5 Emission Control Technologies

EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission controls. In addition to the work by Sargent and Lundy, Base Case v.4.10 includes two Activated Carbon Injections (ACI) options (Standard and Modified) for mercury (Hg) control[27]. Capture and storage options for carbon dioxide (CO_2) have also been added in the new base case.

These emission control options are listed in Table 5-1. They are available in EPA Base Case v.4.10 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.4.10 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.4.10

SO_2 Control Technology Options	NO_X Control Technology Options	Hg Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System	
	Combustion Controls	SO_2 and NO_X Control Technology Removal Cobenefits	

5.1 Sulfur Dioxide Control Technologies

Two commercially available Flue Gas Desulfurization (FGD) technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.4.10: 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 3lb 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.4.10 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning BG, BH, and LG coals due to their high sulfur content.

In EPA Base Case v.4.10 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

[27]The mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA’s 2010 Information Collection Request (ICR).

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. Scrubber efficiencies for existing units were derived from data reported in EIA Form 767. In transferring this data for use in EPA Base Case v.4.10 the following changes were made. The maximum removal efficiency was set at 98% for wet scrubbers and 93% for dry scrubber units. Existing units reporting efficiencies above these levels in Form 767 were assigned the maximum removal efficiency in NEEDS v.4.10 indicated in the previous sentence.

As shown in Table 5-2, existing units that are selected to be retrofitted by the model with scrubbers are given the maximum removal efficiencies of 98% for LSFO and 93% for LSD. 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

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	98% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-4 for examples	Calculated based on characteristics of the unit: See Table 5-4 for examples
Heat Rate Penalty		
Cost (2007$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG	BA, BB, BD, BE, SA, SB, SD, LD, and LE

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of 98% for LSFO and 93% for LSD. In EPA Base Case v.4.10 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

The Sargent and Lundy update of SO_2 and NO_x control costs is notable on several counts. First, it brought costs up to levels seen in the marketplace in 2009. Incorporating these costs into EPA's base case carries an implicit assumption, not universally accepted, that the run up in costs seen over the preceding 5 years and largely attributed to international competition, is permanent and will not settle back to pre-2009 levels. Second, a revised methodology, based on Sargent and Lundy's expert experience, was used to build up the capital, fixed and variable operating and maintenance components of cost. That methodology, which employed an engineering build up of each component of cost, is described here and in the following sections. Detailed example cost calculation spreadsheets for both SO_2 and NO_x controls are included in Appendices 5-1 and 5-2 respectively. The Sargent and Lundy reports in which these spreadsheets appeared can be downloaded via links to the Appendices 5-1A, 5-1B, 5-2A, and 5-2B links found at www.epa.gov/airmarkets/progsregs/epaipm/BaseCasev410.html.

Capital Costs: In building up capital costs three separate cost modules were included for LSD and four for LSFO: absorber island, reagent preparation, waste handling (LSFO only), and everything else (also called "balance of plant") with the latter constituting the largest cost module, consisting of fans, new wet chimney, piping, ductwork, minor waste water treatment, and other costs required for treatment. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, minor, physical and chemical wastewater treatment, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. The major variables affecting capital cost are unit size and the SO_2 content of the fuel with the latter having the greatest impact on the reagent and waste handling facilities. In addition, heat rate affects the amount of flue gas produced and consequently the size of each of the modules. The quantity of flue gas is also a function of coal rank since different coals have different typical heating values.

Table 5-3 Capital Cost Modules and Their Governing Variables for SO_2 and NO_x Emission Controls

Module	Retrofit Difficulty (1 = average)	Coal Rank Factor (Bi_t = 1, PRB = 1.05, Lignite = 1.07)	Heat Rate (Btu/kWh)	SO_2 Rate (lb/MMBtu)	NO_x Rate (lb/MMBtu)[5]	Unit Size (MW)
SO_2 Emission Controls – Wet FGD and SDA FGD						
Absorber Island	X	X	X	X		X
Reagent Preparation	X		X	X		X
Waste Handling	X		X	X		X
Balance of Plant[1]	X	X	X			X
NO_x Emission Controls – SCR and SNCR						
SCR/SNCR Island[2]	X	X	X		X[3]	X
Reagent Preparation[3]					X	
Air Heater Modification[4]	X	X	X	X		X
Balance of Plant[5] – SCR	X	X	X			X
Balance of Plant[1] – SNCR					X	X

Notes:

[1]"Balance of plant" costs include such cost items as ID and booster fans, new wet chimneys, piping, ductwork, minor waste water treatment, auxiliary power modifications, and other electrical and site upgrades.

[2]The SCR island module includes the cost of inlet ductwork, reactor, and bypass. The SNCR island module includes cost of injectors, blowers, distributed control system (DCS), and reagent system.

[3]Only applies to SCR.

[4]On generating units that burn bituminous coal whose SO_2 and content exceeds 3 lbs/MMBtu, air heater modifications used to control SO_3 are needed in conjunction with the operation of SCR and SNCR.

