PM control.
Heat Input	K	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	L	(acfm)	2,068,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Carbon Feed Rate	M	(lb/hr)	248	= If Existing FGD, SCR, and removal is less than 80% then 0 else L*60*(if Baghouse then 2 else 5)/1000000 Based on 2 lb/MMacf for baghouse applications 5 lb/MMacf for ESP applications Flow determined downstream of an air preheater
Carbon Waste Rate	N	(lb/hr)	248	= M
Fly Ash Waste Rate	P	(ton/hr)	20.7	(A*C)* Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Total Waste Rate	Q	(ton/hr)	0.1	Based on no beneficial uses for fly ash with activated carbon without an additional baghouse: If J = True or G = True then 0 else P + N/2000
Aux Power	R	(%)	0.65	If J = True then 0.6 else 0 + (0.1*M/A) **Should be used for model input.**
Carbon Cost	S	($/ton)	1500	
Waste Disposal Cost	T	($/ton)	50	
Aux Power Cost	U	($/kWh)	0.06	
Bag Cost	V	($/bag)	80	
Cage Cost	W	($/cage)	30	
Operating Labor Rate	X	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMC ($) =	1,380,000*B*(M^0.15)	$	3,087,000	Base ACI module includes all equipment from unloading to injection
BMB ($) =	if(J = Not Added then 0, J = 6.0 Air-to-Cloth then 422, J = 4.0 Air-to-Cloth then 476)*B*L^(	$	55,080,000	Base module for an additional baghouse including: ID or booster fans, piping, ductwork, etc...
BMF ($) =	If there is a wet FGD, SCR, and capture is less than 80% then $500,000 else 0	$	-	Base module for wet FGD additive addition (as applicable)
BMA ($) =	If there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then $1,000,000 else 0	$	-	Base module for coal additive addition (as applicable)
BM ($) =	BMC + BMB + BMF + BMA	$	58,167,000	Total Base module cost including retrofit factor
BM ($/KW) =			116	Base module cost per kW
Total Project Cost				
A1 = if baghouse addition then 10% else 5% of BM		$	5,817,000	Engineering and Construction Management costs
A2 = 5% of BM		$	2,908,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$	2,908,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	**69,800,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =			140	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	3,490,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = if baghouse addition then 6% else 0% of CECC + B1		$	4,397,000	AFUDC For ACI system only: 0% for less than 1 year engineering and construction cycle For additional baghouse: 6% for a 2 year engineering and construction cycle
C2 = if there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 2500*A else 0		$	-	One time coal additive royalty fee (as applicable)
TPC ($) = CECC + B1 + B2 + C2		$	**77,687,000**	Total project cost
TPC ($/kW) =			155	Total project cost per kW
Fixed O&M Cost				
FOMO ($/kW-yr) = (0 additional operators)*2080*X/(A*1000)		$	-	Fixed O&M additional operating labor costs
FOMM ($/kW-yr) = BM*0.005/(B*A*1000)		$	0.58	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr) = 0.03*(FOMO+0.4*FOMM)		$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW-yr) = FOMO + FOMM + FOMA		$	0.59	Total Fixed O&M costs
Variable O&M Cost				
VOMR ($/MWh) = M*S/(2000*A)		$	0.37	Variable O&M costs for carbon sorbent
VOMW ($/MWh) = Q*T/A		$	0.01	Variable O&M costs for waste disposal that includes the carbon and the fly ash waste as applicable
VOMB ($/MWh) = if(J = Not Added then 0, J = 6.0 Air-to-Cloth then 0.004, J = 4.0 Air-to-Cloth then 0.005) *(V/3+W/5)		$	0.12	Variable O&M costs for bags and cages.
VOMF ($/MWh) = If there is a wet FGD, SCR, and capture is less than 80% then 115/A else 0		$	-	Variable O&M costs for wet FGD additive addition
VOMA ($/MWh) = if there is an FGD, SCR, the coal is PRB or Lignite, and captures is less than 80% then 290/A else 0		$	-	Variable O&M costs for coal additive addition
VOM ($/MWh) = VOMR + VOMW + VOMB + VOMF + VOMC		$	0.50	

