Control of Mercury Emissions from Coal-Fired Power Plants: A Preliminary Cost Assessment

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ABSTRACT

Mercury emissions from coal-fired power plants are currently being evaluated by the Environmental Protection Agency (EPA) for possible regulation. Because of the possibility for such regulation, this paper discusses a preliminary assessment of mercury capture technologies and associated costs based on commercially available technology. Sorbent-based technologies that may be amenable for mercury control include: sorbent injection; sorbent injection with spray cooling; and sorbent injection with spray cooling and particulate collection. Important design criteria for each of these systems are critically assessed for operability, maintainability, and reliability. The projected impacts of the control system on power plant operations are also evaluated.

INTRODUCTION

Mercury cycles in the environment as a consequence of both natural and human activities. The annual global cycling of mercury in the earth's atmosphere amounts to about 5,000 tons.[1] It is estimated that 4000 tons are the consequence of anthropogenic activities. The United States is responsible for 3 percent of the global anthropogenic emission. Coal-fired power generation in the United States contributes approximately one-third of this amount. The base year for these emission estimates is 1994.

As a consequence of the large natural emissions of mercury to the atmosphere and the difficulty in accurately measuring anthropogenic emissions, these emissions and their subsequent influence on terrestrial deposition and uptake in the food chain is a subject of significant uncertainty. None-theless, the EPA has already issued regulations to control emissions from several types of processes, including municipal waste combustors and medical waste incinerators, and is con-sidering issuing regulations for coal-fired power generators (i. e., electric utilities).[2] Municipal waste combustors are estimated to emit nearly 20 percent of all U. S. anthropogenic emissions; they will be required to reduce these emissions by 90 percent of 1990 emission levels by the year 2000. Medical waste incinerators emitted nearly 10 percent of all U. S. anthropogenic emissions of mercury; they will be required to reduce these emissions by 94 percent of 1990 emission levels by 2002.

In addition, the U.S. recently completed negotiations, under the United Nations Economic Com-mission for Europe's Convention on Long Range Transboundary Air Pollution, on a protocol for reducing heavy metals, which includes mercury.[3] It is anticipated that this protocol will be finalized and signed by member countries in the summer of 1998.

Within this context, the U.S. Department of Energy's (DOE) Federal Energy Technology Center (FETC) is conducting research in its Fossil Energy Program to develop technology options for the characterization and control of air toxics, including mercury, that are emitted from fossil fuel combustion systems. The EPA has recently submitted two Reports to Congress[1,4] on the mercury emissions from coal-fired power plants. FETC made significant contributions to these reports. In this context, the cost and performance models were incorporated into the Report to Congress with FETC's analysis of cost being preferred. In addition, the improved understanding of mercury emission and its control is a direct result of the close collaboration between DOE/FETC and other private and public sector organizations, including the Electric Power Research Institute (EPRI) and the EPA.

COAL-FIRED POWER PLANTS

Coal-fired power plants are the predominant type of power generation in the United States. U.S. electric utility sales of electricity to consumers was 3,098 billion kW-hrs in 1996.[5] Coal-fired electricity generation accounted for 1,737 billion kW-hrs, or 56% of total generation, with a consumption of about 875 million tons of coal.

The most common characteristics of the coal-fired power plant that are thought to influence mercury emissions are the mercury content of the coal, the type of burner(s) on the plant, the boiler operating conditions, the design and operation of any particulate collection devices, and the design and operation of any flue gas treatment systems. A general depiction of a power plant configuration and the potential control system configurations used in this study is provided in Figure 1.

