5. Emission Control Technologies

EPA Base Case v.5.13 includes an update of emission control technology assumptions. EPA contracted with engineering firm Sargent and Lundy to update and add to the retrofit emission control models previously developed for EPA and used in EPA Base Case v.4.10. EPA Base Case v.5.13 thus includes updated assumptions regarding control options for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and particulate matter (PM). These emission control options are listed in Table 5-1. They are available in EPA Base Case v.5.13 for meeting existing and potential federal, regional, and state emission limits. It is important to note that, besides the emission control options shown in Table 5-1 and described in this chapter, EPA Base Case v.5.13 offers other compliance options for meeting emission limits. These include fuel switching, adjustments in the dispatching of electric generating units, and the option to retire a unit.

Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.5.13

SO_2 and HCl Control Technology Options	NO_x Control Technology Options	Mercury Control Technology Options	Particulate Matter Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Activated Carbon Injection (ACI) System	Pulse-Jet Fabric Filter (FF)	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	SO_2 and NO_x Control Technology Removal Co-benefits	Electrostatic Precipitator (ESP) Upgrade Adjustment	Coal-to-Gas Conversion
Dry Sorbent Injection (DSI)	Combustion Controls			Heat Rate Improvement
FGD Upgrade Adjustment				

Detailed reports and example calculation worksheets for Sargent & Lundy retrofit emission control models used by EPA are available in Attachments 5-1 through 5-7 at: www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

5.1 Sulfur Dioxide Control Technologies - Scrubbers

Two commercially available Flue Gas Desulfurization (FGD) “scrubber” technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.5.13: Limestone Forced Oxidation (LSFO) — a wet FGD technology and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Base Casev.5.13 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning certain high sulfur content coals (see Table 5-2).

In EPA Base Case v.5.13 the LSFO and LSD SO_2 emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as “unscrubbed” for modeling purposes in the NEEDS database of existing units which is used in setting up the EPA base case. The scrubber retrofit costs for these units are the same as regular unscrubbed units retrofitting with a scrubber.

Default SO_2 removal rates for wet and dry FGD were based on data reported in EIA 860 (2010). These default removal rates were the average of all SO_2 removal rates for a dry or wet FGD as reported in EIA 860 (2010) for the FGD installation year.

To reduce the incidence of implausibly high, outlier removal rates, units whose reported EIA Form 860 (2010) SO_2 removal rates are higher than the average of the upper quartile of SO_2 removal rates across all scrubbed units are instead assigned the upper quartile average unless the reported EIA 860 rate was recently confirmed by utility comments. One upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter the installation year.

Existing units not reporting FGD removal rates in form EIA 860 (2010) will be assigned the default SO_2 removal rate for a dry or wet FGD for that installation year.

As shown in Table 5-2, for FGD retrofits installed by the model, the assumed SO_2 removal rates will be 96% for wet FGD and 92% for dry FGD. These are the average of the SO_2 removal efficiencies reported in EIA 860 (2008) for dry and wet FGD installed in 2008 or later. These rates have been subjected to numerous reviews from utilities and other stakeholders recently, so they remain unchanged and continue to be used in EPA Base Case v.5.13.

The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions in Base Case v.5.13

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	92% with a floor of 0.08 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-3	Calculated based on characteristics of the unit: See Table 5-3
Heat Rate Penalty		
Cost (2011$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu[1]
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK and WC	BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE

[1] FBC units burning WC and PK fuels are provided with LSD retrofit options

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of 96%. In EPA Base Case v.5.13 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

Sargent and Lundy's updated performance and cost models for wet and dry SO_2 scrubbers are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-1 and 5-2 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Capacity and Heat Rate Penalty: In IPM the amount of electrical power required to operate a retrofit emission control device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. 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 control device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate[24]. 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). In EPA Base Case v.5.13 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations from the Sargent and Lundy models that take into account the rank of coal burned, its uncontrolled SO_2 rate, and the heat rate of the model plant.

Table 5-3 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.5.13 for an illustrative set of generating units with a representative range of capacities and heat rates.

[24] Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100}\right)} - 1 \right) \times 100$$

Table 5-3 Illustrative Scrubber Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)											
					50		100		300		500		700		1000	
Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	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)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO	9,000	-1.50	1.53	2.03	819	23.7	819	23.7	600	11.2	519	8.3	471	7.7	426	6.4
	10,000	-1.67	1.70	2.26	860	24.2	860	24.2	629	11.5	544	8.6	495	8.0	447	6.6
	11,000	-1.84	1.87	2.49	899	24.6	899	24.6	658	11.8	569	8.9	517	8.2	467	6.8
LSD	9,000	-1.18	1.20	2.51	854	29.1	701	17.3	513	8.6	444	6.5	422	5.7	422	5.3
	10,000	-1.32	1.33	2.79	894	29.6	734	17.7	538	8.9	465	6.8	442	5.9	442	5.5
	11,000	-1.45	1.47	3.07	933	30.0	766	18.0	561	9.1	485	7.0	461	6.1	461	5.7

Note: The above cost estimates assume a boiler burning 3 lb/MMBtu SO_2 Content Bituminous Coal for LSFO and 2 lb/MMBtu SO_2 Content Bituminous Coal for LSD.

5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.5.13 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.5.13 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.5.13 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Attachment 3-1. The EPA Base Case v.5.13 cost assumptions for NO_x Combustion Controls are summarized in Table 5-4. Table 3-11 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.5.13 when units under certain conditions are assumed to achieve a state-of-the-art combustion control configuration.

Table 5-4 Cost (2011$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	48	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	65	0.5	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	26	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	41	0.3	0.03
Vertically-Fired	NO_x Combustion Control	31	0.2	0.06

Scaling Factor

The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost.

LNB without OFA & LNB with OFA = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$

LNC1, LNC2, and LNC3 = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$

Vertically-Fired = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.553}$

where ($/kW for 300 MW Unit) is a value from the above table and X is the capacity (in MW) of the unit taking on combustion controls.

5.2.2 Post-combustion NO_x Controls

The EPA Base Case v.5.13 includes two post-combustion retrofit NO_x control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.5.13 oil/gas steam units are eligible for SCR only. NO_x reduction in a SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N_2) and water (H_2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically urea or ammonia, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher than SNCR costs.

Table 5-5 summarizes the performance and applicability assumptions in EPA Base Case v.5.13 for each post-combustion NO_x control technology and provides a cross-reference to information on cost assumptions.

Table 5-5 Summary of Retrofit NO_x Emission Control Performance Assumptions

Control Performance Assumptions	**Selective Catalytic Reduction (SCR)**		**Selective Non-Catalytic Reduction (SNCR)**
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90%	80%	Pulverized Coal: 25% Fluidized Bed: 50%
Rate Floor	Bituminous: 0.07 lb/MMBtu Subbituminous and Lignite: 0.05 lb/MMBtu	--	Pulverized Coal: 0.1 lb/MMBtu Fluidized Bed: 0.08 lb/MMBtu
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Pulverized Coal: Units ≥ 25 MW and ≤ 100 MW Fluidized Bed: Units ≥ 25 MW
Costs (2011$)	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13	See Table 5-7	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

5.2.3 Methodology for Obtaining SCR Costs for Coal

Sargent and Lundy's updated performance/cost models for SCR and SNCR technologies are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-3 and 5-4 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Table 5-6 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities and heat rates.