Appendix 5-4 Example Cost Calculation Worksheet for Dry Sorbent Injection (DSI) for HCl (and SO_2) Emissions Control in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

Complete Dry Sorbent Injection Cost Development Methodology – Final

Table 1. Example Complete Cost Estimate for a DSI System

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0287*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.93	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Costs are all based on 2010 dollars

Capital Cost Calculation	Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona if(M<25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona if(M<25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	$	16,615,000	Base DSI module includes all equipment from unloading to injection
BM ($/KW) =		33	Base module cost per kW
Total Project Cost			
A1 = 5% of BM	$	831,000	Engineering and Construction Management costs
A2 = 5% of BM	$	831,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	831,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**19,108,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	955,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**20,063,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**20,063,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW

Complete Dry Sorbent Injection Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<-- User Input
Retrofit Factor	B		1	<-- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<-- User Input
SO2 Rate	D	(lb/MMBtu)	2	<-- User Input
Type of Coal	E		Bituminous	<-- User Input
Particulate Capture	F		ESP	<-- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Costs are all based on 2010 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1 additional operator)*2080*U/(A*1000)	$	0.25	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.33	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.59**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = M*R/A	$	4.74	Variable O&M costs for trona reagent
VOMW ($/MWh) = (N+P)*S/A	$	3.18	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste
VOMP ($/MWh) = Q*T*10	$	-	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**7.92**	

Appendix 5-5 Example Cost Calculation Worksheets for Fabric Filters (A/C Ratio = 4.0 and A/C Ratio = 6.0) in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

Table 1. Example Complete Cost Estimate for a 4.0 A/C Baghouse Installation (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Baghouse Air-to-Cloth Ratio	E		4.0 A/C Ratio	<--- User Input
Heat Input	F	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	G	(acfm)	2,068,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Aux Power	H	(%)	0.60	0.6 default value **Should be used for model input.**
Aux Power Cost	J	($/kWh)	0.06	
Bag Cost	K	($/bag)	80	
Cage Cost	L	($/cage)	30	
Operating Labor Rate	M	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = if(E = 6.0 Air-to-Cloth then 422, E = 4.0 Air-to-Cloth then 476)*B*G^0.81	$	62,128,000	Base module for an additional baghouse including: ID or booster fans, piping, ductwork, etc...
BM ($/KW) =		124	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	6,213,000	Engineering and Construction Management costs
A2 = 5% of BM	$	3,106,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	3,106,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	**$**	**74,553,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**149**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	3,728,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1	$	4,697,000	AFUDC for baghouse: 6% for a 2 year engineering and construction cycle
TPC ($) = CECC + B1 + B2 + C1 + C2	**$**	**82,978,000**	Total project cost
TPC ($/kW) =		**166**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (0 additional operators)*2080*M/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.005/(B*A*1000)	$	0.62	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.63**	Total Fixed O&M costs
Variable O&M Cost			
VOMB ($/MWh) = if(E = 6.0 Air-to-Cloth then 0.004, E = 4.0 Air-to-Cloth then 0.005)*(K/3+L/9)	$	0.15	Variable O&M costs for bags and cages.
VOM ($/MWh) = VOMB	**$**	**0.15**	

Table 2. Example Complete Cost Estimate for a 6.0 A/C Baghouse Installation (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Baghouse Air-to-Cloth Ratio	E		6.0 A/C Ratio	<--- User Input
Heat Input	F	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	G	(acfm)	2,066,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Aux Power	**H**	**(%)**	**0.60**	0.6 default value **Should be used for model input.**
Aux Power Cost	J	($/kWh)	0.06	
Bag Cost	K	($/bag)	80	
Cage Cost	L	($/cage)	30	
Operating Labor Rate	M	($/hr)	60	Labor cost including all benefits