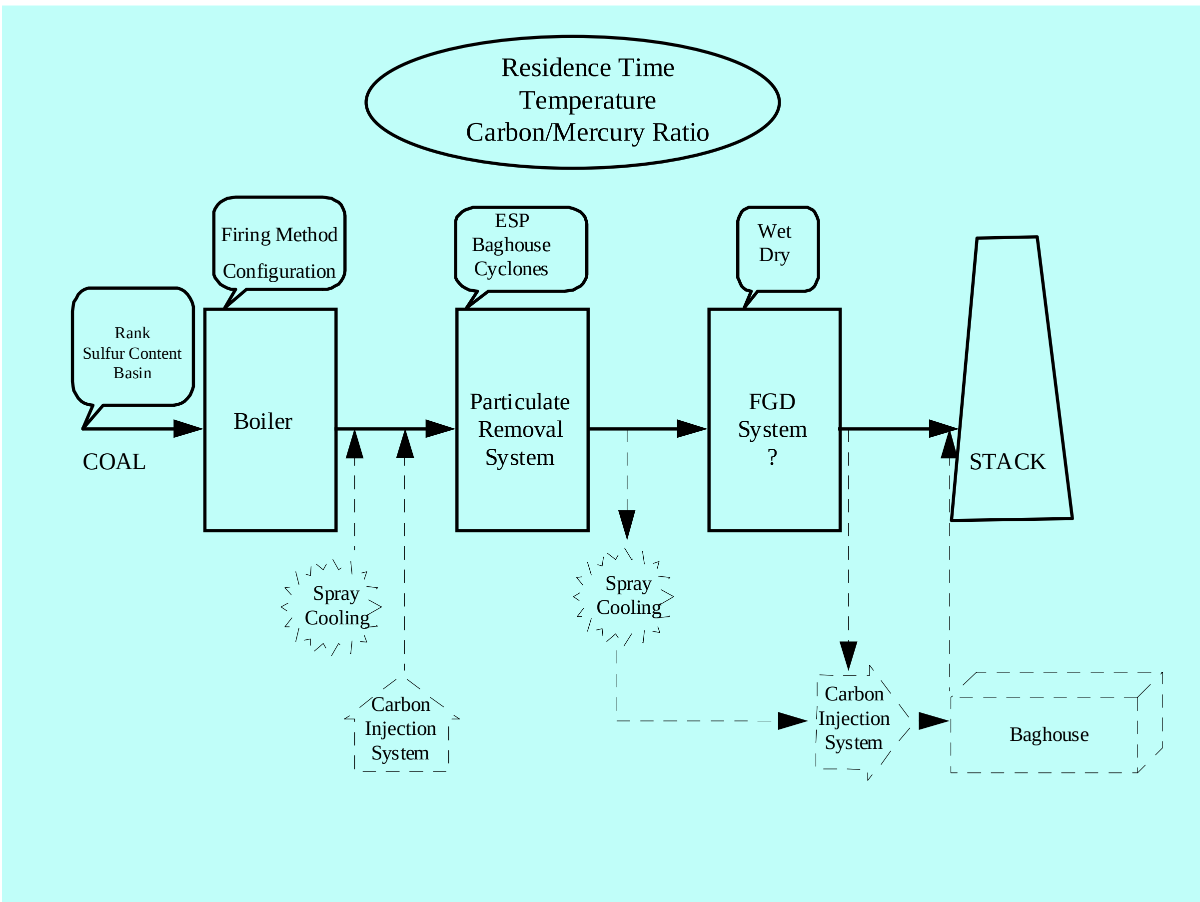

Figure 1. **Power Plant and Mercury Control System Configurations.**

Environmental equipment used to control pollutants emitted from coal combustion flue gas must meet local, state, and federal regulations. The trend in these regulations is to tighten requirements for new sources of pollution as well as to require retrofit of existing power generating equipment with environmental controls. The modern power plant is typically equipped with a high efficiency baghouse (fabric filter) or an electrostatic precipitators (ESP) for particulate removal, staged combustion burner configurations for low-NO_x emissions, and post-combustion flue gas treatment devices for NO_x and SO_2 control. Examples of the latter devices are selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies for NO_x control and high efficiency flue gas desulfurization (FGD) scrubbers for SO_2 control. Additionally, advanced coal-fired power generation technologies are evolving from cooperative efforts between the U.S.

Department of Energy and industry, such as those being demonstrated in the Clean Coal Technology Program. Technologies such as integrated gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC) are capable of producing electricity more efficiently than a conventional pulverized coal combustion power plant. These advanced power systems are also equipped with very high efficiency gas cleanup technologies.

Many of the existing coal-fired power generation facilities do not contain modern flue gas treatment systems, however. In 1996, the net dependable capacity of coal-fired power generation was about 300 billion watts (GW), of which nearly 75 GW (25%) had conventional scrubbing technology for controlling SO_2. Much of the remaining capacity meets regulatory requirements for SO_2 emissions through fuel switching, either to lower sulfur coal or by co-firing low sulfur fuels such as natural gas or biomass.

Similarly, control of NO_x emissions are primarily accomplished with low-NO_x burners (LNB), which are cheaper than SCR or SNCR, but do not reduce the emissions as much. The applications of LNB are limited at present to dry bottom boiler configurations. The burner type distribution for coal-fired power plants is provided in Table 1. This distribution is broken into coal consumption patterns, capacity distribution, and number of boilers. The largest segment of the population (80%) is comprised of tangential and opposed firing burners.

