Appendix A
Summary of Part II EPA ICR Data

Mercury Content and Selected Fuel Properties of As-fired Coals and Supplemental Fuels Burned in Coal-fired Electric Utility Boilers Nationwide in 1999

Table A-1. Selected properties of anthracite coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	5.02 - 35.19	15.28	13.37	6.23
Mercury, ppm dry	0.06 - 0.31	0.16	0.16	0.05
Sulfur, % dry	0.44 - 2.01	0.67	0.60	0.22
Heat content, Btu/lb dry	5,721 - 14,376	10,944	11,598	1,660
Ash, % dry	9.86 - 56.07	24.41	20.26	10.43
Chlorine, ppm dry	100 - 807	384.04	382.5	169.97

Table A-2. Selected properties of bituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.04 - 103.81	8.59	7.05	6.69
Mercury, ppm dry[a]	0.0 - 1.3	0.11	0.091	0.09
Sulfur, % dry	0.07 -13.92	1.70	1.22	1.14
Heat content, Btu/lb dry	8,068 - 21,503	13,196	13,181	712
Ash, % dry	0.11 - 40.37	11.13	10.86	3.33
Chlorine, ppm dry[b]	2.5 - 11,000	1,031	905	879

(a) Includes 112 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes 940 values reported at the non-detect level; 2 the non-detect level has been used in the analyses. Four analyses did not report chlorine content.

Table A-3. Selected properties of South American bituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry Mercury,	0.70 - 66.81	5.94	4.91	5.28
Mercury, ppm dry	0.01 - 0.95	0.08	0.0642	0.07
Sulfur, % dry	0.45 - 1.44	0.77	0.75	0.14
Heat content, Btu/lb dry	11,515 - 17,195	13,678	13,701	490
Ash, % dry	2.03 - 16.32	6.81	6.66	1.90
Chlorine, ppm dry[a]	45 - 1,521	286.71	264.5	180.91

(a) Includes 7 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-4. Selected properties of subbituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.39 - 71.08	5.74	5.00	3.59
Mercury, ppm dry[a]	0.005 - 0.9	0.07	0.06	0.04
Sulfur, % dry	0.02 - 3.12	0.48	0.45	0.25
Heat content, Btu/lb dry	7,636 - 14,401	11,969	12,060	672
Ash, % dry	0.43 - 31.75	7.90	7.15	3.63
Chlorine, ppm dry[b]	1 - 5,800	108.51	50	235.27

(a) Includes 193 values reported at the non-detect level; 2 the non-detect level has been used in the analyses. Two analyses did not report mercury content due to lost samples.

(b) Includes 3,961 values reported at the non-detect level; 2 the non-detect level has been used in the analyses. One analysis did not report chlorine content.

Table A-5. Selected properties of Indonesian subbituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.79 - 4.61	2.51	2.39	0.86
Mercury, ppm dry[a]	0.01 - 0.05	0.03	0.03	0.01
Sulfur, % dry	0.059 - 0.68	0.31	0.30	0.17
Heat content, Btu/lb dry	10,840 - 13,157	12,501	12,532	337
Ash, % dry	1.15 - 12.44	5.26	6.46	3.79
Chlorine, ppm dry[b]	25 - 400	90.79	100	68.65

(a) Includes 4 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes 19 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-6. Selected properties of lignite burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.93 - 75.06	10.54	7.94	9.05
Mercury, ppm dry[a]	0.01 - 0.75	0.10	0.08	0.09
Sulfur, % dry	0.35 - 3.47	1.30	1.21	0.44
Heat content, Btu/lb dry	7,022 - 11,943	10,026	10,205	784
Ash, % dry	8.93 - 39.10	19.45	18.75	6.42
Chlorine, ppm dry[b]	25 - 1,380	166.09	101.00	199.60

(a) Includes 133 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes 361 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-7. Selected properties of waste anthracite coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	2.49 - 73.02	29.31	27.77	11.94
Mercury, ppm dry[a]	0.02 - 0.54	0.19	0.17	0.08
Sulfur, % dry	0.25 - 1.96	0.51	0.44	0.20
Heat content, Btu/lb dry	2,998 - 10,941	6,687	6,889	2,002
Ash, % dry	22.34 - 72.41	49.13	47.77	12.54
Chlorine, ppm dry[b]	11.6 - 1,855	231.29	102.20	241.36

(a) Includes two values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes 21 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-8. Selected properties of waste bituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	2.47 - 172.92	60.50	53.32	44.35
Mercury, ppm dry	0.03 - 1.18	0.46	0.45	0.30
Sulfur, % dry	0.74 - 7.73	2.38	2.38	0.88
Heat content, Btu/lb dry	5,194 - 13,370	8,753	7,929	2,153
Ash, % dry	7.89 - 61.49	37.54	41.43	13.03
Chlorine, ppm dry	29.77 - 4,277	847.92	848.00	493.75

Table A-9. Selected properties of waste subbituminous coal burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	5.81 - 30.35	11.42	10.79	4.66
Mercury, ppm dry	0.07 - 0.35	0.12	0.11	0.05
Sulfur, % dry	0.83 - 3.59	1.95	1.82	0.69
Heat content, Btu/lb dry	7,849 - 11,801	10,506	10,704	927
Ash, % dry	11.17 - 38.52	20.53	19.35	6.40
Chlorine, ppm dry[a]	50 - 100	53.77	50	13.33

(a) Includes 49 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-10. Selected properties of petroleum coke burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.06 - 32.16	23.18	2.16	3.18
Mercury, ppm dry[a]	0.0009 - 0.5	0.045	0.03	0.05
Sulfur, % dry	0.54 - 7.91	4.88	5.18	1.58
Heat content, Btu/lb dry	10,892 - 16,463	15,233	15,319	439.29
Ash, % dry	0.04 - 27.53	0.64	0.40	1.17
Chlorine, ppm dry[b]	7 - 3,000	203.70	110	269.93

(a) Includes 131 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes 169 values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-11. Selected properties of tire-derived fuel burned in 1999.

Fuel Property	Range	Mean	Median	Standard deviation
Mercury, lb/10^{12} Btu dry	0.38 - 19.89	3.58	2.79	2.78
Mercury, ppm dry[a]	0.006 - 0.33	0.05	0.04	0.04
Sulfur, % dry	0.86 - 2.8	1.56	1.58	0.26
Heat content, Btu/lb dry	11,457 - 17,035	15,261	15,890	1,384
Ash, % dry	0.75 - 23.14	7.50	5.91	4.49
Chlorine, ppm dry[b]	100 - 6,483	1,059	800	933

(a) Includes four values reported at the non-detect level; 2 the non-detect level has been used in the analyses.
(b) Includes three values reported at the non-detect level; 2 the non-detect level has been used in the analyses.

Table A-12. Comparison of mercury content by fuel type as burned in 1999.

Fuel Type	Number of analyses	Mercury Concentration in Fuel (ppm)			
		Range	Mean	Median	Standard deviation
Anthracite Coal	114	0.06 - 0.31	0.16	0.16	0.05
Bituminous Coal	27,883	0.0 - 1.3	0.11	0.09	0.09
South American Bituminous Coal	269	0.01 - 0.95	0.08	0.06	0.07
Subbituminous Coal	8,190	0.005 - 0.9	0.07	0.06	0.04
Indonesian Subbituminous Coal	78	0.01 - 0.05	0.03	0.03	0.01
Lignite Coal	1,047	0.01 - 0.75	0.10	0.08	0.09
Waste Anthracite Coal	377	0.02 - 0.54	0.19	0.17	0.08
Waste Bituminous Coal	575	0.03 - 1.18	0.46	0.45	0.30
Waste Subbituminous Coal	53	0.07 - 0.35	0.12	0.11	0.05
Petroleum Coke	1,149	0.0009 - 0.05	0.049	0.03	0.05
Tire-derived fuel	149	0.006 - 0.33	0.054	0.04	0.04

Table A-13. Comparison of mercury content with fuel heat content as burned in 1999.

Fuel Type	Number of analyses	Ratio of Mercury to Fuel Heat Content (lb Hg/trillion Btu)			
		Range	Mean	Median	Standard deviation
Anthracite Coal	114	5.02 - 35.19	15.28	13.37	6.23
Bituminous Coal	27,883	0.04 - 103.81	8.59	7.05	6.69
South American Bituminous Coal	269	0.70 - 66.81	5.94	4.91	5.28
Subbituminous Coal	8,190	0.39 - 71.08	5.74	5.00	3.59
Indonesian Subbituminous Coal	78	0.79 - 4.61	2.51	2.39	0.86
Lignite Coal	1,047	0.93 - 75.06	10.54	7.94	9.05
Waste Anthracite Coal	377	2.49 - 73.02	29.31	27.77	11.94
Waste Bituminous Coal	575	2.47 - 172.92	60.50	53.32	44.35
Waste Subbituminous Coal	53	5.81 - 30.35	11.42	10.79	4.66
Petroleum Coke	1,149	0.06 - 32.16	23.18	2.16	3.18
Tire-derived fuel	149	0.38 - 19.89	3.58	2.79	2.78

Appendix B

Background Material of Methodology Used To Estimate 1999 National Mercury Emissions from Coal-fired Electric Utility Boilers

September 15, 2000

MEMORANDUM

To: William Maxwell, EPA/OAQPS/ESD/CG

From: Jeffrey Cole, RTI

Subject: Draft Interim Report on Data Analyses

PURPOSE

The purpose of this memorandum is to discuss RTI's data analyses after the delivery of the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units Final Report to Congress (issued on February 24, 1998)

BACKGROUND

Section 112(a)(8) of the Clean Air Act, as amended (CAA), defines an "electric utility steam-generating unit" as "any fossil-fuel–fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale." A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility (EU) steam-generating unit (i.e., utility unit).

Section 112(n)(1)(A) also requires that:

- The EPA develop and describe alternative control strategies for hazardous air pollutants (HAPs) that may warrant regulation under section 112; and

- The EPA proceed with rulemaking activities under section 112 to control HAP emissions from utilities if EPA finds such regulation is appropriate and necessary after considering the results of the study.

Based on available information and current analyses, the EPA concluded that: mercury from coal-fired utilities is the HAP of greatest potential concern and merits additional research and monitoring; and, further research and evaluation are needed to gain a better understanding of the risks and impacts of utility mercury emissions.

Two of the potential areas identified for further study included: (1)additional data on the mercury content of various types of coal fired in U.S. utility units; and (2) additional data on mercury emissions (e.g., how much is emitted from various types of units, how much is divalent vs elemental mercury, and how do factors such as control device, fuel type, and plant configuration affect emissions and speciation).

DATA COLLECTION

Following the issuance of the Report to Congress, EPA initiated, under the authority of section 114 of the CAA, the Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort (EU/ICE). As a part of this effort, RTI provided support to EPA in the EU/ICE development, distribution and processing. The EU/ICE has three basic sections: Part 1: General Facility Information; Part II: Coal/Fuel Analysis; and Part III: Speciated Mercury Emissions Testing Data. Parts I, II, and III of the EU/ICE; were mailed out to all facilities that met the CAA definition. As the completed Part I data forms were returned to EPA, they had their data extracted to create a unit configuration database.

From January through December 1999, Part II of the EU/ICE resulted in the collection of data for over 152,000 coal shipments from 1,143 units at 464 coal-fired facilities, a total of approximately 40,500 individual mercury and chlorine analyses. To achieve this compilation of data, a web-based data collection system was developed to allow the affected electric utilities to submit their Part II data over the Internet. The website provided a high-end technical solution to a large data collection effort and reduced the time required for data submission and the potential for data entry errors. The website ended up collecting greater than 8 million pieces of data.

Under Part III of the EU/ICE, stack tests were conducted at 85 separate EU units to measure speciated mercury emissions. These data were reported by the companies to EPA and were entered into a database. These data were used in the emission program (see below) developed to estimate nationwide mercury emissions as well as to estimate mercury collection across different control devices, boilers, and fuel types.

WEBSITE

A web-based, interactive data collection system was developed to gather data on the mercury and chlorine content of the coals fired (including tire-derived fuel and petroleum coke) in U.S. utility units, as well as the fuel consumption data, directly for each electric utility company or facility. The data were collected through the development and use of user-friendly web pages. The website had two different portions, a nonsecure and a secure portion, each with different purposes. The nonsecure portion of the website was developed to serve as a conduit for information from EPA in response to questions from the electric utility industry. The nonsecure website also served as an entry point to the secure website.

The secure website was developed as an online collection point for EU/ICE Part II shipment, analysis, and fuel usage data by unit and by month from 464 coal-fired facilities. To familiarize EU/ICEindustry contacts with the on-line data entry procedures, a website user guide was created in Adobe Acrobat format.

A toll-free customer service hotline (with email access) was manned to answer questions and disseminate information to the participants of the EU/ICE. If a question was thought to be of interest to more than just the facility/company that submitted it, the question and answer were posted in the frequently-asked-question (FAQ) webpage on the nonsecure website. The process was initiated by requesting e-mails from the EU/ICE contacts explaining their problems. The EPA would then answer the questioning facility by e-mail with a copy being posted on the website's FAQ pages.

This method of answering EU/ICE questions had the additional benefit of creating a paper trail of EU/ICE modifications that could be recorded in the Electric Utility Hazardous Air Pollutant Emission Study Docket No. A-92-55.

QUALITY CONTROL

Quality control and customer service were important parts of the EU/ICE. To enhance quality control and customer service during the EU/ICE, the following actions were initiated.

Early in the planning of the EU/ICE, EPA determined that the data from each facility should be able to pass a statistical confidence test on their coal/fuel analyses data. EPA statisticians established what confidence intervals were necessary to determine if the industry were sampling and analyzing at a sufficient frequency to obtain statistically reliable data. Programmers created a statistical evaluation portion of the website to determine if incoming data could pass the EPA-imposed confidence interval test for data quality. The EU/ICE website was programmed to advise contacts on how to increase or decrease the frequency of analyses through a set of flow tables.

For those EU/ICE contacts with numerous facilities who found webpage data entry too time-consuming, a data-upload capability was developed through the use of data entry spreadsheets (saved as text files). To familiarize EU/ICE contacts with these data entry spreadsheets, a spreadsheet user guide was created in Adobe Acrobat format.

Before a data entry spreadsheet-based, tab-delimited, text file upload was allowed, the website checked the data for completeness. If there were data missing from the upload, loading would not occur, and an error message would be displayed. The website was also designed to flag errors in data and to stop all incomplete or incorrect data loading. This error checking was accomplished by implementing online quality control checks. These online checks would not allow the entry of obviously incorrect data (e.g., zeros, text in numeric fields).

Programmers also created a duplicate development website (a mirror image of the live website, but not available to the public) where new features and changes could be tried without affecting the live website. This tactic proved to be a valuable tool because complex procedures could be fully developed before being seen by the EU/ICE contacts.

DATA ANALYSIS

To estimate total mercury emissions from coal-fired electric utility units, an emission factor program (EFP) was developed. The EFP was built to accept data from the three data sources in the EU/ICE. The first is a data input file containing plant configurations created from responses from the ICE (Part I). The second source is a database containing detailed mercury analyses and fuel consumption data, by unit, and by month for all of 1999 (Part II). The third data file is the emission modification factor (EMF) database. This database contains results from the 85 speciated mercury emission tests conducted by the electric utility industry under authority of the ICE (Part III). Eight of the 85 tests were done previously under a DOE study between 1996 and 1998. The use of the eight tests was permitted by EPA because the test methods were the same as or similar to the EU/ICE Part III units (tested in 1999 and 2000) and were tested for speciated mercury.

The program first categorizes each coal-fired electric utility unit by its fuel type/boiler type/emission control system(s) and assigns them to bins with other common units. The program then categorizes the 85 units that were subject to stack testing under Part III by fuel type/boiler type/emission control system(s) and places them into similar combinations of bins. The program then computes unit-by-unit the mercury loading by analyzing the fuel burned by the unit for 1999 and the concentration of mercury in the facilities fuel in 1999 (from Part II). The mercury removals are then averaged from all the units in the stack-tested bins and that removal is applied to the mercury loading for each individual unit. This procedure results in a kg/yr mercury output for each unit and thus, when all units emissions are totaled, estimates nationwide mercury emissions.

Because stack testing did not analyze every configuration of fuel type/emission control/boiler type system, the units that did not match perfectly had to be assigned a stack-tested bin in order for their emissions to be quantified. A hierarchy (fuel type/boiler type/emission control system) was used, as well as engineering judgment, to assign bins to those units that did not perfectly fit into a stack-tested bin.

RESULTS

The results of the EFP model are the following. The estimated national total of mercury emitted from all coal-fired electric utility steam-generating units in 1999 is 43.4 tons. This amount of mercury was emitted from 1,143 units at 464 facilities.

June 19, 2001

MEMORANDUM

To: William Maxwell, EPA/OAQPS/ESD/CG

From: Jeffrey Cole, RTI

Subject: Updated Draft Interim Report on Data Analyses

PURPOSE

The purpose of this memorandum is to discuss changes to RTI's data analyses data that were made after my 9/15/00 memorandum to you entitled, "Draft Interim Report on Data Analyses." In February-March 2001, EPA conducted a thorough quality assurance/quality-control (QA/QC) review of the data extracted from the Hg emissions stack test reports. Changes to the national Hg emissions total as a result of updated data and the initial presentation of the estimated speciated Hg split are presented in this memorandum.

BACKGROUND

Since the "Draft Interim Report on Data Analyses" was written, several changes have been made. RTI found three of four units that had reported their type of fuel burned incorrectly. Five or six plants had incorrect Department of Energy's, Energy Information Administration (DOE/EIA) Office of the Regulatory Information System (ORIS) codes. These and other minor changes were made to the unit configuration, fuel usage, and mercury (Hg)/chlorine (Cl) analyses databases. The Brayton Point facility, was mis-located in the previous configuration output file. It was listed as being in Maryland, when it's actual location is Massachusetts.

In February 2001, RTI began a thorough review of the data extracted from the 80 Electric Utility/Information Collection Effort (EU/ICE) speciated mercury emissions stack test reports. RTI developed and implemented a QA/QC study of the reports to determine the quality of the original data extraction and to correct any errors. As part of this effort, RTI developed a sophisticated spreadsheet data entry form that allowed all test reports to be analyzed in a uniform manner using a single standard QC method.

