5 Emission Control Technologies

The EPA Base Case 2000 includes emission control technologies as compliance options for meeting air regulatory requirements. Although the EPA Base Case 2000 includes only existing SO_2 and NO_x air regulations, detailed assumptions on the cost and performance for mercury control were developed for use in mercury policy cases built on EPA Base Case 2000. In addition, two other control options — combustion optimization and biomass co-firing — are offered for policy scenarios where such control options might be applicable.

SO_2 and NO_x control technologies are offered as retrofit options that existing units may utilize to comply with modeled air regulations. Both existing and potential (new) units in EPA Base Case 2000 use the same cost and performance assumptions for NO_x control technologies. For potential units (discussed in Section 4.4), the cost and performance of SO_2 and NO_x control technologies (discussed in Section 5.1 and 5.2 below) are included in the total capital, fixed and variable operations costs of the units. Since cost estimates for potential (new) pulverized coal units based on Annual Energy Outlook (AEO) 2000 already included SO_2 scrubber costs, no additional cost adjustments were assumed for SO_2 reduction from potential pulverized coal units. Activated carbon injection is provided as a mercury control retrofit option for existing units.

The availability of emission control technologies in the EPA Base Case 2000 and its policy cases complements other air regulatory compliance options such as fuel switching, repowering or generation dispatch adjustments. This section describes the cost and performance assumptions of emission control technologies available under the EPA Base Case 2000 and associated policy cases. Table 5.1 summarizes key emission control performance assumptions that are discussed in detail below.

Table 5.1. Summary of Emission Control Performance Assumptions in EPA Base Case 2000

	SO_2 Scrubbers			NO_x Post-Combustion Controls				Mercury[1]	Other Controls[1]	
	Limestone Forced Oxidation (LSFO)	**Magnesium Enhanced Lime (MEL)**	**Lime Spray Dryer (LSD)**	**SCR**	**SNCR**	**Gas Reburn**		**Activated Carbon Injection**	**Combustion Optimization**	**Biomass Cofiring**
						Low NO_x	**High NO_x**			
Percent Removal	95%	96%	90%	Coal: 90% down to 0.05 lb/mmBtu Gas: 80%	Coal: 35% Gas: 50%	40%	50%	80%[2]	0.5% heat rate (Btu/kwh) improvement — 20% NO_x reduction	
Capacity Penalty[3]	-2.1%	-2.1%	-2.1%							
Heat Rate Penalty[3]	+2..1%	+2..1%	+2..1%							
Fuel Use Impacts						16% gas use	16% gas use			Cyclones 5% Biomass, >200MW 15% Biomass, #200 MW Other Coal 2% Biomass, >200MW 15% Biomass, #200 MW
Cost (1999$)	See Table 5.2 and Appendix 5.1	See Table 5.2 and Appendix 5.1	See Table 5.2 and Appendix 5.1	See Tables 5.3 and 5.4				See Tables 5.8 and Appendix 5.3	$250,000 capital cost $40,000/yr FOM cost	See Table 5.11
Applicable Population	Coal boilers $ 100 MW	Coal boilers < 550 MW and $100 MW	Coal boilers $ 550 MW	Coal boilers $100 MW All oil/gas steam units.	All coal and oil/gas steam units	All coal steam units with NOx rates higher than 0.5 lbs/mmBtu and without post-combustion controls		All coal units > 25 MW	Coal boilers $ 100 MW	All coal units

Notes

1. Activated carbon injection, combustion optimization, and biomass cofiring are not exercised in EPA Base Case 2000, but are available capabilities that can be implemented, as applicable, in policy runs built on the base case.

2. While 80% is the mercury removal rate achieved by all units that retrofit with ACI under the assumptions in EPA Base Case 2000, alternative removal rates (e.g., 70% and 90%) can be modeled if desired.

3. The capacity penalty captures the fact that the electricity required to operate the scrubber reduces the maximum capacity available for sale to the grid by 2.1%. The heat rate penalty is a modeling procedure used to scale up a unit's heat rate in order to capture the fuel used in generation both for internal load and sale to the grid. It does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency).

5.1 Sulfur Dioxide Control Technologies

The EPA Base Case 2000 includes three technologies for removing SO_2 produced by coal-fired power plants. Known collectively as Flue Gas Desulfurization (FGD), or SO_2 scrubbers, the three specific technologies are Limestone Forced Oxidation (LSFO), Lime Spray Drying (LSD) and Magnesium-Enhanced Lime (MEL). The inclusion of these three technologies in EPA Base Case 2000 is the result of a comprehensive survey of FGD technologies and a detailed engineering cost and performance evaluation of the different FGD technologies. The results of this evaluation are reported in *Controlling SO_2 Emissions: A Review of Technologies*[1] (henceforth referred to as "the EPA scrubber report").

5.1.1 Methodology for Obtaining Cost of SO_2 Controls

Using a bottom-up approach that identifies the cost and performance of all the different components of the SO_2 scrubber system, the EPA scrubber report provides detailed engineering cost and performance estimates for SO_2 scrubbers in power plants. The cost and performance equations in the scrubber report were primarily a function of heat rate, capacity, and sulfur content. (For a summary of the scrubber report cost equations, see Appendix 5.1.)

To adapt the EPA scrubber report's engineering equations for use in IPM, a number of adjustments were made.

- In identifying the coal appropriate for each scrubber type, it was first necessary to convert percent sulfur by weight to sulfur per mmBtu. The assumed heating values for the conversion were: bituminous – 23.8 million Btu per ton; sub-bituminous – 17.1 million Btu per ton; and lignite – 12.8 million Btu per ton.
- The appropriate IPM coal types were then assigned to each technology based on sulfur content. Conservative assumptions were used in making these assignments. That is, each technology was assigned only those coal types whose sulfur content was unambiguously appropriate.
- Economic and modeling considerations were used to define power plant capacity categories applicable for each scrubber type. Capacity restrictions were imposed if it was clear that a particular scrubber technology would not provide the most cost effective SO_2 reduction option for units of a particular size. These assumptions also helped keep the model size manageable. The scrubber-specific sections below contain further details on capacity restrictions.
- To facilitate incorporating the cost functions in IPM, polynomial fits — not the original engineering equations — were used in the model. Using *Table Curve 3D*, v3.0 software, separate rational polynomials were derived for capital cost, fixed operation and maintenance cost (FOM), and variable operating and maintenance cost (VOM). Checks were performed to ensure that the resulting polynomials produced costs within acceptable tolerances of the original engineering equations.