Table 5-6 Illustrative Post-combustion NO_x Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

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)
SCR	9,000	-0.54	0.54	1.23	321	1.76	263	0.76	243	0.64	232	0.58	222	0.53
	10,000	-0.56	0.56	1.32	349	1.86	287	0.81	266	0.69	255	0.63	244	0.57
	11,000	-0.58	0.59	1.41	377	1.96	311	0.87	289	0.73	277	0.67	265	0.62
SNCR - Tangential	9,000	-0.05	0.78	1.04	55	0.48	30	0.26	22	0.20	18	0.16	15	0.13
	10,000			1.15	56	0.50	30	0.27	23	0.20	19	0.17	15	0.14
	11,000			1.27	57	0.51	31	0.27	23	0.21	19	0.17	16	0.14
SNCR - Fluidized Bed	9,000	-0.05	0.78	1.04	41	0.36	22	0.20	17	0.15	14	0.12	11	0.10
	10,000			1.15	42	0.37	23	0.20	17	0.15	14	0.12	12	0.10
	11,000			1.27	43	0.38	23	0.21	17	0.15	14	0.13	12	0.10

Note: Assumes a boiler burning bituminous coal with an input NO_x rate of 0.5 lbs/MMBtu. The technology is applied to boilers larger than 25 MW.

5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam Units

The cost calculations for SCR described in section 5.2.2 apply to coal units. For SCR on oil/gas steam units the cost calculation procedure shown in Table 5-7 is used in EPA Base Case v.5.13. The scaling factor for capital and fixed O&M costs, described in footnote a, applies to all size units from 25 MW and up.

Table 5-7 Post-Combustion NO_x Controls for Oil/Gas Steam Units in EPA Base Case v.5.13

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Percent Removal
SCR[a]	80	1.16	0.13	80%

Notes:
The "Coefficients" in the table above are multiplied by the terms below to determine costs.
"MW" in the terms below is the unit's capacity in megawatts.
Cost data are adjusted to 2011$ by EPA.

[a] SCR Cost Equations:
SCR Capital Cost and Fixed O&M: $(200/MW)^{0.35}$
The scaling factors shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.

Example for 275 MW unit:
SCR Capital Cost ($/kW) = $80 * (200/275)^{0.35} \approx 71.64$ $/kW
SCR FOM Cost ($/kW-yr) = $1.16 * (200/275)^{0.35} \approx 1.04$ $/kW-yr
SCR VOM Cost ($/MWh) = 0.13 $/MWh

5.2.5 Methodology for Obtaining SNCR Costs

In the Sargent and Lundy's cost update for SNCR a generic NO_x removal efficiency of 25% is assumed. However, the capital, fixed and variable operating and maintenance costs of SNCR on circulating fluidized bed (CFB) units are distinguished from the corresponding costs for other boiler types (e.g. cyclone, and wall fired). As with SCR an air heater modification cost applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater.

5.2.6 SO_2 and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 MW ≤ capacity < 100 MW)

In EPA Base Case v.5.13 coal units with capacities between 25 MW and 100 MW are offered the same SO_2 and NO_x emission control options as larger units. However, for purposes of modeling, the costs of controls for these units are assumed to be equivalent to that of a 100 MW unit for SCR, 50 MW for Dry FGD, and 100 MW for Wet FGD. These assumptions are based on several considerations. First, to achieve economies of scale, several units in this size range are likely to be ducted to share a single common control, so the minimum capacity cost equivalency assumption, though generic, would be technically plausible. Second, single units in this size range that are not grouped to achieve economies of scale are likely to have the option of hybrid multi-pollutant controls currently under development.[25] These hybrid controls achieve cost economies by combining SO_2, NO_x and particulate controls into a single control unit. Singly, the costs of the individual control would be higher for units below 100 MW than for a 100 MW unit, but when combined in the Multi-Pollutant Technologies (MPTs) their costs would be roughly equivalent to the cost of individual controls on a 100 MW unit. While MPTs are not explicitly represented in EPA Base Case v.5.13, single units in the 25-100 MW range that take on combinations of SO_2 and NO_x controls in a model run can be thought of as being retrofitted with an MPT.

[25] See, for example, the Greenidge Multi-Pollutant Control Project, which was part of the U.S. Department of Energy, National Energy Technology Lab's Power Plant Improvement Initiative. A joint effort of CONSOL Energy Inc. AES Greenidge LLC, and Babcock Power Environmental, Inc., the project is described in greater detail at *www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/bib_greenidge.html*.

Illustrative SCR costs for 25-100 MW coal units with a range of heat rates can be found by referring to the 100 MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-6 and illustrative scrubber costs for 25-100 MW coal units with a range of heat rates can be found by referring to the LSFO 100 MW and LSD 50MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-3. The Variable O&M cost component, which applies to units regardless of size, can be found in the fifth column in these tables.

5.3 Biomass Co-firing

Biomass co-firing is provided as a fuel choice for all coal-fired power plants in EPA Base Case v.5.13. However, logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistic considerations arise because it is only economic to transport biomass a limited distance from where it is grown given the low energy density of the fuel. In addition, the extent of storage that can be devoted at a power plant to this relatively low density fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely due to the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the level of co-firing.

In EPA Base Case v.5.13 the limit on biomass co-firing is expressed as the percentage of the facility level power output that is produced from biomass. Based on analysis by EPA's power sector engineering staff, a maximum of 10% of the facility level power output (not to exceed 50 MW) can be fired by biomass in modeling projections. In EPA Base Case v.5.13 "facility level" is defined as the set of generating units which share the same ORIS code[26] in NEEDS v.5.13.

The capital and FOM cost assumptions informing EPA Base Case v.5.13 regarding biomass co-firing are summarized in Table 5-8, developed by EPA's power sector engineering staff and updated to 2011$.[27]

Table 5-8 Biomass Co-firing for Coal Plants

Output From Biomass (MW)	5	10	15	20	25	30	35	40	45	50
Capital Cost (2011$/kW From Biomass)	521	439	396	368	349	333	320	309	301	293
Fixed O&M (2011$/kW-yr)	25.8	17.3	12.5	10.0	8.5	11.8	10.6	9.5	8.6	8.0

In order to economize on model space, instead of designing a biomass co-firing "retrofit" modification for units that would include direct representations of the capital and FOM costs shown in Table 5-8. The

[26] The ORIS plant locator code is a unique identifying number (originally assigned by the Office of Regulatory Information Systems from which the acronym derived). The ORIS code is given to power plants by EIA and remains unchanged ownership changes.

[27] Among the studies consulted in developing these costs were:

(a) Briggs, J. and J. M. Adams, Biomass Combustion Options for Steam Generation, Presented at Power-Gen 97, Dallas, TX, December 9 – 11, 1997.

(b) Grusha, J and S. Woldehanna, K. McCarthy, and G. Heinz, Long Term Results from the First US Low NOx Conversion of a Tangential Lignite Fired Unit, presented at 24th International Technical Conference on Coal & Fuel Systems, Clearwater, FL., March 8 – 11, 1999.

(c) EPRI, Biomass Co-firing: Field Test Results: Summary of Results of the Bailly and Seward Demonstrations, Palo Alto, CA, supported by U.S. Department of Energy Division of Energy Efficiency and Renewable Energy, Washington D.C.; U.S. Department of Energy Division Federal Energy Technology Center, Pittsburgh PA; Northern Indiana Public Service Company, Merrillville, IN; and GPU Generation, Inc., Johnstown, PA: 1999. TR-113903.