RTI found several types of errors in data extracted from different test reports. Occasionally the data errors were a result of incorrectly transferring data to EPA's national utility mercury model or in misreporting the fuel a specific unit burned. However, more data errors occurred when the testing contractor or the report writing contractor incorrectly reported details about the testing and process data. RTI reviewed the original Ontario Hydro Method data sheets, in each test report, and examined each data point to determine its validity. RTI had to call several plant representatives either to confirm items reported or to extract crucial data that was not included in the test report.

The individual data corrections inside a test report had some effect on the average EMF for that test. However the more significant change occurred when a tested plant's fuel type was incorrectly reported. This error could cause the test data to reside in a different database segment (bin) than originally modeled. Once these errors were found and corrected RTI proceeded with updating the Electric Utility National Mercury Emissions Model with the newly quality-controlled data from the emissions test reports.

RESULTS

Because of this further QA/QC examination of data extracted from the Hg emissions stack test reports, the estimated national total of mercury emitted from all coal-fired electric utility steam-generating units in 1999 is now approximately 48 tons. This amount of mercury was emitted from 1,143 units at 461 facilities. This total is composed of 1.48 tons/yr of particle-bound mercury (Hg^p), 20.41 tons/yr of oxidized mercury(Hg^{2+}), and 26.10 tons/yr of elemental mercury (Hg^0).

January 17, 2001

MEMORANDUM

To: William Maxwell, EPA/OAQPS/ESD/CG

From: Jeffrey Cole, RTI

Subject: Detailed Overview of How the Electric Utility Mercury National Emissions Model Estimated Nationwide Emissions

PURPOSE

The purpose of this memorandum is to provide a detailed explanation of the mercury national emissions model addressing specific inquiries about how the emissions modification factors (EMFs) were developed and implemented in the model. This memorandum is intended to be an addendum to the memorandum "Draft Interim Report on Data Analyses" dated 9/15/00 available on EPA's website http://www.epa.gov/ttn/uatw/combust/utiltox/utoxpg.html. Also included in this memorandum are tables showing the EMFs used in the national emissions model.

INTRODUCTION

The national emissions model first categorizes each coal-fired electric utility unit by its fuel type/boiler type/emission control system(s) and classifies each unit under a simplified nomenclature. An example of this nomenclature would be a CYCLONE/NONOX/WET w/ESP-CS. This unit would be a cyclone-fired boiler/furnace with a wet bottom (ash removed in a molten state) without NO_x control followed by a cold-side electrostatic precipitator.

The program then categorizes the 80 units were stack test data were available by fuel type/boiler type/emission control system(s) and classifies them into similar nomenclatures and places them in their similar categories (stack-tested bins). The program then computes, unit-by-unit, the mercury (Hg) loading in the boiler flue-gas by analyzing the fuel burned by the unit for 1999 and the concentration of Hg in the facility's fuel in 1999 (from Part II of the Electric Utility/Information Collection Effort [EU/ICE]). The Hg removals (obtained from EU/ICE Part III data) are then averaged from all the units in each of the stack-tested bins and those removals are applied to the Hg loading for each individual unit according to its bin configuration. This procedure results in a Hg output in kg/yr for each unit and thus, when all unit emissions are totaled, estimates nationwide Hg emissions. A detailed explanation follows.

DETAILED EXPLANATION

Because stack testing did not analyze every configuration of fuel type/emission control/boiler type system, the units that did not match perfectly had to be assigned a stack-tested bin in order for their emissions to be quantified. A hierarchy chosen was fuel type/boiler type/emission control system. Some engineering judgment was also used to assign bins to those units that did not perfectly fit into a stack-tested bin. The speciated Hg concentration data, extracted from the test reports and segregated into similar stack-tested bins, were then analyzed by the national emissions model.

Typically, each emissions test report contained data from three emission stack test runs which included speciated Hg information. The national emissions model sums the speciated Hg concentrations at the inlet and outlet of the final control device of each unit. Thus, an EMF is determined for each run. The EMF is a fraction of the amount of total Hg exiting an air pollution control device (APCD) divided by the amount of the total Hg entering that device. The EMF can also be defined as one minus the total Hg removal fraction. For example, an EMF of 0.68 is equal to a Hg removal of 0.32 (or 32 %). The equation used to compute the EMF also contained a correction made to the EU/ICE Part III test data to account for flowrate differences at the emissions test sampling inlet and outlet (see Equation 1).

The total EMF's of each run were then averaged in each bin (see Table 1). This average EMF was multiplied by each Hg loading (in kilograms) for each unit that matched the bin configuration. As a rule, when a non-detect was encountered in the national emissions model, one-half the non-detection value was used. This procedure is consistent with the method EPA has used to deal with non-detect values since the electric utility study was begun.

A different method was used to average fuel type/boiler type/emission control system(s) from all dual controlled units (units having both a PM and an SO_2 control device). Since stack test flue-gas speciated Hg was analyzed at the inlet and outlet of the last control device, the effect of the PM control on Hg removal on these dual controlled units was not clear. Thus:

- EPA decided that it would be more realistic to add the PM control device removal of Hg to the SO_2 control device removal of Hg for dual controlled units.
- The PM control device average EMF was taken from the bin of a unit with a similar fuel type/boiler type/PM emission control system to the dual controlled bin it was modifying.
- The average EMF of a tested unit with a single PM control device was multiplied by each individual run EMF from a similarly configured dual controlled unit.
- These modified EMFs were averaged. This average was used to compute the Hg removal of a dual controlled unit in the national emissions model.

Table 2 (the accompanying spreadsheet) shows how the modified EMFs were calculated.

Coal gasification units could not have their EMF's determined by either of the previous methods. Mercury testing was done in the coal feed, and emissions testing was done after the boiler/furnace. These plants do not have conventional APCD's. Thus, EMF's were determined across two points, the Hg in the coal and the total Hg exiting the boiler/furnace for each run.

It should be noted that not all EMF averages (single or dual control) showed removal of Hg. Some EMF averages showed a generation of Hg by the tested unit. This discrepancy could be accounted for by a number of factors, such as, an inaccurate mercury-in-coal analysis or an inaccurate flue-gas Hg test before and after the last control device. None of the stack tests used in these computations were found to have any documentation as to errors or problems found during or after the stack testing. EPA decided that if no errors or problems were presented in the stack tests that the data would be used. EPA's main purpose in this model was to determine the 1999 Hg emissions total nationwide from all coal-fired electric utility power plants in the U.S. Because of the combination of test inaccuracies and bin assignments, it was inevitable that some units would be modeled as emitting less Hg than they actually emitted and some would be modeled as emitting more. In some cases the computed emission rate was greater than the inlet amount. Although physically improbable, these cases were used as computed to balance cases that were modeled as emitting too little mercury.

Two small discrepancies were found in the EMF portion of the nationwide emission model. A single emission test run outlet speciated Hg content was entered incorrectly in the thousandth place. This error produced an EMF of 0.238499 during Run 1 from the stack testing on the Intermountain facility instead of the correct EMF of 0.23448. This difference would have had the effect of changing the modified dual controlled unit combined EMF (Bin 12) from 0.11071 (used in the existing model) to 0.110446. EPA feels that this change would have a negligible effect on the national Hg emissions estimate. The second discrepancy was the incorrect use of the modified, dual controlled EMF for Bin 36 (0.58277) for Bin 32 instead of the correct modified EMF (0.19477). Bin 32 is used on only 3 units at one plant and has a negligible effect on national Hg emissions estimate. Both discrepancies are highlighted in Table 1 and 2 and will be corrected in future versions of the national emissions model.

Table 1. A LISTING OF TEST RUNS WITH EMISSION MODIFICATION FACTORS

Test Report	Run #	EMF	EMF Analysis	Unit Configuration	PM Control	SO2 Control	Fuel
Emission control device bin/type 0							
Polk Power	1	.55622	coal to stack	COAL GAS	COAL GAS	COAL GAS	Bituminous
Polk Power	2	.56521	coal to stack	COAL GAS	COAL GAS	COAL GAS	Bituminous
Polk Power	3	.64844	coal to stack	COAL GAS	COAL GAS	COAL GAS	Subbituminous
Wabash River Gen Sta	1	.71294	coal to stack	COAL GAS	COAL GAS	COAL GAS	Subbituminous
Wabash River Gen Sta	2	1.08624	coal to stack	COAL GAS	COAL GAS	COAL GAS	Subbituminous
Wabash River Gen Sta	3	.69517	coal to stack	COAL GAS	COAL GAS	COAL GAS	Subbituminous
Average emission factor		.7107					
Emission control device bin/type 1							
Brayton Point 1	1	.85267	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Brayton Point 1	2	.63886	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Brayton Point 1	3	.6781	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Brayton Point 3	1	.61791	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Brayton Point 3	2	.71529	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Brayton Point 3	3	.82287	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Meramec	1	.18986	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
Meramec	2	.3003	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
Meramec	3	.28044	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
George Neal South	1	.84823	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
George Neal South	2	.91106	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
George Neal South	3	1.52286	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Bituminous
Jack Watson	1	.78292	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
Jack Watson	2	.623	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
Jack Watson	3	.70962	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Bituminous
Widows Creek	1	.55725	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Bituminous
Widows Creek	2	.50002	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Bituminous
Widows Creek	3	.34892	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Bituminous
Presque Isle 5	1	.34713	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous
Presque Isle 5	2	.3813	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous
Presque Isle 5	3	.29159	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous
Average emission factor		.61525					
Emission control device bin/type 2							
Presque Isle 6	1	.45459	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous/Pet Coke
Presque Isle 6	2	.4971	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous/Pet Coke

$$EMF = 1 - \left(1 - \left[\frac{\Sigma Hg \text{ species concentration the outlet}}{\Sigma Hg \text{ species concentration at the inlet}}\right] \cdot \frac{[21 - O_2 \text{ concentration at the inlet}]}{[21 - O_2 \text{ concentration at the outlet}]}\right)$$

Equation (1) Individual run EMF calculation with flow correction

Presque Isle 6	3	.41997	across control	CONV/PC/NONOX/WET	ESP- CS	COMP COAL	Bituminous/Pet Coke
Average emission factor		.45722					

Emission control device bin/type 3

Salem Harbor	1	.12978	across control	CONV/PC/NOX/SNCR/DRY	ESP- CS	COMP COAL	Bituminous
Salem Harbor	2	.07435	across control	CONV/PC/NOX/SNCR/DRY	ESP- CS	COMP COAL	Bituminous
Salem Harbor	3	.06945	across control	CONV/PC/NOX/SNCR/DRY	ESP- CS	COMP COAL	Bituminous

Average emission factor .09119

Emission control device bin/type 4

Cholla 3	1	1.01304	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Cholla 3	2	.79577	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Cholla 3	3	1.12281	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Cliffside	1	.99144	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Cliffside	2	.61999	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Cliffside	3	.57491	across control	CONV/PC/NONOX/DRY	ESP- HS	NONE	Bituminous
Dunkirk	1	.93916	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Bituminous
Dunkirk	2	.6867	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Bituminous
Dunkirk	3	.82925	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Bituminous
Gaston	1	1.00192	across control	CONV/PC/NOX/DRY	ESP- HS	NONE	Bituminous
Gaston	2	1.41373	across control	CONV/PC/NOX/DRY	ESP- HS	NONE	Bituminous
Gaston	3	1.1	across control	CONV/PC/NOX/DRY	ESP- HS	NONE	Bituminous

Average emission factor .92406

Emission control device bin/type 5

Cholla 2	1	.70701	across control	CONV/PC/NONOX/DRY	MECH/PARTSCRUB	WETSCRUB	Bituminous
Cholla 2	2	1.07508	across control	CONV/PC/NONOX/DRY	MECH/PARTSCRUB	WETSCRUB	Bituminous
Cholla 2	3	.81712	across control	CONV/PC/NONOX/DRY	MECH/PARTSCRUB	WETSCRUB	Bituminous
Bruce Mansfield	1	.85193	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Bituminous
Bruce Mansfield	2	.85059	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Bituminous
Bruce Mansfield	3	.92579	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Bituminous

Average emission factor .87125

Emission control device bin/type 6

Port Washington	1	.59319	across control	CONV/PC/NONOX/DRY	ESP- CS	SORBENT INJECTION	Bituminous
Port Washington	2	.47394	across control	CONV/PC/NONOX/DRY	ESP- CS	SORBENT INJECTION	Bituminous
Port Washington	3	.58628	across control	CONV/PC/NONOX/DRY	ESP- CS	SORBENT INJECTION	Bituminous

Average emission factor .55114

Emission control device bin/type 7

W. H. Sammis	1	.08586	across control	CONV/PC/NONOX/DRY	BAGHOUSE	NONE	Bituminous
W. H. Sammis	2	.07033	across control	CONV/PC/NONOX/DRY	BAGHOUSE	NONE	Bituminous
W. H. Sammis	3	.06992	across control	CONV/PC/NONOX/DRY	BAGHOUSE	NONE	Bituminous
Shawnee	1	.33271	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous
Shawnee	2	.29648	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous
Shawnee	3	.28837	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous
Valley	1	.94333	across control	CONV/PC/NOX/DRY	BAGHOUSE	NONE	Bituminous
Valley	2	1.00699	across control	CONV/PC/NOX/DRY	BAGHOUSE	NONE	Bituminous
Valley	3	1.25146	across control	CONV/PC/NOX/DRY	BAGHOUSE	NONE	Bituminous
Valmont	1	.13019	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous
Valmont	2	.10475	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous
Valmont	3	.15846	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Bituminous

Average emission factor .3949

Emission control device bin/type 8							
Logan Gen Plant	1	.01292	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous
Logan Gen Plant	2	.01834	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous
Logan Gen Plant	3	.01273	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous
Mecklenburg Cogen	1	.00773	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous
Mecklenburg Cogen	2	.03096	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous
Mecklenburg Cogen	3	.02409	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Bituminous

Average emission factor .01779

Emission control device bin/type 9							
SEI Birchwood Power Facility	1	.03439	across control	CONV/PC/NOX/SCR/DRY	BAGHOUSE	SDA	Bituminous
SEI Birchwood Power Facility	2	.02211	across control	CONV/PC/NOX/SCR/DRY	BAGHOUSE	SDA	Bituminous
SEI Birchwood Power Facility	3	.01613	across control	CONV/PC/NOX/SCR/DRY	BAGHOUSE	SDA	Bituminous

Average emission factor .02421

Emission control device bin/type 10							
AES Cayuga (NY) (formerly Milliken)	1	.38117	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Bituminous
AES Cayuga (NY) (formerly Milliken)	2	.32086	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Bituminous
AES Cayuga (NY) (formerly Milliken)	3	.38365	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Bituminous

Second unit Average .36189
First unit correction factor .61525
Combined emission factor .22266

Emission control device bin/type 11							
R. D. Morrow	1	.46544	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Bituminous
R. D. Morrow	2	.50824	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Bituminous
R. D. Morrow	3	.553	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Bituminous

Second unit Average .5089
First unit correction factor .92406
Combined emission factor .47025

Emission control device bin/type 12

Intermountain	1	.23448	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous
Intermountain	2	.40334	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous
Intermountain	3	.31322	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous
Clover	1	.41849	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous
Clover	2	.17405	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous
Clover	3	.1345	last control	CONV/PC/NOX/DRY	BAGHOUSE	WETSCRUB	Bituminous

Second unit Average	.27968
First unit correction factor	.39585
Combined emission factor	.11071

Emission control device bin/type 13

Gibson (03/00)	1	1.03854	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Gibson (03/00)	2	.90019	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Gibson (03/00)	3	.98339	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Gibson (10/99)	1	.61081	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Gibson (10/99)	2	.41305	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Gibson (10/99)	3	.91315	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Subbituminous
Montrose	1	.82538	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous
Montrose	2	1.02306	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous
Montrose	3	.87465	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous
Newton	1	1.00101	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous
Newton	2	.8367	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous-
Newton	3	.91535	across control	CONV/PC/NOX/DRY	ESP- CS	COMP COAL	Subbituminous
St Clair	1	.64369	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Subbituminous
St Clair	2	.80355	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Subbituminous
St Clair	3	.91291	across control	CONV/PC/NONOX/DRY	ESP- CS	COMP COAL	Subbituminous

Average emission factor	.84636

Emission control device bin/type 14

Clifty Creek	1	.64416	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Clifty Creek	2	.70486	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Clifty Creek	3	.63012	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Columbia	1	.94982	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Subbituminous
Columbia	2	.72657	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Subbituminous
Columbia	3	1.01475	across control	CONV/PC/NOX/DRY	ESP- HS	COMP COAL	Subbituminous
Platte	1	.73075	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Platte	2	1.33203	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Platte	3	1.02404	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Presque Isle 9	1	.99901	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Presque Isle 9	2	1.05232	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous
Presque Isle 9	3	1.05765	across control	CONV/PC/NOX/WET	ESP- HS	COMP COAL	Subbituminous

Average emission factor	.90551

Emission control device bin/type 15							
Clay Boswell 2	1	.2394	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Clay Boswell 2	2	.12551	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Clay Boswell 2	3	.15683	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Comanche	1	.3142	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Comanche	2	.47328	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Comanche	3	.34481	across control	CONV/PC/NOX/DRY	BAGHOUSE	COMP COAL	Subbituminous
Average emission factor		.27567					

Emission control device bin/type 16							
Clay Boswell 3	1	.92841	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB/COMP COAL	Subbituminous
Clay Boswell 3	2	.86191	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB/COMP COAL	Subbituminous
Clay Boswell 3	3	.94752	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB/COMP COAL	Subbituminous
Clay Boswell 4	1	1.0308	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Clay Boswell 4	2	1.18251	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Clay Boswell 4	3	1.44396	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Colstrip	1	1.86536	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Colstrip	2	1.07793	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Colstrip	3	.25733	across control	CONV/PC/NOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Lawrence	1	1.00071	across control	CONV/PC/NONOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Lawrence	2	1.31139	across control	CONV/PC/NONOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Lawrence	3	1.14729	across control	CONV/PC/NONOX/DRY	PARTSCRUB	WETSCRUB	Subbituminous
Average emission factor		1.08793					