Table 1. Firing Type Distribution for Coal-Fired Power Plants (1996)*

Firing Type	Coal Consumption, million tons	Net Dependable Summer Capacity, GW	Number of Boilers
Front	82.1	33.9	254
Tangential	393.3	128.5	424
Opposed	314.5	107.5	203
Vertical	7.7	3.5	28
Cyclone	68.0	22.4	86
Other	9.0	3.1	40
Total	874.7	299.0	1035

* Compiled from FETC database

Particulates from coal-fired power plants are principally controlled with either ESPs or fabric filters. The majority of ESPs are located on the “cold-side” of a system, i. e., after the air preheater.

The distribution of all typical particulate and SO_2 flue gas cleanup devices by amount of coal burned (in all coal-fired power generation plants in the U. S. in 1996) is provided in Table 2. It can be seen that the predominant particulate cleanup device is a “cold-side” ESP, and that most of the SO_2 removal is performed by (wet) flue gas desulfurization.

Table 2. Flue Gas Cleanup Systems for Coal-Fired Power Plants (1996)*

Particulate Control	Coal Consumption, (million tons)	Net Dependable Summer Capacity (GW)	Number of Boilers
Cold-Side ESP	650.2	226.7	777
Fabric Filter	67.2	19.3	74
Particulate Scrubber	14.6	4.0	10
Other	142.8	49.0	174
Total	874.7	299.0	1035
SO2 Control			
FGD	240.2	69.5	159
Spray Dryer	22.6	5.2	16
Other	611.9	224.2	860
Total	874.7	299.0	1035

* Compiled from FETC database

The “other” particulate matter control systems are principally comprised of “hot-side” ESPs (where control occurs upstream of the air preheater) and mechanical devices such as cyclones and multiclones. The “other” sulfur control is mainly due to fuel switching with a minor amount of control associated with sorbent injection and regenerable SO_2 control systems.

MERCURY EMISSIONS

Flue gas cleanup systems and other operational strategies imposed at the power plant have a variable impact on the emissions of mercury. Table 3, modified from a table in the Electric Utility Report to Congress,[4] qualitatively describes the impact these have on mercury emissions. The carbon adsorption system is the only system deliberately installed to control mercury emissions. This, and other mercury control options, to be discussed later, are expensive to implement. One reason for the expense is the large flue gas volumes that must be treated to capture a very small amount of mercury; typical mercury concentrations in uncleaned flue gas are in the low parts per billion range. The mercury in the flue gas can be characterized as being in two forms: oxidized or elemental. The ability of systems to capture the mercury is dependent, in part, on the species of mercury in the flue gas, as evidenced by Table 3.

Table 3. Power Plant Operations Affecting Mercury Emissions*

Power Plant Configuration and Operations Strategy	**Effect on Mercury Emissions**	
	Primarily Oxidized Mercury	**Primarily Elemental Mercury**
Conventional Coal Cleaning	Decrease in emission (highly coal specific)	
Fuel Switching: Coal to Gas	Decrease in emission	
Electrostatic Precipatator	Some decrease in emission	Some decrease in emission
Fabric Filter	Some decrease in emission	Greater decrease in emission
Scrubber	Decrease in emission	No Effect
Spray Dryer/Fabric Filter	Some decrease in emission	Limited decrease in emission
Carbon Adsorption System	Decrease in emission (based on pilot-scale studies)	

* Updated by FETC

Further elaboration of the impact various unit processes in a power plant have on mercury emissions has been investigated and was described by FETC in the Electric Utility Report to Congress.

An emission modification factor (EMF) was developed by EPA that reflects the ratio of the mercury emissions after installation of a particular subsystem or unit process to the mercury emissions that would be realized if 100% of the mercury entering the subsystem or unit process left in the flue gas. EPA EMF's, shown in Table 4, are subject to a degree of uncertainty since only limited measurements of mercury are available for each unit process or subsystem.

An inventory of mercury emissions from fossil fuel power plants was prepared by the EPA in the Utility Report to Congress. The base year for this inventory was 1994. For coal-fired electric utility power plants, the total emission inventory for the U.S. was estimated to be 51.34 tons. Coal consumption at electric utility plants was 817.3 million tons.[6] The most recent data of annual coal consumption that contain sufficient detail on coal quality is for 1996, where consumption rose to 874.7 million tons. Using the method established by EPA, a detailed estimate of annual mercury emissions can be made from available data sets that characterize the coal-fired power generation industry in 1996.