(d) Laux S., J. Grusha, and D. Tillman, Co-firing of Biomass and Opportunity Fuels in Low NOx Burners, PowerGen 2000 - Orlando, FL, www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.

(e) Tillman, D. A., Co-firing Biomass for Greenhouse Gas Mitigation, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.

(f) Tillman, D. A. and P. Hus, Blending Opportunity Fuels with Coal for Efficiency and Environmental Benefit, presented at 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9, 2000 capital and FOM costs were implemented by in EPA Base Case v.5.13 as a $/MMBtu biomass fuel cost adder. The discrete costs shown in Table 5-8 are first represented as continuous exponential cost functions showing the FOM and capital costs for all biomass outputs between 0 and 50 MW in size. Then, for every coal generating unit represented in EPA Base Case 5.13, the annual payment to capital for the biomass co-firing capability was derived by multiplying the total capital cost obtained from the capital cost exponential function by a 12.1% capital charge rate for utility-owned units and a 16.47% capital charge rate for merchant units. The resulting value was added to the annual FOM cost obtained from the FOM exponential function to obtain the total annual cost for the biomass co-firing for each generating unit.

Then, the annual amount of fuel (in MMBtus) required for each generating unit was derived by multiplying the size of a unit (in MW) by its heat rate (in Btu/kWh) by its capacity factor (in percent) by 8,760 hours (i.e., the number of hours in a year). Dividing the resulting value by 1000 yielded the annual fuel required by the generating unit in MMBtus. Dividing this number into the previously calculated total annual cost for biomass co-firing capability resulted in the cost of biomass co-firing per MMBtu of biomass combusted. This was represented in IPM as a fuel cost adder incurred when a coal unit co-fires biomass. In this manner, the model's decision process for determining biomass consumption takes into account not just the cost of the biomass fuel, but also the capital and FOM costs associated with biomass co-firing at the units in question.

Chapter 11 discusses factors related to the delivered cost of biomass fuel in EPA Base Case v.5.13.

5.4 Mercury Control Technologies

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of activated carbon injection (ACI), mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from other pollution control technologies, e.g., the SO_2, NO_x, and particulate matter controls. The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 explain the two factors that determine mercury emissions that result from unit configurations lacking ACI under EPA Base Case v.5.13. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Base Case v.5.13. Section 5.4.2 looks at the procedure used to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.4 explains the mercury emission control options that are available under EPA Base Case v.5.13. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case v.5.13 on the mercury content of coal (and the majority of emission modification factors discussed below in Section 5.4.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR).[28] 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 [MWe]), 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.

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

In 2009, EPA collected some additional information regarding mecury through the Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631), however the information collected was not similarly comprehensive and was thus not used to update mercury assumptions in this EPA base case.

The ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable, these data points were first grouped by IPM coal types and IPM coal supply regions. IPM coal types divide bituminous, subbituminous, and lignite coal into different grades based on sulfur content.

Oil, natural gas, and waste fuels: The EPA Base Case v.5.13 also includes assumptions on the mercury content for oil, gas and waste fuels, which were based on data derived from previous EPA analysis of mercury emissions from power plants.[29] Table 5-9 provides a summary of the assumptions on the mercury content for oil, gas and waste fuels included in EPA Base Case v.5.13.

Table 5-9 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.5.13

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00 [a]
Petroleum Coke	2.66 [b]
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:

[a] The values appearing in this table are rounded to two decimal places. The zero value shown for natural gas is based on an EPA study that found a mercury content of 0.000138 lbs/TBtu. Values for geothermal resources represent a range.

[b] A previous computational error in the mercury emission factor for petroleum coke as presented in Table 6-3 of the EPA report titled Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report Including Errata, 3-21-02 was corrected (from 23.18 lbs/TBtu to 2.66 lb/TBtu) based on re-examination of the 1999 ICR data for petroleum coke and implementation of a procedure for flagging and excluding outlier values above the 95 percentile value.

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO_2, NO_x, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_x control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to the inlet) during combustion and flue-gas treatment process is (1-EMF). The EMF varies by the type of coal (bituminous, subbituminous, and lignite) used during the combustion process.

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representative set of coal units. As noted above, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry participants[30] has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbituminous and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This understanding of mercury capture with SCRs is incorporated in EPA Base Case v.5.13 mercury EMFs for unit configurations with SCR and wet scrubbers.

[29] Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.

[30] For a detailed summary of emissions test data see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, February 2005. This report can be found at www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf.

Table 5-10 below provides a summary of EMFs used in EPA Base Case v.5.13. Table 5-11 provides definitions of acronyms for existing controls that appear in

Table 5-16. Table 5-12 provides a key to the burner type designations appearing in

Table 5-16.

Table 5-10 Mercury Emission Modification Factors Used in EPA Base Case v.5.13

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP	No SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP	No SCR	Wet FGD	0.34	0.84	0.56
Cyclone	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FF	SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
Cyclone	Cold Side ESP + FF	No SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FF	No SCR	Wet FGD	0.3	0.3	0.56
Cyclone	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FGC	No SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP + FGC	No SCR	Wet FGD	0.34	0.84	0.56
Cyclone	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.1	0.3	0.56
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Cyclone	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
Cyclone	Fabric Filter	No SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	No SCR	Wet FGD	0.1	0.27	0.56
Cyclone	Fabric Filter	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP	SCR	None	0.9	0.9	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP	No SCR	None	0.9	0.94	1
Cyclone	Hot Side ESP	No SCR	Wet FGD	0.58	0.8	1
Cyclone	Hot Side ESP	No SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
Cyclone	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP + FF	No SCR	None	0.11	0.27	1
Cyclone	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.27	0.56
Cyclone	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP + FGC	No SCR	None	0.9	0.94	1
Cyclone	Hot Side ESP + FGC	No SCR	Wet FGD	0.58	0.8	1
Cyclone	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	No SCR	Wet FGD	0.1	0.7	1
FBC	Cold Side ESP	No SCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
FBC	Cold Side ESP + FF	No SCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
FBC	Fabric Filter	SCR	None	0.11	0.27	1
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
FBC	Fabric Filter	No SCR	None	0.05	0.43	0.43
FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.43	0.43
FBC	Hot Side ESP + FGC	No SCR	None	1	1	1
FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1
FBC	No Control	No SCR	None	1	1	1
PC	Cold Side ESP	SCR	None	0.64	0.97	1
PC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	No SCR	None	0.64	0.97	1
PC	Cold Side ESP	No SCR	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	No SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	No SCR	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	No SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	No SCR	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	SCR	None	0.11	0.27	1
PC	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	No SCR	None	0.11	0.27	1
PC	Fabric Filter	No SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	No SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP	SCR	None	0.9	0.9	1
PC	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	No SCR	None	0.9	0.94	1
PC	Hot Side ESP	No SCR	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	No SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
PC	Hot Side ESP + FF	No SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	No SCR	None	0.9	0.94	1
PC	Hot Side ESP + FGC	No SCR	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	No SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.75	1
PC	No Control	SCR	None	1	1	1
PC	No Control	SCR	Wet FGD	0.1	0.7	1
PC	No Control	SCR	Dry FGD	0.6	0.85	1
PC	No Control	No SCR	None	1	1	1
PC	No Control	No SCR	Wet FGD	0.58	0.7	1
PC	No Control	No SCR	Dry FGD	0.6	0.85	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	SCR	Wet FGD	0.1	0.7	1
PC	PM Scrubber	SCR	Dry FGD	0.6	0.85	1
PC	PM Scrubber	No SCR	None	0.9	0.91	1
PC	PM Scrubber	No SCR	Wet FGD	0.58	0.7	1
PC	PM Scrubber	No SCR	Dry FGD	0.6	0.85	1

Table 5-11 Definition of Acronyms for Existing Controls

Acronym	Description
ESP	Electro Static Precipitator - Cold Side
HESP	Electro Static Precipitator - Hot Side
ESP/O	Electro Static Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

Table 5-12 Key to Burner Type Designations in Table 5-10

"PC" refers to conventional pulverized coal boilers. Typical configurations include wall-fired and tangentially fired boilers (also called T-fired boilers). In wall-fired boilers the burner's coal and air nozzles are mounted on a single wall or opposing walls. In tangentially fired boilers the burner's coal and air nozzles are mounted in each corner of the boiler.