The following sections present the specific cost and performance assumptions for each of the three FGD technologies.

5.1.2 Limestone Forced Oxidation (LSFO)

Limestone Forced Oxidation (LSFO) is a wet SO_2 scrubber technology option that is offered in EPA Base Case 2000 to coal steam units, 100 MW and larger, that combust bituminous coal with 2% or higher sulfur by weight. In the IPM modeling context, this means that the LSFO scrubber option is available to model plants using coal types BF and BG, whose sulfur content is within or close to the sulfur content criterion for LSFO. (See Table 8.5 for a list of IPM coal types.) In EPA Base Case 2000, LSFO is assumed to provide 95% SO_2 removal.

[1]U.S. Environmental Protection Agency, Office of Research and Development, *Controlling SO_2 Emissions: A Review of Technologies* (EPA-600/R-00-093), October 2000.

5.1.3 Magnesium Enhanced Lime (MEL)

Magnesium Enhanced Lime (MEL) is another wet SO_2 scrubber technology option that is offered in the EPA Base Case 2000. It is available to coal steam units, from 100 MW to 550 MW in capacity, that combust bituminous, sub-bituminous or lignite coal with less than 2.5% sulfur by weight, i.e., IPM coal types BA, BB, BD, BE, BF, SB, SD, SE, LD, LE and LF. In EPA Base Case 2000, MEL is assumed to provide 96% SO_2 removal.

5.1.4 Lime Spray Drying (LSD)

Lime Spray Drying (LSD) is a dry SO_2 scrubber technology that is available in the EPA Base Case 2000 to coal steam units, 550 MW or larger, that combust bituminous, sub-bituminous or lignite coal with sulfur content between 0.4% and 2% sulfur by weight, i.e., IPM coal types BA, BB, BD, BE, BF, SB, SD, SE, LD, LE and LF. In EPA Base Case 2000, LSD is assumed to provide 90% SO_2 removal.

For examples of the typical costs resulting from the assumptions presented in sections 5.1.2.-5.1.4, see Table 5.2. This table shows the capital, FOM, and VOM costs that would result with each of the three scrubber technologies for a representative set of coal unit capacities and heat rates. It should be noted that each of the three FGD technologies carries a 2.1% capacity penalty[2]. That is, the power required to operate the scrubber reduces the maximum amount of electricity that is available for sale to the grid by 2.1%. In addition, to capture the total fuel used for generation both for sale to the grid and for internal load (i.e., operating the scrubber) the model scales up the heat rate by 2.1%. This "heat rate penalty" is a modeling procedure only and does represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency).

New conventional pulverized coal units are assumed to be built with SO_2 scrubbers. The cost estimates for potential (new) pulverized coal based on Annual Energy Outlook (AEO) 2000 already include SO_2 scrubber costs. No additional cost adjustments were included.

In addition to providing SO_2 reductions, FGD technologies (singly and in combination with other emission controls) provide mercury reductions. These reductions are captured in EPA Base Case 2000 through mercury emission modification factors (EMFs). There is no uniform mercury reduction factor for SO_2 scrubbers because the mercury reductions vary by unit configuration (i.e. boiler design and array of pollution controls). Section 5.3.2 below contains a detailed description of mercury EMFs, including details on mercury reductions from SO_2 scrubbers.

[2]The EPA scrubber report estimates the capacity and heat rate penalty for scrubbers as ranging from 0.7% to 2.0%. To be conservative, a 2.1% capacity and heat rate penalty was adopted in EPA Base Case 2000.

Table 5.2. Illustrative Scrubber Costs (1999$) for Representative MW and Heat Rates under the Assumptions in EPA Base Case 2000.

		Heat Rate			
Scrubber Type	**MW**	9,000	10,000	11,000	**Cost**
LSFO	100	514	528	541	Capital Cost ($/kW)
Minimum Cutoff: $ 100 MW		18	18	18	Fixed O&M ($/kW-yr)
Maximum Cutoff: None		1	1	2	Variable O&M (mills/kWh)
	300	252	262	272	Capital Cost ($/kW)
		10	10	11	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	500	193	201	209	Capital Cost ($/kW)
		8	8	9	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	700	159	166	173	Capital Cost ($/kW)
		7	7	7	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	1,000	176	186	194	Capital Cost ($/kW)
		7	7	7	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
MEL	100	352	364	375	Capital Cost ($/kW)
Minimum Cutoff: $ 100 MW		15	16	16	Fixed O&M ($/kW-yr)
Maximum Cutoff: < 500 MW		1	1	1	Variable O&M (mills/kWh)
	200	232	242	251	Capital Cost ($/kW)
		11	11	12	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	300	233	244	255	Capital Cost ($/kW)
		10	11	11	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	400	207	218	229	Capital Cost ($/kW)
		9	9	10	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	500	185	195	204	Capital Cost ($/kW)
		8	9	9	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
LSD	600	148	156	163	Capital Cost ($/kW)
Minimum Cutoff: $ 550 MW		5	5	5	Fixed O&M ($/kW-yr)
Maximum Cutoff: None		2	2	2	Variable O&M (mills/kWh)
	700	137	145	152	Capital Cost ($/kW)
		5	5	5	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	800	134	140	146	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	900	135	142	149	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	1,000	128	135	141	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)

5.2 Nitrogen Oxides Control Technology

The EPA Base Case 2000 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. Post-combustion controls operate downstream of the combustion process and remove NO_x from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case 2000 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case 2000 retains the assumptions on the cost and performance of combustion controls developed for the EPA Winter 1998 Base Case[3]. Appendix 5.2 contains a detailed description of the combustion control cost and performance assumptions developed for the EPA Winter 1998 Base Case. Tables A5.2.1 and A5.2.2 in the appendix present the cost equations for combustion controls. Table A5.2.4 shows the NO_x reduction rates resulting from combustion controls on various types of boilers.