Table 4. EPA Mercury Emission Modification Factors

Emission Modification Factors for Coal-Fired Power Plants	Mercury Emission Modification Factor
Front-Fired Dry Bottom without NOx Control	0.94
Tangentially-Fired Dry Bottom with NOx Control	0.92
Tangentially-Fired Dry Bottom without NOx Control	0.81
Opposed-Fired Dry Bottom with NOx Control	0.81
Vertically-Fired Dry Bottom with NOx Control	0.78
Opposed-Fired Dry Bottom without NOx Control	0.41
Cyclone-Fired Wet Bottom without NOx Control	0.93
Cyclone-Fired Wet Bottom with NOx Control	0.54
Particulate Matter Scrubber	0.96
Flue Gas Desulfurization Scrubber	0.66
Spray Dryer Absorber / Fabric Filter	0.70
Cold-Side Electrostatic Precipitator	0.68
Fabric Filters	0.56

Coal consumption at each power plant facility is obtained from the Utility Data Institute's Power Plant Statistics.[7] The consumption of coal at the boiler level is assigned by capacity distribution within the facility. The quality of the coal and the state of origin is used as a proxy to estimate the average state-wide mercury concentration in the coal. The impact of coal cleaning is assigned as prescribed in Appendix D of the Utility Report to Congress. Power plant characteristics, such as firing configuration, particulate control, and flue gas treatment, are identified on a boiler level basis, and the subsequent EMFs are assigned based on measurements at representative coal-fired power plants (Table 4).

From this analysis, it is possible to build an estimate of mercury emissions for 1996 using the following expression:

$$M_{coal} * \frac{c_{hg}}{10^6} * ccf * \prod EMF_i = M_{hg}$$

Where M_{coal} is the coal consumption (tons/yr), C_{hg} is the mercury content in the coal (ppmw), ccf is the coal cleaning factor, $\prod EMF_i$ is product of the applicable emission modifcation factors on a boiler level basis, and M_{hg} is the mercury emissions (tons/yr). The mercury content in the coal was estimated from Table D-8a of the Utility Report to Congress and a coal cleaning factor of 0.79 was assigned to coal mined in thirteen states where coal cleaning is a common practice. A summary of the estimated annual emissions of mercury as a function of firing configuration and points within the mercury capture pathway is provided in Table 5.

Table 5. Summary of Mercury Emission Inventory from Coal-Fired Power Plants*

Mercury Emissions (1996), tons/yr					
Firing Configuration	Uncontrolled	After Coal Cleaning	After Combustion	After Particulate Control	Stack Emission
Front	10.5	8.9	8.7	6.1	5.9
Tangential	48.5	43.5	38.1	27.7	24.6
Opposed	39.7	34.3	24.1	18.1	15.7
Vertical	1.2	1.0	0.9	0.6	0.6
Cyclone	7.2	6.7	6.1	4.3	3.9
Other	1.5	1.3	1.3	0.8	0.8
Total	108.6	95.7	79.1	57.6	51.46

* Compiled by FETC using EPA EMFs and EPA methodology

It can be seen that the largest amount of mercury released to the atmosphere (from coal-fired power plants in the U. S.) is from tangentially fired boilers. This is a direct result of the amount of coal consumption for this firing configuration relative to the total coal consumption. Stack emissions are reduced by about half (53%) of the uncontrolled emissions. The greatest reduction occurs in the particulate control area of the power plant and represents 20% of the uncontrolled emission reduction. This reduction is strongly influenced by the widespread use of cold-side ESPs. Coal cleaning and scrubbers provide an additional reduction of about 17%, and the coal combustion boiler island pathway provides an addition 15% reduction over the uncontrolled emissions. At this time, the mercury inventory should be considered preliminary.

MERCURY CONTROL SYSTEMS

Three carbon injection based technologies will be considered for mercury emission control options: carbon injection alone, carbon injection with spray cooling, and carbon injection with spray cooling and a fabric filter. The control system is assumed to be retrofitted into an existing power plant with moderate congestion at the control points. The configuration of the control system is designed around two coal-fired power plant models using the EPA methodology developed in Appendix B of Volume VIII of the Mercury Study Report to Congress.
Both plants operate with a capacity factor of 65 percent. Fuel characteristics include chloride levels assumed to be sufficiently high that all the mercury in the flue gas is in the form of $HgCl_2$

(i. e., oxidized). The inlet mercury level in the flue gas to the control systems associated with each coal-fired model plant is assumed to be 10 µg/dscm (4.4 gr/million dscf) at 20°C (68°F).

Model plant 1 is a 975-megawatt (MW) boiler firing low-sulfur coal with a chloride content of 0.1 percent. The plant has a flue gas volume of 4,050,000 dscm/hr and is equipped with a cold-side ESP. The temperature ahead of the ESP is 157°C (314°F), and the temperature exiting the ESP is 150°C (302°F). No mercury control across the ESP is assumed.