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = if(E = 6.0 Air-to-Cloth then 422, E = 4.0 Air-to-Cloth then 476)*B*G^0.81	$	55,080,000	Base module for an additional baghouse including: ID or booster fans, piping, ductwork, etc...
BM ($/KW) =		110	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	5,508,000	Engineering and Construction Management costs
A2 = 5% of BM	$	2,754,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	2,754,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	**$**	**66,096,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**132**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	3,305,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1	$	4,164,000	AFUDC for baghouse: 6% for a 2 year engineering and construction cycle
TPC ($) = CECC + B1 + B2 + C1 + C2	**$**	**73,565,000**	Total project cost
TPC ($/kW) =		**147**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (0 additional operators)*2080*M/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.005/(B*A*1000)	$	0.55	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.56**	Total Fixed O&M costs
Variable O&M Cost			
VOMB ($/MWh) = if(E = 6.0 Air-to-Cloth then 0.004, E = 4.0 Air-to-Cloth then 0.005)*(K/3+L/9)	$	0.12	Variable O&M costs for bags and cages.
VOM ($/MWh) = VOMB	**$**	**0.12**	

Documentation Supplement to Chapter 9 ("Coal")
To allow HCl emissions to be modeled, the chlorine content of the coal offered to electric generating units in EPA Base Case v4.10_PTox had to be represented in the model. This involved adding data on coal chlorine content and then re-running the clustering set-up procedure, which makes the coal quality data usable in the model. The following discussion will refer to the HCl emission rate (in lbs/MMBtu) of the coal and the chlorine content of the coal interchangeably. The HCl emission rate is obtained by multiplying the chlorine content of the coal by a factor of 1.03. This is an alternate way of expressing chlorine content and is consistent with using an SO_2 emission rate (in lbs/MMBtu) to express the sulfur content of the coal.

For EPA Base Case v4.10 the clustering procedure was performed on SO_2 and mercury data only. For Base Case v4.10_PTox it had to be performed jointly on the SO_2, mercury, and HCl data. The addition of HCl data and the consequent re-clustering are reflected in complete updates of Tables 9-5 through 9-9 and the addition of a new table for HCl equivalent to Tables 9-6 through 9-9. These tables show the SO_2, mercury, ash, HCl, and CO_2 emission factors that result after the clustering procedure is performed.

The enhancements made to accommodate the HCl data in the model are documented below in the form of a mark-up of sections 9.1.3 ("Coal Quality Characteristics") and 9.1.4 ("Emission Factors") of the v4.10 documentation report "Documentation for EPA Base Case v4.10 Using the Integrated Planning Model" (August 2010). Substantive changes to the original text are shown in red, boldface italics. Revised Tables 9-5 through 9-9 and the new HCl emission factor Table 9-10 are shown without special highlighting.

Note: For EPA Base Case v4.10_PTox the only coal assumptions and procedures which changed are those presented in sections 9.1.3 and 9.1.4 below. The other unchanged sections of Chapter 9 can be found at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter9.pdf.

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9 Coal

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9.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content***, HCl content,*** and mercury content among other characteristics. To capture differences in the sulfur and heat content of coal, a two letter "coal grade" nomenclature is used. The first letter indicates the "coal rank" (bituminous, sub-bituminous, or lignite) with their associated heat content ranges (as shown in Table 9-3). The second letter indicates their "sulfur grade," i.e., the SO_2 ranges associated with a given type of coal. (The sulfur grades and associated SO_2 ranges are shown in Table 9-4.)

Table 9-3 Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260 – 13,000	B
Sub-bituminous	> 7,500 – 10,260	S

Lignite	less than 7,500	L

Table 9-4 Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00 – 0.80
B	0.81 – 1.20
D	1.21 – 1.66
E	1.67 – 3.34
G	3.35 – 5.00
H	> 5.00

The assumptions in EPA Base Case v4.10***_PTox*** regarding the heat, ***HCl,*** mercury, SO_2, and ash content of coal are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR)[11]. A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit… with a capacity greater than 25 megawatts electric, as well as accurate information on the total amount of coal burned by each such unit,", and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations. Data regarding the SO_2***, chlorine,*** and ash content of the coal used were obtained along with mercury content.

The 1998-2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, ***chlorine content,*** and other characteristics of coal burned at coal-fired utility units greater than 25 MW.

9.1.4 Emission Factors

To make this data usable in EPA Base Case v4.10***_PTox***, the ICR data points were first grouped by IPM coal grades and IPM coal supply regions. Using the grouped ICR data, the average heat, SO_2, mercury, ***HCl,*** and ash content were calculated for each coal grade/supply region combination. In instances where no data were available for a particular coal grade in a specific supply region, the national average SO_2***, HCl,*** and mercury values for the coal grade were used as the region's values. The resulting values are shown in Table 9-5.