[5]For SCR, the NO_x rate is frequently expressed through the calculated NO_x removal efficiency.

Once the key variables that figure in the cost of the four modules are identified, they are used to derive costs for each base module in equations developed by Sargent and Lundy based on their experience with multiple engineering projects. The base module costs are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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. The resulting sum is then increased by another 10% to build in an Allowance for Funds used During Construction (AFUDC) over the 3-year engineering and construction cycle. The resulting value, expressed in $/kW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running the emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For FGD, Sargent and Lundy identified four components of VOM: (a) costs for reagent usage, (b) costs for waste generation, (c) make up water costs, and (d) cost of additional power required to run the control (often called the "parasitic load"). For a given coal rank and a pre-specified SO_2 removal efficiency, each of these components of VOM cost is a function of the generating unit's heat rate (Btu/kWh) and the sulfur content (lb SO_2/MMBtu) of the coal (also referred to as the SO_2 feed rate). For purposes of modeling, the total VOM includes the first three of these component costs. 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. Due to the differences in the removal processes, the per MWh cost for waste handling, makeup water, and auxiliary power tend to be higher for LSFO while reagent usage cost and total VOM (excluding parasitic load) are higher for LSD.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the FGD 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 FGD 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[28]. 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). Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

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 and Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

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

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

- 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 and the type of FGD control. For LSFO 12 additional operators were assumed to be required for a 500 MW or smaller installation and 16 for a unit larger than 500 MW. For LSD 8 additional operators were assumed to be needed.
- FOM for maintenance is a direct function of the FGD capital cost
- FOM for administration is a function of the FOM for operations and maintenance.

Table 5-4 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for the two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities and heat rates.

Table 5-4 Illustrative Scrubber Costs (2007$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10

Scrubber 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)
LSFO Minimum Cutoff: ≥ 25 MW	9,000	-1.5	1.53	1.66	747	22.5	547	10.5	473	7.8	430	7.2	388	5.9
Maximum Cutoff: None	10,000	-1.67	1.7	1.84	783	22.8	573	10.8	496	8.0	451	7.4	407	6.1
Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.84	1.87	2.03	817	23.2	598	11.0	517	8.2	470	7.6	425	6.3
LSD Minimum Cutoff: ≥ 25 MW	9,000	-1.18	1.2	2.13	641	16.4	469	8.1	406	6.1	385	5.3	385	4.9
Maximum Cutoff: None	10,000	-1.32	1.33	2.36	670	16.7	491	8.3	424	6.3	403	5.5	403	5.1
Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.45	1.47	2.60	698	17.0	511	8.5	442	6.5	420	5.7	420	5.2

5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.4.10 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.4.10 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.4.10 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 Appendix 3-1. The EPA Base Case v.4.10 cost assumptions for NO_x Combustion Controls are summarized in Table 5-5. Table 5-6 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.4.10 to achieve state-of-the-art combustion control configuration.

Table 5-5 Cost (2007$) 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)	45	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	61	0.4	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	24	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	33	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	38	0.3	0.03
Vertically-Fired	NO_x Combustion Control	29	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 = (\$ for X MW Unit) = (\$ for 300 MW Unit) x $(300/X)^{0.359}$

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

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

where

(\$ for 300 MW Unit) is the value obtained using the factors shown in the above table and X is the capacity (in MW) of the unit taking on combustion controls.

Table 5-6 Incremental Combustion NO_x Controls in EPA Base Case v.4.10

Boiler Type	Existing NO_x Combustion Control	Incremental Combustional Control
Cell	LNB	OFA
	NGR	LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	--	LNC3
	LA	LNC3
	LNB	CONVERSION FROM LNC1 TO LNC3
	LNB + OFA	CONVERSION FROM LNC1 TO LNC3
	LNC1	CONVERSION FROM LNC1 TO LNC3
	LNC2	CONVERSION FROM LNC2 TO LNC3
	OFA	LNC1
	ROFA	LNB
Vertical	--	NO_x Combustion Control - Vertically Fired Units
Wall	--	LNB AND OFA
	LA	LNB AND OFA
	LNB	OFA
	LNF	OFA
	OFA	LNB

5.2.2 Post-combustion Controls

The EPA Base Case v.4.10 includes two post-combustion retrofit control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.4.10 oil/gas steam units are eligible for SCR only. NO_x reduction in an SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N2) 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 ammonia or urea, 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.

Table 5-7 summarizes the performance and applicability assumptions in EPA Base Case v.4.10 for each NO_x post-combustion control technology and provides a cross reference to information on cost assumptions.

Table 5-7 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% down to 0.06 lb/MMBtu	80%	Pulverized Coal: 35% Fluidized Bed: 50%
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Units ≥ 25 MW
Costs (2007$)	See Table 5-8	See Table 5-9	See Table 5-8

Potential (new) coal-fired, combined cycle, and IGCC units are modeled to be constructed with SCR systems and designed to have emission rates ranging between 0.01 and 0.06 lb NO_x/MMBtu. EPA Base Case v.4.10 cost assumptions for these units include the cost of SCR

5.2.3 Methodology for Obtaining SCR Costs for Coal Units

As with the update of SO_2 control costs, Sargent and Lundy employed an engineering build-up of the capital, fixed and variable operating and maintenance components of cost to update post-combustion NO_x control costs. This section describes the approach used for SCR. The next section treats SNCR. Detailed example cost calculation spreadsheets for both technologies can be found in Appendix 5-2.