Model plant 2 is similar to Model plant 1, except that it has a capacity of 100 MW (Noblett et al., 1993). This plant has a flue gas volume of 411,000 dscm/hr. The gas temperature ahead of the ESP is 146°C (295°F), and the ESP outlet temperature is 137°C (280°F). Again, no mercury control across the ESP is assumed.

Mercury control of the units is accomplished by one of the following methods:

A ➟ Direct injection of activated carbon ahead of the existing particulate control device;

B ➟ Spray cooling of the flue gas after the existing particulate control device, followed by activated carbon injection and a fabric filter to collect the mercury-laden carbon;

C ➟ Spray cooling of the flue gas after the air preheater, followed by activated carbon injection before the existing particulate control device.

Table 6 summarizes the model utility boilers and mercury controls used in the cost analysis.

Table 6. Description of Utility Model Cases

Utility Model		1A	1B	1C	2A	2B
Boiler Size	MWe	975	975	975	100	100
Hg Concentration	µg/dscm	10	10	10	10	10
Flue Gas Temperature	°C	157	93	93	146	93
Flue Gas Temperature	°F	315	199	199	295	199
Carbon Usage[a]	g C/g Hg	100,000	9,398	30,000	100,000	12,572
Carbon Injection Rate	Kg C/hr	4,050	381	1,215	411	52
Flue Gas Flow	dscm/hr	4,050,00	4,050,00	4,050,000	411,000	411,000
Spray Cooling		No	Yes	Yes	No	Yes
Carbon Injection		Yes	Yes	Yes	Yes	Yes
Fabric Filter		No	Yes	No	No	Yes
Existing Controls		ESP	ESP	ESP	ESP	ESP

Utility Model		1A	1B	1C	2A	2B
Coal Sulfur Content		low	low	low	low	low
Hg Removal		90%	90%	90%	90%	90%
Capacity Factor		65%	65%	65%	65%	65%

[a] Derived from laboratory and pilot-scale mercury sorbent tests.[8-16]

The utility model numbering system conforms with that in Appendix B of Volume VIII of the Mercury Study Report to Congress. Cases 1A and 2A refer to carbon injection upstream of an existing ESP. Cases 1B and 2B refer to spray cooling of the flue gas after the existing ESP, followed by activated carbon injection and a fabric filter particulate cleanup module. Model 1C refers to spray cooling after the air preheater followed by carbon injection upstream of an existing ESP. The mercury removal efficiency of each control system is designed to remove 90% of the mercury in the flue gas. It should be noted that spray cooling is an effective method for reducing the temperature of the flue gas stream, which in most cases reduces the amount of required carbon sorbent for mercury capture.

Incremental costs associated with mercury control in this setting are addressed first. The design criteria and assumptions that specify each of the three control modules are addressed next. Finally, a summary of the control system costs for each case is provided.

<u>Incremental Costs - Capital Cost Adjustment for Retrofit</u>
The retrofit factors for the mercury control systems are used to account for site specific criteria such as:

- access and congestion
- underground obstructions
- ductwork tie-in difficulty
- distance between control system and waste handling system

EPRI[17] has developed rough guidelines for capital adjustments that consider these factors. As indicated, "...for a relative comparison of costs for crude comparisons, suggested retrofit factors are 1.25 for plants 5 years old, 1.30 for 15 year old plants and 1.4 for plants 25 years old or over." In the present cost analysis, a conservative retrofit factor of 1.3 for the model control systems is used in the development of installation costs.

<u>Incremental Costs - Operating Penalties</u>
It is estimated[18] that 90 million tons of solid by-products are produced each year from coal combustion. The American Coal Ash Association, Inc. (ACAA) data for 1994 indicate that about 61% of the solid by-product is fly ash. Fly ash used offsite amounts to approximately 10 million tons per year, of which 7.5 million tons is used as high quality pozzolan cement in concrete applications. "The price of high quality fly ash pozzolan is beginning to rise in areas where there

are shortages and prices of $25 to $30 per ton are not uncommon.[18]" The cost for transportation is between $0.10 and $0.30/ton-mile.

Based upon the above observations, 18.2% of all fly ash generated will be rendered unfit for by-product sales in the activated carbon injection process (used in Models 1A and 2A). This cost is reflected in the levelized cost estimate for mercury control for Models 1A and 2A. A conservative estimate of $3/ton for lost revenue in fly ash sales is assigned to carbon injection systems, since the carbon-to-mercury ratios are high enough to push fly ash beyond the specification for pozzolan.