"Cyclone" refers to cyclone boilers where air and crushed coal are injected tangentially into the boiler through a "cyclone burner" and "cyclone barrel" which create a swirling motion allowing smaller coal particles to be burned in suspension and larger coal particles to be captured on the cyclone barrel wall where they are burned in molten slag.

"FBC" refers to "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.

5.4.3 Mercury Control Capabilities

EPA Base Case v.5.13 offers two options for mercury pollution control: (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 v.5.13, 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 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).

Activated Carbon Injection (ACI)

The technology used for mercury control in EPA Base Case v.5.13 is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. Sargent & Lundy's updated cost and performance assumptions for ACI are used.

Three alternative ACI options are represented as capable of providing 90% mercury removal for all possible configurations of boiler, emission controls, and coal types used in the U.S. electric power sector. The three ACI options differ, based on whether they are used in conjunction with an electrostatic precipitator (ESP) or a fabric filter (also called a "baghouse"). The three ACI options are:

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

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 it is contaminated by the mercury.

For modeling purposes, EPA currently assumes that all three configurations use brominated ACI, where a small amount of bromine is chemically bonded to the powdered carbon which is injected into the flue gas stream. EPA recognizes that amended silicates and possibly other non-carbon, non-brominated substances are in development and may become available as alternatives to brominated carbon as a mercury sorbent.

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 5-13 shows the ACI assignment scheme used in EPA Base Case v.5.13 to achieve 90% mercury removal.

Table 5-13 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.5.13

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

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)
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

5.4.4 Methodology for Obtaining ACI Control Costs

Sargent & Lundy's ACI model assumes that 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. Sargent & Lundy 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 5-14 as qualifying for ACI systems with existing ESP. For generating units with fabric filters a lower injection rate of 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.

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, as opposed to a polishing baghouse with a 6.0 A/C ratio[31].

Table 5-14 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 v.5.13. For each ACI option values are shown for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-6 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details on the Sargent & Lundy model of ACI for Hg control.

[31] 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

5.5 Hydrogen Chloride (HCl) Control Technologies

The following sub-sections describe how HCl emissions from coal are represented in IPM for EPA Base Case v.5.13, 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 This data is incorporated into the model in order to provide the capability for EPA Base Case v.5.13 to project HCl emissions. The procedures used for this are presented below.

Western subbituminous coal (such as that mined in the Powder River Basin) and lignite coal contain natural alkalinity in the form of non-glassy calcium oxide (CaO) and other alkaline and alkaline earth oxides. This fly ash (classified as 'Class C' fly ash) has a natural pH of 9 and higher and the natural alkalinity can effectively neutralize much of the HCl in the flue gas stream prior to the primary control device.

Eastern bituminous coals, by contrast, tend to produce fly ash with lower natural alkalinity. Though bituminous fly ash (classified as 'Class F' fly ash) may contain calcium, it tends to be present in a glassy matrix and unavailable for acid-base neutralization reactions.

In order to assess the extent of expected natural neutralization, the 2010 ICR[32] data was examined. According to that data, units burning some of the subbituminous coals without operating acid gas control technology emitted substantially lower HCl emissions than would otherwise be expected from the chlorine content of those coals The data also showed that some other units burning subbituminous or lignite coals with higher levels of Cl were achieving 50-85 % HCl control with only cold-side ESP (i.e., with no flue gas desulfurization or other acid gas control technology). Comparing the Cl content of the subbituminous coals modeled in IPM with the ICR results supports an assumption that combustion of those coals can expect to experience at least 75% natural HCl neutralization from the alkaline fly ash. Therefore, the HCl emissions from combustion of lignite and subbituminous coals are reduced by 75% in EPA Base Case v.5.13.

[32] Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631)

Table 5-14 Illustrative Activated Carbon Injection (ACI) Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M cost (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	-0.10	0.10	2.19	37.89	0.32	14.90	0.13	9.65	0.08	7.25	0.06	5.35	0.04
	10,000	-0.11	0.11	2.43	38.51	0.32	15.14	0.13	9.81	0.08	7.36	0.06	5.44	0.05
Sorbent Injection Rate of 5 lbs/million acfm	11,000	-0.12	0.12	2.68	39.07	0.33	15.35	0.13	9.95	0.08	7.47	0.06	5.52	0.05
ACI System with an Existing Baghouse	9,000	-0.04	0.04	1.57	33.03	0.28	12.98	0.11	8.41	0.07	6.32	0.05	4.66	0.04
	10,000	-0.04	0.04	1.75	33.54	0.28	13.18	0.11	8.54	0.07	6.42	0.05	4.74	0.04
Sorbent Injection Rate of 2 lbs/million acfm	11,000	-0.05	0.05	1.92	34.02	0.29	13.38	0.11	8.66	0.07	6.51	0.06	4.81	0.04
ACI System with an Additional Baghouse	9,000	-0.64	0.64	0.47	291.26	1.02	219.74	0.77	195.35	0.68	181.36	0.63	167.98	0.59
	10,000	-0.64	0.65	0.52	314.32	1.10	238.18	0.83	212.02	0.74	196.97	0.69	182.55	0.64
Sorbent Injection Rate of 2 lbs/million acfm	11,000	-0.65	0.65	0.57	336.91	1.18	256.26	0.90	228.37	0.80	212.28	0.74	196.83	0.69

Note: The above cost estimates assume bituminous coal consumption.

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 5-15. New supercritical pulverized coal units (column 3) that the model builds include FGD (wet or dry) which is assumed to provide a 99% removal rate for HCl. For existing conventional pulverized coal units with pre-existing FGD (column 5), the HCl removal rate is assumed to be 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 assumed to be the same as the SO_2 removal rate up to a maximum of 95%. FBCs with fabric filters are assumed to have an HCl removal rate of 95%.

Table 5-15 HCl Removal Rate Assumptions for Potential (New) and Existing Units in EPA Base Case v.5.13

		Potential (New)	Existing Units with FGD		
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%.

In EPA Base Case v.5.13, coal steam units with existing FGD that do not achieve an SO_2 removal rate of at least 90% are assumed to upgrade their FGDs in order to obtain at least 90% SO_2 removal and 99% HCl removal. The cost of this “FGD Upgrade Adjustment” is assumed to be $100/kW and is considered a sunk cost for modeling purposes.

5.5.3 HCl Retrofit Emission Control Options

The retrofit options for HCl emission control are discussed in detail in the following sub-sections and summarized in

Table 5-16. The scrubber upgrade adjustment was discussed above in 5.5.2.

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 5-16.