[11] Data from the ICR can be found at www.epa.gov/ttn/atw/combust/utiltox/mercury.html.

Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade in EPA Base Case v4.10_PTox

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	Cluster Number
AL	BB	24.82	1.1	4.2	9.8	0.012	1
	BD	24.00	1.4	7.3	10.8	0.029	6
	BE	23.82	2.7	12.6	10.7	0.028	1
AZ	BB	24.64	1.1	5.3	7.9	0.067	2
CG	BA	21.49	0.7	3.1	7.3	0.040	3
	BB	22.01	0.9	4.1	8.4	0.021	1
CR	BA	25.50	0.7	3.5	7.0	0.027	5
	BD	22.20	1.4	7.0	8.3	0.096	6
CU	BA	23.80	0.7	2.6	6.3	0.007	1
	BB	23.22	0.9	4.0	7.8	0.009	1
	BD	23.21	1.3	3.1	8.1	0.008	1
IL	BE	23.00	2.2	6.5	6.6	0.214	3
	BG	23.01	4.6	6.5	8.1	0.113	2
	BH	22.19	5.6	5.4	9.1	0.103	1
IN	BD	22.62	1.4	3.8	7.4	0.030	5
	BE	23.43	2.3	5.2	8.0	0.037	3
	BG	23.37	4.3	7.2	8.2	0.028	2
	BH	23.41	6.1	7.1	8.6	0.019	2
KE	BA	25.32	0.7	3.0	6.1	0.114	4
	BB	25.79	1.0	4.8	6.4	0.112	5
	BD	25.33	1.4	6.0	7.4	0.087	4
	BE	25.14	2.1	7.9	7.7	0.076	4
	BG	24.09	3.8	12.0	10.2	0.041	3
KS	BG	25.32	4.8	4.1	8.5	0.133	4
KW	BD	24.23	1.6	5.6	6.2	0.281	4
	BE	24.45	2.8	7.1	7.4	0.199	3
	BG	23.93	4.5	6.9	8.0	0.097	2
	BH	22.84	5.7	8.2	10.2	0.054	3
LA	LE	14.09	2.5	7.3	17.1	0.014	2
MD	BB	24.64	1.1	5.3	7.9	0.067	2
	BD	26.32	1.6	7.8	9.5	0.029	6
	BE	24.85	2.8	15.6	11.7	0.072	6
	BG	23.26	3.6	16.6	16.6	0.018	5
ME	LD	13.36	1.4	8.6	11.3	0.019	1
MP	SA	18.90	0.6	4.2	4.0	0.007	1
	SD	17.23	1.5	4.5	10.1	0.006	1
MS	LE	13.19	2.8	12.4	21.5	0.018	1
MT	BB	21.00	1.1	5.3	7.9	0.067	2
ND	LD	13.70	1.5	6.4	10.7	0.012	1
	LE	13.46	2.3	8.3	12.8	0.014	2
NS	BB	26.40	1.1	5.3	7.9	0.067	2
	BD	18.10	1.6	5.5	19.6	0.005	4
	BE	18.10	1.8	8.2	18.8	0.006	4
OH	BB	24.68	1.1	5.7	9.8	0.083	6
	BD	25.55	1.4	6.4	10.3	0.065	4
	BE	25.24	3.1	18.7	7.1	0.075	5
	BG	24.34	4.0	18.5	8.0	0.072	5
	BH	23.92	6.4	13.9	9.1	0.058	4

Table 9-5 (cont'd): Coal Quality Characteristics by Supply Region and Coal Grade in EPA Base Case v4.10_PTox