For cost calculation purposes the Sargent and Lundy methodology calculates plant specific NO_x removal efficiencies, i.e., the percent difference between the uncontrolled NO_x rate[29] for a model plant and the cost calculation floor NO_x rate corresponding to the predominant coal rank used at the plant (0.07 lb/MMBtu for bituminous and 0.05 lb/MMBtu for subbitumionus and lignite coals). For example, a plant that burns subbitumionus coal with an uncontrolled NO_x rate of 0.1667 lb/MMBtu, and a cost calculation floor NO_x rate of 0.05 lb/MMBtu would have a removal efficiency of 70%, i.e., (0.1667 – 0.05)/0.1667 = 0.1167/0.1667 = .70. The NO_x removal efficiency so obtained figures in the capital, VOM, and FOM components of SCR cost.

Capital Costs: In building up SCR capital costs, four separate cost modules were included: SCR island (e.g., inlet ductwork, reactor, and bypass), reagent preparation, air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). Air pre-heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. All four capital cost modules, except reagent preparation, are functions of retrofit difficulty, coal rank, heat rate, and unit size. NO_x rate (expressed via the NO_x removal efficiency) affects the SCR and reagent preparation cost modules. Not shown in Table 5-3, heat input (in Btu/hr) also impacts reagent preparation costs. As noted above, the SO_2 rate becomes a factor in SCR cost for plants that combust bituminous coal with 3 lbs SO_2/MMBtu or greater, where air pre-heater modifications are needed for SO_3 control.

As with FGD capital costs, the base module costs for SCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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. Whereas the resulting sum is then increased by another 10% for FGD, for SCR it is increased by 6% to factor in an Allowance for Funds used During Construction (AFUDC) over the 2-year engineering and construction cycle (in contrast to the 3-year cycle assumed for FGD). The resulting value, expressed in $/MW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): For SCR Sargent and Lundy identified four components of VOM: (a) costs for the urea reagent, (b) costs of catalyst replacement and disposal, (c) cost of required steam, and (d) cost of additional power required to run the control

[29] More precisely, the uncontrolled NO_X rate for a model plant in EPA Base Case v.4.10 is the capacity weighted average of the Mode 1 NO_X rates of the generating units comprising the model plant. The meaning of "Mode 1 NO_X rate" is discussed in section 3.9.2 and Appendix 3-1 ("NO_X Rate Development in EPA Base Case v.4.10).

(i.e., the “parasitic load”). As was the case for FGD, 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 earlier. Of the first three of these component costs, reagent cost and catalyst replacement are predominant while steam cost is much lower in magnitude. NO_x rates and heat rates are key determinates of reagent and steam costs, while NO_x rate (via removal efficiency), capacity factor, and coal rank are key drivers of catalyst replacement costs.

<u>Capacity and Heat Rate Penalty</u>:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

<u>Fixed Operating and Maintenance Costs (FOM)</u>: For SCR the following assumptions were made:

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- FOM for maintenance is assumed to $193,585 (in 2007$) for generating units less than 500 MW and $290,377 (in 2007$) for generating units 500 MW or greater
- There was assumed to be no FOM for administration for SCR.

Table 5-8 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, heat rates, and NO_x removal efficiencies. The illustrations include and identify plants that do and do not burn bituminous coal with 3 lbs SO_2/MMBtu or greater.

Table 5-8 Illustrative Post Combustion NO_X Controls for Coal Plants Costs (2007$) for Representative Sizes and Heat Rates under the Assu Assumptions in EPA Base Case v.4.10

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW) 100 Capital Cost ($/kW)	100 Fixed O&M ($/kW-yr)	300 Capital Cost ($/kW)	300 Fixed O&M ($/kW-yr)	500 Capital Cost ($/kW)	500 Fixed O&M ($/kW-yr)	700 Capital Cost ($/kW)	700 Fixed O&M ($/kW-yr)	1000 Capital Cost ($/kW)	1000 Fixed O&M ($/kW-yr)
SCR Minimum Cutoff: ≥ 25 MW	9,000	-0.54	0.54	1.15	221	2.5	177	0.8	163	0.7	155	0.5	147	0.4
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.56	0.56	1.24	240	2.5	193	0.8	178	0.7	169	0.5	162	0.4
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000	-0.58	0.59	1.33	258	2.5	209	0.8	193	0.7	184	0.5	176	0.4
SNCR - Non-FBC Minimum Cutoff: ≥ 25 MW	9,000			0.88	45	1								
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	47	1	Size Not Modeled							
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	48	1								
SNCR - Fluidized Bed Minimum Cutoff: ≥ 25 MW	9,000			0.88	34	0.9	18	0.4	14	0.2	11	0.2	9	0.1
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	35	0.9	19	0.4	14	0.2	12	0.2	10	0.1
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	36	0.9	19	0.4	14	0.2	12	0.2	10	0.1