Table 5-16 Summary of Retrofit HCl (and SO_2) Emission Control Performance Assumptions in v.5.13

Performance Assumptions	Limestone Forced Oxidation (LSFO)		Lime Spray Dryer (LSD)		Dry Sorbent Injection (DSI)	
	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 0.08 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	70%	90% with a floor of 0.0001 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Excerpt from Table 5-22	
Heat Rate Penalty						
Cost (2011$)						
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 3.0 lbs of SO_2/MMBtu		Coals ≤ 2.0 lbs of SO_2/MMBtu	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK and WC		BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE		BA, BB, BD, SA, SB, SD, and LD	

Dry Sorbent Injection

EPA Base Case v.5.13 includes dry sorbent injection (DSI) 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 compounds that are 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 (sodium sesquicarbonate), 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 5-16. The assumptions shown in the last two columns of

Table 5-16 were derived from assessments by EPA engineering staff in consultation with Sargent & Lundy. As indicated in this table, the assumed SO_2 removal rate for DSI + fabric filter is 70%. The retrofit DSI option on an existing unit with existing ESP is always provided in combination with a fabric filter (Toxecon configuration) in EPA Base Case v.5.13.

Methodology for Obtaining DSI Control Costs: Sargent & Lundy's updated performance/cost model for DSI is used in EPA Base Case v.5.13 to derive the cost of DSI retrofits with two alternative, associated particulate control devices, i.e., ESP and fabric filter "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.

In EPA Base Case v.5.13 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 SO_2 removal rate is 70%. 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.

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 sodium-based DSI may make the fly ash unsalable, which would mean 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.

Table 5-17 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. See Attachment 5-5 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details on the Sargent & Lundy DSI model.

5.6 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option. In EPA Base Case v.5.13, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit, and the cost of these retrofits at plants without an existing fabric filter include the cost of installing a new fabric filter. This cost was added to the DSI costs discussed in section 5.5.3.2. The costs associated with a new fabric filter retrofit are derived from Sargent & Lundy's performance/cost model. Similarly, dry scrubber retrofit costs also include 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: The major driver of fabric filter capital cost is the "air-to-cloth" (A/C) ratio. 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. An air-to-cloth ratio of 4.0 is used in EPA Base Case v.5.13, and it is assumed that the existing ESP remains in place and active.

Table 5-18 presents the capital, VOM, and FOM costs for fabric filters as represented in EPA Base Case v.5.13 for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-7 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details of the Sargent & Lundy fabric filter PM control model.

Table 5-17 Illustrative Dry Sorbent Injection (DSI) Costs for Representative Sizes and Heat Rates under Assumptions in EPA Base Case v.5.13

						Capacity (MW)									
						100		300		500		700		1000	
Control Type	Heat Rate (Btu/kWh)	SO_2 Rate (lb/ MMBtu)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	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	9,000	2.0	-0.64	0.65	8.49	138.5	3.71	63.1	1.38	43.7	0.88	34.4	0.65	31.6	0.52
Assuming	10,000	2.0	-0.71	0.72	9.44	142.8	3.75	65.0	1.40	45.1	0.89	35.1	0.66	35.1	0.55
Bituminous Coal	11,000	2.0	-0.79	0.79	10.39	146.8	3.78	66.9	1.41	46.4	0.90	38.6	0.69	38.6	0.58

Table 5-18 Illustrative Particulate Controls for Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)									
					100		300		500		700		1000	
Coal Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	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)
	9,000	-0.60	0.60	0.05	251	0.9	204	0.7	185	0.6	174	0.6	162	0.6
Bituminous	10,000			0.06	274	1.0	222	0.8	202	0.7	189	0.7	177	0.6
	11,000			0.07	296	1.0	240	0.8	218	0.8	204	0.7	191	0.7

5.6.1 MATS Filterable Particulate Matter (PM) Compliance

EPA Base Case v.5.13 assumes that all coal-fired generating units with a capacity greater than 25 MW will comply with the MATS filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. The control mechanism is not modeled endogenously but supplied as an input when setting up the run as specified below.

Units with existing fabric filters are assumed to be able to meet the filterable PM compliance requirement. For units with existing ESPs the following procedure is used to determine if they already meet the filterable PM requirement, can meet it by one of three possible ESP upgrades, or can only meet it by installing a FF.

First, PM emission rate data derived either from 2005 EIA Form 767 or (where available) from EPA's 2010 Information Collection Request[33] are compared to the applicable filterable PM compliance requirement. If the unit's emission rate is equal to or less than the compliance requirement, adequate controls are assumed already to be in place and no additional upgrade costs are imposed. For units that do not meet the filterable PM compliance requirement, the incremental reduction needed (in lbs/mmBtu) is calculated by subtracting the filterable PM compliance standard from the reported emission rate. Depending on the magnitude of the incremental reduction needed, the unit is assigned one of three ESP upgrade costs (designated ESP1, ESP2, and ESP3) or the cost of a FF installation (designated ESP4), if the required incremental reduction cannot be achieved by an ESP upgrade. Table 5-19 shows the four levels of ESP upgrades (column 1), the key technologies included in each upgrade (column 2), trigger points for the upgrades (column 3), the capital cost of each upgrade (column 4), and the percent increase in collection efficiency provided by the upgrade, differentiated according to the rank (subbituminous, bituminous, or lignite) of coal burned.

The percentage improvements in collection efficiency shown in column 5 in Table 5-19 are additive in the sense that the values shown in this column are added to the pre-upgrade collection efficiency to obtain the after-upgrade collection efficiency.

Table 5-19 Electrostatic Precipitator (ESP) Upgrades as Implemented in EPA Base Case v.5.13 --- Characteristics, Trigger Points, Associated Costs, and Performance Improvements

Upgrade Level	Key Technologies Employed in Upgrade	Trigger Points for ESP Upgrade (Expressed in terms of incremental reduction needed (lbs/mmBtu) to meet the filterable PM Compliance Standard)	Capital Cost	Additive Percent Improvement[e] in Collection Efficiency as a Result of the Upgrade (differentiated by the rank of coal combusted)
1	High Frequency transformer-rectifier (TR) sets	> 0.0 to ≤ 0.005	\$55/kW[a]	0.12 for subbituminous 0.05 for bituminous 0.01 for lignite
2	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height)	> 0.005 to ≤ 0.01	\$80/kW[b]	0.25 for subbituminous 0.10 for bituminous 0.02 for lignite

[33] 2005 EIA Form 767 is the last year where the data was reported in the format of lb/MMBtu, which is compatible with this analysis. Since any changes to facilities since 2005 would likely have improved (reduced) emissions, the use of this data is conservative. More recent 2010 ICR test data is used where available. (Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631).

Upgrade Level	Key Technologies Employed in Upgrade	Trigger Points for ESP Upgrade (Expressed in terms of incremental reduction needed (lbs/mmBtu) to meet the filterable PM Compliance Standard)	Capital Cost	Additive Percent Improvement[e] in Collection Efficiency as a Result of the Upgrade (differentiated by the rank of coal combusted)
3	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height) + Additional field	> 0.01 to ≤ 0.02	\$100/kW[c]	0.50 for subbituminous 0.20 for bituminous 0.05 for lignite
4	Replacement with fabric filter (baghouse)	> 0.02	Use capital cost equations for a fabric filter[d]	(Not Applicable)

[a] Assumes upgrading the specific collection area (SCA) to 250 square-feet/1000 afm (actual feet per minute).
[b] Assumes upgrading the specific collection area (SCA) to 300 square-feet/1000 afm (actual feet per minute).
[c] Assumes upgrading the existing specific collection area (SCA) by 100 square-feet/1000 afm (actual feet per minute), a 20% height increase, and additional field.
[d] The cost equations for fabric filters are described in Section 5.5.4
[e] The percentage improvement due to the ESP upgrade as shown in this column is added to the pre-upgrade collection efficiency to obtain the after-upgrade collection removal efficiency.