5.2.2 Post-combustion Controls

The EPA Base Case 2000 includes three post-combustion control technologies: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR) and Gas Reburn. As noted above, each of the technologies is commercially available and in operation at a number of power plants. The cost and performance assumptions for SCR in EPA Base Case 2000 were derived from recent studies by U.S. EPA's Office of Research and Development[4]. For Gas Reburn and SNCR the assumptions in the EPA Winter 1998 Base Case were retained.

In the EPA Base Case 2000, SCR, SNCR and Gas Reburn are available to existing coal and oil/gas steam units as NO_x reduction options. SCR is available as a retrofit option for coal fired units whose capacity is 100 MW or greater[5]. There are no capacity restrictions on SCR for oil/gas fired units and on SNCR for any type of unit. There is no capacity or heat rate penalty associated with SCR[6]. To capture economies of scale for installation and operation of post-combustion controls, the costs of the controls are expressed as functions of capacity. The removal efficiency of post-combustion controls is applied to the NO_x policy rate, i.e., the emission rate (in lbs/mmBtu) attributed to an existing unit based on a series of assumptions about the presence or absence of combustion controls prior to the imposition of a control policy. (For a detailed discussion of the derivation of NO_x policy rates, see Appendix 5.2.) Table 5.3 below provides a brief summary of the cost and performance assumptions for post-combustion control for coal steam units[7]. Table 5.4 provides similar information for oil/gas steam units. The notes at the bottom of each of these tables present the equations that are used to obtain the retrofit costs actually assigned to IPM model plants from the cost parameters shown in the body of the tables.

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[3]For a full discussion of the EPA Winter 1998 Base Case, see "Analyzing Electric Power Generation under the CAAA," Office of Air and Radiation, US EPA, March 1998.

[4]*Cost of Selective Catalytic Reduction (SCR) Applications for NOx Control on Coal-Fired Boilers*, US EPA Office of Research and Development, October 2001, EPA-600/R-01-087.

[5]See report cited in previous footnote.

[6]Studies suggest that the operating penalties associated with SCR are in the 0.2% to 0.5% range and are largely due to the equipment required to counter the pressure drop resulting from SCR. (See *Cost Estimates for Selected Applications of NO_X Control Technologies in Stationary Combustion Boilers: Responses to Comments on the Draft Report,* U.S. EPA, Washington, D.C., June 1997.) Because the operating penalties for SCR were small, they were not included in the modeling.

[7]For a fuller treatment of the cost and performance of SCR, see previously cited EPA October 2001 report. For SNCR and gas reburn, see *Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers*, Bechtel Power Corp. for US EPA, June 1997.

Singly and in combination with other emission controls, NO_x post-combustion controls have the added benefit of mercury removal. This is captured in the EPA Base Case 2000 through mercury emission modification factors (EMFs). Section 5.3.2 below contains a detailed description of the mercury EMFs used in the EPA Base Case 2000.

Table 5.3. Post-Combustion NO_x Controls for Coal Plants (1999 $)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Gas Use	Percent Removal
SCR[2]	$80	$0.53	0.37	--	90%[1]
SNCR[3] (Low NO_x Rate)	$17.1	$0.25	0.84	--	35%
SNCR[4] (High NO_x Rate—Cyclone)	$9.9	$0.14	1.31	--	35%
SNCR[5] (High NO_x Rate—Other)	$19.5	$0.30	0.90	--	35%
Natural Gas Reburn[6] (Low NO_x)	$33.3	$0.50	--	16%	40%
Natural Gas Reburn[6] (High NO_x)	$33.3	$0.50	--	16%	50%

Notes:

Low NO_x is < 0.5 lbs/mmBtu. High NO_x is $\geq$ 0.5 lbs/mmBtu.

[1] Cannot provide reductions any further beyond 0.05 lbs/mmBtu.

[2] SCR Cost Scaling Factor:
SCR Capital and Fixed O&M Costs: $(242.72/MW)^{0.35}$.
For Variable O&M, multiply the VOM value shown in the table by the previous scaling factor. Then, add the constant 0.603212 to the resulting product.
Scaling factor applies up to 500 MW.

[3] Low NO_x SNCR Cost Scaling Factor:
Low NO_x Coal SNCR Capital and Fixed O&M Costs: $(200/MW)^{0.577}$.
Scaling factor applies up to 500 MW.

[4] High NO_x SNCR—Cyclone Cost Scaling Factor:
High NO_x Coal SNCR—Cyclone Capital and Fixed O&M Costs: $(100/MW)^{0.577}$
VO&M = 1.27 for MW $\leq$ 300,
VO&M = 1.27 – ((MW – 300)/100) * 0.015 for MW > 300.

[5] High NO_x Coal SNCR—Other Cost Scaling Factor:
High NO_x Coal SNCR—Other Capital and Fixed O&M Costs: $(100/MW)^{0.681}$
VO&M = 0.88 for MW $\leq$ 480,
VO&M = 0.89 for MW > 480.

[6] Gas Reburn includes $5.2/kW charge for pipeline.

References

Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers, US EPA Office of Research and Development, October 2001, EPA-600/R-01-087.