Emission control device bin/type 17							
GRDA	1	.57991	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
GRDA	2	1.24231	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
GRDA	3	.44283	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Laramie River 3	1	4.55004	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Laramie River 3	2	.42652	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Laramie River 3	3	.37468	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Wyodak	1	.56046	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Wyodak	2	.60129	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Wyodak	3	.60014	across control	CONV/PC/NOX/DRY	ESP- CS	SDA	Subbituminous
Average emission factor		1.04202					

Emission control device bin/type 18							
Craig 3	1	.6621	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Craig 3	2	.58165	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Craig 3	3	.68334	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Rawhide	1	.82842	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Rawhide	2	.67975	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Rawhide	3	.52691	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Sherburne County	1	.7619	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Sherburne County	2	1.10936	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Sherburne County	3	.98954	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Subbituminous
Average emission factor		.75811					
Emission control device bin/type 19							
Jim Bridger	1	.89679	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Jim Bridger	2	.84355	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Jim Bridger	3	.9694	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Laramie River 1	1	.47432	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Laramie River 1	2	.55464	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Laramie River 1	3	.42468	last control	CONV/PC/NOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Sam Seymour	1	1.03425	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Sam Seymour	2	.79918	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Sam Seymour	3	.71422	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Subbituminous
Second unit Average		.74567					
First unit correction factor		.84636					
Combined emission factor		.63111					
Emission control device bin/type 20							
Charles R. Lowman	1	.63558	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Charles R. Lowman	2	.70694	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Charles R. Lowman	3	.58821	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Coronado	1	1.12946	last control	CONV/PC/NOX/WET	ESP- HS	WETSCRUB	Subbituminous
Coronado	2	.73182	last control	CONV/PC/NOX/WET	ESP- HS	WETSCRUB	Subbituminous
Coronado	3	1.11298	last control	CONV/PC/NOX/WET	ESP- HS	WETSCRUB	Subbituminous
Craig 1	1	.56966	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Craig 1	2	.7707	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Craig 1	3	.97558	last control	CONV/PC/NOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Navajo	1	.58001	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Navajo	2	.87346	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Navajo	3	.91752	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
San Juan	1	.6326	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
San Juan	2	.68646	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
San Juan	3	.57686	last control	CONV/PC/NONOX/DRY	ESP- HS	WETSCRUB	Subbituminous
Second unit Average		.76586					
First unit correction factor		.9055					
Combined emission factor		.69348					
Emission control device bin/type 21							
Stanton Station 1	1	.95581	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Lignite

Stanton Station 1	2	1.09703	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Lignite
Stanton Station 1	3	1.05413	across control	CONV/PC/NOX/DRY	ESP- CS	NONE	Lignite
Average emission factor		1.03566					
Emission control device bin/type 22							
La Cygne	1	.7682	across control	CYCLONE/NOX/WET	PARTSCRUB	WETSCRUB	Bituminous
La Cygne	2	.75471	across control	CYCLONE/NOX/WET	PARTSCRUB	WETSCRUB	Bituminous
La Cygne	3	.7783	across control	CYCLONE/NOX/WET	PARTSCRUB	WETSCRUB	Bituminous
Average emission factor		.76707					
Emission control device bin/type 23							
Nelson Dewey	1	.99871	across control	CYCLONE/NONOX/WET	ESP- HS	COMP COAL	Subbituminous
Nelson Dewey	2	1.06895	across control	CYCLONE/NONOX/WET	ESP- HS	COMP COAL	Subbituminous
Nelson Dewey	3	1.24952	across control	CYCLONE/NONOX/WET	ESP- HS	COMP COAL	Subbituminous
Average emission factor		1.10573					
Emission control device bin/type 24							
Leland Olds Station	1	1.18696	across control	CYCLONE/NONOX/WET	ESP- CS	NONE	Lignite
Leland Olds Station	2	.66739	across control	CYCLONE/NONOX/WET	ESP- CS	NONE	Lignite
Leland Olds Station	3	.73521	across control	CYCLONE/NONOX/WET	ESP- CS	NONE	Lignite
Average emission factor		.86319					
Emission control device bin/type 25							
Stockton Cogen Company	1	.03689	across control	FBC/SNCR	BAGHOUSE	FBC	Bituminous
Stockton Cogen Company	2	.07829	across control	FBC/SNCR	BAGHOUSE	FBC	Bituminous
Stockton Cogen Company	3	.05571	across control	FBC/SNCR	BAGHOUSE	FBC	Bituminous
Average emission factor		.05696					
Emission control device bin/type 26							

Bin/type 26 was not used

Emission control device bin/type 27							
Scrubgrass Generating Company L.P.	1	.0008	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Bituminous
Scrubgrass Generating Company L.P.	2	.00101	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Bituminous
Scrubgrass Generating Company L.P.	3	.00148	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Bituminous
Average emission factor		.0011					

Emission control device bin/type 28

R. M. Heskett	1	.50707	across control	FBC/NONOX	ESP- CS	FBC	Lignite
R. M. Heskett	2	.88912	across control	FBC/NONOX	ESP- CS	FBC	Lignite
R. M. Heskett	3	.45514	across control	FBC/NONOX	ESP- CS	FBC	Lignite

Average emission factor .61711

Emission control device bin/type 29

TNP-One	1	.44798	across control	FBC/NONOX	BAGHOUSE	FBC	Lignite
TNP-One	2	.45928	across control	FBC/NONOX	BAGHOUSE	FBC	Lignite
TNP-One	3	.38122	across control	FBC/NONOX	BAGHOUSE	FBC	Lignite

Average emission factor .42949

Emission control device bin/type 30

Kline Township Cogen	1	.00259	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Anthracite
Kline Township Cogen	2	.00268	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Anthracite
Kline Township Cogen	3	.00257	across control	FBC/NONOX	BAGHOUSE	FBC	Waste Anthracite

Average emission factor .00261

Emission control device bin/type 31

Dwayne Collier Battle Cogen	1	.07072	across control	STOKER/NOX/DRY	BAGHOUSE	SDA	Bituminous
Dwayne Collier Battle Cogen	2	.05519	across control	STOKER/NOX/DRY	BAGHOUSE	SDA	Bituminous
Dwayne Collier Battle Cogen	3	.06285	across control	STOKER/NOX/DRY	BAGHOUSE	SDA	Bituminous

Average emission factor .06292

Emission control device bin/type 32

Big Bend	1	.33301	last control	STOKER/NOX/WET	ESP- CS	WETSCRUB	Bituminous
Big Bend	2	.25633	last control	STOKER/NOX/WET	ESP- CS	WETSCRUB	Bituminous
Big Bend	3	.35991	last control	STOKER/NOX/WET	ESP- CS	WETSCRUB	Bituminous

Second unit Average .31642
First unit correction factor .61525
Combined emission factor .58277

Emission control device bin/type 33

Big Brown	1	.99082	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite
Big Brown	2	1.12876	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite
Big Brown	3	1.12202	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite
Monticello 1-2	1	.71314	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite
Monticello 1-2	2	1.51459	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite
Monticello 1-2	3	1.40836	last control	CONV/PC/NONOX/DRY	ESP- CS/BAGHOUSE	NONE	Lignite

Second unit Average 1.14628
First unit correction factor 1.03566
Combined emission factor 1.18716

Emission control device bin/type 34

Antelope Valley	1	.05466	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Antelope Valley	2	1.06273	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Antelope Valley	3	.91505	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Stanton Station 10	1	.98757	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Stanton Station 10	2	1.0254	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Stanton Station 10	3	1.01769	across control	CONV/PC/NOX/DRY	BAGHOUSE	SDA	Lignite
Average emission factor		.84385					
Emission control device bin/type 35							
Lewis & Clark	1	.49252	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Lignite
Lewis & Clark	2	.61262	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Lignite
Lewis & Clark	3	.91187	across control	CONV/PC/NOX/DRY	PARTSCRUB	NONE	Lignite
Average emission factor		.67234					
Emission control device bin/type 36							
Monticello 3	1	.78694	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Lignite
Monticello 3	2	.54432	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Lignite
Monticello 3	3	.57559	last control	CONV/PC/NONOX/DRY	ESP- CS	WETSCRUB	Lignite
Limestone	1	.50597	last control	CONV/PC/NOX/WET	ESP- CS	WETSCRUB	Lignite
Limestone	2	.52407	last control	CONV/PC/NOX/WET	ESP- CS	WETSCRUB	Lignite
Limestone	3	.43934	last control	CONV/PC/NOX/WET	ESP- CS	WETSCRUB	Lignite
Second unit Average		.5627					
First unit correction factor		1.03566					
Combined emission factor		.58277					
Emission control device bin/type 37							
Bay Front	1	.99664	across control	CYCLONE/NONOX/WET	MECH	COMP COAL	Bituminous
Bay Front	2	1.46539	across control	CYCLONE/NONOX/WET	MECH	COMP COAL	Bituminous
Bay Front	3	2.24996	across control	CYCLONE/NONOX/WET	MECH	COMP COAL	Bituminous
Average emission factor		1.57066					
Emission control device bin/type 38							
Bailly	1	.55564	last control	CYCLONE/NONOX/WET	ESP- CS	WETSCRUB	Bituminous
Bailly	2	.54693	last control	CYCLONE/NONOX/WET	ESP- CS	WETSCRUB	Bituminous
Bailly	3	.55714	last control	CYCLONE/NONOX/WET	ESP- CS	WETSCRUB	Bituminous
Second unit Average		.55324					
First unit correction factor		.86319					
Combined emission factor		.47755					

Emission control device bin/type 39

Coyote	1	.88207	across control	CYCLONE/NONOX/WET	BAGHOUSE	SDA	Lignite
Coyote	2	.8932	across control	CYCLONE/NONOX/WET	BAGHOUSE	SDA	Lignite
Coyote	3	.94525	across control	CYCLONE/NONOX/WET	BAGHOUSE	SDA	Lignite
Average emission factor		.90684					

Emission control device bin/type 40

AES Hawaii	1	.44101	across control	FBC/SNCR	BAGHOUSE	FBC	Subbituminous
AES Hawaii	2	.4865	across control	FBC/SNCR	BAGHOUSE	FBC	Subbituminous
AES Hawaii	3	.35088	across control	FBC/SNCR	BAGHOUSE	FBC	Subbituminous
Average emission factor		.42613					

Appendix C
Summary of Part II EPA ICR Data

Mercury Capture Efficiencies of Existing Post-combustion Controls Used for Coal-fired Electric Utility Boilers

Table C-1. Post-combustion controls: cold-side ESPs.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T O-H	%R Hg_T Coal
Bituminous Coal, PC Boiler with CS-ESP												
Brayton Point 1	1	2.01	3.34	0.32	5.68	6.80	0.77	3.83	0.23	4.84	14.73	28.86
Brayton Point 1	2	2.61	3.69	0.25	6.55	4.21	0.75	3.19	0.25	4.18	36.11	0.68
Brayton Point 1	3	2.17	3.50	0.26	5.93	5.01	0.77	3.02	0.24	4.02	32.19	19.64
Average		2.27	3.51	0.28	6.05	5.34	0.76	3.35	0.24	4.35	27.68	16.39
Brayton Point 3	1	3.14	3.67	0.36	7.17	8.55	0.78	3.18	0.46	4.43	38.21	48.20
Brayton Point 3	2	1.83	3.14	0.34	5.31	5.30	0.96	2.47	0.37	3.80	28.47	28.27
Brayton Point 3	3	1.40	3.26	1.60	6.26	5.58	0.01	3.43	1.70	5.15	17.70	7.71
Average		2.12	3.36	0.77	6.25	6.48	0.59	3.03	0.85	4.46	28.13	28.06
Gibson 0300	1	1.94	31.74	4.39	38.08	13.69	0.00	32.03	7.51	39.54	-3.85	-188.83
Gibson 0300	2	1.25	38.06	2.92	42.23	13.33	0.01	32.21	5.80	38.01	9.98	-185.13
Gibson 0300	3	1.75	44.44	1.65	47.85	13.53	0.01	42.87	4.17	47.05	1.66	-247.76
Average		1.65	38.08	2.99	42.72	13.52	0.01	35.70	5.83	41.54	2.60	-207.24
Gibson 1099	1	5.53	10.33	2.34	18.20	14.00	0.03	6.06	5.03	11.12	38.92	20.62
Gibson 1099	2	27.57	3.78	1.25	32.60	15.09	0.05	8.41	5.00	13.46	58.69	10.76
Gibson 1099	3	4.60	11.02	1.58	17.20	14.69	0.03	11.03	4.65	15.71	8.68	-6.93
Average		12.57	8.38	1.72	22.67	14.59	0.04	8.50	4.90	13.43	35.43	8.15
Meramec	1	7.61	0.49	0.14	8.23	8.46	0.00	0.76	0.80	1.56	81.01	81.54
Meramec	2	9.34	1.36	0.44	11.15	10.72	0.01	2.20	1.13	3.35	69.97	68.77
Meramec	3	5.65	1.93	0.62	8.19	5.89	0.00	1.51	0.79	2.30	71.96	60.99
Average		7.53	1.26	0.40	9.19	8.36	0.00	1.49	0.91	2.40	74.32	70.43
Jack Watson	1	3.60	1.22	0.92	5.74	4.70	0.05	2.57	1.87	4.49	21.71	4.39
Jack Watson	2	4.91	1.16	0.25	6.32	5.67	0.05	2.99	0.89	3.94	37.70	30.53
Jack Watson	3	4.64	0.60	0.23	5.46	6.20	0.06	2.92	0.89	3.88	29.04	37.45
Average		4.38	0.99	0.47	5.84	5.52	0.05	2.83	1.22	4.10	29.48	24.13
Widows Creek	1	3.36	0.44	0.54	4.34	3.11	0.14	1.48	0.78	2.40	44.75	22.95
Widows Creek	2	2.98	0.45	0.51	3.94	2.67	0.01	1.28	0.68	1.97	50.00	26.25
Widows Creek	3	2.87	0.47	0.50	3.83	2.15	0.01	0.65	0.67	1.34	65.11	37.81
Average		3.07	0.45	0.51	4.04	2.64	0.06	1.14	0.71	1.90	53.29	29.00
Average		4.80	8.00	1.02	13.82	8.06	0.22	8.00	2.09	10.31	35.85	-4.44
Minimum		1.25	0.44	0.14	3.83	2.15	0.00	0.65	0.23	1.34	-3.85	-247.76
Maximum		27.57	44.44	4.39	47.85	15.09	0.96	42.87	7.51	47.05	81.01	81.54
STDEV		5.62	13.05	1.09	13.86	4.35	0.34	12.01	2.24	13.67	23.90	88.31
Bituminous Coal and Pet Coke, PC Boiler with CS-ESP												
Presque Isle 5	1	4.56	0.48	0.14	5.17	4.27	0.01	0.72	1.06	1.80	65.29	57.92
Presque Isle 5	2	3.60	0.66	0.57	4.82	3.48	0.00	0.82	1.02	1.84	61.87	47.14
Presque Isle 5	3	5.06	0.45	0.12	5.63	3.93	0.02	0.71	0.91	1.64	70.84	58.19
Average		4.40	0.53	0.27	5.21	3.89	0.01	0.75	1.00	1.76	66.00	54.42
Presque Isle 6	1	2.73	0.63	0.17	3.52	2.29	0.06	0.84	0.70	1.60	54.54	30.10
Presque Isle 6	2	2.97	0.72	0.25	3.94	4.34	0.03	1.00	0.93	1.96	50.29	54.87
Presque Isle 6	3	2.96	0.62	0.17	3.75	3.85	0.03	0.73	0.81	1.57	58.00	59.17
Average		2.89	0.65	0.20	3.74	3.49	0.04	0.86	0.81	1.71	54.28	48.05
Average		3.65	0.59	0.24	4.47	3.69	0.02	0.81	0.90	1.73	60.14	51.23
Minimum		2.73	0.45	0.12	3.52	2.29	0.00	0.71	0.70	1.57	50.29	30.10
Maximum		5.06	0.72	0.57	5.63	4.34	0.06	1.00	1.06	1.96	70.84	59.17
STDEV		0.96	0.11	0.17	0.86	0.75	0.02	0.11	0.13	0.15	7.44	11.25

(continued)

Table C-1. (continued).