Carbon Injection System

The carbon injection system design consists of a carbon storage silo equipped with pneumatic loading capabilities, a feed bin, a gravimetric feeder, a pneumatic conveyer system, and carbon injection ports. The carbon injection system is evaluated for cases 1A, 1C, and 2A. In case 1C, the carbon injection system is integrated with a spray cooler.

For the activated carbon storage silo, a Class III (detailed) level estimate was made with the use of the ICARUS Process Evaluator.[19] The silo was designed for 15 days of storage and compliance with all relevant construction codes. The design considerations included elevation legs of 8 feet for access criteria, a carbon steel shell, and a pulse jet baghouse for loading the activated carbon from a pneumatic truck transfer system.

The remainder of the carbon injection system cost estimate was made based on a recent EPA report.[20] This report provides algorithms for carbon injection systems for hazardous waste combustors that have been validated both by quotes and by an architectural and engineering design team for the Office of Solid Waste and Emergency Response within the EPA. The level for this estimate is considered to be between a Class I (simplified) and Class II (preliminary). Only one change has been made in the use of this model: a change in the retrofit factor from 1.15 to one more suitable for the utility industry of 1.3.

Table 7 provides a capital cost breakdown for the carbon injection system applied to a 100-MW and a 975-MW power plant, including a listing of the major design criteria and assumptions. Only one carbon silo is used in the 100-MW plant. Two silos operating in parallel are used in the 975-MW plant.

Spray Cooling

Spray cooling or humidification is used to cool the flue gas from coal-fired power plants upstream of the ESP. In addition to increasing the sorbent reactivity of the activated carbon, it also can improve the ESP collection performance by reducing the flue gas volume and fly ash resistivity. Humidification prior to a fabric filter can be of concern, however, since the increase in moisture content of the flue gas can lead to blinding (e.g., condensed sulfuric acid mist) and cake release problems within the fabric filter.

Table 7. Carbon Injection System Design and Costs

Reference Power Plant Size	100 MWe	975 MWe
bulk carbon density, lb/ft^3	24	24
carbon injection rate, lb/hr	906	8929
silo volume (15 day storage), ft^3	13,600	134,000
Mass of carbon, lb	326,000	3,210,000
Equipment Item Costs	**thousand $**	
carbon silo	143	1,722
feed bin	6	24
gravimetric feeder	10	12
pneumatic conveyor	35	96
carbon injection ports	25	36
Total Equipment (1989 basis)	218	1,891
Equipment w/instrument, tax & freight	257	2,231
Escalated Total Equipment (Jan 1, 1996)	291	2,526
Purchased Equipment w/retrofit	379	3,283
Total Capital Cost (Jan 1, 1996)	708	6,139

The spray cooling system consists of a water supply tank, pump, compressor, water level control system, in-duct temperature sensor array, and a spray bar with an array of nozzles. The spray cooling chamber is normally designed for a gas residence time on the order of 0.5 seconds, but in the present study the existing ductwork is considered to be able to substitute for the spray cooling chamber and provide for sufficient residence time. Water is injected into the flue gas through a spray distribution header equipped with aerated nozzles. Aeration is provided with compressed air. The water feed tank is a conventional vessel with no mixers.

The water injection rate is estimated by the following expression derived from an energy balance:

$$w_i = \frac{(T_i - T_o) * (G_i - M_i) * c_{pg}}{\lambda_{vap}}$$

W_i is the water injection rate requirement. T_i and T_o refer to the inlet and outlet flue gas temperatures, respectively. The mass flow rate of flue gas into the spray cooler (dry basis) is the quantity (G_i - M_i). The specific heat capacity of the flue gas is expressed by C_{pg}, and the heat of vaporization for the water is expressed as λ_{vap}.

The capital cost estimate for both the spray cooler and fabric filter provided in the Mercury Study Report to Congress are reasonable and are used in the preliminary assessment. Some areas that require further definition include: the widespread availability of sufficient duct length between the spray injection point and particulate control device (of concern in case 1C); the ability to control flue gas temperatures sufficiently above the adiabatic saturation temperature so that corrosion problems are avoided; the ability to avoid blinding of the fabric filters (of concern in cases 1B and 2B); and a sufficient straight length of ductwork to avoid wall wetting and ash deposition downstream of the spray injectors.

Fabric Filter

The fabric filter control system for the present study consists of a reverse-gas fabric filter or baghouse (one of EPA's model assumptions), a carbon injection system, and a spray cooler (for cases 1B and 2B) located after the ESP. The baghouse consists of isolated compartments containing rows of fabric filter bags. Particle-laden flue gas passes along the surface of the bags before exiting radially through the fabric filter. The filter is operated cyclically — alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Most of the energy needs for operating the fabric filter are associated with fan requirements to overcome the pressure drop across the bags and associated hardware and ducting. The most important design parameter is the air-to-cloth ratio. The largest capital cost associated with cases 1B and 2B is for a reverse air fabric filter. As such, the capital costs for the fabric filter estimated in the Mercury Study Report to Congress was checked for reasonableness. Other capital components associated with Cases 1B and 2B were accepted as reasonable estimates.