Note:

If a coal plant burns bituminous coal with a SO_2 content above 3.0 lb/MMBtu then the capital costs will increase due to the required air preheater modification. For example, a 100 MW coal boiler with an SCR burning bituminous coal at a heat rate of 11,000 Btu/kWh and an SO_2 rate of 4.0 lb/MMBtu will have a capital cost of 296 $/kW, a 36 $/kW increase in capital costs from an identical boiler burning coal with an SO_2 rate of 2.0 lb/MMBtu.

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

The cost calculations for SCR described in section 5.2.3 apply to coal units. For SCR on oil/gas steam units the cost calculation procedure employed in EPA's most recent previous base case was used. However, capital costs were scaled up by 2.13 to account for increases in the component costs that had occurred since the assumptions were incorporated in that base case. All costs were expressed in constant 2007$ for consistency with the dollar year cost basis used throughout EPA Base Case v4.10. Table 5-9 shows that resulting capital, FOM, and VOM cost assumptions for SCR on oil/gas steam units. The scaling factor for capital and fixed operating and maintenance costs, described in footnote 1, applies to all size units from 25 MW and up.

Table 5-9 Post-Combustion NO_X Controls for Oil/Gas Steam Units in EPA Base Case v.4.10

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	Percent Removal
SCR[1]	75	1.08	0.12	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.

This data is used in the generation of EPA Base Case v.4.0

[1] 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) = $75 * (200/275)^{0.35} \approx 67$ $/kW

SCR FOM Cost ($/kW-yr) = $1.08 * (200/275)^{0.35} \approx 0.97$ $/kW-yr

SCR VOM Cost (mills/kWh) = 0.12 mills/kWh

Reference:

Cost Estimates for Selected Applications of NO_X Control Technologies on Stationary Combustion Boilers, Bechtel Power Corporation for US EPA, June 1997

5.2.5 Methodology for Obtaining SNCR Costs

In the Sargent and Lundy 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).

Capital Costs: Due to the absence of a catalyst and, with it, the elimination of the need for more extensive reagent preparation, the Sargent and Lundy engineering build up of SNCR capital costs includes three rather than four separate cost modules: SNCR (injectors, blowers, distributive control system, reagent system), air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). For CFB units, the SNCR and balance of plan module costs are 75% of what they are on other boiler types. The air pre-heater modification cost module is the same as for SCR and there is no cost difference between CFB and other boiler types. As with SCR the air heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the three modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. Unit size affects all three modules. Retrofit difficulty, coal rank, and heat rate impact the SNCR and air heater modification modules. The SO_2 rate impacts the air pre-heater modification module. NO_X rate (expressed via the NO_X removal efficiency) and heat input (not shown in Table 5-3) affect the balance of plan module.

The base module costs for SNCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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 SNCR projects are typically completed in less than a year, there is no Allowance for Funds used During Construction (AFUDC) in the SNCR capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): Sargent and Lundy identified two components of VOM for SNCR: (a) cost for the urea reagent and (b) the cost of dilution water. The magnitude of the reagent cost predominates the VOM with the cost of dilution water at times near zero. There is no capacity or heat rate penalty associated with SNCR since the only impact on power are compressed air or blower required for urea injection and the reagent supply system.

Capacity and Heat Rate Penalty:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SNCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): The assumptions for FOM for operations and for administration are the same for SNCR as for SCR, i.e.,

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- There was assumed to be no FOM for administration for SCR.

FOM for maintenance materials and labor was assumed to be a direct function of base module cost, specifically, 1.2% of those costs divided by the capacity of the generating unit expressed in kilowatts.

Detailed example cost calculation spreadsheets for SNCR can be found in Appendix 5-2.

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

In EPA Base Case v.4.10 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. This assumption is 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 100 MW 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.[30] 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,

[30] 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., information on the project can be found at www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/bib_greenidge.html.

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.4.10, 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 retrofit with an MPT.

Illustrative scrubber, SCR, and SNCR costs for 25-100 MW coal units with a range heats rates can be found by referring to the 100 MW “Capital Costs ($/kW)” and “Fixed O&M” columns in Table 5-4 and Table 5-8. 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

Under most climate policies currently being discussed, biomass is treated as “carbon neutral,” i.e., a zero contributor of CO_2 to the atmosphere. The reasoning is that the CO_2 emitted in the combustion of biomass will be reabsorbed via photosynthesis in plants grown to replace the biomass that was combusted. Consequently, if a power plant can co-fire biomass and thereby replace a portion of fossil fuel, it reduces its CO_2 emissions by approximately the same proportion, although combustion efficiency losses may somewhat diminish the proportion of CO_2 reduction. Roughly speaking, by co-firing enough biomass to produce 10% of a coal plant’s power output, a co-fired plant can realize close to an effective 10% reduction in CO_2 emitted.