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
Bituminous Coal, PC Boiler with SNCR and CS-ESP												
Salem Harbor	1	4.12	0.32	0.32	4.76	3.44	0.07	0.28	0.27	0.62	87.07	82.11
Salem Harbor	2	4.09	0.04	0.16	4.29	2.35	0.10	0.07	0.15	0.32	92.57	86.40
Salem Harbor	3	3.96	0.06	0.15	4.17	3.27	0.08	0.08	0.14	0.29	93.06	91.16
Average		4.06	0.14	0.21	4.41	3.02	0.08	0.14	0.19	0.41	90.90	86.55
Subbituminous Coal, PC Boiler with CS-ESP												
Montrose	1	1.94	1.85	6.00	9.79	44.90	0.03	2.57	5.48	8.08	17.46	82.01
Montrose	2	0.91	2.52	4.93	8.36	51.99	0.02	2.60	5.94	8.56	-2.31	83.54
Montrose	3	1.63	2.85	4.68	9.16	47.76	0.02	2.30	5.69	8.01	12.54	83.22
Average		1.49	2.41	5.20	9.10	48.21	0.02	2.49	5.70	8.22	9.23	82.92
George Neal So.	1	0.17	4.78	6.34	11.29	8.96	0.03	4.07	5.47	9.58	15.18	-6.90
George Neal So.	2	0.07	4.35	8.24	12.66	7.82	0.06	4.60	6.87	11.53	8.89	-47.37
George Neal So.	3	0.02	3.53	3.77	7.32	10.19	0.02	4.74	6.39	11.15	-52.29	-9.36
Average		0.09	4.22	6.12	10.42	8.99	0.04	4.47	6.24	10.75	12.04	-21.21
Newton	1	0.04	0.58	9.70	10.32	9.07	0.00	2.26	8.07	10.33	-0.10	-14.00
Newton	2	0.04	0.63	9.85	10.52	8.05	0.00	1.66	7.13	8.80	16.33	-9.28
Newton	3	0.08	1.65	9.26	11.00	9.34	0.00	2.04	8.03	10.07	8.46	-7.82
Average		0.05	0.95	9.61	10.61	8.82	0.00	1.99	7.74	9.73	8.23	-10.36
Average		0.54	2.53	6.98	10.05	22.01	0.02	2.98	6.56	9.57	2.69	17.12
Minimum		0.02	0.58	3.77	7.32	7.82	0.00	1.66	5.47	8.01	-52.29	-47.37
Maximum		1.94	4.78	9.85	12.66	51.99	0.06	4.74	8.07	11.53	17.46	83.54
STDEV		0.76	1.50	2.34	1.61	19.75	0.02	1.16	1.02	1.30	21.75	50.89
SPF		0.05	0.25	0.69	1.00	1.00	0.00	0.31	0.69	1.00		
Subbituminous/ Bituminous Coal, PC Boiler with CS-ESP												
St Clair	1	2.53	2.29	1.97	6.79	16.26	0.01	1.35	3.01	4.37	35.63	73.13
St Clair	2	2.87	2.13	1.40	6.39	14.36	0.01	1.39	3.74	5.14	19.65	64.24
St Clair	3	0.98	1.94	4.28	7.20	17.71	0.01	1.33	5.24	6.57	8.71	62.89
Average		2.13	2.12	2.55	6.79	16.11	0.01	1.35	4.00	5.36	21.33	66.75
Lignite, PC Boiler with CS-ESP												
Stanton 1	1	0.04	0.15	11.96	12.15	31.51	0.04	0.42	11.16	11.62	4.42	63.13
Stanton 1	2	0.13	0.13	10.81	11.06	41.24	0.02	0.43	11.68	12.14	-9.70	70.56
Stanton 1	3	0.08	0.05	11.66	11.79	19.94	0.01	0.45	11.97	12.43	-5.41	37.67
Average		0.08	0.11	11.48	11.67	30.89	0.02	0.44	11.60	12.06	-3.57	57.12

Table C-2. Post-combustion controls: hot-side ESPs.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
Bituminous Coal, PC Boiler with HS-ESP												
Cliffside	1	0.17	3.72	3.31	7.20	5.43	0.41	2.79	3.95	7.14	0.86	-31.58
Cliffside	2	0.09	3.54	3.33	6.95	3.84	0.10	2.27	1.95	4.31	38.00	-12.17
Cliffside	3	0.08	4.15	7.27	11.49	8.80	0.10	3.97	2.54	6.61	42.51	24.94
Average		0.11	3.80	4.63	8.55	6.02	0.20	3.01	2.81	6.02	27.12	-6.27
Gaston	1	4.28	0.86	2.64	7.77	5.20	0.74	4.70	2.34	7.78	-0.19	-49.56
Gaston	2	2.57	0.71	3.56	6.84	6.27	0.40	5.80	3.47	9.66	-41.37	-54.19
Gaston	3	0.43	3.94	2.83	7.20	4.70	1.15	4.73	2.04	7.92	-10.00	-68.41
Average		2.42	1.84	3.01	7.27	5.39	0.76	5.08	2.62	8.46	-17.19	-57.39
Dunkirk	1	0.09	8.56	2.82	11.47	10.06	0.21	6.89	3.67	10.77	6.08	-7.09
Dunkirk	2	0.01	8.91	1.43	10.36	10.30	0.08	4.57	2.46	7.12	31.27	30.90
Dunkirk	3	0.01	9.15	3.20	12.36	9.65	0.03	6.40	3.82	10.25	17.08	-6.26
Average		0.04	8.87	2.48	11.40	10.00	0.11	5.95	3.32	9.38	18.14	5.85
Average		0.86	4.84	3.38	9.07	7.14	0.36	4.68	2.92	7.95	9.36	-19.27
Minimum		0.01	0.71	1.43	6.84	3.84	0.03	2.27	1.95	4.31	-41.37	-68.41
Maximum		4.28	9.15	7.27	12.36	10.30	1.15	6.89	3.95	10.77	42.51	30.90
STDEV		1.52	3.28	1.59	2.30	2.55	0.37	1.54	0.80	2.02	26.41	34.54

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
Subbituminous Coal, PC Boiler (Dry Bottom) with HS-ESP												
Cholla 3	1	0.07	0.37	1.93	2.37	51.98	0.01	0.51	1.87	2.40	-1.30	95.39
Cholla 3	2	0.51	0.32	0.46	1.28	54.43	0.01	0.01	1.00	1.02	20.42	98.12
Cholla 3	3	0.45	0.43	0.61	1.49	40.48	0.01	0.39	1.27	1.67	-12.28	95.87
Average		0.34	0.37	1.00	1.71	48.96	0.01	0.30	1.38	1.70	2.28	96.46
Columbia	1	0.01	0.93	14.27	15.22	9.85	0.00	2.74	11.71	14.45	5.02	-46.78
Columbia	2	0.01	5.82	13.40	19.24	10.30	0.00	2.16	11.82	13.98	27.34	-35.71
Columbia	3	0.01	0.46	14.65	15.12	10.35	0.00	2.65	12.68	15.34	-1.47	-48.18
Average		0.01	2.41	14.11	16.52	10.17	0.00	2.51	12.07	14.59	10.30	-43.56
Average		0.18	1.39	7.55	9.12	29.57	0.01	1.41	6.73	8.14	6.29	26.45
Minimum		0.01	0.32	0.46	1.28	9.85	0.00	0.01	1.00	1.02	-12.28	-48.18
Maximum		0.51	5.82	14.65	19.24	54.43	0.01	2.74	12.68	15.34	27.34	98.12
STDEV		0.23	2.18	7.21	8.26	21.77	0.00	1.24	5.87	7.09	14.88	76.82
Subbituminous Coal, PC Boiler (Wet Bottom) with HS-ESP												
Platte	1	0.03	4.15	9.82	14.00	11.10	0.01	1.45	8.76	10.23	26.93	7.88
Platte	2	0.02	1.92	11.31	13.25	9.65	0.01	0.78	16.86	17.65	-33.20	-82.85
Platte	3	0.03	4.39	11.63	16.04	6.05	0.01	1.51	14.90	16.43	-2.40	-171.57
Average		0.03	3.48	10.92	14.43	8.93	0.01	1.25	13.51	14.77	-2.89	-82.18
Presque Isle 9	1	0.04	0.14	6.70	6.89	9.86	0.00	0.57	6.30	6.88	0.10	30.22
Presque Isle 9	2	0.01	0.14	6.89	7.05	8.92	0.00	0.67	6.74	7.41	-5.23	16.87
Presque Isle 9	3	0.01	0.10	6.43	6.55	9.91	0.00	0.54	6.38	6.92	-5.76	30.11
Average		0.02	0.13	6.68	6.83	9.56	0.00	0.59	6.47	7.07	-3.63	25.73
Average		0.02	1.80	8.80	10.63	9.25	0.01	0.92	9.99	10.92	-3.26	-28.22
Minimum		0.01	0.10	6.43	6.55	6.05	0.00	0.54	6.30	6.88	-33.20	-171.57
Maximum		0.04	4.39	11.63	16.04	11.10	0.01	1.51	16.86	17.65	26.93	30.22
STDEV		0.01	2.03	2.41	4.27	1.72	0.01	0.44	4.69	4.91	19.13	82.08
Subbituminous/Bituminous Coal, PC Boiler with HS-ESP												
Clifty	3	0.01	3.41	11.46	14.87	7.84	0.07	5.50	3.80	9.37	36.99	-19.53
Clifty	1	0.40	2.35	11.17	13.92	8.02	0.70	3.60	4.67	8.96	35.58	-11.78
Clifty	2	0.02	3.58	11.13	14.73	7.66	0.01	5.04	5.34	10.39	29.51	-35.57
Average		0.14	3.11	11.25	14.51	7.84	0.26	4.71	4.60	9.57	34.03	-22.29

Table C-3. Post-combustion controls: fabric filters.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data											
Plant ID	**Run No.**	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T O-H	%R Hg_T Coal
Bituminous Coal, PC Boiler with FF												
Sammis	1	11.78	0.48	0.61	12.86	6.64	0.01	0.49	0.61	1.11	91.37	83.28
Sammis	2	15.35	0.50	0.54	16.38	9.54	0.01	0.58	0.55	1.14	93.04	88.05
Sammis	3	14.62	0.51	0.52	15.65	9.55	0.02	0.51	0.57	1.10	92.97	88.48
Average		13.92	0.50	0.55	14.97	8.58	0.01	0.53	0.57	1.12	92.46	86.60
Valmont	1	0.92	0.12	0.18	1.22	0.80	0.00	0.12	0.04	0.16	86.98	80.04
Valmont	2	0.92	0.07	0.14	1.12	0.44	0.00	0.10	0.02	0.12	89.53	73.26
Valmont	3	1.23	0.10	0.17	1.51	0.60	0.00	0.21	0.03	0.24	84.15	60.16
Average		1.02	0.10	0.17	1.29	0.61	0.00	0.14	0.03	0.17	86.89	71.16
Average		7.47	0.30	0.36	8.13	4.59	0.01	0.34	0.30	0.64	89.67	78.88
Minimum		0.92	0.07	0.14	1.12	0.44	0.00	0.10	0.02	0.12	84.15	60.16
Maximum		15.35	0.51	0.61	16.38	9.55	0.02	0.58	0.61	1.14	93.04	88.48
STDEV		7.16	0.22	0.22	7.59	4.49	0.01	0.22	0.30	0.52	3.54	10.76
Bituminous Coal/Pet. Coke, PC Boiler with FF (Measurements not valid, disregard)												
Valley	1	0.04	1.44	1.21	2.69	0.95	0.11	2.02	0.41	2.54	5.67	-165.84
Valley	2	0.05	1.49	0.45	1.99	1.33	0.04	1.55	0.42	2.00	-0.70	-50.84
Valley	3	0.04	1.22	0.67	1.92	1.52	0.00	1.89	0.52	2.41	-25.15	-58.75
Average		0.04	1.38	0.78	2.20	1.27	0.05	1.82	0.45	2.31	-6.73	-91.81
Bituminous/Subbituminous Coal, PC Boiler with FF												
Shawnee	1	3.18	0.58	0.72	4.48	2.39	0.01	0.63	0.84	1.49	66.73	37.66
Shawnee	2	3.01	0.98	0.66	4.65	4.29	0.02	0.61	0.75	1.37	70.51	68.03
Shawnee	3	3.44	0.57	0.67	4.68	2.66	0.01	0.60	0.68	1.28	72.62	51.82
Average		3.21	0.71	0.68	4.61	3.11	0.01	0.61	0.76	1.38	69.95	52.50
Subbituminous Coal, PC Boiler with FF												
Boswell 2	2	1.99	1.26	1.46	4.71	4.35	0.00	0.35	0.23	0.59	87.45	86.43
Boswell 2	3	0.83	1.15	2.49	4.46	5.20	0.00	0.58	0.12	0.70	84.32	86.54
Boswell 2	1	2.75	1.81	1.60	6.16	8.35	0.07	1.26	0.14	1.47	76.06	82.34
Average		1.85	1.41	1.85	5.11	5.97	0.03	0.73	0.16	0.92	82.61	85.10
Comanche	1	1.81	3.93	5.71	11.46	15.91	0.00	3.33	0.27	3.60	68.58	77.37
Comanche	3	5.27	1.28	3.67	10.22	14.24	0.00	3.20	0.33	3.52	65.52	75.26
Comanche	2	2.59	1.45	5.77	9.82	17.08	0.00	3.99	0.65	4.65	52.67	72.80
Average		3.23	2.22	5.05	10.50	15.74	0.00	3.51	0.42	3.92	62.26	75.14
Average		2.54	1.81	3.45	7.80	10.86	0.01	2.12	0.29	2.42	72.43	80.12
Minimum		0.83	1.15	1.46	4.46	4.35	0.00	0.35	0.12	0.59	52.67	72.80
Maximum		5.27	3.93	5.77	11.46	17.08	0.07	3.99	0.65	4.65	87.45	86.54
STDEV		1.50	1.06	1.94	3.06	5.59	0.03	1.57	0.20	1.72	12.91	5.85

Table C-4. Post-combustion controls: miscellaneous PM controls.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T O-H	%R Hg_T Coal
TX Lignite, PC Boiler with CS-ESP and FF (COHPAC)												
Bigbrown	1	2.59	8.35	31.24	42.18	50.86	0.01	16.58	25.20	41.80	0.92	17.82
Bigbrown	2	0.54	10.37	27.31	38.21	49.95	0.01	17.66	25.47	43.13	-12.88	13.65
Bigbrown	3	0.14	14.14	21.93	36.21	46.92	0.01	18.49	22.12	40.62	-12.20	13.42
Average		1.09	10.95	26.83	38.87	49.24	0.01	17.58	24.26	41.85	-7.68	14.96
Monticello 1-2	1	15.97	22.54	8.82	47.34	53.79	0.17	32.01	1.58	33.76	28.69	37.23
Monticello 1-2	2	0.37	14.82	46.29	61.48	54.09	0.11	78.08	14.93	93.11	-51.46	-72.13
Monticello 1-2	3	7.97	22.74	44.19	74.90	84.65	0.08	86.89	18.51	105.48	-40.84	-24.61
Average		8.10	20.03	33.10	61.24	64.18	0.12	65.66	11.67	77.45	-21.20	-19.83
Average		4.60	15.49	29.96	50.05	56.71	0.07	41.62	17.97	59.65	-13.63	-2.44
Minimum		0.14	8.35	8.82	36.21	46.92	0.01	16.58	1.58	33.76	-51.46	-72.13
Maximum		15.97	22.74	46.29	74.90	84.65	0.17	86.89	25.47	105.48	28.69	37.23
STDEV		6.31	6.03	14.07	15.16	13.94	0.07	32.27	8.99	31.13	26.49	39.61
Subbituminous Coal, PC Boiler with PM Scrubber												
Boswell 3	1	0.01	0.25	6.06	6.32	5.00	0.00	0.05	5.82	5.87	7.16	-17.51
Boswell 3	2	0.01	0.31	6.00	6.32	6.38	0.00	0.06	5.39	5.45	13.81	14.54
Boswell 3	3	0.06	0.62	5.21	5.89	5.79	0.00	0.06	5.51	5.58	5.25	3.60
Average		0.03	0.39	5.76	6.18	5.72	0.00	0.06	5.57	5.63	8.74	0.21

Table C-5. Post-combustion controls: dry FGD scrubbers using ESP.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run**	Hg_p In	**Hg^{2+} In**	**Hg° In**	**Hg_T In**	**Hg_T In**	**Hg_p Out**	**Hg^{2+} Out**	**Hg° Out**	**HG_T Out**	**%R H_T**	**%R Hg_T**
	No.	**O-H**	**O-H**	**O-H**	**O-H**	**Coal**	**O-H**	**O-H**	**O-H**	**O-H**	**O-H**	**Coal**
Bituminous Coal, PC Boiler with DSI/CS-ESP												
Washington	1	0.00	4.33	11.63	15.97	13.01	0.00	6.41	3.06	9.47	40.68	27.22
Washington	2	0.00	7.75	11.02	18.77	13.36	0.00	5.84	3.05	8.90	52.61	33.42
Washington	3	0.00	6.40	9.95	16.36	13.33	0.04	6.52	3.04	9.59	41.37	28.06
Average		0.00	6.16	10.86	17.03	13.24	0.02	6.26	3.05	9.32	44.89	29.56
Subbituminous Coal, PC Boiler with SDA/CS-ESP												
GRDA	1	0.13	4.42	7.77	12.31	11.22	0.01	1.55	5.58	7.13	42.06	36.42
GRDA	2	0.53	2.97	6.50	9.99	10.73	0.01	1.28	11.12	12.42	-24.23	-15.70
GRDA	3	0.51	8.78	3.71	13.01	12.24	0.01	0.34	5.41	5.76	55.72	52.94
Average		0.39	5.39	5.99	11.77	11.40	0.01	1.06	7.37	8.44	24.51	24.55
Laramie 3	1	0.03	0.22	0.63	0.88	15.03	0.03	0.10	3.87	4.00	0.00	73.40
Laramie 3	2	1.69	0.52	8.53	10.75	17.67	0.03	0.04	4.52	4.58	57.35	74.05
Laramie 3	3	4.55	0.44	9.28	14.27	14.94	0.03	0.04	5.27	5.35	62.53	64.22
Average		2.09	0.39	6.15	8.63	15.88	0.03	0.06	4.56	4.64	39.96	70.56
Wyodak	1	2.49	3.88	11.63	18.00	4.46	0.05	0.07	9.97	10.09	43.95	-126.38
Wyodak	2	3.05	4.71	9.42	17.17	6.41	0.05	0.17	10.11	10.32	39.87	-61.16
Wyodak	3	2.25	3.57	11.51	17.34	8.17	0.05	0.25	10.11	10.41	39.99	-27.41
Average		2.60	4.05	10.85	17.50	6.34	0.05	0.16	10.06	10.27	41.27	-71.65
Average		1.69	3.28	7.67	12.64	11.21	0.03	0.43	7.33	7.78	35.25	7.82
Minimum		0.03	0.22	0.63	0.88	4.46	0.01	0.04	3.87	4.00	-24.23	-126.38
Maximum		4.55	8.78	11.63	18.00	17.67	0.05	1.55	11.12	12.42	62.53	74.05
STDEV		1.54	2.72	3.60	5.28	4.32	0.02	0.57	2.91	3.06	28.72	70.07