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	Cluster Number
OK	BE	22.15	2.7	25.8	11.3	0.033	2
PC	BD	25.06	1.4	21.7	49.3	0.066	2
	BE	25.66	2.6	18.0	9.2	0.096	5
	BG	25.33	3.8	21.5	9.6	0.092	1
	BH	23.39	6.3	34.7	13.9	0.149	5
PW	BD	24.26	1.6	11.2	10.0	0.086	3
	BE	26.22	2.5	8.4	5.4	0.091	4
	BG	25.86	3.7	8.6	6.5	0.059	2
TN	BB	24.18	1.1	3.8	10.4	0.084	3
	BD	23.91	1.3	6.3	10.4	0.083	4
	BE	26.75	2.1	8.4	6.5	0.043	4
TX	LD	13.06	1.6	12.0	22.3	0.028	2
	LE	13.22	3.0	14.7	25.6	0.020	1
	LG	12.27	3.9	14.9	25.5	0.036	1
UT	BA	23.68	0.7	4.4	7.4	0.015	2
	BB	23.23	0.9	3.9	8.6	0.016	1
	BD	23.05	1.4	4.4	10.5	0.026	5
	BE	25.06	2.3	9.2	7.4	0.095	4
VA	BA	22.70	0.7	3.5	7.0	0.027	5
	BB	25.97	1.0	4.6	7.0	0.054	5
	BD	25.76	1.4	5.7	8.0	0.028	4
	BE	26.03	2.1	8.4	8.1	0.028	4
WG	BB	21.67	1.1	1.8	5.6	0.005	4
	SD	18.50	1.3	4.3	10.0	0.008	2
WH	SA	17.43	0.6	5.6	5.5	0.012	2
	SB	17.43	0.9	6.4	6.5	0.012	1
WL	SB	17.15	0.9	6.4	6.5	0.012	1
WN	BD	25.01	1.5	10.3	9.2	0.100	3
	BE	25.67	2.5	10.3	7.9	0.092	4
	BG	26.03	4.0	9.3	6.9	0.075	2
	BH	25.15	6.1	8.8	9.6	0.045	3
WS	BA	26.20	0.7	3.5	7.0	0.027	5
	BB	24.73	1.1	5.7	9.2	0.091	6
	BD	24.64	1.3	8.1	9.3	0.098	6
	BE	24.38	1.9	8.8	9.9	0.102	4
	BG	25.64	4.7	7.1	6.4	0.051	2

Next, a clustering algorithm was used to further aggregate the data in EPA Base Case v4.10***_PTox***, for model size management purposes. The clustering analysis was performed on the mercury***, HCl,*** and SO_2 data shown in Table 9-5 using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. (In the following write-up BG coal is used to illustrate how the procedure worked.) First, the number of clusters of mercury***, HCl,*** and SO_2 concentrations for each IPM coal type was determined based on the range in average mercury***, HCl,*** and SO_2 concentrations across all coal supply regions for a specific coal type. ***In EPA Base Case v4.10*** each coal type used either one or two clusters. ***After adding the HCl data in EPA Base Case v4.10_PTox, three coal grades (BB, BD, and BE) were assigned 6 clusters, another three coal grades (BA, BG, and BH) were assigned 5 clusters, four coal grades (SA, SD, LD, LE) were assigned 2 clusters, and two grades (SB, and LG) were assigned one cluster each.***

The total number of clusters for each coal grade was limited to keep the model size and run time within feasible limits. (***Whereas*** three clusters were used for BG coal ***in v4.10, with the addition of HCl as a clustering parameter, five clusters were needed for BG coal in v4.10_PTox***.) Second, for each coal grade the clustering procedure was applied to all the regional SO_2***, HCl,*** and mercury values shown in Table 9-5 for that coal grade. (In the BG coal example there are 11 such regional SO_2***, HCl,*** and mercury values.) Using the SAS cluster procedure, each of the constituent regional values was assigned to a cluster and the cluster average SO_2***, HCl,*** and mercury values were recorded. The resulting values are shown in Tables 9-6, 9-7, ***and Table 9-10.*** (For BG coal the Cluster #1 average SO_2***, HCl,*** and mercury values are ***3.79*** lbs/MMBtu***, 0.092 lbs/MMBtu,*** and ***21.54*** lbs/TBtu respectively. The Cluster #2 average SO_2***, HCl,*** and mercury values are ***4.28*** lbs/MMBtu***, 0.070 lbs/MMBtu,*** and ***7.60*** lbs/TBtu respectively. The Cluster #3 average SO2***, HCl,*** and mercury values are ***3.79*** lbs/MMBtu***, 0.041 lbs/MMBtu,*** and ***11.99*** lbs/TBtu respectively. ***The Cluster #4 average*** SO_2***, HCl, and mercury values are 4.84 lbs/MMBtu, 0.133 lbs/MMBtu, and 4.09 lbs/TBtu respectively. The Cluster #5 average*** SO_2***, HCl, and mercury values are 3.78 lbs/MMBtu, 0.045 lbs/MMBtu, and 17.59 lbs/TBtu respectively.***)