Biomass co-firing is provided as a fuel choice for all coal-fired power plants in EPA Base Case v.4.10. 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. 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.4.10 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 EPA Base Case v.4.10 “facility level” is defined as the set of generating units which share the same ORIS code[31] in NEEDS v.4.10.

The capital and FOM costs associated with biomass co-firing are summarized in Table 5-10. Developed by EPA’s power sector engineering staff[32], they are on the same cost basis as the

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[31] 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 under ownership changes.

[32] 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 Cofiring: 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

costs shown in Table 4-16 which resulted from EPA's comparative analysis of electricity sector costs as described in Chapter 4.

Table 5-10 Biomass Cofiring for Coal Plants

Size of Biomass Unit (MW)	5	10	15	20	25	30	35	40	45	50
Capital Cost (2007$/kW From Biomass)	488	411	371	345	327	312	300	290	282	275
Fixed O&M (2007$/kW-yr)	24.2	16.2	11.7	9.4	8.0	11.1	9.9	8.9	8.1	7.5

The capital and FOM costs were implemented by ICF in EPA Base Case v.4.10 as a $/MMBtu biomass fuel cost adder. The procedure followed to implement this was first to represent the discrete costs shown in Table 5-10 as continuous exponential cost functions showing the FOM and capital costs for all size coal generating units between 0 and 50 MW in size. Then, for every coal generating unit represented in EPA Base Case 4.10, 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 an 11% capital charge rate. (This is the capital charge rate for environmental retrofits found in Table 8-1 and discussed in Chapter 8.) 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 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 units co-fires biomass.

5.4 Mercury Control Technologies

As previously noted, the mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA's 2010 Information Collection Request (ICR). The following discussion is based on EPA's earlier work on mercury controls.

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 emission policies that would require the installation of mercury emission controls, mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from non-mercury control technologies, i.e., the SO_2, NO_X, and particulate controls. While the base case itself does not include any federal mercury control policies, it does include some State mercury reduction requirements. IPM has the capability to model mercury controls that might be installed in response to such State mercury control policies. These same controls come into play in model runs that analyze possible federal mercury policies relative to the base case. The technology specifically designated for mercury control in such policy runs is Activated Carbon Injection (ACI) downstream of the combustion process.

Burners, PowerGen 2000 - Orlando, FL, www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.
Tillman, D. A., *Cofiring Biomass for Greenhouse Gas Mitigation*, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.
(e) 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

The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 treat the two factors that figure into the unregulated mercury emissions resulting under EPA Base Case v.4.10. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Base Case v.4.10. Section 5.4.2 looks at the procedure used in the base case to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.3 explains the mercury emission control options that are available under EPA Base Case v.4.10. A major focus is on the cost and performance features of Activated Carbon Injection. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case v.4.10 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).[33] 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.

The ICR second component 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 in EPA Base Case v.4.10, these data points were first grouped by IPM coal types and IPM coal supply regions. (IPM coal types divide bituminous, sub-bituminous, and lignite coal into different grades based on sulfur content. See Table 5-11.) Next, a clustering analysis was performed on the data 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. First, the number of clusters of mercury concentrations for each IPM coal type was determined based on the range of mercury and SO_2 concentrations for that coal type. Each coal type used one, two or three clusters. To the greatest extent possible the total number of clusters for each coal type was limited to keep the model size and run time within feasible limits. Second, the clustering procedure was used to group each coal type within each IPM coal supply region into the previously determined number of clusters and show the resulting mercury concentration for each cluster. The average of each cluster is the mercury content of coal finally used in EPA Base Case v.4.10 for estimating mercury emissions. IPM input files retain the mapping between different coal type-supply region combinations and the mercury clusters. Table 5-11 below provides a summary by coal type of the number of clusters and their mercury concentrations.

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

Table 5-11 Mercury Clusters and Mercury Content of Coal by IPM Coal Types

Coal Type by Sulfur Grade	Mercury Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Easter Bituminous (BA)	3.19	4.37	--
Low Sulfur Western Bituminous (BB)	1.82	4.86	--
Low Medium Sulfur Bituminous (BD)	5.38	8.94	21.67
Medium Sulfur Bituminous (BE)	19.53	8.42	--
High Sulfur Bituminous (BG)	7.10	20.04	14.31
High Sulfur Bituminous (BH)	7.38	13.93	34.71
Low Sulfur Subbituminous (SA)	4.24	5.61	--
Low Sulfur Subbituminous (SB)	6.44	--	--
Low Medium Sulfur Subbituminous (SD)	4.43	--	--
Low Medium Sulfur Lignite (LD)	7.51	12.00	--
Medium Sulfur Lignite (LE)	13.55	7.81	--
High Sulfur Lignite (LG)	14.88	--	--

Oil, natural gas, and waste fuels: The EPA Base Case v.4.10 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.[34] Table 5-12 provides a summary of the assumptions on the mercury content for oil, gas and waste fuels included in EPA Base Case v.4.10.