A crucial concern for design considerations of the fabric filter control system used in this study is the build-up rate of a dust cake for the filtering of particulate-laden activated carbon that allows for mercury removal. If this rate process is too slow, then a significant amount of mercury will not be exposed to the activated carbon at the fabric filter interface, thereby lowering the utilization rate of carbon. Even more importantly, the filtration efficiency of the fabric filter would be jeopardized if the flow rate of particulates were insufficient to establish a filter cake over normal cleaning cycles of the baghouse.

A key design criteria established for the fabric filter system was a minimum cake thickness for activated carbon of 1/128-inches, representing a string length of thirteen 15-micron particles, (1/16-1/32 of an inch is considered normal for a dust cake thickness for a reverse air baghouse). The reverse air cleaning cycle is assumed to occur over a one-hour time period for each compartment in the baghouse. Furthermore, the ESP upstream of the baghouse is assumed to operate at New Source Performance Standards (NSPS) for particulates. Taking all of these factors into consideration, the requirement for activated carbon exceeds the flow of flyash by about a factor of three. The following expression for activated carbon injection rate is used in the development of a preliminary cost estimate:

$$w_{ac} = \frac{A_{cloth} * T_{cake} * \rho_{cake}}{t_{cycle}}$$

Where w_{ac} is the mass flow rate of activated carbon, A_{cloth} is the net cloth area of a baghouse compartment, and T_{cake} and ρ_{cake} are the thickness and the density (prior to cleaning) of the filter cake, respectively, and t_{cycle} is the filtering cycle time period. The flow rates of activated carbon are substantially higher than theoretical requirements proposed by the EPA in their Mercury Study Report to Congress. Potential reductions in the activated carbon requirements could be realized if the configuration of the fabric filter control system were changed. For example, recycle of the flyash and activated carbon collected in the baghouse dust hoppers might relax the constraint on the carbon injection needed to achieve a reasonable cake thickness.

The OAQPS Control Cost Manual[21] and OAQPS-AIRS software were used to estimate the reasonableness of capital and operating costs provided in EPA's Mercury Study Report to Congress. The results of this analysis for the fabric filter capital cost were compared to EPA's cost estimate. The costs are similar for the 100-MW model and are slightly higher for the 975-MW model. Therefore, for the preliminary assessment of cases 1B and 2B, the capital costs were taken as those provided in EPA's cost estimate after including the retrofit factor adjustment for installation.

The following should be considered in a more detailed cost analysis:

- Accounting for auxiliaries such as induced draft (ID) fan and waste conveying system.
- The use of a high air-to-cloth ratio pulse-jet filter (i.e. EPRI's COHPAC and/or UNDEERC's Hybrid Particle Collector) versus a reverse-gas baghouse downstream of the ESP.
- Incorporating manufacturers recommendations for cake thickness and cleaning cycle for dilute particluate streams.
- Examining the impact of recycle on fabric filter performance.

Summary of Case Studies

Table 8 summarizes the costs for each case. Of the five cases developed in this preliminary assessment, Cases 1A and 2A represent the least complex control configuration. Capital costs are minimized at the expense of higher operating and maintenance costs. The dominant operating cost is for the activated carbon. The next level of complexity is adding spray cooling to activated carbon injection, Case 1C. Here, operating costs are reduced significantly and provide a more cost effective control system than for carbon injection alone. However, uncertainty in the potential adverse impact of spray cooling on downstream equipment and the ability to maintain a close tolerance on the cooling temperature raise concerns on the ability to achieve cost effective mercury reductions.

The final set of technology control options include a fabric filter with spray cooling and carbon injection. This option provided the greatest activated carbon utilization rate at the expense of additional capital outlays (Cases 1B and 2B). Although this provides similar cost effective removal as with case 1C, the reliability of this control option is thought to have similar uncertainties with additional concerns associated with the fabric filter operations such as the potential for filter blinding.