Table C-6. Post-combustion controls: dry FGD scrubbers using FF.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run**	Hg_p In	**Hg^{2+} In**	**Hg° In**	**Hg_T In**	**Hg_T In**	**Hg_p Out**	**Hg^{2+} Out**	**Hg° Out**	**HG_T Out**	**%R H_T**	**%R Hg_T**
	No.	**O-H**	**O-H**	**O-H**	**O-H**	**Coal**	**O-H**	**O-H**	**O-H**	**O-H**	**O-H**	**Coal**
Bituminous Coal, PC Boiler with SDA/FF												
Mecklenburg	1	11.34	3.40	6.16	20.91	11.52	0.00	0.07	0.09	0.16	99.23	98.60
Mecklenburg	2	5.66	4.21	0.02	9.89	13.28	0.00	0.07	0.23	0.31	96.91	97.70
Mecklenburg	3	6.90	3.04	0.02	9.96	11.50	0.00	0.01	0.23	0.24	97.60	97.92
Average		7.97	3.55	2.07	13.59	12.10	0.00	0.05	0.18	0.24	97.91	98.07
Bituminous Coal, PC Boiler with SCR and SDA/FF												
Logan	1	12.87	7.22	0.21	20.31	18.28	0.02	0.08	0.16	0.26	98.71	98.57
Logan	2	12.74	4.36	0.35	17.46	18.14	0.02	0.13	0.17	0.32	98.16	98.23
Logan	3	12.45	4.59	0.25	17.29	17.51	0.01	0.04	0.17	0.22	98.72	98.74
Average		12.69	5.39	0.27	18.35	17.98	0.02	0.09	0.16	0.27	98.53	98.51
SEI	1	13.48	0.30	0.14	13.92	11.79	0.01	0.34	0.13	0.48	96.56	95.94
SEI	2	9.47	0.25	0.18	9.90	11.74	0.01	0.09	0.12	0.22	97.79	98.13
SEI	3	12.01	0.25	0.16	12.42	11.97	0.02	0.08	0.11	0.21	98.34	98.28
Average		11.66	0.26	0.16	12.08	11.83	0.01	0.17	0.12	0.30	97.56	97.45
Average		12.17	2.83	0.22	15.22	14.90	0.02	0.13	0.14	0.28	98.05	97.98
Minimum		9.47	0.25	0.14	9.90	11.74	0.01	0.04	0.11	0.21	96.56	95.94
Maximum		13.48	7.22	0.35	20.31	18.28	0.02	0.34	0.17	0.48	98.72	98.74
STDEV		1.41	2.98	0.08	3.82	3.38	0.00	0.11	0.03	0.10	0.81	1.03
Subbituminous Coal, PC Boiler with SDA/FF												
Craig 3	1	0.57	0.65	0.20	1.42	1.20	0.00	0.04	0.90	0.94	33.79	21.49
Craig 3	2	0.92	0.50	0.17	1.60	1.06	0.00	0.04	0.89	0.93	41.83	11.88
Craig 3	3	0.90	0.23	0.12	1.25	0.93	0.00	0.03	0.82	0.86	31.67	7.38
Average		0.80	0.46	0.16	1.42	1.06	0.00	0.04	0.87	0.91	35.76	13.58
Rawhide	1	0.25	1.38	12.46	14.09	8.09	0.12	0.76	10.80	11.68	17.16	-44.36
Rawhide	2	1.92	0.83	12.85	15.59	7.33	0.01	0.69	9.91	10.60	32.03	-44.61
Rawhide	3	3.76	0.46	14.79	19.01	9.24	0.03	0.98	9.00	10.01	47.31	-8.41
Average		1.98	0.89	13.37	16.23	8.22	0.05	0.81	9.90	10.76	32.16	-32.46
NSP Sherburne	1	0.03	0.53	10.92	11.48	8.29	0.12	0.20	8.42	8.74	23.81	-5.43
NSP Sherburne	2	0.03	0.23	10.92	11.18	8.27	0.14	0.18	12.09	12.40	-10.94	-49.92
NSP Sherburne	3	0.03	0.19	10.24	10.46	7.73	0.27	0.24	9.84	10.35	1.05	-34.01
Average		0.03	0.32	10.69	11.04	8.10	0.18	0.20	10.12	10.50	4.64	-29.78
Average		0.93	0.56	8.07	9.56	5.79	0.08	0.35	6.96	7.39	24.19	-16.22
Minimum		0.03	0.19	0.12	1.25	0.93	0.00	0.03	0.82	0.86	-10.94	-49.92
Maximum		3.76	1.38	14.79	19.01	9.24	0.27	0.98	12.09	12.40	47.31	21.49
STDEV		1.23	0.37	6.08	6.63	3.59	0.09	0.36	4.68	4.97	18.96	27.38

(continued)

Table C-6. (continued).

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data											
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
ND Lignite, PC Boiler with SDA/FF												
Antelope Valley	1	0.16	0.38	7.80	8.34	13.85	0.01	0.25	omit	NA	NA	NA
Antelope Valley	2	0.21	0.42	7.82	8.45	16.03	0.02	0.79	8.16	8.98	-6.27	44.01
Antelope Valley	3	0.16	0.16	7.67	8.00	12.50	0.02	0.33	6.97	7.32	8.49	41.45
Average		0.18	0.29	7.75	8.22	14.27	0.02	0.56	7.56	8.15	1.11	42.73
Stanton 10	1	0.22	0.24	10.23	10.70	12.82	0.02	0.40	10.14	10.56	1.24	17.63
Stanton 10	2	0.27	0.36	9.86	10.49	15.63	0.01	0.17	10.58	10.76	-2.54	31.15
Stanton 10	3	0.50	0.69	9.45	10.64	9.45	0.01	0.01	10.81	10.83	-1.77	-14.61
Average		0.33	0.43	9.85	10.61	12.63	0.01	0.19	10.51	10.72	-1.02	11.39
Average		0.27	0.38	9.01	9.65	13.29	0.02	0.34	9.33	9.69	-0.17	23.93
Minimum		0.16	0.16	7.67	8.00	9.45	0.01	0.01	6.97	7.32	-6.27	-14.61
Maximum		0.50	0.69	10.23	10.70	16.03	0.02	0.79	10.81	10.83	8.49	44.01
STDEV		0.13	0.20	1.18	1.32	2.67	0.01	0.29	1.69	1.53	5.53	23.91
Bituminous, Stoker with SDA/FF												
Dwayne Collier	1	2.19	0.03	0.06	2.28	3.37	0.06	0.02	0.08	0.16	92.84	95.16
Dwayne Collier	2	2.14	0.18	0.42	2.75	3.48	0.03	0.03	0.09	0.15	94.48	95.64
Dwayne Collier	3	1.99	0.03	0.11	2.13	3.29	0.01	0.03	0.06	0.10	95.43	97.04
Average		2.11	0.08	0.20	2.39	3.38	0.03	0.03	0.08	0.14	94.25	95.95

Table C-7. Post-combustion controls: wet FGD scrubbers.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data											
Plant ID	Run No.	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T O-H	%R Hg_T Coal
Bituminous Coal, PC Boiler with PS and Wet FGD Scrubber											
Bruce Mansfield	1	0.27	8.65	1.58	10.50	10.93	0.04	1.89	7.01	8.95	14.81	18.11
Bruce Mansfield	2	0.73	9.84	2.08	12.65	8.93	0.06	2.73	7.96	10.76	14.94	-20.57
Bruce Mansfield	3	0.27	8.34	1.70	10.31	11.82	0.04	1.22	8.29	9.55	7.42	19.25
Average		0.42	8.94	1.79	11.15	10.56	0.05	1.95	7.76	9.75	12.39	5.60
Subbituminous Coal, PC Boiler with PS and Wet FGD Scrubber											
Boswell 4	1	0.11	0.33	5.05	5.48	6.98	0.02	0.10	5.53	5.65	-3.08	19.00
Boswell 4	2	2.98	1.07	1.47	5.53	6.63	0.20	0.44	5.89	6.53	-18.25	1.41
Boswell 4	3	2.75	0.55	1.16	4.45	7.93	0.28	0.59	5.57	6.43	-44.40	18.91
Average		1.95	0.65	2.56	5.15	7.18	0.17	0.38	5.66	6.21	-21.91	13.11
Cholla 2	1	0.42	0.97	4.68	6.07	6.99	0.15	0.21	3.93	4.29	29.30	38.59
Cholla 2	2	1.11	0.93	2.62	4.66	6.37	0.19	0.14	4.67	5.01	-7.51	21.38
Cholla 2	3	0.41	2.06	2.99	5.46	5.09	0.11	0.14	4.22	4.46	18.29	12.27
Average		0.65	1.32	3.43	5.40	6.15	0.15	0.16	4.27	4.59	13.36	24.08
Colstrip	1	1.78	2.29	1.08	5.15	7.63	0.05	0.42	9.13	9.60	-86.54	-25.89
Colstrip	2	1.94	2.37	6.37	10.68	7.98	0.02	0.45	11.03	11.51	-7.74	-44.19
Colstrip	3	1.63	2.86	5.39	9.88	7.93	0.02	0.39	2.13	2.54	74.27	67.94
Average		1.78	2.51	4.28	8.57	7.85	0.03	0.42	7.43	7.88	-6.67	-0.71
Lawrence	1	0.23	1.65	4.99	6.86	6.24	0.01	0.49	6.37	6.87	-0.07	-10.01
Lawrence	2	0.53	0.63	4.41	5.58	5.47	0.08	0.53	6.71	7.32	-31.14	-33.75
Lawrence	3	0.24	0.65	4.96	5.86	6.03	0.09	0.51	6.20	6.81	-16.21	-12.96
Average		0.33	0.98	4.79	6.10	5.91	0.06	0.51	6.42	7.00	-15.81	-18.91
Average		1.18	1.36	3.76	6.30	6.77	0.10	0.37	5.95	6.42	-7.76	4.39
Minimum		0.11	0.33	1.08	4.45	5.09	0.01	0.10	2.13	2.54	-86.54	-44.19
Maximum		2.98	2.86	6.37	10.68	7.98	0.28	0.59	11.03	11.51	74.27	67.94
STDEV		1.02	0.85	1.82	1.96	0.98	0.09	0.17	2.34	2.40	39.47	31.96
ND Lignite, PC Boiler with PS and Wet FGD Scrubber											
Lewis and Clark	1	1.15	16.47	11.65	29.27	15.33	0.06	0.50	13.86	14.42	50.75	5.98
Lewis and Clark	2	1.68	13.64	8.43	23.75	15.54	0.00	0.35	14.19	14.55	38.74	6.41
Lewis and Clark	3	1.41	6.28	10.20	17.89	18.96	0.00	0.50	15.81	16.31	8.81	13.94
Average		1.41	12.13	10.09	23.64	16.61	0.02	0.45	14.62	15.09	32.77	8.78

(continued)

Table C-7. (continued).

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	Run No.	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T Wet FGD	%R Hg_T PM+FGD
Bituminous Coal, PC Boiler with CS-ESP and wet FGD Scrubber												
AES Cayuga	2	0.00	6.40	2.58	8.98	11.87	0.00	0.18	2.70	2.88	67.91	76.06
AES Cayuga	1	0.00	5.87	2.24	8.11	10.70	0.00	0.36	2.73	3.09	61.88	71.56
AES Cayuga	3	0.00	5.55	2.95	8.50	10.80	0.00	0.18	3.08	3.26	61.63	71.38
Average		0.00	5.94	2.59	8.53	11.12	0.00	0.24	2.83	3.08	63.81	73.00
Big Bend	1	0.09	4.86	2.40	7.34	17.52	0.05	0.21	2.18	2.44	66.70	75.16
Big Bend	2	0.05	4.92	2.31	7.29	11.25	0.00	0.12	1.75	1.87	74.37	80.88
Big Bend	3	0.02	4.26	2.13	6.41	12.01	0.03	0.23	2.05	2.31	64.01	73.15
Average		0.05	4.68	2.28	7.01	13.59	0.03	0.19	1.99	2.21	68.36	76.39
Average		0.03	5.31	2.43	7.77	12.36	0.01	0.22	2.41	2.64	66.08	74.70
Minimum		0.00	4.26	2.13	6.41	10.70	0.00	0.12	1.75	1.87	61.63	71.38
Maximum		0.09	6.40	2.95	8.98	17.52	0.05	0.36	3.08	3.26	74.37	80.88
STDEV		0.03	0.78	0.30	0.94	2.59	0.02	0.08	0.50	0.53	4.78	3.56
Subbituminous Coal, PC Boiler with CS-ESP and wet FGD Scrubber												
Jim Bridger	1	0.05	2.49	5.21	7.74	no coal flow	0.06	0.25	6.63	6.95	10.32	14.60
Jim Bridger	2	0.44	2.04	5.64	8.12	no coal flow	0.05	0.29	6.51	6.85	15.64	19.67
Jim Bridger	3	0.07	1.78	4.50	6.35	no coal flow	0.03	0.20	5.92	6.15	3.06	7.69
Average		0.19	2.10	5.12	7.41	not included	0.05	0.25	6.36	6.65	9.68	13.99
Laramie River 1	1	0.25	3.14	7.52	10.91	13.52	0.02	0.29	4.86	5.18	52.57	54.83
Laramie River 1	2	0.04	2.16	8.35	10.55	15.45	0.00	0.12	5.73	5.85	44.54	47.18
Laramie River 1	3	0.02	3.08	7.53	10.63	15.71	0.01	0.03	4.48	4.52	57.53	59.56
Average		0.10	2.79	7.80	10.70	14.90	0.01	0.15	5.02	5.18	51.55	53.86
Sam Seymour	1	0.03	3.00	9.10	12.13	60.48	0.06	0.24	12.25	12.54	1.51	1.51
Sam Seymour	2	0.01	4.08	13.10	17.19	43.20	0.11	0.29	13.33	13.74	23.90	23.90
Sam Seymour	3	0.01	5.39	11.96	17.35	51.04	0.06	0.35	11.99	12.39	31.99	31.99
Average		0.01	4.16	11.38	15.56	51.58	0.07	0.29	12.53	12.89	19.13	19.13
Average		0.10	3.02	8.10	11.22	33.24	0.04	0.23	7.97	8.24	26.78	28.99
Minimum		0.01	1.78	4.50	6.35	13.52	0.00	0.03	4.48	4.52	1.51	1.51
Maximum		0.44	5.39	13.10	17.35	60.48	0.11	0.35	13.33	13.74	57.53	59.56
STDEV		0.15	1.13	2.94	3.88	20.84	0.03	0.10	3.50	3.59	21.09	20.83
TX Lignite, PC Boiler with CS-ESP and wet FGD Scrubber												
Monticello 3	1	0.19	16.49	29.39	46.07	61.96	0.31	6.50	29.45	36.25	21.31	21.31
Monticello 3	2	0.11	19.77	28.15	48.03	63.13	0.18	0.44	25.52	26.14	45.57	45.57
Monticello 3	3	0.13	25.83	27.21	53.16	76.52	0.24	7.26	23.10	30.60	42.44	42.44
Average		0.14	20.70	28.25	49.09	67.20	0.24	4.73	26.02	31.00	36.44	36.44
Limestone	1	0.01	23.55	13.38	36.94	14.49	0.04	2.69	15.96	18.69	49.40	49.40
Limestone	2	0.01	24.55	13.11	37.68	20.84	0.33	3.18	16.23	19.74	47.59	47.59
Limestone	3	0.02	28.15	14.11	42.29	15.29	0.12	1.27	17.18	18.58	56.07	56.07
Average		0.02	25.42	13.54	38.97	16.87	0.17	2.38	16.46	19.01	51.02	51.02
Average		0.08	23.06	20.89	44.03	42.04	0.20	3.56	21.24	25.00	43.73	43.73
Minimum		0.01	16.49	13.11	36.94	14.49	0.04	0.44	15.96	18.58	21.31	21.31
Maximum		0.19	28.15	29.39	53.16	76.52	0.33	7.26	29.45	36.25	56.07	56.07
STDEV		0.07	4.24	8.09	6.28	28.12	0.11	2.76	5.63	7.32	11.89	11.89

(continued)

Table C-7. (continued).