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

Table 5.4. Post-Combustion NO_x Controls for Oil/Gas Steam Units (1999 $)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Removal
SCR[1]	28.9	0.89	0.10	80%
SNCR[2]	9.7	0.15	0.45	50%

Notes:
[1] SCR Cost Scaling Factor:
SCR and Gas Reburn Capital Cost and fixed O&M: $(200/MW)^{0.35}$
Scaling factor applies up to 500 MW

[2] SNCR Cost Scaling Factor: :
SNCR Capital Cost and fixed O&M: $(200/MW)^{0.577}$
Scaling factor applies up to 500 MW

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

5.3 Mercury Control Technologies

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. No mercury control policy is included in EPA Base Case 2000. Consequently, 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 mercury control policies, it does include the capability to model mercury controls in anticipation of future model runs that would evaluate mercury policies relative to the base case. The technology specifically designated for mercury control in future policy runs is Activated Carbon Injection (ACI) downstream of the combustion process.

The following discussion is divided into three parts. Sections 5.3.1 and 5.3.2 treat the two factors that figure into the unregulated mercury emissions resulting under EPA Base Case 2000. Section 5.3.1 discusses how mercury content of fuel is modeled in EPA Base Case 2000. Section 5.3.2 looks at the procedure used in the base case to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.3.3 explains the mercury emission control options that are available for future modeling of mercury policies. A major focus is on the cost and performance features of Activated Carbon Injection. Each section indicates the data sources and methodology used.

5.3.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case 2000 on the mercury content of coal (and the emission modification factors discussed below in Section 5.3.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR)[8]. 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.

[8] Information on the ICR is found at http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html.

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 all coal-fired utility units greater than 25 MW. To make this data usable in EPA Base Case 2000, 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 8.5 for a definition of each IPM coal type.) 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 concentrations for that coal type. Each coal type used one, two or three clusters. To the greatest extent possible the total number of mercury 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 mercury 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 2000 for estimating mercury emissions. IPM input files retain the mapping between different coal type-supply region combinations and the mercury clusters. Table 5.5 below provides a summary by coal type of the number of clusters and range and average mercury content of coal across all IPM coal supply regions as used in EPA Base Case 2000. Columns 3-5 show the range criteria that are used to map the weighted average mercury content for a specific coal type-supply region (derived from the ICR) into the average mercury concentration cluster values (columns 6-8) used in EPA Base Case 2000.

Table 5.5. Mercury Clusters and Mercury Content of Coal by IPM Coal Types

		Range of mercury concentration within each coal cluster (lbs/Tbtu)			*Average Mercury concentration within each cluster (lbs/Tbtu)*		
Coal Type by Sulfur Grade	*No. of clusters*	**Cluster #1**	**Cluster #2**	**Cluster #3**	**Cluster #1**	**Cluster #2**	**Cluster #3**
Low Sulfur Eastern Bituminous (BA)	2	< = 3.7	> 3.7	--	3.69	5.17	--
Low Sulfur Western Bituminous (BB)	3	< = 3.72	> 3.72 to <= 4.2	> 4.2	3.41	4.1	7.85
Low Medium Sulfur Bituminous (BD)	3	< = 7.29	> 7.29 to <= 15.42	> 15.42	5.07	12.54	21.95
Medium Sulfur Bituminous (BE)	3	< = 8.23	> 8.23 to <= 12.35	> 12.35	6.08	10.45	18.42
Medium High Sulfur Bituminous (BF)	3	< = 8.54	> 8.54 to <= 12.2	> 12.2	6.83	11.09	18.69
High Sulfur Bituminous (BG)	3	< = 9.82	> 9.82 to <= 21.46	> 21.46	8.04	17.43	28.73
Low Sulfur Subbituminous (SB)	2	< = 4.6	> 4.6	--	4.55	6.48	--
Low Medium Sulfur Subbituminous (SD)	2	< = 4.5	> 4.5	--	4.4	6.7	--
Medium Sulfur Subbituminous (SE)	2	< = 6.46	> 6.46	--	5.53	10.71	--
Low Medium Sulfur Lignite (LD)	1	> = 0	--	--	8.45	--	--
Medium High Sulfur Lignite (LF)	2	< = 5.89	> 5.89	--	5.88	9.79	--

Oil, natural gas, and waste fuels: The EPA Base Case 2000 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[9] Table 5.6 below provides a summary of the assumptions on the mercury content for oil, gas and waste fuels include in EPA Base Case 2000.

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

Table 5.6. Assumptions on Mercury Concentrations in Non-Coal Fuel in EPA Base Case 2000

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00*
Wood Waste	0.57
Municipal Solid Waste	71.85
Geothermal Resource	4.08

*The values appearing in this table are rounded to two decimal places. As indicated below in section 8.2.2, an EPA study found that the mercury content of natural gas is 0.00014 lbs/TBtu.

5.3.2 Mercury Emission Modification Factors

As noted above the third component of the ICR involved obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representation set of coal units This provided the most extensive data set available to date on the mercury reduction characteristics of the most prevalent coal unit configurations. The data were used to derive emission modification factors (EMF) that capture the mercury reductions attributable to different unit configurations and different configurations of SO_2, NO_X, and particulate controls. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration and depends on the unit's burner type, particulate control, post-combustion NO_x control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to the inlet rate) during combustion and flue-gas treatment processes is (1-EMF). The EMF varies by the type of coal (i.e. bituminous, sub-bituminous and lignite) used during the combustion process. Sub-bituminous and lignite coal were assumed to have the same EMFs. The resulting EMFs were incorporated into EPA Base Case 2000 to characterize the mercury emissions from either existing or retrofitted units with SCR, SNCR and SO_2 scrubbers. Table 5.7a below provides a summary of the EMFs used in EPA Base Case 2000[10]. Table 5.7b provides a key to the burner type designations appearing in Table 5.7a.

[10]IPM has the capability of modeling other EMF scenarios. For example, Appendix 5.4 shows alternative EMFs developed for a sensitivity analysis based on the U.S. Department of Energy, Energy Information Administration's mercury removal assumptions.