Table 8. Summary of Cost Estimation for Mercury Control

Utility Model	1A	1B	1C	2A	2B
Capital Cost	thousand $				
Purchased Equipment	3,283	16,082	3,529	379	2,182
Installation	984	10,379	1,141	114	1,410
Installed Eq. w/retrofit	4,268	34,399	6,071	492	4,669
Indirect	1,871	7,220	1,685	216	965
Total Capital Cost*	6,139	41,620	7,756	708	5,634
Total Capital Cost, $/kW	6.3	42.7	8.0	7.1	56.3
Operating & Maintenance	thousand $/yr				
Operating Labor	104	207	52	39	95
Supervision Labor	16	31	8	6	14
Operating Materials	0	522	220	0	80
Maintenance Labor & Material	114	238	67	38	133
Carbon	27,903	2,622	8,371	2,832	356
Power	14	2,047	959	1	200
Activated Carbon Disposal	761	96	228	77	12
Disposal of Fly Ash	1,012	0	1,012	104	0
Lost Fly Ash Revenue (@ $3/ton)	101	0	101	10	0
Overhead	140	286	76	50	145
Taxes, Insurance, Admin	246	1,665	310	28	225
Total O&M Cost	**30,411**	**7,714**	**11,404**	**3,185**	**1,260**
Annual Cost & Performance					
Capital Recovery, thousand $/yr	**580**	**3,928**	**732**	**67**	**532**
Total Levelized Cost, $/yr*	**30,990**	**11,642**	**12,135**	**3,251**	**1,793**
Total Levelized Cost, mills/kWh*	5.58	2.10	2.19	5.71	3.15
Mercury Reduction, lb/yr	458	458	458	46	46
Cost Effectiveness, $/lb Hg*	**67,730**	**25,445**	**26,522**	**70,018**	**38,614**

* As reported in EPA Mercury Report to Congress

DOE's position on mercury control system costs is exemplified with the following comparative of DOE and EPA model boiler cost and performance estimates wherein DOE's cost analysis became the basis for the system wide estimate of control costs ultimately used in EPA Mercury Study Report to Congress - Table 9.

Table 9. Comparison of DOE and EPA Cost Analysis

Characteristic	Model 1a		Model 1b		Model 1c		Model 2a		Model 2b	
	EPA	DOE	EPA	DOE	EPA	DOE	EPA	DOE	EPA	DOE
Carbon Usage (g carbon/ g Hg)	34,200	100,000	460	9,400	460	30,000	17,200	100,000	460	12,600
Capital Cost (10^6 $)	1.26	6.14	33.7	41.6	5.52	7.76	0.167	0.708	4.56	5.63
Annual Cost (10^6 $/yr)	10.1	31.0	7.94	11.6	2.26	12.1	0.66	3.25	1.29	1.79
Cost effectiveness (mills/kWh)	1.82	5.58	1.43	2.10	0.40	2.19	1.16	5.71	2.09	3.15
Cost Effectiveness ($/lb Hg)	22,100	67,700	17,400	25,400	4,940	26,500	14,200	70,000	27,700	38,600

CONCLUSIONS and NEXT STEPS

A preliminary evaluation of costs for mercury control options at coal-fired power plants has been conducted. This evaluation provides insights into the cost trade-offs associated with controlling the temperature at reduced sorbent utilization versus reduced capital control strategies at higher sorbent injection rates.

A simplified estimate of system-wide control costs can be obtained from the cost effectiveness and mercury inventory. Using carbon injection control as an example, the annual cost for mercury control is about $6 billion to reduce mercury emissions by about 46 tons (90 percent of the estimated 51.5 tons currently emitted). The following expression provides a more universal depiction of the factors that impact annual costs.

$$AnnualCost(Billion\$/yr) = \frac{CostEffectiveness(\$/lb) * AnnualMercuryCaptured(lb/yr)}{10^9\$/Billion\$}$$

The cost effectiveness of mercury control options is strongly related to the following key parameters: activated carbon usage and unit cost; fabric filter installation and parasitic power costs; and contaminated flyash disposal costs.

The annual mercury emissions inventory for coal-fired power plants contains uncertainty associated with the variable mercury content of coal received at electric utilities as well as the mercury captured by conventional equipment in flue gas treatment systems (characterized by emission modification factors).

The U.S. EPA and DOE continue to strive for reducing the uncertainty of the mercury emissions and control options. A few examples of current efforts to improve understanding of mercury emissions are:

- More detailed evaluation of mercury control technology's cost and performance
- Proposed mercury measurements at coal-fired power plants
- Large-scale fate of mercury studies in Great Lakes region
- Research and development for improved sorbent

The preliminary findings in the present study indicate that mercury control measures, if mandated by the regulatory process, will have a significant impact on coal-fired power plant economics. To place this in perspective, an annual $6 billion incremental cost for mercury control is about 25% of the annual cost to deliver coal to electric utilities. Prudent evaluation of control measures now will provide significant dividends for the electric utility industry and its customers in the future.

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