Plant ID	Run No.	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T Wet FGD	%R Hg_T PM+FGD
Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Bituminous Coal, PC Boiler with HS-ESP and wet FGD Scrubber												
Charles Lowman	1	2.64	3.33	2.09	8.06	23.49	0.06	1.68	3.39	5.13	36.44	44.29
Charles Lowman	2	1.55	3.98	2.17	7.69	21.50	0.07	1.86	3.50	5.44	29.31	38.03
Charles Lowman	3	3.45	3.55	2.02	9.01	23.94	0.05	2.06	3.19	5.30	41.18	48.44
Average		2.55	3.62	2.09	8.26	22.98	0.06	1.87	3.36	5.29	35.64	43.58
Morrow	1	0.05	10.80	4.41	15.27	5.48	0.05	2.06	5.00	7.11	53.46	59.20
Morrow	2	0.01	8.31	4.10	12.42	5.42	0.03	1.79	4.50	6.31	49.18	55.45
Morrow	3	0.03	6.98	3.32	10.33	5.38	0.04	1.12	4.55	5.71	44.70	51.52
Average		0.03	8.70	3.94	12.67	5.43	0.04	1.65	4.68	6.38	49.11	55.39
Average		1.29	6.16	3.02	10.46	14.20	0.05	1.76	4.02	5.83	42.38	49.49
Minimum		0.01	3.33	2.02	7.69	5.38	0.03	1.12	3.19	5.13	29.31	38.03
Maximum		3.45	10.80	4.41	15.27	23.94	0.07	2.06	5.00	7.11	53.46	59.20
STDEV		1.50	3.05	1.08	2.91	9.65	0.02	0.35	0.75	0.75	8.74	7.66
Subbituminous Coal, PC Boiler with HS-ESP and wet FGD Scrubber												
Coronado	1	0.03	0.99	2.19	3.20	4.45	0.02	0.04	3.56	3.61	-12.95	-0.87
Coronado	2	0.03	0.82	1.86	2.71	4.76	0.08	0.07	1.83	1.98	26.82	34.64
Coronado	3	0.03	1.09	1.87	2.99	3.86	0.11	0.13	3.08	3.32	-11.30	0.60
Average		0.03	0.96	1.97	2.96	4.36	0.07	0.08	2.82	2.97	0.86	11.46
Craig 1	1	0.04	0.33	3.61	3.97	2.45	0.00	0.13	2.13	2.26	43.05	49.14
Craig 1	2	0.04	0.29	2.52	2.85	2.79	0.00	0.11	2.09	2.20	22.93	31.17
Craig 1	3	0.04	0.16	1.99	2.19	2.30	0.01	0.09	2.03	2.14	2.44	12.87
Average		0.04	0.26	2.71	3.01	2.51	0.01	0.11	2.08	2.20	22.81	31.06
Navajo	1	0.03	2.91	3.55	6.49	4.37	0.05	0.04	3.67	3.76	42.00	48.20
Navajo	2	0.03	0.45	3.93	4.41	2.63	0.02	0.04	3.79	3.85	12.65	21.99
Navajo	3	0.03	0.62	3.50	4.16	2.63	0.01	0.04	3.77	3.82	8.25	18.06
Average		0.03	1.33	3.66	5.02	3.21	0.03	0.04	3.75	3.81	20.97	29.42
San Juan	1	0.02	6.25	5.81	12.08	7.94	0.05	0.45	7.14	7.64	36.74	43.50
San Juan	2	0.08	3.31	4.26	7.65	8.69	0.08	0.38	4.79	5.25	31.35	38.69
San Juan	3	0.02	5.07	3.62	8.70	11.00	0.05	0.31	4.66	5.02	42.31	48.48
Average		0.04	4.87	4.56	9.47	9.21	0.06	0.38	5.53	5.97	36.80	43.56
Average		0.03	1.86	3.23	5.12	4.82	0.04	0.15	3.54	3.74	20.36	28.87
Minimum		0.02	0.16	1.86	2.19	2.30	0.00	0.04	1.83	1.98	-12.95	-0.87
Maximum		0.08	6.25	5.81	12.08	11.00	0.11	0.45	7.14	7.64	43.05	49.14
STDEV		0.02	2.05	1.19	3.02	2.86	0.04	0.14	1.52	1.64	20.32	18.15

Plant ID	Run No.	Hg_p In O-H	Hg^{2+} In O-H	Hg° In O-H	Hg_T In O-H	Hg_T In Coal	Hg_p Out O-H	Hg^{2+} Out O-H	Hg° Out O-H	HG_T Out O-H	%R H_T Wet FGD	%R Hg_T PM+FGD
Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Bituminous Coal, PC Boiler with FF and wet FGD scrubber												
Clover	1	0.06	1.00	1.11	2.17	29.21	0.05	0.42	0.42	0.88	59.42	96.78
Clover	2	0.03	1.11	1.99	3.13	41.19	0.02	0.34	0.17	0.53	83.13	98.66
Clover	3	0.08	1.16	0.62	1.86	49.02	0.06	0.05	0.14	0.25	86.76	98.95
Average		0.06	1.09	1.24	2.39	39.81	0.04	0.27	0.24	0.55	76.43	98.13
Intermountain	1	0.01	1.01	0.20	1.22	2.00	0.01	0.03	0.25	0.29	76.15	98.11
Intermountain	2	0.01	1.08	0.24	1.33	1.97	0.01	0.07	0.46	0.54	59.67	96.80
Intermountain	3	0.01	1.36	0.22	1.58	3.09	0.01	0.08	0.41	0.50	68.68	97.52
Average		0.01	1.15	0.22	1.38	2.35	0.01	0.06	0.37	0.44	68.16	97.48
Average		0.03	1.12	0.73	1.88	21.08	0.03	0.16	0.31	0.50	72.30	97.80
Minimum		0.01	1.00	0.20	1.22	1.97	0.01	0.03	0.14	0.25	59.42	96.78
Maximum		0.08	1.36	1.99	3.13	49.02	0.06	0.42	0.46	0.88	86.76	98.95
STDEV		0.03	0.13	0.71	0.70	21.47	0.02	0.17	0.14	0.23	11.66	0.92

Table C-8. Cyclone-fired boilers.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
ND Lignite, Cyclone Boiler with CS-ESP												
Leland Olds	1	0.56	0.23	3.30	4.09	5.63	0.00	0.82	4.04	4.86	-18.68	13.66
Leland Olds	2	0.26	0.46	8.80	9.51	10.18	0.00	1.09	5.26	6.35	33.26	37.64
Leland Olds	3	2.85	0.81	4.77	8.43	7.94	0.00	1.60	LS	NA	NA	NA
Average		0.41	0.34	6.05	6.80	7.90	0.00	0.95	4.65	5.60	7.29	25.65
Sub-bituminous/Pet. Coke, Cyclone Boiler with HS-ESP												
Nelson Dewey	1	0.01	0.49	3.20	3.69	6.62	0.10	0.26	3.33	3.69	0.13	44.27
Nelson Dewey	2	0.01	0.24	2.19	2.43	6.47	0.04	0.16	2.40	2.60	-6.90	59.83
Nelson Dewey	3	0.01	0.12	2.06	2.18	6.09	0.04	0.25	2.44	2.73	-24.95	55.22
Average		0.01	0.28	2.48	2.77	6.39	0.06	0.22	2.72	3.00	-10.57	53.11
Lignite, Cyclone Boiler with Mechanical Collector												
Bay Front	1	0.76	0.78	2.17	3.70	3.58	1.19	0.60	1.91	3.69	0.34	-2.95
Bay Front	2	1.08	0.67	1.94	3.69	3.01	0.86	2.75	1.80	5.40	-46.54	-79.21
Bay Front	3	0.09	0.77	1.74	2.60	3.36	0.48	3.57	1.78	5.84	-125.00	-73.79
Average		0.64	0.74	1.95	3.33	3.32	0.84	2.30	1.83	4.98	-57.07	-51.99
Lignite, Cyclone Boiler with SDA/FF												
Coyote	1	0.69	1.62	13.68	15.99	10.51	0.08	0.04	13.97	14.10	11.81	-34.23
Coyote	2	1.18	2.98	13.90	18.06	18.55	0.14	0.24	LS	NA	NA	NA
Coyote	3	1.69	3.07	14.91	19.66	11.39	0.08	0.44	18.06	18.58	5.48	-63.12
Average		1.19	2.34	14.29	17.82	10.95	0.08	0.24	16.02	16.34	8.64	-48.67
Bituminous, Cyclone Boiler with PS and Wet FGD Scrubbers												
Lacygne	1	6.70	3.99	1.30	12.00	no inlet flow	0.04	0.44	8.74	9.22	23.18	no inlet flow
Lacygne	2	6.52	3.34	0.60	10.46	no inlet flow	0.05	0.43	7.41	7.89	24.53	no inlet flow
Lacygne	3	5.98	0.59	0.61	7.18	no inlet flow	0.09	0.41	5.10	5.59	22.17	no inlet flow
Average		6.40	2.64	0.84	9.88	no inlet flow	0.06	0.43	7.08	7.57	23.29	no inlet flow
Bituminous, Cyclone Boiler with CS-ESP and wet FGD Scrubber												
Bailly	1	0.04	3.18	2.57	5.79	4.41	0.00	0.36	2.85	3.22	54.24	27.09
Bailly	2	0.04	2.37	2.95	5.36	5.20	0.00	0.31	2.62	2.93	54.95	43.53
Bailly	3	0.09	3.01	2.58	5.68	4.08	0.00	0.39	2.78	3.17	54.11	22.31

Table C-9. Fluidized-bed combustion.

Hg Speciation at Inlet and Outlet (µg/dscm@ 3%O_2) : % Reduction for O-H Train and Coal Data												
Plant ID	**Run No.**	Hg_p In O-H	**Hg^{2+} In O-H**	**Hg° In O-H**	**Hg_T In O-H**	**Hg_T In Coal**	**Hg_p Out O-H**	**Hg^{2+} Out O-H**	**Hg° Out O-H**	**HG_T Out O-H**	**%R H_T O-H**	**%R Hg_T Coal**
Lignite, FBC with CS-ESP												
R.M. Heskett	1	4.73	5.39	3.83	13.95	13.54	1.06	1.44	4.57	7.07	49.29	47.76
R.M. Heskett	2	2.93	0.96	2.61	6.50	12.68	0.07	0.41	5.31	5.78	11.09	54.40
R.M. Heskett	3	7.43	0.44	3.08	10.94	11.11	0.05	0.18	4.74	4.98	54.49	55.19
Average		5.03	2.26	3.17	10.46	12.44	0.39	0.68	4.87	5.95	38.29	52.45
Anthracite Waste, FBC with FF												
Kline Township	1	44.54	0.12	0.45	45.11	148.68	0.00	0.06	0.06	0.12	99.74	99.92
Kline Township	2	43.12	0.06	0.40	43.58	212.95	0.00	0.06	0.06	0.12	99.73	99.95
Kline Township	3	44.97	0.06	0.34	45.37	153.77	0.00	0.06	0.06	0.12	99.74	99.92
Average		44.21	0.08	0.40	44.69	171.80	0.00	0.06	0.06	0.12	99.74	99.93
Bituminous Waste, FBC with FF												
Scrubgrass	1	184.04	0.68	0.19	184.91	100.09	0.00	0.07	0.08	0.15	99.92	99.85
Scrubgrass	2	124.11	0.42	0.09	124.62	101.35	0.00	0.05	0.07	0.12	99.91	99.89
Scrubgrass	3	76.68	0.22	0.07	76.97	100.25	0.00	0.04	0.07	0.11	99.85	99.89
Average		128.28	0.44	0.12	128.83	100.56	0.00	0.05	0.07	0.13	99.89	99.88
Bituminous/Pet. Coke, FBC with SNCR and FF												
Stockton Cogen	1	2.71	0.06	0.06	2.83	1.68	0.02	0.04	0.05	0.11	96.09	93.39
Stockton Cogen	2	1.56	0.07	0.06	1.69	1.44	0.03	0.05	0.05	0.13	92.16	90.80
Stockton Cogen	3	2.08	0.06	0.06	2.20	1.66	0.03	0.05	0.05	0.12	94.48	92.67
Average		2.12	0.07	0.06	2.24	1.59	0.03	0.05	0.05	0.12	94.25	92.29
Subbituminous, FBC with SCR and FF												
AES Hawaii	1	0.26	0.04	1.29	1.59	3.77	0.00	0.02	0.68	0.70	55.84	81.39
AES Hawaii	2	0.35	0.17	1.38	1.90	3.72	0.00	0.02	0.90	0.92	51.35	75.16
AES Hawaii	3	0.36	0.11	1.18	1.64	2.51	0.00	0.02	0.55	0.58	64.91	77.06
Average		0.32	0.10	1.28	1.71	3.33	0.00	0.02	0.71	0.73	57.37	77.87
Lignite, FBC with CS-FF												
TNP	1	21.65	8.68	7.42	37.74	63.81	0.04	12.13	4.74	16.91	55.20	73.50
TNP	2	10.65	4.51	6.09	21.25	44.22	0.03	6.78	2.94	9.76	54.07	77.93
TNP	3	28.12	13.78	7.04	48.94	95.04	0.04	13.54	5.07	18.66	61.88	80.37

Appendix D

Assessment of Mercury Control Options
for
Coal-fired Power Plants

Assessment of Mercury Control Options for Coal-Fired Power Plants

Prepared for

United States Environmental Protection Agency
National Risk Management Research Laboratory
Air Pollution Prevention and Control Division
Research Triangle Park

Prepared by
United States Department of Energy
National Energy Technology Laboratory

August, 2000

List of Attachments

ATTACHMENT 1

Description of
National Energy Technology Laboratory
Mercury Control Performance and Cost Model

Description of the National Energy Technology Laboratory Mercury Control Performance and Cost Model

1. Model Description

The National Energy Technology Laboratory (NETL) Mercury Control Performance and Cost Model (MCPCM) is an Excel spreadsheet model that can be used to assess the performance and cost of mercury (Hg) control systems that utilize activated carbon injection (ACI) and other methods. The primary goal of the model is to calculate key performance parameters that are then used to calculate detailed capital costs and O&M costs of a mercury control technology for either of two types of power plant applications – either a bituminous or subbituminous coal-fired power plant configuration. This overview describes the model layout, its specific capabilities, and its current limitations.

1.1 MCPCM Layout

The spreadsheet model is currently divided into seven (7) different, functional sheets that are integrated together to perform the costing goal defined above. The five sheets are identified below:

Hg Control Scenario Definition Sheet	*Characterization of Control Technology Retrofit Configurations*
Hg Control Performance Models Sheet	*Performance Algorithms for Different Control Technology Retrofit Configurations*
Application Input Sensitivity Sheet	*User Data Input*
Technical Model Results Sheet	*PowerPlant and Mercury Control Technical Performance Results*
Combustion Calculations Sheet	*Power Plant Performance Calculations*
Capital Cost Model Sheet	*Capital Cost Calculations*
System Economic Model Sheet	*O&M Cost Calculations and Levelized Cost Calculations*

1.1.1 Hg Control Scenario Definition Sheet

This sheet documents the different mercury control technology retrofit scenarios that can potentially be evaluated by the model. The information provided for each scenario is presented below:

Scenario Number: *Number, no units*
This number uniquely identifies each control scenario within the program.

Configuration Designation: Abbreviation that identifies a control technology scenario, e.g., *ESP-1* (activated carbon injection upstream of ESP with no spray cooling)

Configuration Definition: Brief description that uniquely defines a control technology scenario, e.g., ESP-1, “ACI upstream of existing ESP”

Comment: Further descriptive information that qualifies the functionality of the control technology scenario within the model.

Data Sources: Identifies and documents specific data and information sources used to establish the performance of a control technology.

1.1.2 Hg Control Performance Models Sheet

This sheet contains performance models for each control technology configuration identified in the **Hg Control Scenario Definition Sheet** (as currently available). These models currently calculate total sorbent feed (lb/MMacf of flue gas) based on a specified total mercury control efficiency (e.g., 50%) and flue gas temperature.

Currently, each control configuration (e.g., ESP-1) makes use of separate algorithms for mid- to high-sulfur bituminous coals (e.g., Pittsburgh (Pgh) #8) and Western subbituminous coals (e.g., Wyoming PRB). Therefore, the coal type that is specified in the **Application Input Sensitivity Sheet** will determine the specific algorithm that is used for a specified control configuration and application case. These algorithms were developed based on curve-fitting available pilot- and full-scale test data. The data sources are also documented in the sheet.

1.1.3 Application Input Sensitivity Sheet

This sheet is intended as the primary user interface to run up to 20 different mercury control cases simultaneously. For each control case, the sheet defines the desired mercury control requirements, a specific power plant variant of either of two power plant application types, and some key economic parameters used for costing purposes. Additional parametric changes can be made to the model to add greater evaluation flexibility, but these need to be made within the other functional sheets of the model. Model parameters included here are:

1.1.3.1 Mercury Control Parameters

Case Number: *Numerical value, Fixed (e.g., 1,2, etc.)* **–**
Sequentially identifies each application case. Up to 20 cases can be specified.

Hg Removal Configuration Type: *Numerical entry by user (e.g., 1,2, etc.)* --
Specifies the mercury control configuration as documented in the **Hg Control Scenario Definition Sheet**. The user must select a configuration type.

Hg Control Flue Gas Temperature Specification: *Number, units = ^{o}F (e.g., 250)*
Specifies the temperature at which mercury control is to take place. The program calculates this temperature as follows:

> *Control Temperature = Flue Gas Acid Dew Point Temperature (^{o}F) + 18 ^{o}F*
> (For Configurations 1 to 11)
>
> *Control Temperature = 200 ^{o}F*
> (Current default for all other configurations)

Injection of cooling water can be used to lower the flue gas temperature below the power plant air heater outlet temperature for configurations 1 to 11. Configurations 12 to 18 incorporate wet or dry scrubbing, which yield a relatively low flue gas temperature at their outlet. A default temperature of 200 ^{o}F is currently used because it represents a value that is below the lower limit of the algorithms contained in the **Hg Control Scenario Definition Sheet**.

Mercury Concentration: *Number, units = $\mu g/Nm^3$ (e.g., 10)*
The total mercury concentration within the flue gas at the exit of the air heater. The user specifies this value.

Mercury Speciation as % Hg^o: *Number as a percentage, no units (e.g., 50)*
The percentage of total mercury that is elemental mercury. The difference is assumed to be oxidized mercury in the form of $HgCl_2$. The user specifies this value.

Total SI (sorbent injection) Mercury Removal Efficiency - % of Hg Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of total mercury that is removed by the control technology.

SI Mercury Removal Efficiency - % Hg^o Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of elemental Hg that is removed by the control technology. This value is currently assumed to be calculated by the performance model, but this capability is currently not available.

ACI Mercury Removal Efficiency - % $HgCl_2$ Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of $HgCl_2$ that is removed by the control technology, but this capability is currently not available.

Sorbent Injection Ratio: *Number, units = lb/MMacf (e.g., 3)*
The primary feed of sorbent (based on lb sorbent per MMacf of flue gas) that corresponds to the specified Hg removal efficiency. The configuration performance model calculates this value.

Sorbent Recycle Split: *Percent, no units (e.g., 10)*
The ratio of recycled spent sorbent to total sorbent feed into the flue gas (expressed as a percentage). This value is currently assumed to be calculated by the performance model, but this capability is currently not available.

FGD Mercury Removal Efficiency - % Hg^o Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of Hg^0 (in the flue gas) that is removed by an existing wet FGD system. Mercury removal via an FGD system can be incorporated manually if desired. This is permitted as an option in case the user wants to combine FGD with other mercury removal technologies such as ACI. Set values equal to zero if no wet FGD exists or mercury control scenarios 14 - 18 are being used. If utilized, total mercury control is calculated within the "Technical Model Results Sheet."

FGD Mercury Removal Efficiency - % $HgCl_2$ Removed: *Number as a percentage, no units (e.g., 50)*
The percentage of $HgCl_2$ (in the flue gas) that is removed by the wet FGD system. Mercury removal via an FGD system can be incorporated manually if desired. This is permitted as an option in case the user wants to combine FGD with other mercury removal technologies such as ACI. Set value equal to zero if no wet FGD exists or mercury control scenarios 14 - 18 are being used. If utilized, total mercury control is calculated within the "Technical Model Results Sheet."

If Hg speciation is unknown set value equal to "% Hg^0 removal efficiency." For example, if total Hg removal via FGD is to be set at 80% and speciation is unknown, then set both Hg^0 and $HgCl_2$ removal efficiencies equal to the 80% value.