Although not used in determining the clusters, ash and CO_2 values were calculated for each of the clusters. These values are shown in Table 9-8 and Table 9-9. (The CO_2 values were derived from data in the Energy Information Administration's *Annual Energy Outlook* 2009 (AEO 2009), not from data collected in the ICR.)

IPM input files retain the mapping between different coal grade/supply region combinations and the clusters. The mapping can be seen in the last column of Table 9-5 which shows the cluster number associated with the coal grade/supply region combination indicated in the first and second columns of this table. (For BG coal, the SAS cluster procedure mapped supply region ***PC*** into Cluster #1, ***IL, IN, KW, PW,WN and WS*** into Cluster #2, ***KE*** into Cluster #3***, KS into Cluster #4, and MD and OH into Cluster #5.***. See Figure 9-2 for an illustration of this mapping.) Table 9-6 to Table ***9-10*** show the SO_2, mercury, ash, CO_2***, and HCl values*** that are assigned to coal grades and regions based on this cluster mapping. The values shown in Table 9-6 to Table ***9-10*** are used in EPA Base Case v4.10 for calculating emissions.

Table 9-6 SO_2 Emission Factors of Coal Used in EPA Base Case v4.10_PTox

Coal Type by Sulfur Grade	Sulfur Emission Factors (lbs/MMBtu)					
	Cluster #1	Cluster #2	Cluster # 3	Cluster #4	Cluster # 5	Cluster # 6
Low Sulfur Eastern Bituminous (BA)	0.70	0.67	0.72	0.74	0.68	--
Low Sulfur Western Bituminous (BB)	0.95	1.05	1.14	1.13	1.04	1.08
Low Medium Sulfur Bituminous (BD)	1.31	1.42	1.51	1.46	1.41	1.41
Medium Sulfur Bituminous (BE)	2.68	2.68	2.46	2.19	2.82	2.78
High Sulfur Bituminous (BG)	3.79	4.28	3.79	4.84	3.78	--
High Sulfur Bituminous (BH)	5.58	6.15	5.91	6.43	6.29	--
Low Sulfur Subbituminous (SA)	0.62	0.58	--	--	--	--
Low Sulfur Subbituminous (SB)	0.94	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	1.49	1.33	--	--	--	--
Low Medium Sulfur Lignite (LD)	1.46	1.61	--	--	--	--
Medium Sulfur Lignite (LE)	2.88	2.38	--	--	--	--
High Sulfur Lignite (LG)	3.91	--	--	--	--	--

Table 9-7 Mercury Emission Factors of Coal Used in EPA Base Case v4.10_PTox

Coal Type by Sulfur Grade	Mercury Emission Factors (lbs/Tbtu)					
	Cluster #1	Cluster #2	Cluster #3	Cluster #4	Cluster # 5	Cluster # 6
Low Sulfur Eastern Bituminous (BA)	2.55	4.37	3.07	3.01	3.50	--
Low Sulfur Western Bituminous (BB)	4.05	5.27	3.78	1.82	4.70	5.84
Low Medium Sulfur Bituminous (BD)	3.13	21.67	10.76	5.91	4.08	7.54
Medium Sulfur Bituminous (BE)	12.58	25.83	6.28	8.70	18.33	15.62
High Sulfur Bituminous (BG)	21.54	7.60	11.99	4.09	17.59	--
High Sulfur Bituminous (BH)	5.43	7.11	8.49	13.93	34.71	--
Low Sulfur Subbituminous (SA)	4.24	5.61	--	--	--	--
Low Sulfur Subbituminous (SB)	6.44	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	4.53	4.33	--	--	--	--
Low Medium Sulfur Lignite (LD)	7.51	12.00	--	--	--	--
Medium Sulfur Lignite (LE)	13.55	7.81	--	--	--	--
High Sulfur Lignite (LG)	14.88	--	--	--	--	--