Table 5.7a. Mercury Emission Modification Factors Used in EPA Base Case 2000

Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
Cyclone	Cold side ESP	None	None	0.6	0.85
Cyclone	Cold side ESP	SCR	None	0.6	0.85
Cyclone	Cold side ESP	SNCR/Other	None	0.6	0.85
Cyclone	Cold side ESP	None	Wet FGD	0.45	0.6
Cyclone	Cold side ESP	SCR	Wet FGD	0.05	0.05
Cyclone	Cold side ESP	SNCR	Wet FGD	0.1	0.1
Cyclone	Hot side ESP	None	None	0.9	1
Cyclone	Hot side ESP	SCR	None	0.9	1
Cyclone	Hot side ESP	SNCR/Other	None	0.9	1
Cyclone	Hot side ESP	None	Wet FGD	0.45	0.6
Cyclone	Fabric Filter	None	None	0.45	0.95
Cyclone	Fabric Filter	SCR	None	0.45	0.95
Cyclone	Fabric Filter	SNCR/Other	None	0.45	0.95
Cyclone	Fabric Filter	None	Wet FGD	0.4	0.95
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95
Cyclone	Fabric Filter	SCR	Wet FGD	0.05	0.05
Cyclone	Fabric Filter	SCR	Dry FGD	0.45	0.95
Cyclone	Fabric Filter	SNCR	Wet FGD	0.1	0.1
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95
Cyclone	PM Scrubber	None	None	0.8	1
Cyclone	No Control	None	None	1	1
Cyclone	No Control	SCR	None	1	1
Cyclone	No Control	SNCR/Other	None	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6
Cyclone	No Control	SCR	Wet FGD	0.05	0.05
Cyclone	No Control	SNCR	Wet FGD	0.1	0.1
PC	Cold side ESP	None	None	0.6	0.85
PC	Cold side ESP	SCR	None	0.6	0.85
PC	Cold side ESP	SNCR/Other	None	0.6	0.85
PC	Cold side ESP	None	Wet FGD	0.2	0.65
PC	Cold side ESP	None	Dry FGD	0.6	0.85
PC	Cold side ESP	SCR	Wet FGD	0.05	0.05
PC	Cold side ESP	SNCR	Wet FGD	0.1	0.1
PC	Cold side ESP	SNCR	Dry FGD	0.6	0.85
PC	Hot side ESP	None	None	0.9	0.9
PC	Hot side ESP	SCR	None	0.9	0.9
PC	Hot side ESP	SNCR/Other	None	0.9	0.9
PC	Hot side ESP	None	Wet FGD	0.45	0.7
PC	Hot side ESP	None	Dry FGD	0.6	0.85
PC	Hot side ESP	SCR	Wet FGD	0.05	0.05
PC	Hot side ESP	SCR	Dry FGD	0.6	0.85
PC	Hot side ESP	SNCR	Wet FGD	0.1	0.1
PC	Hot side ESP	SNCR	Dry FGD	0.6	0.85
PC	Fabric Filter	None	None	0.4	0.75
PC	Fabric Filter	SCR	None	0.4	0.75
PC	Fabric Filter	SNCR/Other	None	0.4	0.75
PC	Fabric Filter	None	Wet FGD	0.05	0.3
PC	Fabric Filter	None	Dry FGD	0.05	0.75
PC	Fabric Filter	SCR	Wet FGD	0.05	0.05
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75
PC	Fabric Filter	SNCR	Wet FGD	0.1	0.1
PC	Fabric Filter	SNCR	Dry FGD	0.05	0.75

Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
PC	Cold side ESP + FF	None	None	0.2	0.75
PC	Cold side ESP + FF	SCR	None	0.2	0.75
PC	Cold side ESP + FF	SNCR/Other	None	0.2	0.75
PC	Cold side ESP + FF	None	Wet FGD	0.05	0.3
PC	Hot side ESP + FF	None	Wet FGD	0.05	0.3
PC	Hot side ESP + FF	None	Dry FGD	0.05	0.75
PC	Hot side ESP + FF	SCR	Wet FGD	0.05	0.05
PC	Hot side ESP + FF	SCR	Dry FGD	0.05	0.75
PC	Hot side ESP + FF	SNCR	Wet FGD	0.05	0.1
PC	Hot side ESP + FF	SNCR	Dry FGD	0.05	0.75
PC	PM Scrubber	None	None	0.9	1
PC	PM Scrubber	SCR	None	0.9	1
PC	No Control	None	None	1	1
PC	No Control	SCR	None	1	1
PC	No Control	SNCR/Other	None	1	1
PC	No Control	None	Wet FGD	0.45	0.7
PC	No Control	None	Dry FGD	0.6	0.85
PC	No Control	SCR	Wet FGD	0.05	0.05
PC	No Control	SCR	Dry FGD	0.45	0.7
PC	No Control	SNCR	Wet FGD	0.1	0.1
PC	No Control	SNCR	Dry FGD	0.6	0.85
FBC	Cold side ESP	None	None	0.65	0.65
FBC	Cold side ESP	None	Wet FGD	0.65	0.65
FBC	Cold side ESP	SCR	Wet FGD	0.05	0.05
FBC	Cold side ESP	SNCR	Wet FGD	0.1	0.1
FBC	Fabric Filter	None	None	0.45	0.45
FBC	Fabric Filter	SCR	None	0.25	0.45
FBC	Fabric Filter	None	Wet FGD	0.45	0.45
FBC	Fabric Filter	SCR	Wet FGD	0.05	0.05
FBC	Fabric Filter	SNCR	Wet FGD	0.1	0.1
FBC	No Control	None	None	1	1
FBC	No Control	SCR	None	1	1
FBC	No Control	SNCR/Other	None	1	1
FBC	No Control	None	Wet FGD	1	1
FBC	No Control	None	Dry FGD	0.45	0.45
FBC	No Control	SCR	Wet FGD	0.05	0.05
FBC	No Control	SNCR	Dry FGD	0.45	0.45
Stoker	Cold side ESP	None	None	0.65	0.85
Stoker	Cold side ESP	SCR	None	0.65	0.65
Stoker	Cold side ESP	SNCR/Other	None	0.65	0.65
Stoker	Cold side ESP	None	Wet FGD	0.6	0.65
Stoker	Hot side ESP	None	None	1	1
Stoker	Hot side ESP	SCR	None	1	1
Stoker	Hot side ESP	SNCR/Other	None	1	1
Stoker	Hot side ESP	None	Wet FGD	1	1
Stoker	Fabric Filter	None	None	0.1	0.45
Stoker	Fabric Filter	SCR	None	0.1	0.45
Stoker	Fabric Filter	SNCR/Other	None	0.1	0.45
Stoker	Fabric Filter	None	Wet FGD	0.1	0.45
Stoker	Fabric Filter	None	Dry FGD	0.1	0.45
Stoker	No Control	None	None	1	1
Stoker	No Control	SCR	None	1	1