Excerpt from Table 5-20 contains a complete listing of coal generating units with either cold- or hot-side ESPs but no fabric filters. For each generating unit in Excerpt from Table 5-20 shows the incremental reductions needed to meet the PM filterable compliance requirement and the corresponding ESP upgrade (if any) assigned to the unit to enable it to meet that requirement. A filterable PM limit of 0.279 lb/mmBtu was used in this analysis. This value is roughly 10% below the limit in the final MATS rule, therefore resulting in a conservative estimate of the need to upgrade existing ESPs.

5.7 Coal-to-Gas Conversions[34]

In EPA Base Case v.5.13 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 pipeline. These two components of cost and their associated performance implications are discussed in the following sections.

5.7.1 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, reheaters, economizers, and recirculating fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

[34] 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

Excerpt from Table 5-20 ESP Upgrade Provided to Existing Units without Fabric Filters so that They Meet Their Filterable PM Compliance Requirement

This is a small excerpt of the data in Excerpt from Table 5-20. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html)

Plant Name	Unit ID	State Name	Unique ID	Capacity (MW)	Level of ESP Upgrade Required to Meet Filterable PM Requirement
A B Brown	2	Indiana	6137_B_2	245	---
AES Beaver Valley Partners Beaver Valley	2	Pennsylvania	10676_B_2	43	ESP-4
AES Beaver Valley Partners Beaver Valley	3	Pennsylvania	10676_B_3	43	ESP-4
AES Beaver Valley Partners Beaver Valley	4	Pennsylvania	10676_B_4	43	ESP-1
AES Cayuga	1	New York	2535_B_1	150	---
AES Cayuga	2	New York	2535_B_2	151	---
AES Deepwater	AAB001	Texas	10670_B_AAB001	139	---
AES Somerset LLC	1	New York	6082_B_1	681	---
Allen Steam Plant	1	Tennessee	3393_B_1	245	---
Allen Steam Plant	2	Tennessee	3393_B_2	245	---
Allen Steam Plant	3	Tennessee	3393_B_3	245	---
Alma	B4	Wisconsin	4140_B_B4	51	---
Alma	B5	Wisconsin	4140_B_B5	77	ESP-4
Ames Electric Services Power Plant	7	Iowa	1122_B_7	33	---
Ames Electric Services Power Plant	8	Iowa	1122_B_8	70	---
Apache Station	2	Arizona	160_B_2	175	---
Apache Station	3	Arizona	160_B_3	175	---
Asbury	1	Missouri	2076_B_1	213	ESP-4
Asheville	1	North Carolina	2706_B_1	191	---
Asheville	2	North Carolina	2706_B_2	185	---

The following table summarizes the cost and performance assumptions for coal-to-gas boiler modifications as incorporated in EPA Base Case v.5.13. The values in the table were developed by EPA's engineering staff based on technical papers[35] and discussions with industry engineers familiar with such projects. They were designed to be applicable across the existing coal fleet.

Table 5-21 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.

[35] 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).

Factor	Description	Notes
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 = 267*(75/MW)^0.35 Cyclone units: $/kW = 374*(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 = 267*(75/50)^0.35 = 308
Incremental Fixed O&M:	-33% of the FOM cost of the existing coal unit	Due to reduced needs for operators, maintenance materials, and maintenance staff when natural gas combusted, FOM costs decrease by 33%.
Incremental Variable O&M:	-25% of the VOM cost of the existing coal unit	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 location to the natural gas transmission pipeline. See section 5.7.2.
NO_x emission rate:	50% of existing coal unit NO_x emission rate, with a floor of 0.05 lbs/MMBtu	The 0.05 lbs/MMBtu floor is the same as the NO_x rate floor for new retrofit SCR on units burning subbituminous coal
SO_2 emissions:	Zero	

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

For every individual coal boiler in the U.S., EPA tasked ICF 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[36].
- 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.

[36] 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.

- 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

Mainline Flow Capacity, Qm (million cubic feet per day)

$Qm = 0.06745 * d^{2.667}$, where d is the diameter of the mainline in inches

Required Capacity of Lateral/s for Each Boiler, Ql (million cubic feet per day)

Ql = (Boiler Capacity * Heat Rate *24) / 1,030,000, where Boiler Capacity is in MW and the Heat Rate is in Btu/kWh

Diameter of Each Lateral, D (inches)

$D = (14.83 * Ql)^{0.37495}$, where each lateral's capacity may not exceed 10% of the mainline capacity to which the lateral connects

Cost per Lateral, C ($)

C = 90,000 *D * Number of Miles

Note: The above calculations assume a pipeline cost of $90,000 per inch-mile based on recently completed projects.

There are several points to note about the above 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). Excerpt from Table 5-22 shows the pipeline costing results for each qualifying existing coal fired unit represented in EPA Base Case v.5.13.