Table 9-8 Ash Emission Factors of Coal Used in EPA Base Case v4.10_PTox

Coal Type by Sulfur Grade	Ash Emission Factors (lbs/MMBtu)					
	Cluster #1	Cluster #2	Cluster #3	Cluster #4	Cluster # 5	Cluster # 6
Low Sulfur Eastern Bituminous (BA)	6.31	7.39	7.26	6.09	6.99	--
Low Sulfur Western Bituminous (BB)	8.65	7.86	10.35	5.59	6.69	7.87
Low Medium Sulfur Bituminous (BD)	8.12	49.31	9.61	10.33	8.97	9.49
Medium Sulfur Bituminous (BE)	10.70	11.35	7.34	8.95	8.16	11.71
High Sulfur Bituminous (BG)	9.59	7.35	10.21	8.47	12.30	--
High Sulfur Bituminous (BH)	9.06	8.63	9.91	9.13	13.89	--
Low Sulfur Subbituminous (SA)	3.98	6.50	--	--	--	--
Low Sulfur Subbituminous (SB)	6.50	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	10.13	10.02	--	--	--	--
Low Medium Sulfur Lignite (LD)	11.01	22.33	--	--	--	--
Medium Sulfur Lignite (LE)	23.58	15.00	--	--	--	--
High Sulfur Lignite (LG)	25.51	--	--	--	--	--

Table 9-9 CO_2 Emission Factors of Coal Used in EPA Base Case v4.10_PTox

Coal Type by Sulfur Grade	CO_2 Emission Factors (lbs/MMBtu)					
	Cluster #1	Cluster #2	Cluster #3	Cluster #4	Cluster # 5	Cluster # 6
Low Sulfur Eastern Bituminous (BA)	205.4	205.4	205.4	205.4	205.4	--
Low Sulfur Western Bituminous (BB)	205.8	205.8	205.8	205.8	205.8	205.8
Low Medium Sulfur Bituminous (BD)	206.6	206.6	206.6	206.6	206.6	206.6
Medium Sulfur Bituminous (BE)	206.3	206.3	206.3	206.3	206.3	206.3
High Sulfur Bituminous (BG)	205.2	205.2	205.2	205.2	205.2	--
High Sulfur Bituminous (BH)	205.2	205.2	205.2	205.2	205.2	--
Low Sulfur Subbituminous (SA)	213.1	213.1	--	--	--	--
Low Sulfur Subbituminous (SB)	212.7	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	213.1	213.1	--	--	--	--
Low Medium Sulfur Lignite (LD)	217.0	217.0	--	--	--	--
Medium Sulfur Lignite (LE)	214.8	214.8	--	--	--	--
High Sulfur Lignite (LG)	213.5	--	--	--	--	--

Table 9-10 HCl Emission Factors of Coal Used in EPA Base Case v4.10_PTox

Coal Type by Sulfur Grade	HCl Emission Factors (lbs/MMBtu)					
	Cluster #1	Cluster #2	Cluster #3	Cluster #4	Cluster # 5	Cluster # 6
Low Sulfur Eastern Bituminous (BA)	0.007	0.015	0.040	0.114	0.027	--
Low Sulfur Western Bituminous (BB)	0.015	0.067	0.083	0.005	0.083	0.065
Low Medium Sulfur Bituminous (BD)	0.008	0.066	0.092	0.091	0.028	0.063
Medium Sulfur Bituminous (BE)	0.028	0.033	0.150	0.067	0.085	0.072
High Sulfur Bituminous (BG)	0.092	0.070	0.041	0.133	0.045	--
High Sulfur Bituminous (BH)	0.103	0.019	0.049	0.058	0.148	--
Low Sulfur Subbituminous (SA)	0.007	0.010	--	--	--	--
Low Sulfur Subbituminous (SB)	0.012	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	0.006	0.008	--	--	--	--
Low Medium Sulfur Lignite (LD)	0.016	0.028	--	--	--	--
Medium Sulfur Lignite (LE)	0.019	0.014	--	--	--	--
High Sulfur Lignite (LG)	0.036	--	--	--	--	--

Figure 9-2 Cluster Mapping Example – BG Coal