Fabric Filter Pressure Drop: *Number, units =* inches H_2O *(e.g., 6)*
Differential pressure across baghouse tubesheet. Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

Fabric Filter Air/cloth Ratio: *Number, units = ft*/min *(e.g., 12)*
Ratio of volumetric gas flow into baghouse (ft^3/min) to total bag surface area (ft^2). Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

Fabric Filter Particle Collection Efficiency: *Number as a percentage, no units (e.g., 99.98)*
Mass flow of particulate into baghouse/mass flow of particulate emitted from baghouse. Input a value if a pulse-jet FF will be added to the plant after the primary particulate collector to collect Hg sorbent. This applies to retrofit scenarios 3, 6, 7, 8, and 11.

1.1.3.2 Power Plant Design Parameters

Gross Power Plant Size: *Number, units* = MWe *(e.g., 500)*
Gross power plant electricity output (excludes plant auxiliary power).

Reference Power Plant Type: *Alphanumeric entry (HS* or LS)
HS refers to the high sulfur reference power plant and LS refers to the low sulfur reference plant.

Plant Capacity Factor: *Number as a percentage, no units (e.g., 65)*
Ratio of the energy generated during some time period to the total energy that could have been generated had the plant run at its full rating over the entire time period.

Power Plant Coal Type: *Alphanumeric entry (e.g., Pgh #8*)
Select a coal type from a menu list of six coals. The coal types are Illinois #6, Wyoming PRB, Texas Lignite, Utah Bituminous (LS), Appalachian (HS), Pittsburgh #8, and bituminous process derived fuel (LS). The Combustion Calculations Sheet contains detailed analysis data for each coal (cell range AE61 to AP141).

1.1.3.3 Economic Assessment Parameters

Levelized Carrying Charge Rate: *Number, no units (e.g., 0.133)*
The levelized amount of revenue per dollar of investment in the mercury control system that must be collected in order to pay the carrying charges on the investment.

Sorbent Unit Cost: *Number, units* = $/lb *(e.g., 0.5)*
Unit cost of the activated carbon or other sorbent, including the cost of the material and shipping.

Waste Disposal Removal Service?: *Yes or No*
This logical question is asked to identify the need to treat the mercury laden AC as hazardous waste. **Yes = hazardous,** in which case the AC is removed and processed to remove the mercury; a processing cost can be specified by the user. **No = non-hazardous,** in which case the AC is disposed of with the fly ash; a disposal cost can be specified by the user.

Normal Waste Disposal Cost: *Number, units* =$/ton *(e.g., 30)*
Unit cost of disposing non-hazardous power plant waste, such as fly ash. Use of a negative number indicates a waste byproduct credit.

Hazardous Waste Disposal Cost: *Number, units* =$/ton *(e.g., 1,750)*
Unit cost of disposing hazardous power plant waste materials. AC is removed and processed to remove the mercury.

Power Cost: *Number, units* =$/MW-Hr *(e.g., 25)*
Unit cost of power the plant charges for running auxiliary equipment.

Mercury By-Product Cost: *Number, units* =$/ton *(e.g., 50)*
Unit cost of recovered mercury that could be sold in the marketplace.

1.1.4 Technical Model Results Sheet

The purpose of this sheet is to document the case study input data for the power plant and the mercury control technology, as well as the results of the performance calculations from the Power Plant Combustion Model Sheet. Up to twenty case studies can be simultaneously created and documented in the sheet. Two reference power plants are documented; additional changes to the reference plant design and operating conditions can be made in this sheet in order to modify plant performance.

For the power plant definition, the sheet uses the input data from the Application Input Sensitivity Sheet and combines it with the reference plant data to create a specific plant for each case study. For example, if the high sulfur power plant gross power rating is input as 900 MWe in the input sensitivity sheet, then this overrides the reference plant rating of 541.9 MWe; plant auxiliary power is scaled accordingly. Sheet data for the reference plants should not be changed unless modifications are needed to simulate a different plant. For example, if a different net heat rate were desired, then the reference plant value would need to be replaced with a new value.

The mercury control data inputs are taken directly from both the *Input Sensitivity Sheet* and the *Hg Control Performance Models Sheet* and are listed for the sake of documentation and use by other parts of the spreadsheet.

Calculated power plant performance results from the Power Plant Combustion Model Sheet are returned to this sheet for documentation and use by the sheet to calculate specific performance results for the mercury control technology.

This sheet also uses results returned from the Combustion Model Sheet to calculate the flue gas acid dew point. This is an important design parameter given the significant influence of temperature on sorbent-based mercury control. While test data indicates that lower temperatures enhance mercury capture from the flue gas, reducing the gas temperature (via water injection) must be limited to a specified temperature approach to the acid dew point. Maintaining the gas temperature at such an increment will help prevent corrosion within the ductwork and particulate control devices. The sulfuric acid dew point calculation is based on the following algorithms:

$$1000/Tdp = 2.276-0.0294*\ln(PH_2O)-.0858*\ln(PH_2SO_4) + 0.0062*\ln(PH_2O)*\ln(PH_2SO_4)$$

Where,

Tdp = Acid Dew Point
PH_2O = Partial pressure of water in the flue gas
PH_2SO_4 = Partial pressure of sulfuric acid in the flue gas

The dew point is in degree K and partial pressures in mm Hg.

For example, if a flue gas contains 12 % volume of water vapor and 0.02 % volume SO_2 and say 2 % of SO_2 converts to SO3, compute the sulfuric acid dew point.

Gas pressure = 10 in wg or (10/407) =0.02457 atmg or 1.02457 atma.
PH_2O =0.12 * 1.02457 * 760 = 93.44 mm Hg.
$\ln(PH_2O) = 4.537$
$PSO_3 = PH_2SO_4$.
PSO_3 = 0.02 * .0002 * (64/80) * 760 * 1.02457 = 0.0024917
$\ln(SO_3) = -6$
Note that 2 % conversion is on weight basis and hence we multiplied and divided by the molecular weights of SO_2 and SO_3 in the above calculation.

1000/Tdp = 2.276 - 0.0294 * 4.537 + 0.0858 * 6-0.0062 * 4.537 * 6 = 2.489
Or Tdp=402 K or 129 C or 264 F

The percent conversion of SO_2 to SO_3 is calculated in the Combustion Model Sheet based on an algorithm that accounts for the sulfur in the coal and specific ash constituents (Fe_2O_3).

1.1.5 Combustion Calculations Sheet

The purpose of this sheet is to take the power plant case study design and operating data from the Technical Model Results Sheet and calculate the power plant technical performance parameters, such as combustion gas constituent flows and total gas flows at strategic boiler locations (e.g., after the air heater). Also, if flue gas cooling via water injection is specified by the user (by specifying a flue gas temperature lower than the reference plant's post air heater temperature), then this sheet will calculate the quantity of water required via energy balance calculations. This sheet also contains the coal analysis data described previously. The coal types are Illinois #6, Wyoming PRB, Texas Lignite, Utah Bituminous (LS), Appalachian (HS), Pittsburgh #8, and bituminous process derived fuel (LS). Detailed analysis data for each coal can be found within cell range AE61 to AP141.

1.1.6 Capital Cost Model Sheet

The Capital Cost Model Sheet makes use of the power plant and mercury control performance data to calculate the capital costs associated with a case study's mercury control design configuration. The costing currently covers the following equipment sections:

Spray Cooling Water System
Sorbent Injection System
Sorbent Recycle System
Pulse-Jet Baghouse and Accessories
Ash/Spent Sorbent Handling System
Continuous Emissions Monitoring System (CEMS) Upgrade

A total mercury control system cost is calculated from the following cost components: 1) equipment, 2) related materials, 3) field and indirect labor, 4) sales tax, 5) base erected cost, 6) Engineering design, 7) process and project contingencies, and 8) general facilities. Maintenance costs are also calculated as a percentage of the bare erected cost (e.g., 2%). This sheet also contains an "Economic Master Table" in which a number of key costing parameters, such as contingency factors, can be changed and incorporated into the case study calculations. Twenty case studies can be handled simultaneously in this sheet.

1.1.7 System Economic Model Sheet

This sheet calculates mercury control system O&M, total system investment, total system capital requirement, and then levelizes the capital and O&M to establish single value for $/lb of mercury removed. Twenty case studies can be handled simultaneously in this sheet.

1.1.7.1 Mercury Control System O&M Costs

Operating Labor: cost of system operating and administrative personnel; unit labor rates and manpower requirements/shift are specified in the case study O&M table and can be specified independently for each case study.

Maintenance Labor: 40% of the total maintenance cost calculated in the Capital Cost Model Sheet

Maintenance Material: 60% of the total maintenance cost calculated in the Capital Cost Model Sheet

Administrative and Support Labor: Calculated as a percentage (labor overhead charge rate) of the sum of the operating and maintenance labor cost; overhead charge specified in the case study O&M table and can be specified independently for each case study.

Consumable values are taken from the Technical Model Results Sheet. The O&M cost consists of the following consumable components:

Water (for flue gas humidification), gallons/Hr: *unit cost = $/1000 gallons (e.g., 0.80), specified in case study table*

Sorbent (e.g., Activated Carbon), tons /Hr: *unit cost = $/ton (e.g., 1,100), specified in case study table*

Incremental Power, kW-Hr: *unit cost = $/MW-Hr (e.g., 30), specified in case study table*
Fan power accounts for the added pressure drop across the mercury control equipment, such as the fabric filter. Sorbent injection system power is required to transport the sorbent to the flue gas duct. Humidification system power is required to pump water to an injection grid in the ductwork.

Waste Disposal, tons/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*
Waste AC is generated by the mercury control system. This mercury-laden AC must be disposed of or processed for mercury removal and recovery. This material can be disposed of with the rest of the plant's fly ash or it can be processed separately if deemed a hazardous material.

Mercury Byproduct, lb/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*
If the spent AC is processed for recovery of mercury, then a by-product credit can be applied. This will be applied only if the user has designated the spent AC as hazardous waste material.

1.1.7.2 Total Mercury Control System Capital Requirement

The total calculated investment in the mercury control system includes the total capital investment calculated in the Capital Cost Model Sheet, interest during construction (AFUDC), and the following additional cost components:

Royalty allowance -- possible technology royalty charges may apply

Preproduction Costs -- covers the cost of operator training, equipment checkout, major modifications to equipment, extra maintenance, and inefficient use of consumables. Calculated as 1 month of fixed operating costs (O&M labor, admin and support labor, and maintenance materials); 1 month of variable operating costs (all consumables) at full capacity; and 2 % of the total system investment.

Inventory Capital -- value of initial inventory of activated carbon that is capitalized. This accounts for an initial storage supply of AC (e.g., 30 day supply).

Initial Catalysts and Chemicals Charge -- the initial cost of any catalysts or chemicals contained in the process equipment, but not in storage. Does not apply to the mercury control systems.

1.1.7.3 Levelized Cost of Mercury Control

The total cost of mercury control must account for the total capital requirement (expressed as $/kW) and the total operating and maintenance expenses (expressed as mills/kWh). In order to calculate an annualized cost that accounts for both of these, the capital requirement is annuitized via use of the "Levelized Carrying Charge Rate." The Levelized Carrying Charge Rate assumes a 30-year operating period and accounts for return on debt, return on equity, income taxes, book depreciation, property tax, and insurance payments. The Levelized Carrying Charge Rate is specified in this sheet in the section called "Financial Data-Factors." It is multiplied times the total system capital requirement to derive the annualized value and converted to units of mills/kWh based on the annual operating hours of the plant (capacity factor x 8,760 h/yr).

The first-year O&M costs that are calculated in this sheet are also levelized in order to account for both apparent and real escalation rates of labor, materials, and consumables over the expected operating time period (e.g., 30 years). A levelization factor is specified in this sheet in the section called "Financial Data-Factors." It is multiplied by the total O&M cost.

The levelized carrying charge and the levelized O&M are summed to yield a total annualized cost which is divided by the annual mercury removed in order to derive a unique cost of removal with units of $/ton mercury removed.

2. DOCUMENTATION OF REFERENCE POWER PLANTS USED IN MERCURY CONTROL MODEL.

Two (2) representative power plant applications are being employed in this study to investigate the mercury control costs for the baseline designs as well as parametric variations of these baseline plants. These plants are characterized as:

1) Plant firing high-sulfur, bituminous coal (Pgh #8) with low-NO_X burners for NO_X control, cold-side ESP for particulate control, and a wet FGD system for SO_2 control.

2) Plant firing low-sulfur coal with low-NO_X burners for NO_X control and a cold-side ESP for particulate control.

This section develops the basic specifications for each power plant variant: plant size, coal analysis, boiler performance parameters, flue gas mass/volumetric flow rates, gas constituents (including HCl), gas temperature/pressure profiles, total mercury concentration, and mercury speciation.

2.1 High Sulfur Power Plant Reference Case

The high sulfur reference coal (PC) plant design is comprised of a balanced draft, natural circulation steam generator, providing steam for a turbine generator set, condensing at 2.5 inches Hg absolute back pressure at the design point. The plant design and performance reflect current commercial practice in the U.S. utility industry. The turbine-generator is a tandem compound machine, with high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. The LP turbine is comprised of two double flow sections exhausting downward into the condenser sections. The plant uses a 2400 psig/1000 ^oF/1000 ^oF single reheat steam power cycle. The boiler and the turbine are designed for a main steam flow of 3,621,006 pounds of steam per hour at 2520 pounds per square inch, gauge (psig) and 1000 ^oF at the superheater outlet, throttled to 2415 pounds per square inch, absolute (psia) at the inlet to the high pressure turbine. The cold reheat flow is 3,233,808 lb/hr of steam at 590 psia and 637 ^oF, which is reheated to 1000 ^oF before entering the intermediate pressure turbine section. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 508 MWe. The overall net plant higher heating value (HHV) efficiency is nominally 36.8 percent. Refer to **Table 2-1** for the plant performance summary information.

Applicable Federal, State, and Local environmental standards relating to air, water, solid waste and noise have been designed into the high sulfur reference plant. Projected plant air emissions are identified in **Table 2-2**. The wet, limestone FGD system ensures an SO_2 emission rate of less than 0.371 lb/MMBtu (92% reduction). The use of low NO_X burner technology, combined with over fire air, results in NO_X emissions of less than 0.30 lb/MMBtu. The control or reduction of N_2O has not been addressed in this design because N_2O levels are presently unregulated. The flue gas scrubber is a wet limestone type system, with scrubbing and demisting occurring in the same vessel. An organic acid is added to the circulating reagent to enhance the scrubbing performance. Air is blown into the scrubber module sump to promote forced oxidation of the sulfite to sulfate. The gypsum byproduct is dried to a cake-like consistency in a train of centrifuges, and is ready to landfill.

TABLE 2-1
HIGH SULFUR PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature °F	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	541,900
AUXILIARY LOAD SUMMARY, kWe	
Pulverizers	2,000
Primary Air Fans	1,840
Forced Draft Fans	1,350
Induced Draft	7,500
Seal Air Blowers	60
Main Feed Pump (Note 1)	2,400
Steam Turbine Auxiliaries	900
Condensate Pumps	1,100
Circulating Water Pumps	5,070
Cooling Tower Fans	2,400
Coal Handling	230
Limestone Handling & Reagent Prep.	1,160
FGD Pumps and Agitators	3,000
Ash Handling	2,000
Dewatering Centrifuges (FGD byproduct)	1,100
Precipitators	1,100
Soot Blowers (Note 2)	neg.
Miscellaneous Balance of Plant (Note 3)	2,000
Transformer Loss	1,300
TOTAL AUXILIARIES, kWe	34,100
Net Power, kWe	507,800
Net Efficiency, % HHV	36.8
Net Heat Rate, Btu/kWh (HHV)	9,279
CONDENSER COOLING DUTY, 10^6 Btu/hr	2,350
CONSUMABLES	
As-Received Coal Feed, lb/hr	378,550
Sorbent, lb/hr	46,790

Note 1 - Driven by auxiliary steam turbine, electric equivalent not included in total.
Note 2 - Soot blowing medium is boiler steam. Electric power consumption is negligible.
Note 3 - Includes plant control systems, lighting, HVAC, etc.

TABLE 2-2
HS PLANT AIR EMISSIONS - 65% CAPACITY FACTOR

	lb/MMBtu	Tons/Year
SO_X	0.46	5,880
NO_X	0.30	3,840
Particulate	0.01	125

The following indicates the state point conditions at various flue gas stream locations;

Flue gas mass flow rate, boiler exit	4,966,633 lb/hr (1,561,834 acfm)
Flue gas temperature at boiler exit	290 ^oF
Flue gas temperature at ESP exit	290 ^oF
Flue gas temperature at FGD exit	128 ^oF

The flue gas composition and temperatures at various points of the gas stream are detailed in **Table 2-3.** This data was calculated using the ACI Mercury Control Cost Model described in Section 3.

2.1.1 Plant Site Ambient Conditions

The plant site is assumed to be in the Ohio River Valley of western Pennsylvania/eastern Ohio/ northern West Virginia. The site consists of approximately 300 usable acres, not including ash disposal, within 15 miles of a medium sized metropolitan area, with a well established infrastructure capable of supporting the required construction workforce.

The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions will be:

Pressure	14.4 psia
Dry bulb temperature	60 ^oF
Dry bulb temperature range	(-) 10 to (+) 110 ^oF
Wet bulb temperature	52 ^oF

2.1.2 Fuel and Sorbent Composition

The plant performance will be based on the Pittsburgh #8 Coal and Greer limestone compositions and data listed in **Tables 2-4** and **2-5**. Unit start-up will use No.2 fuel oil.