Table 5-12 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.4.10

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00[1]
Petroleum Coke	23.18
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:
[1]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 0.00014 lbs/TBtu. Values for geothermal resources represent a range.

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

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

the inlet) during combustion and flue-gas treatment process is (1-EMF). The EMF varies by the type of coal (bituminous, sub-bituminous, 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 representation 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[35] 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 subbitumionus 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 improved understanding of mercury capture with SCRs was incorporated in EPA Base Case v.4.10 mercury EMFs for unit configurations with SCR and wet scrubbers.

Table 5-13 below provides a summary of EMFs used in EPA Base Case v.4.10. Table 5-14 provides definitions of acronyms for existing controls that appear in Table 5-13. Table 5-15 provides a key to the burner type designations appearing in Table 5-13.

5.4.3 Mercury Control Capabilities

EPA Base Case v.4.10 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.

[35] 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 5-13 Mercury Emission Modification Factors Used in EPA Base Case v.4.10

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Cold Side ESP	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.58
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	None	0.11	0.27	1
Cyclone	Hot Side ESP	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	SCR	None	0.9	1	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.9	1	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Hot Side ESP	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	None	None	0.9	1	1
Cyclone	Hot Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Hot Side ESP + FGC	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	None	0.9	1	1
Cyclone	No Control	SNCR	None	1	1	1
Cyclone	No Control	SNCR	Wet FGD	0.45	0.6	1
Cyclone	No Control	SNCR	Dry FGD	1	1	1
Cyclone	No Control	SCR	None	1	1	1
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	SCR	Dry FGD	1	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6	1
Cyclone	No Control	None	Dry FGD	1	1	1
Cyclone	No Control	None	None	1	1	1
Cyclone	PM Scrubber	None	None	0.8	1	1
FBC	Cold Side ESP	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP + FGC	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP + FGC	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Wet FGD	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	SCR	None	0.05	0.43	0.43

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
FBC	Fabric Filter	SCR	Wet FGD	0.05	0.27	0.43
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	Wet FGD	0.1	0.43	0.43
FBC	Fabric Filter	None	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	None	0.05	0.43	0.43
FBC	Hot Side ESP	SNCR	None	1	1	1
FBC	Hot Side ESP	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	None	1	1	1
FBC	No Control	SNCR	None	1	1	1
FBC	No Control	SNCR	Wet FGD	1	1	1
FBC	No Control	SNCR	Dry FGD	0.45	0.45	1
FBC	No Control	SCR	None	1	1	1
FBC	No Control	SCR	Wet FGD	0.1	0.7	1
FBC	No Control	SCR	Dry FGD	0.45	0.45	1
FBC	No Control	None	Wet FGD	1	1	1
FBC	No Control	None	Dry FGD	0.45	0.45	1
FBC	No Control	None	None	1	1	1
PC	Cold Side ESP	SNCR	None	0.64	0.97	1
PC	Cold Side ESP	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	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	None	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	None	0.64	0.97	1
PC	Cold Side ESP + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.75	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	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	None	0.2	0.75	1
PC	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	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	None	Wet FGD	0.34	0.84	0.56