Burner Type	Particulate Control	Post Combustion Control -- NO_x	Post Combustion Control -- SO_2	Bituminous EMF	Sub-bituminous EMF
Stoker	No Control	SNCR/Other	None	1	1
Stoker	No Control	None	Wet FGD	1	1
Other	Cold side ESP	None	None	0.6	0.85
Other	Cold side ESP	SCR	None	0.6	0.85
Other	Cold side ESP	SNCR/Other	None	0.6	0.85
Other	Cold side ESP	None	Wet FGD	0.6	0.85
Other	Hot side ESP	None	None	1	1
Other	Hot side ESP	SCR	None	1	1
Other	Hot side ESP	SNCR/Other	None	1	1
Other	Hot side ESP	None	Wet FGD	1	1
Other	Fabric Filter	None	None	0.45	0.95
Other	Fabric Filter	SCR	None	0.45	0.95
Other	Fabric Filter	None	Wet FGD	0.4	0.95
Other	Fabric Filter	None	Dry FGD	0.4	0.95
Other	Fabric Filter	SCR	Wet FGD	0.05	0.05
Other	Fabric Filter	SCR	Dry FGD	0.4	0.95
Other	Fabric Filter	SNCR	Wet FGD	0.1	0.1
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.95
Other	No Control	None	None	1	1
Other	No Control	SCR	None	1	1
Other	No Control	SNCR/Other	None	1	1
Other	No Control	None	Wet FGD	1	1
Other	No Control	SCR	Wet FGD	0.05	0.05
Other	No Control	SNCR	Wet FGD	0.1	0.1
Cyclone	No Control	None	None	1	1
FBC	No Control	None	None	1	1
PC	No Control	None	None	1	1
PC	No Control	None	Wet FGD	0.45	0.7
PC	No Control	SNCR/Other	None	1	1
PC	Cold side ESP	None	Dry FGD	0.55	0.85
PC	Cold side ESP + FF	SCR	Wet FGD	0.05	0.05
PC	Cold side ESP + FF	SNCR	Wet FGD	0.1	0.1
Cyclone	No Control	None	Dry FGD	1	1
Cyclone	Cold side ESP	None	Dry FGD	0.6	0.85
Cyclone	Cold side ESP	SCR	Dry FGD	0.6	0.85
Cyclone	Hot side ESP	None	Dry FGD	0.9	1
Other	No Control	None	Dry FGD	1	1
Other	Cold side ESP	None	Dry FGD	0.6	0.85
Other	Hot side ESP	None	Dry FGD	1	1
PC	Cold side ESP	SCR	Dry FGD	0.6	0.85
PC	Cold side ESP + FF	None	Dry FGD	0.05	0.75
Stoker	No Control	None	Dry FGD	1	1
Stoker	Cold side ESP	None	Dry FGD	0.65	0.85
Stoker	Hot side ESP	None	Dry FGD	1	1
Cyclone	Hot side ESP	SCR	Dry FGD	0.9	1
Cyclone	No Control	SCR	Dry FGD	1	1
PC	Cold side ESP + FF	SCR	Dry FGD	0.05	0.75
FBC	No Control	SCR	Dry FGD	0.45	0.45
Stoker	Cold side ESP	SCR	Dry FGD	0.65	0.85
Stoker	Hot side ESP	SCR	Dry FGD	1	1
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.45
Stoker	No Control	SCR	Dry FGD	1	1

Table 5.7b. Key to Burner Type Designations in Table 5.7a

"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.

5.3.3 Mercury Control Capabilities

As noted earlier, EPA Base Case 2000 does not include any mercury control policies. However, it does include Activated Carbon Injection (ACI) as a separate mercury reduction option that could be utilized in future mercury policy runs. SO_2 and NO_x control retrofits which deliver mercury reductions as a co-benefit are included in the base case and all policy runs. These two options, ACI and SO_2/NO_x retrofits, are discussed below.

Mercury Control through SO_2 and NO_X Retrofits: In EPA Base Case 2000, units that install SO_2 and NO_X controls, reduce mercury emissions as an unintended byproduct of these SO_2 and NO_X retrofits. Section 5.3.2 described how EMFs are used in the base case to capture the unregulated mercury emissions attributable to different unit configurations and different configurations of SO_2, NO_X, and particulate controls. 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 and SO_2 scrubbers. The absence of a mercury emission reduction policy in the base case means that such controls would only be installed to meet SO_2 and NO_X limits in EPA Base Case 2000. However, in 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: The technology specifically designated for mercury control in future policy runs is Activated Carbon Injection downstream of the combustion process in coal fired units. Data on the cost and performance of ACI were obtained from a pilot study by U.S. Department of Energy's National Energy Technology Laboratory (NETL) and EPA's Office of Research and Development (ORD).