Figure 5-2 Number of Laterals Required per Boiler

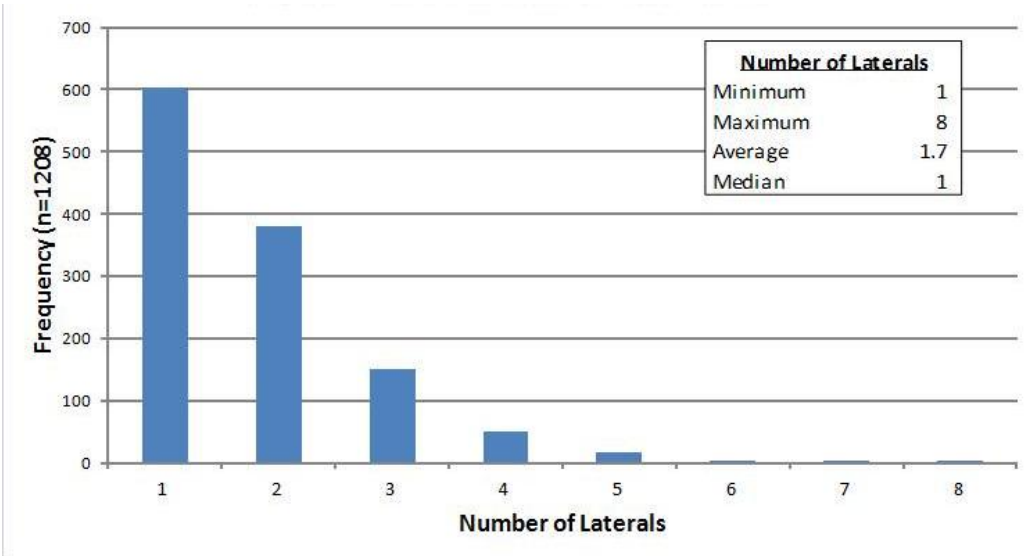


Figure 5-3 Miles of Pipeline Required per Boiler

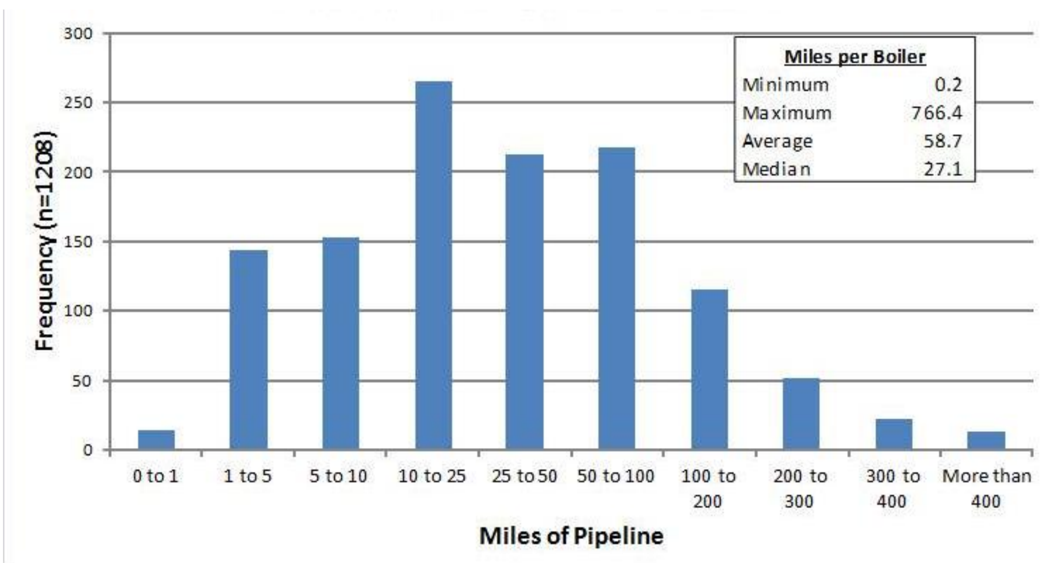


Figure 5-4 Diameter of Laterals

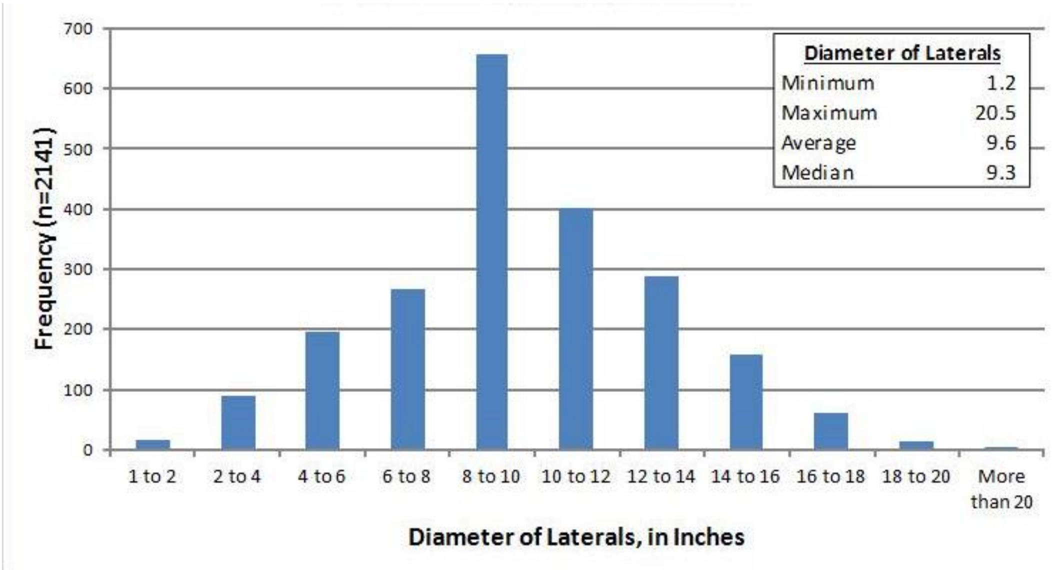


Figure 5-5 Total Inch-Miles of Laterals Required per Boiler

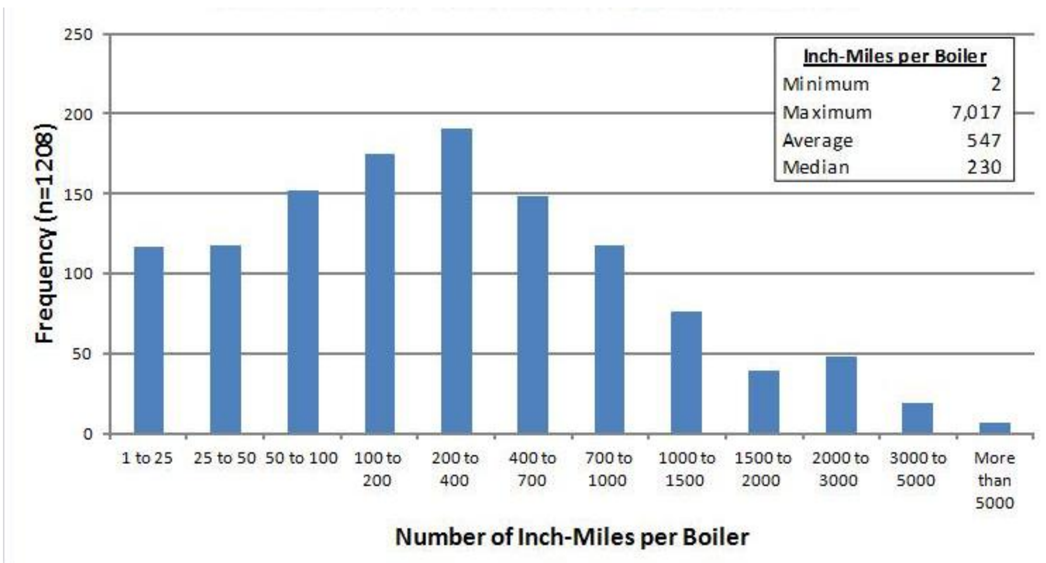


Figure 5-6 Total Cost to Each Boiler

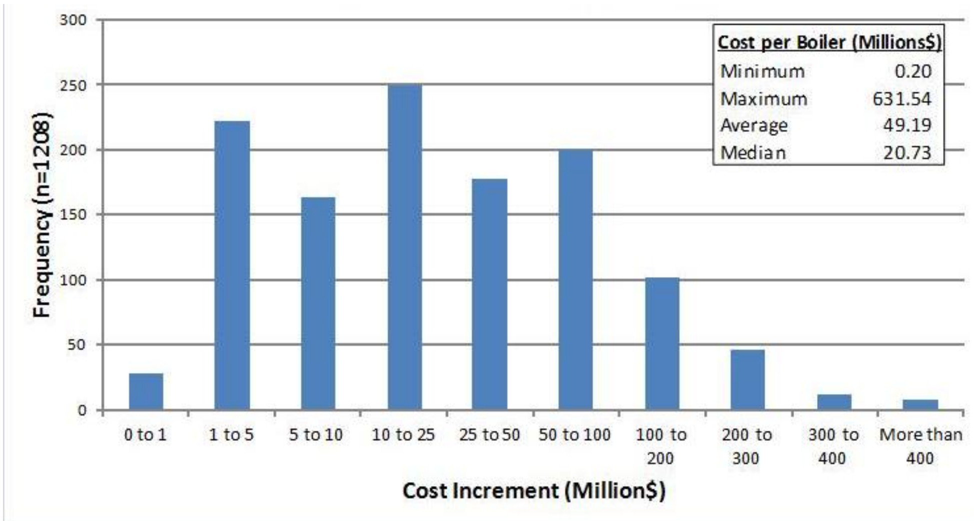
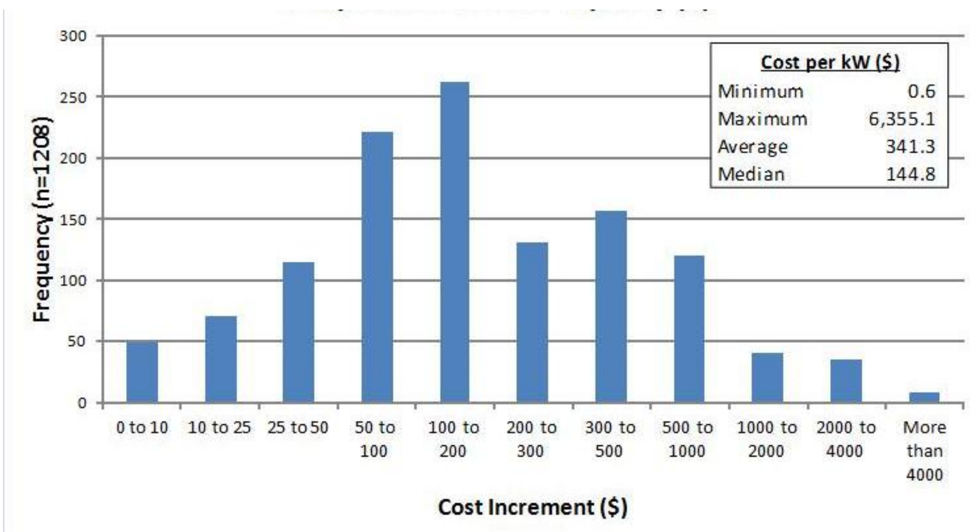