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	None	0.64	0.97	1
PC	Cold Side ESP + FGC + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	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	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	None	0.2	0.75	1
PC	Fabric Filter	SNCR	None	0.11	0.27	1
PC	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
PC	Fabric Filter	SNCR	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	None	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	None	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	None	0.11	0.27	1
PC	Hot Side ESP	SNCR	None	0.9	0.9	1
PC	Hot Side ESP	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP	SNCR	Dry FGD	0.6	0.85	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	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	None	0.9	0.94	1
PC	Hot Side ESP + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	SNCR	Dry FGD	0.05	0.75	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
PC	Hot Side ESP + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	None	0.11	0.27	1
PC	Hot Side ESP + FGC	SNCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP + FGC	SNCR	Dry FGD	0.6	0.85	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	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	None	0.9	0.94	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Hot Side ESP + FGC + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
PC	No Control	SNCR	None	1	1	1
PC	No Control	SNCR	Wet FGD	0.58	0.7	1
PC	No Control	SNCR	Dry FGD	0.6	0.85	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	None	Wet FGD	0.58	0.7	1
PC	No Control	None	Dry FGD	0.6	0.85	1
PC	No Control	None	None	1	1	1
PC	PM Scrubber	SNCR	None	0.9	0.91	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	None	None	0.9	0.91	1
Stoker	Cold Side ESP	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP + FGC	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP + FGC	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP + FGC	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	None	0.65	0.97	1
Stoker	Fabric Filter	SNCR	None	0.11	0.27	1
Stoker	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Stoker	Fabric Filter	SNCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	SCR	None	0.11	0.27	1
Stoker	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	None	Dry FGD	0.1	0.75	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Stoker	Fabric Filter	None	None	0.11	0.27	1
Stoker	Hot Side ESP	SNCR	None	1	1	1
Stoker	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	SCR	None	1	1	1
Stoker	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	None	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	SCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	None	1	1	1
Stoker	No Control	SNCR	None	1	1	1
Stoker	No Control	SNCR	Wet FGD	0.58	1	1
Stoker	No Control	SNCR	Dry FGD	1	1	1
Stoker	No Control	SCR	None	1	1	1
Stoker	No Control	SCR	Wet FGD	0.1	0.7	1
Stoker	No Control	SCR	Dry FGD	1	1	1
Stoker	No Control	None	Wet FGD	0.58	1	1
Stoker	No Control	None	Dry FGD	1	1	1
Stoker	No Control	None	None	1	1	1
Stoker	PM Scrubber	None	None	1	1	1
Other	Cold Side ESP	SNCR	None	0.64	0.97	1
Other	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	SCR	None	0.64	0.97	1
Other	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	None	0.64	0.97	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Other	Fabric Filter	SNCR	None	0.45	0.75	1
Other	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	SCR	None	0.11	0.27	1
Other	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	SCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	None	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	None	0.11	0.27	1
Other	Hot Side ESP	SNCR	None	1	1	1
Other	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP	SCR	None	1	1	1
Other	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP	SCR	Dry FGD	1	1	1
Other	Hot Side ESP	None	Wet FGD	0.58	1	1
Other	Hot Side ESP	None	Dry FGD	1	1	1
Other	Hot Side ESP	None	None	1	1	1
Other	Hot Side ESP + FF	None	None	0.11	0.27	1
Other	Hot Side ESP + FGC	SNCR	None	1	1	1
Other	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	SCR	None	1	1	1
Other	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	None	1	1	1
Other	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
Other	No Control	SNCR	None	1	1	1
Other	No Control	SNCR	Wet FGD	0.58	0.7	1
Other	No Control	SNCR	Dry FGD	1	1	1
Other	No Control	SCR	None	1	1	1
Other	No Control	SCR	Wet FGD	0.1	0.7	1
Other	No Control	SCR	Dry FGD	1	1	1
Other	No Control	None	Wet FGD	0.58	0.7	1
Other	No Control	None	Dry FGD	1	1	1
Other	No Control	None	None	1	1	1
Other	PM Scrubber	None	None	0.9	0.91	1

Table 5-14 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 5-15 Key to Burner Type Designations in Table 5-13

"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.

"Stoker" refers to stoker boilers where lump coal is fed continuously onto a moving grate or chain which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.

"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.

"Other" refers to miscellaneous burner types including cell burners and arch- , roof- , and vertically-fired burner configurations**.**

Mercury Control through SO_2 and NO_X Retrofits

In EPA Base Case v.4.10, 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, SNCR, 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. A comprehensive ACI update, which will incorporate the latest field experience through 2010, is being prepared by Sargent and Lundy (the same engineering firm that developed the SO_2 and NO_X control assumptions used in EPA Base Case v.4.10). It will be incorporated in a future EPA base case. The ACI assumptions in the current base case release are the result of a 2007 internal EPA engineering study.

Based on this study, it is assume that 90% removal from the level of mercury in the coal is achievable with the application of one of three alternative ACI configurations: Standard Powered Activated Carbon (SPAC), Modified Powered Activated Carbon (MPAC), or SPAC in combination with a fabric filter. The MPAC option 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. In the MPAC system, a small amount of bromine is chemically bonded to the powdered carbon which is then injected into the flue gas stream either upstream of both the particulate control device (ESP or fabric filter) and the air pre-heater (APH), between the APH and the particulate control device, or downstream of both the pre-existing APH and particulate control devices but ahead of a new dedicated pulsed-jet fabric filter. (The latter is known as the TOXECON™ approach, an air pollution control process patented by EPRI.)

Table 5-16 presents the capital, FOM, and VOM costs as well as the capacity and heat rate penalty for the five Hg emission control technologies included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities.

Table 5-16 Illustrative Activated Carbon Injection Costs (2007$) for Representative Sizes under the Assumptions in EPA Base Case v.4.10

Control Type	Capacity Penalty (%)	Heat Rate Penalty (%)	Capacity (MW) 100			300			500			700		
			Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)
MPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	3	0.1	0.16	2	0.05	0.17	2	0.04	0.17	2	0.03	0.16
MPAC_CESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	8	0.1	0.57	6	0.1	0.61	5	0.1	0.61	5	0.1	0.59
SPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	5	0.1	0.22	4	0.1	0.23	3	0.1	0.23	3	0.1	0.23
SPAC_ESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	27	0.5	2.29	21	0.3	2.46	18	0.3	2.44	17	0.3	2.39
SPAC_ESP+Toxecon Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	269	4.3	2.44	202	2.5	2.61	176	2.1	2.59	161	2.0	2.54

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 or SCR NO_x post-combustion control are present. Table 5-17 shows the ACI assignment scheme used in EPA Base Case v.4.10 to achieve 90% mercury removal.