Taking a bottom-up approach, the NETL-ORD study identified the capital, fixed operation and maintenance (FOM), and variable operation and maintenance (VOM) cost of all the different components of an ACI retrofit (e.g. spray cooling, sorbent injection, sorbent disposal, and pulse-jet fabric filter systems). Since the cost of ACI retrofits depends on the desired mercury removal rate and vary based on coal type (bituminous, sub-bituminous and lignite), sulfur content of coal (low and high), and pre-existing SO_2, NO_X, and particulate controls, separate cost functions for 26 unique control configurations and coal types were developed for a range of mercury removal rates. The engineering equations were expressed as functions of such parameters as sorbent feed concentration, high heating value of coal, gas flow factors, and gas temperature changes. By pre-specifying certain engineering parameters, based on the known characteristics of each configuration, the cost functions at any specified removal rate can be reduced to functions of a unit's capacity and heat rate. The ACI engineering cost equations are described in full in Appendix 5.3.

Several steps were taken to adapt the ACI engineering equations for use in IPM.

- The coal sulfur categories used in the NETL-ORD study were defined on the basis of percent by weight, whereas sulfur content in the EPA Base Case 2000 is defined on an energy basis, i.e., sulfur per mmBtu. It was therefore necessary to use average heating values of coal to convert sulfur by weight into lbs of sulfur per mmBtu. The assumed heating values for the conversion were: bituminous – 23.8 million Btu per ton; sub-bituminous – 17.1 million Btu per ton ; and lignite – 12.8 million Btu per ton.
- To facilitate incorporating the cost functions in IPM, polynomial fits — not the original engineering equations — were used in the model. Using *Table Curve 3D,* v3.0 software, separate rational polynomials were derived for capital cost, fixed operation and maintenance cost (FOM), and variable operating and maintenance cost (VOM) for each of the different coal and control configurations. Like the initial engineering cost equations, the resulting rational polynomials were a function of heat rate, specified in BTUs/kWh, and capacity, specified in MW. Checks were performed to ensure that the resulting polynomials produced costs within acceptable tolerances of the original engineering equations.

To simplify the modeling of ACI costs, all ACI applications in a policy run would typically be assumed to provide the same percentage of mercury reduction. As a conservative, achievable starting point, 80% removal is anticipated to serve as the default mercury removal rate in future mercury policy runs. Thus, with an assumption of 80% removal, polynomial fits would be derived for the capital, FOM, and VOM engineering costs for each of the 26 configurations in the NETL/ORD study. These equations would be used to derive the cost of using ACI to reduce mercury by 80% from the level in the coal burned at similarly configured IPM model plants. Since the mercury removal efficiency from ACI depends directly on the amount of sorbent-feed injected into the mercury control system, performing a sensitivity analysis on alternative ACI removal rates (e.g., 70% or 90%) would simply involve varying the sorbent feed rates in the NETL-ORD engineering equations and deriving an alternative set for polynomial fit cost equations for the new removal rates. .

As an illustration of the costs resulting at an ACI 80% mercury removal rate, Table 5.8 shows the costs for all 26 NETL-ORD coal types and control configurations at a 500 MW coal unit with a heat rate of 10,000 Btu/kWh. (Definitions of the control technology acronyms appearing in this table can be found in Section A 5.3.1 in Appendix 5.3. The coal sulfur grades shown in the table are defined as follows: coal with a sulfur content greater than 1.8% (by weight) is defined as "high sulfur" coal; coal with a sulfur content of 1.8% or lower (by weight) is considered "low sulfur" coal.)

Table 5.8. Cost Components for 80% Mercury Removal Efficiency Using ACI, for Representative 500 MW, 10,000 Btu/kWh Heat Rate Unit

Coal Type	Existing Pollution Control Technology	Sulfur Grade: H-High; L-Low.	Capital Cost (1999$/kW)	FOM (1999$/kW/yr)	VOM (1999mills/kWh)	Removal Efficiency (%)
Bituminous	ESP	L	13.48	2.21	0.61	80
Bituminous	ESP/O	L	13.48	2.21	0.61	80
Bituminous	ESP+FF	L	12.50	2.09	0.37	80
Bituminous	ESP+FGD	H	3.63	1.03	0.69	80
Bituminous	ESP+FGD+SCR	H	ACI not applicable			
Bituminous	ESP+SCR	L	13.48	2.21	0.61	80
Bituminous	FF	L	13.48	2.21	0.61	80
Bituminous	FF+DS	H	2.34	0.87	0.36	80
Bituminous	FF+FGD	H	3.63	1.03	0.69	80
Bituminous	HESP	L	3.63	1.03	0.69	80
Bituminous	HESP+FGD	H	52.03	6.85	0.31	80
Bituminous	HESP+SCR	L	47.00	6.39	0.43	80
Bituminous	PMSCRUB+FGD	H	3.63	1.03	0.69	80
Bituminous	PMSCRUB+FGD+SCR	H	ACI not applicable			
Bituminous	ESP	H	10.93	1.91	3.54	80
Bituminous	ESP/O	H	10.93	1.91	3.54	80
Bituminous	ESP+FF	H	6.56	1.38	1.66	80
Bituminous	ESP+FGD	L	11.03	1.92	0.11	80
Bituminous	ESP+FGD+SCR	L	ACI not applicable			
Bituminous	ESP+SCR	H	10.93	1.91	3.54	80
Bituminous	FF	H	10.93	1.91	3.54	80
Bituminous	FF+DS	L	2.34	0.87	0.36	80
Bituminous	FF+FGD	L	12.98	2.15	0.48	80
Bituminous	HESP	H	55.70	1.38	1.75	80
Bituminous	HESP+FGD	L	45.28	6.17	0.13	80
Bituminous	HESP+SCR	H	55.70	7.45	1.75	80
Bituminous	PMSCRUB+FGD	L	11.03	1.92	0.11	80
Bituminous	PMSCRUB+FGD+SCR	L	ACI not applicable			
Lignite	ESP	L	16.28	2.61	1.24	80
Lignite	ESP+FF	L	12.09	2.05	0.16	80
Lignite	ESP+FGD	L	14.99	2.39	0.83	80
Lignite	FF+DS	L	1.05	0.72	0.11	80
Lignite	FF+FGD	L	11.34	1.96	0.07	80
Subbituminous	ESP	L	16.28	2.61	1.24	80
Subbituminous	ESP+DS	L	13.47	2.21	0.93	80
Subbituminous	ESP+FGD	L	12.40	2.08	0.62	80
Subbituminous	ESP+SCR	L	13.47	2.21	0.93	80
Subbituminous	FF	L	10.01	1.80	0.12	80
Subbituminous	FF+DS	L	0.87	0.70	0.08	80
Subbituminous	FF+FGD	L	9.39	1.72	0.05	80
Subbituminous	HESP	L	54.44	7.30	0.13	80
Subbituminous	HESP+FGD	L	54.33	7.28	0.13	80
Subbituminous	HESP+SCR	L	54.44	7.30	0.13	80
Subbituminous	PMSCRUB	L	13.47	2.21	0.93	80
Subbituminous	PMSCRUB+FGD	L	12.40	2.08	0.62	80