Figure 5-7 Cost per kW of Boiler Capacity



Excerpt from Table 5-22 Cost of Building Pipelines to Coal Plants

This is a small excerpt of the data in Table-22. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

Unique ID	Plant Name	State Name	Coal Boiler Capacity (MW)	Number of Laterals Required	Miles of New Pipeline Required to Hook Up Unit (miles)	Cost of New Pipeline (2011$)	Cost of New Pipeline per KW of Coal Capacity (2011$/kW)
3_B_1	Barry	Alabama	138	2	8.5	2324786	16.85
3_B_2	Barry	Alabama	137	2	8.5	2136794	15.60
3_B_3	Barry	Alabama	249	2	8.5	7209727	28.95
3_B_4	Barry	Alabama	362	2	8.5	8979092	24.80
3_B_5	Barry	Alabama	726	2	8.5	12412831	17.10
7_G_1	Gadsden	Alabama	64	1	28.7	22383509	349.74
7_G_2	Gadsden	Alabama	66	1	28.7	22617875	342.70
8_B_10	Gorgas	Alabama	703	2	68.4	87979597	125.15
8_B_6	Gorgas	Alabama	103	1	7.6	6250679	60.69
8_B_7	Gorgas	Alabama	104	1	7.6	6269532	60.28
8_B_8	Gorgas	Alabama	161	1	7.6	7407093	46.01
8_B_9	Gorgas	Alabama	170	1	7.6	7533473	44.31
10_B_1	Greene County	Alabama	254	1	6.9	7898586	31.10
10_B_2	Greene County	Alabama	243	1	6.9	7776757	32.00
26_B_1	E C Gaston	Alabama	254	1	23.0	26126943	102.86
26_B_2	E C Gaston	Alabama	256	1	23.0	26294370	102.71
26_B_3	E C Gaston	Alabama	254	1	23.0	26143766	102.93
26_B_4	E C Gaston	Alabama	256	1	23.0	26143766	102.12
26_B_5	E C Gaston	Alabama	842	3	162.4	201898208	239.78
47_B_1	Colbert	Alabama	178	1	0.7	725276	4.07
47_B_2	Colbert	Alabama	178	1	0.7	722785	4.06
47_B_3	Colbert	Alabama	178	1	0.7	722785	4.06
47_B_4	Colbert	Alabama	178	1	0.7	723409	4.06
47_B_5	Colbert	Alabama	472	2	4.6	5183155	10.98
50_B_7	Widows Creek	Alabama	473	3	253.0	231385577	489.19
50_B_8	Widows Creek	Alabama	465	3	253.0	227553333	489.36
51_B_1	Dolet Hills	Louisiana	638	4	28.3	28812871	45.16
56_B_1	Charles R Lowman	Alabama	80	1	17.3	13132673	164.16
56_B_2	Charles R Lowman	Alabama	235	2	43.8	38349442	163.19
56_B_3	Charles R Lowman	Alabama	235	2	43.8	38128365	162.25
59_B_1	Platte	Nebraska	100	1	25.8	21561000	215.61
60_B_1	Whelan Energy Center	Nebraska	77	1	8.1	6169545	80.12
60_B_2	Whelan Energy Center	Nebraska	220	1	8.1	9036600	41.08
87_B_1	Escalante	New Mexico	247	2	11.4	7831404	31.71
108_B_SGU1	Holcomb	Kansas	362	5	77.1	43429164	119.97
113_B_1	Cholla	Arizona	116	1	27.5	23648324	203.86
113_B_2	Cholla	Arizona	260	1	27.5	32391059	124.58
113_B_3	Cholla	Arizona	271	1	27.5	32691880	120.63

5.8 Natural Gas Co-firing

Existing coal plants with existing natural gas pipelines have an option of co-firing with natural gas. Gas co-firing at these units is limited to 10% of the unit's power output.

The option of co-firing with gas at an existing coal boiler is only offered if one of the following two criteria based on 2012 EIA 860, 2012 EIAForm 923 and NEEDS v.5.13 is met: (1) the unit reported the use of gas as a startup fuel, or (2) an existing gas-fired unit (e.g., NGCC) is located at the same facility (with the same ORIS) as the coal-fired unit. EPA assumes that in either of these cases, sufficient pipeline capacity exists to supply up to 10% of total power output of the coal steam boiler located at these sites. These units are detailed below in Excerpt from Table 5-23.

Similar to the coal-to-gas retrofit option, there is a 5% increase in heat rate for the share of generation fueled by natural gas (accounting for the increased flue gas moisture and stack heat loss). On a $/kWh basis, any change in capital or operating costs of co-firing with natural gas at low levels is very small. Hence, EPA do not include additional capital or operating costs for this option.

Excerpt from Table 5-23 List of Coal Steam Units with Natural Gas Co-firing option

This is a small excerpt of the data in Excerpt from Table 5-23. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

UniqueID	Plant Name	ORIS Code	State Name	Capacity (MW)
10684_G_TG5	Argus Cogen Plant	10684	California	7
1077_G_3	Sutherland	1077	Iowa	78
1554_G_2	Herbert A Wagner	1554	Maryland	135
2943_G_3	Shelby Municipal Light Plant	2943	Ohio	5
511_G_1	Trinidad	511	Colorado	3.8
54407_G_1	Waupun Correctional Central Heating Plt	54407	Wisconsin	0.2
54407_G_2	Waupun Correctional Central Heating Plt	54407	Wisconsin	0.5
56564_G_1	John W Turk Jr Power Plant	56564	Arkansas	609
56785_G_WG01	Virginia Tech Power Plant	56785	Virginia	2.5
7_G_1	Gadsden	7	Alabama	64
7_G_2	Gadsden	7	Alabama	66
728_G_4	Yates	728	Georgia	133
728_G_5	Yates	728	Georgia	135
10_B_1	Greene County	10	Alabama	254
10_B_2	Greene County	10	Alabama	243