Table 5-17 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.4.10

Applicability of Activated Carbon Injection

Coal Type	SO_2 in Coal (lb/MMBtu)	Boiler Type	Particulate Control Type	FGD System	SCR System	Toxecon Required?	ACI Type With 90% Hg Reduction
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP or BH (no FGC)	--	No	No	MPAC
Bit/Sub-bit/ Lig	--	Non-CFB	CS-ESP or BH (no FGC)	LSD	--	No	MPAC
Bit/Sub-bit/Lig	--	CFB	CS-ESP or BH (no FGC)	--	--	No	MPAC
Bit	< 1.6	Non-CFB	CS-ESP	Non-LSD	Yes	No	SPAC
Bit	≥ 1.6	Non-CFB	CS-ESP or BH	--	--	No	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	CS-ESP	--	--	Yes	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	BH	--	--	No	SPAC
Bit/Sub-bit/ Lig	--	Non-CFB	HESP	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	--	--	HESP or CS-ESP (with FGC)	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	BH	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP (no FGC)	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	--	--	No Control	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	--	BH	Non-LSD	Yes	No	SPAC
Sub-bit/ Lig	< 1.6	--	CS-ESP (no FGC)	Non-LSD	Yes	Yes	SPAC
Bit/Sub-bit/Lig	--	--	Cyclone	--	--	Yes	SPAC

Notes:

Legends:

ACI	Activated carbon injection
BH	Baghouse
Bit	Bituminous coal
CFB	Circulating fluidized-bed boiler
CS-ESP	Cold side electrostatic precipitator
FGC	Flue gas conditioning
HESP	Hot electrostatic precipitator
Lig	Lignite
MPAC	Modified powdered activated carbon
SPAC	Standard powdered activated carbon
Sub-bit	Subbituminous coal

If the existing equipment provides 90% Hg removal, no ACI system is required.

"--" means that the category type has no effect on the ACI application.

Appendix 5-1 Example Cost Calculation Worksheets for SO_2 Control Technologies in EPA Base Case v.4.10

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

Table 3. Example Complete Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<— User Input (Greater than 100 MW)
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)	3	<— User Input
Type of Coal	E		Bituminous	<— User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$ 46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$ 22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$ 13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$ 84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc...
BMWW ($) =		$ -	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$ 166,702,000	Total base cost including retrofit factor
BM ($/KW) =		333	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$ 16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$ 10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**501**	Total project cost per kW

Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<---- User Input (Greater than 100 MW)
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)	3	<---- User Input
Type of Coal	E		Bituminous	<---- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.36**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc...
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

Appendix 5-2 Example Cost Calculation Worksheets for NO_x Post-Combustion Control Technologies in EPA Base Case v.4.10

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

SCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation			Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.				
BMR ($) =	180000*(B)*(L)^0.2*(A*G*H)^0.92	$	65,199,000	SCR (Inlet Ductwork, Reactor, Bypass) Island Cost
BMF ($) =	410000*(M)^0.25	$	2,228,000	Base Reagent Preparation Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G*H)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	380000*(B)*(A*G*H)^0.42	$	5,666,000	ID or booster fans & Auxiliary Power Modification Costs
BM ($) =	BMR + BMF + BMA + BMB	$	73,093,000	Total bare module cost including retrofit factor
BM ($/KW) =			122	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	7,309,000	Engineering and Construction Management costs
A2 = 10% of BM		$	7,309,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	7,309,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**95,020,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			**158**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	4,751,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1		$	5,986,000	AFUDC (Based on approximately 3% per year for a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$**	**105,757,000**	Total project cost
TPC ($/kW) =			**176**	Total project cost per kW

Table 2. Example of the Fixed and Variable O&M Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080**V/(A*1000)	$	0.10	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = IF A < 500 then $200,00 ELSE $300,000	$	0.50	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.60**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = N*R/A/1000	$	0.31	Variable O&M costs for Urea
VOMW ($/MWh) = discrete function of A, G, J, K, S	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMM	**$**	**0.66**	

SNCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.26; ELSE UF = 0.16
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	B*F/1.05*200000*(A*G)^0.42	$	2,090,000	SNCR (Injectors, Blowers, DCS, Reagent System) Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	270000*(A)^0.33*(K)^0.12	$	3,273,000	Balance of Plant Cost (Piping, Including Site Upgrades)
BM ($) =	BMS + BMA + BMB	$	5,363,000	Total bare module cost including retrofit factor
BM ($/KW) =			18	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	536,000	Engineering and Construction Management costs
A2 = 10% of BM		$	536,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	536,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	6,971,000	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			23	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	349,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC ($) = CECC + B1		$	7,320,000	Total project cost
TPC ($/kW) =			24	Total project cost per kW

Table 2. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	$	0.21	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = 0.012*BM/A/1000	$	0.21	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.42**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = L*P/A/1000	$	0.74	Variable O&M costs for Urea
VOMM ($/MWh) = O*R/A	$	0.00	Variable O&M costs for dilution water
VOM ($/MWh) = VOMR + VOMM	**$**	**0.74**	