5.4 Other Emission Control Options

While not included in EPA Base Case 2000, the capability to model combustion optimization and biomass cofiring is available for use in future policy runs built upon the base case. These two control options are most likely to be applicable in modeling carbon dioxide and NO_X emission policies. Unlike the control technologies currently included in EPA Base Case 2000, which are modeled endogenously (i.e., the model decides whether a plant should install the control), the decision to employ combustion optimization and biomass cofiring would be made exogenously. That is, if this capability were exercised in a policy run, a pre-specified set of plants would be required to take on the controls. The following sections describe the nature of these two control options.

5.4.1 Combustion Optimization

Combustion optimization is a commercially available technology enhancement that plants use to increase their efficiency and decrease their NO_x emission rates. If employed in a policy run built upon EPA Base Case 2000, combustion optimization would be assumed to be installed by all coal plants that are at least 100 MW in size. Table 5.9 shows the cost and performance assumptions of the combustion optimization option. The values in Table 5.9 were derived from literature surveys and discussions with vendors and other experts familiar with combustion optimization software.

Table 5.9. Assumptions on Cost and Performance of Combustion Optimization

Unit Types	Costs (1999 $)		Improvement (in Percent)	
	Capital ($/unit)	Fixed O&M ($/unit-yr)	NO_x Removal	Heat Rate
Coal-fired units of 100 MW and greater	$ 250,000	$ 40,000	20%	0.5%

5.4.2 Biomass Co-firing

In policy cases built upon EPA Base Case 2000, coal-fired units can be given the control option of co-firing a specified percentage of biomass. Since biomass is considered a net zero emitter of CO_2 (i.e., it releases into the atmosphere the same amount of CO_2 that it absorbed from the atmosphere in its growth), this option is most likely to be employed in policy runs involving CO_2 reductions. However, as seen in Table 5.10, it can also provide some reductions in SO_2 and mercury due to the low contents of these pollutants in biomass. (Data from EPA's 1999 report *Analysis of Emission Reduction Options for the Electric Power Industry* were used to develop assumptions on mercury emissions from biomass[11]. Data from DOE/EPRI report *Renewable Energy Technology Characterizations* were used for assumptions on SO_2 emissions[12],) The assumptions for biomass co-firing do not include any incremental reductions for NO_x because the supporting data was inconclusive[13].

[11] *Analysis of Emission Reduction Options for the Electric Power Industry*, Office of Air and Radiation, US EPA, March 1999.
[12] "Biomass Co-firing", Chapter 2 in *Renewable Energy Technology Characterizations*, U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.
[13] Hughes, E., "Role of Renewables in Greenhouse Gas Reduction", Electric Power Research Institute (EPRI): November, 1998. Report TR-111883.

Table 5.10. Assumptions on Biomass Emissions Rates in EPA Base Case 2000

Emission	Emission Rate
CO_2	0.00 lbs/MMBtu
SO_2	0.08 lbs/MMBtu
Mercury	0.57 lbs/TBtu

Different co-firing options are provided to coal units depending on their unit type and size. Coal fired units with cyclone boilers and non-cyclone units larger than 200 MW would blend biomass into existing fuel, whereas non-cyclone units up to 200 MW would make capital investments for a separate feeder system. Table 5.11 below provides a summary of the cost, and performance assumptions for each of these systems.

Data for the assumptions about the cost and performance characteristics of biomass co-firing came primarily from research conducted by EPRI and DOE. The DOE/EPRI report provided the core data for capital cost, VOM, and FOM cost.[14] FOM data from the DOE/EPRI report was refined with data from a separate EPRI report.[15]

Table 5.11. Assumptions on Cost (1999 $) for Biomass Co-firing

Unit Type	Applicable Size (MW)	Co-firing Rate	Biomass Fuel Handling System	Capital Cost ($/kW)	FO&M ($/kW-Yr)
Coal Cyclone	> 200	5 %	Blended	2.62	0.37
Coal Cyclone	<= 200	15 %	Blended	7.86	1.10
Non-Cyclone Coal	> 200	2 %	Blended	1.05	0.15
Non-Cyclone Coal	<= 200	15 %	Separate	31.43	1.57

The EPA Base Case 2000 includes assumptions on biomass fuel supply. In policy cases where the biomass co-firing option is exercised, units co-firing with biomass and dedicated-biomass units would both draw biomass from the same supply curve. The data for the biomass fuel supply curves were based on EIA's Annual Energy Outlook (AEO) 2001. The prices reported in the AEO supply curve represent costs at the plant gate and include transportation costs. The biomass supply curve is an aggregation of the supply for forestry residue, urban wood waste and mill residue, energy crops and agricultural residues. The supply curves in AEO contained 50 different price steps. The EPA Base Case 2000 uses a more condensed version, i.e. with fewer discrete price steps. The biomass fuel supply assumptions in EPA Base Case 2000 are presented in greater detail in section 8.4.

[14] "Biomass Co-firing", Chapter 2 in Renewable Energy Technology Characterizations, U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.
[15] Hughes, E., "Role of Renewables in Greenhouse Gas Reduction", Electric Power Research Institute (EPRI): November, 1998. Report TR-111883.