TABLE 2-3
HIGH SULFUR (HS) REFERENCE POWER PLANT GAS STREAM DATA

Boiler & Plant Data Summary	PGH #8 (HS)
Btu Input Rate (MMBtu/h)	4,711.88
Coal Input Rate (tons/h)	188.337
Coal Mass-Energy Ratio (lb/MMBtu)	79.94
MMBtu/hr Out of Boiler	4,162.49
Flue Gas @ Economizer Outlet (SCFM/MMBtu)	12,503
Flue Gas @ Economizer Outlet (SCFM)	981,877
Wet Flue Gas @ Economizer Outlet (lb/h)	4,598,641
Wet Air Based on Economizer Outlet (SCFM)	934,407
Wet Air Based on Economizer Outlet (lb/h)	4,260,670
Total Air, % (Economizer Outlet)	120.0
Excess Air, % (Economizer Outlet)	20.0
Flue Gas @ Air Heater Outlet (SCFM/MMBtu)	13,753
Flue Gas @ Air Heater Outlet (SCFM)	1,080,065
Wet Flue Gas @ Air Heater Outlet (lb/h)	5,042,924
Wet Air Based on Air Heater Outlet (SCFM)	1,031,843
Wet Air Based on Air Heater Outlet (lb/h)	4,704,952
Wet Air Leakage @ Air Heater (SCFM)	97,436
Wet Air Leakage @ Air Heater (lb/h)	444,283
Equivalent Total Air, % (Air Heater Outlet)	132.5
Equivalent Excess Air, % (Air Heater Outlet)	32.5
Wet Flue Gas @ Air Heater Outlet (ACFM)	1,689,826
Air Heater Outlet Flue Gas Temperature, ^{o}F	290
Air Heater Outlet Pressure, inches Hg.	29.31
Fly Ash (ton/h)	15.48
Bottom Ash (ton/h)	3.87
Total Ash (ton/h)	19.35

NOTE: Standard Conditions = 60 ^{o}F, 29.92 inches Hg

TABLE 2-4
GREER LIMESTONE ANALYSIS

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.4
Magnesium Carbonate $MgCO_3$	3.5
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

TABLE 2-5
PITTSBURGH NO. 8 COAL ANALYSIS

Constituent	Air Dry, %	Dry, %	As Received, %
Carbon	71.88	73.79	69.36
Hydrogen	4.97	4.81	5.18
Nitrogen	1.26	1.29	1.22
Sulfur	2.99	3.07	2.89
Ash	10.30	10.57	9.94
Oxygen	8.60	6.47	11.41
Total	100.00	100.00	100.00

	Dry Basis, %	As Received, %
Moisture	-----	6.00
Ash	10.57	9.94
Volatile Matter	38.20	35.91
Fixed Carbon	51.23	48.15
Total	100.00	100.00
Cl, ppm in Coal	650	
Hg, ppb in Coal	78 $\pm$ 24	
Sulfur	3.07	2.89
Btu Content	13,244	12,450
Moisture and Ash Free (MAF), Btu	14,810	

	Ash Analysis, %
Silica, SiO_2	48.1
Aluminum Oxide, AlO_3	22.3
Iron Oxide, Fe_2O_3	24.2
Titanium Dioxide, TiO_2	1.3
Calcium Oxide, CaO	1.3
Magnesium Oxide, MgO	0.6
Sodium Oxide, Na_2O	0.3
Potassium Oxide, K_2O	1.5
Sulfur Trioxide, SO_3	0.8
Phosphorous Pentoxide, P_2O_5	0.1
Total	100.5

	Ash Fusion Temperature, ^oF	
	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2015	2570
Spherical	2135	2614
Hemispherical	2225	2628
Fluid	2450	2685

2.1.3 Air Quality Standards

The plant pollution emission requirements for the High Sulfur Reference Case reflect current environmental emissions standards for a plant sited in a non-attainment area with respect to ambient air standards for ozone. **Table 2-2** presents emissions for the plant without site sensitive NO_X reduction enhancements.

2.1.4 Flue Gas Acid Dew Point.1.4

Based on a flue gas SO_3 concentration of 22 ppm and a water concentration of 7.65% at the exit of the air heater, the acid dew point is estimated to be approximately 280 ^{o}F.

2.1.5 Mercury Emission Assumptions

Table 2-6, presented below, provides basic data for baseline and variant mercury emissions.

TABLE 2-6
MERCURY EMISSIONS DATA

Total Mercury Concentration (μg/Nm^3)	Total Mercury Emissions Rate (g/h)	Total Annual Mercury Release[1] (Kg/yr)
10 (Baseline)	18.35	104.4
3	5.5	31.3
30	55.05	313.2

1. Based on a 65% plant capacity factor.

2.2 Low Sulfur Power Plant Reference Case

The low sulfur reference pulverized coal (PC) plant design utilizes a balanced draft, natural circulation type, pulverized coal subcritical fired boiler, providing steam for a turbine generator set. The boiler design and performance reflect current commercial practice in the U.S. utility industry. The turbine-generator is a tandem compound machine, with high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. The LP turbine is comprised of two double flow sections exhausting downward into the condenser sections. The low sulfur reference plant uses a 2400 psig/1000 ^{o}F/1000 ^{o}F single reheat steam power cycle. The boiler and the turbine are designed for a main steam flow of 2,734,000 pounds of steam per hour at 2520 psig and 1000 ^{o}F at the superheater outlet, throttled to 2415 psia at the inlet to the high pressure turbine. The cold reheat flow is 2,425,653 lb/hr of steam at 604 psia and 635 ^{o}F, which is reheated to 1000 ^{o}F before entering the intermediate pressure turbine section. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 404 MWe. The overall net plant higher heating value (HHV) efficiency is nominally 39.1 percent. Refer to **Table 2-7** for the plant performance summary information.

The plant also is designed to meet applicable Federal, State, and Local environmental standards relating to air, water, solid waste and noise. The plant has baseline SO_2 emissions of about 0.70 lb/MMBtu, and it is designed to utilize in-duct spray drying of lime to provide a removal efficiency of 50%. Lime slurry is sprayed into the flue gas duct, where it dries and captures SO_2 as a particle. The particulate is then collected in the electrostatic precipitator for disposal. If placed in service, the FGD system results in a SO_2 emission rate of less than 0.35 lb/MMBtu; the current investigation assumes that the FGD system will not be in operation. The use of low NO_X burner technology, combined with over-fire air, results in NO_X emissions of less than 0.30 lb/MMBtu. The control or reduction of N_2O has not been addressed in this design because N_2O levels are presently unregulated.

The low Sulfur Case Reference plant achieves a net plant efficiency of 39.1%, which is an increase of over 6% above that achieved by the High Sulfur Reference plant (36.8%). This increase in efficiency is achieved although the units are virtually identical in terms of size, boiler selection, steam cycle configuration, heat sink, and other considerations. The net efficiency improvements are due to the following:

- The low sulfur reference auxiliary plant load is lower than the high sulfur plant's auxiliary load. This reduction occurs because of the reduced ID fan power requirements, which result from the elimination of the pressure losses due to a scrubber. In addition, elimination of the reagent and byproduct handling systems associated with a wet scrubber reduce the auxiliary load but is offset by the atomizing air compressors for the duct injection system.

- The low sulfur plant gas temperature leaving the boiler is set at 270 ^oF versus 290 ^oF for the high sulfur plant. This reduction in exhaust temperature, which improves the boiler efficiency, is feasible because of the low SO_2 concentrations in the gas leaving the boiler, and the gas passes directly into the duct injection system that is upstream of the ESP.

2.2.1 Plant Site Ambient Conditions

The plant site is assumed to be in the Ohio River Valley of western Pennsylvania/eastern Ohio/ northern West Virginia. The site consists of approximately 300 usable acres; not including ash disposal, within 15 miles of a medium sized metropolitan area, with a well established infrastructure capable of supporting the required construction workforce. The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions will be:

Pressure	14.4 psia
Dry bulb temperature	60 ^oF
Dry bulb temperature range	-10 to +110 ^oF
Wet bulb temperature	52 ^oF

TABLE 2-7
LOW SULFUR POWER PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, ^oF	1,000
Reheat Outlet Temperature	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	427,060
AUXILIARY LOAD SUMMARY, kWe	
Pulverizers	1,600
Primary Air Fans	1,410
Forced Draft Fans	1,020
Induced Draft	3,230
Seal Air Blowers	50
Main Feed Pump (Note 1)	8,660
Steam Turbine Auxiliaries	800
Condensate Pumps	800
Circulating Water Pumps	3,400
Cooling Tower Fans	1,800
Coal Handling	180
Limestone Handling & Reagent Prep.	230
Ash Handling	1,600
Atomizing Air compressors (Duct Injection)	2,700
Precipitators	900
Soot Blowers (Note 2)	neg.
Miscellaneous Balance OF Plant (Note 3)	2,000
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	22,740
Net Power, kWe	404,320
Net Efficiency, % HHV	39.1
Net Heat Rate, Btu/kWh (HHV)	8,726
CONDENSER COOLING DUTY, 10^6 Btu/h	1,722
CONSUMABLES	
As-Received Coal Feed, lb/h	299,204
Sorbent, lb/h	4,277

Note 1 - Driven by auxiliary steam turbine, electric equivalent shown.
Note 2 - Soot blowing medium is boiler steam. Electric power consumption is negligible.
Note 3 - Includes plant control systems, lighting HVAC, etc.

2.2.2 Fuel and Sorbent Composition

The plant performance will be based on a, sub-bituminous, western Powder River Basin (PRB) coal that has undergone a moisture reduction and stabilization process. The coal analysis and data are listed in **Tables 2-8** and **2-9**. Unit start-up will use No.2 fuel oil.

2.2.3 Air Quality Standards

The plant pollution emission requirements for the Low Sulfur Reference Case adhered to Federal and State control emission regulations. Although, some environmental regulations may apply on a site specific basis (National Environmental Policy Act, Endangered Species Act, National Historic Preservation Act, etc.) will not be considered in this project. The following ranges will generally cover most cases:

SO_X:	92 to 95% reduction
NO_X:	0.2 to 0.45 lb per MMBtu
Particulate:	0.015 to 0.03 lb per MMBtu
Opacity:	10 to 20 percent

2.2.4 Flue Gas Acid Dew Point.

Based on a flue gas SO_3 concentration of 0.5 ppm and a water concentration of 6.5% at the exit of the air heater, the acid dew point is estimated to be approximately 175 ^{o}F.

2.2.5 Mercury Emission Assumptions

Table 2-10 provides basic data for baseline and variant mercury emissions.

2.2.6 LS Reference Power Plant Gas Stream Data

The following indicates the state point conditions at various flue gas stream locations.

Flue gas mass flow rate, boiler exit	3,821,126 lb/hr (1,309,735 cfm)
Flue gas temperature at AH exit	270 ^{o}F
Flue gas temperature at ESP exit	270 ^{o}F

The flue gas composition and temperatures at various points of the gas stream are detailed in **Table 2-11.** This data was calculated using the MCPCM described in Section 1 and coal properties for a low sulfur processed derived PRB coal.

TABLE 2-8
TYPICAL PROCESSED PRB COAL ANALYSIS

Constituent	**Dry, %**	**As Received, %**
Moisture	-------	--------
Carbon	75.25	70.98
Hydrogen	3.46	4.00
Nitrogen	1.13	1.07
Sulfur	0.56	0.53
Ash	8.19	7.72
Oxygen	11.41	15.70
Total	100.00	100.00

	Dry Basis, %	**As Received, %**
Moisture	-----	4.83
Ash	8.19	7.72
Volatile Matter	27.00	25.72
Fixed Carbon	64.81	61.73
Total	100.00	100.00
Sulfur	0.56	0.53
Btu Content	12,389	11,791
Moisture and Ash Free (MAF), Btu Content	13,494	

	Ash Analysis, %
Silica, SiO_2	22.5
Aluminum Oxide, Al	13.8
Iron Oxide,	7.4
Titanium Dioxide, TiO_2	0.8
Calcium Oxide, MgO	26.6
Magnesium Oxide, MgO	5.9
Sodium Oxide, Na_2O	1.8
Potassium Oxide, K_2O	0.2
Sulfur Trioxide, SO_3	19.3
Phosphorous Pentoxide, P_2O_5	0.6
Strontium Oxide, SrO	0.4
Barium Oxide, BaO	0.6
Manganese Oxide, Mn_4	0.1
Total	**100.00**

Ash Fusion Temperature, °F

	Reducing Atmosphere	**Oxidizing Atmosphere**
Initial Deformation	2295	2395
Spherical	2300	2405
Hemispherical	2305	2415
	2310	2425

TABLE 2-9
COMPARISON OF FEED COAL AND MODIFIED COAL BASIS

	Feed Coal	Process Derived Fuel
Heating Value (Btu/lb)	12,740	13,840
Carbon (%)	73.4	84.0
Hydrogen (%)	5.5	3.6
Nitrogen (%)	1.1	1.3
Volatiles (%)	47.0	32.0

TABLE 2-10
MERCURY EMISSIONS DATA

Total Mercury Concentration ($\mu g/Nm^3$)	Total Mercury Emissions Rate (g/Hr)	Total Annual Mercury Release[1] (Kg/Yr)
10 (Baseline)	13.8	78.5
3	3.5	23.5
30	138	235.5

1. Based on a 65% plant capacity factor.

TABLE 2-11
LS REFERENCE POWER PLANT GAS STREAM DATA

Boiler & Plant Data Summary	LS PDF (LS)
Btu Input Rate (MMBtu/h)	3,528.10
Coal Input Rate (tons/h)	150.739
Coal Mass-Energy Ratio (lb/MMBtu)	85.45
MMBtu/hr Out of Boiler	3,119.59
Flue Gas @ Economizer Outlet (SCFM/MMBtu)	12,656
Flue Gas @ Economizer Outlet (SCFM)	744,192
Wet Flue Gas @ Economizer Outlet (lb/h)	3,518,066
Wet Air Based on Economizer Outlet (SCFM)	710,817
Wet Air Based on Economizer Outlet (lb/h)	3,241,152
Total Air, % (Economizer Outlet)	120.0
Excess Air, % (Economizer Outlet)	20.0
Flue Gas @ Air Heater Outlet (SCFM/MMBtu)	13,795
Flue Gas @ Air Heater Outlet (SCFM)	811,169
Wet Flue Gas @ Air Heater Outlet (lb/h)	3,821,126
Wet Air Based on Air Heater Outlet (SCFM)	777,281
Wet Air Based on Air Heater Outlet (lb/h)	3,544,213
Wet Air Leakage @ Air Heater (SCFM)	66,464
Wet Air Leakage @ Air Heater (lb/h)	303,061
Equivalent Total Air, % (Air Heater Outlet)	131.2
Equivalent Excess Air, % (Air Heater Outlet)	31.2
Wet Flue Gas @ Air Heater Outlet (ACFM)	1,309,735
Air Heater Outlet Flue Gas Temperature, ^{o}F	314
Air Heater Outlet Pressure, inches Hg.	29.31
Fly Ash (ton/h)	9.83
Bottom Ash (ton/h)	2.46
Total Ash (ton/h)	12.28

NOTE: Standard Conditions = 60 ^{o}F, 29.92 inches Hg

3. Bituminous and Subbituminous Coals Used in Mercury Control Model Runs

EPA's mercury control technology application matrix cites three different coals for the model runs. The purpose of this section is to identify and document these three coals.

The two bituminous coals are from West Virginia – ultimate analysis and ash analysis data were obtained from the USGS Coal Quality Database. The high sulfur coal has a 3% sulfur content (by weight) and a HHV of 12,721 Btu/Lb, while the other has a 0.6% S content (by weight) and a HHV of 14,224 Btu/Lb.

The subbituminous coal is from Wyoming's Powder River Basin (PRB) and was already contained in the model's coal library. Data originally came from EPRI's FGD Cost Program. This coal has a coal sulfur content of 0.5% (by weight) and a HHV of 8,335 Btu/Lb.

TABLE 3-1
Bituminous and Subbituminous Coals Used in Mercury Control Model Runs

	WYOMING PRB (LS)	E. Bituminous (HS)	E. Bituminous (LS)
COAL ULTIMATE ANALYSIS (ASTM, as received, weight percent)			
Moisture	30.40%	3.10%	2.20%
Carbon	47.85%	69.82%	78.48%
Hydrogen	3.40%	5.00%	5.50%
Nitrogen	0.62%	1.26%	1.30%
Chlorine	0.03%	0.12%	0.12%
Sulfur	0.48%	3.00%	0.60%
Ash	6.40%	9.00%	3.80%
Oxygen	10.82%	8.70%	8.00%
TOTAL	100.00%	100.00%	100.00%
Mott Spooner HHV (Btu/lb)	8,335	12,721	14,224
Acid Dew Point, ^{o}F	224	215	292
COAL ASH ANALYSIS	WYOMING PRB (LS)	E. Bituminous (HS)	E. Bituminous (LS)
SiO2	31.60%	29.00%	51.00%
Al2O3	15.30%	17.00%	30.00%
TiO2	1.10%	0.74%	1.50%
Fe2O3	4.60%	36.00%	5.60%
CaO	22.80%	6.50%	4.20%
MgO	4.70%	0.83%	0.76%
Na2O	1.30%	0.20%	1.40%
K2O	0.40%	1.20%	0.40%
P2O5	0.80%	0.22%	1.80%
SO3	16.60%	7.30%	2.60%
Other Unaccounted for	0.80%	1.01%	0.74%
TOTAL	100.00%	100.00%	100.00%

4. COST ESTIMATION BASIS

4.1 Introduction

This section defines the methodology used to estimate capital and O&M costs within the NETL Mercury Control Performance and Cost Model. Two different spreadsheets within the model provide for cost estimation. The **Capital Cost Model Sheet** makes use of the power plant and mercury control performance data to calculate the capital costs associated with a case study's mercury control design configuration. The costing covers the following equipment sections:

- **Spray Cooling Water System** (*Equipment: water storage tank, pumps, transport piping, and injection grid with nozzles, and control system*)
- **Solid Sorbent Storage and Injection System** (*Equipment: silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, control system*)
- **Sorbent Recycle System** (*Equipment: hoppers, blowers, transport piping, control system*)
- **Pulse-Jet Fabric Filter and Accessories** (*Equipment: pulse-jet FF, filter bags, ductwork, dampers, and MCCs and instrumentation and PLC controls for baghouse operation. Excludes Ash Removal System, power distribution and power supply, and distributed control system*)
- **Sorbent Disposal System** (*Equipment: hoppers, blowers, transport piping, control system*)
- **CEMS Upgrade**
- **Flue Gas Desulfurization (FGD) System** (cost algorithms are currently not provided)
- **FGD System Enhancements** (cost algorithms are currently not provided)
- **Circulating Fluidized Bed Absorber System** (cost algorithms are currently not provided)

A total mercury control system cost is calculated from the following cost components: 1) equipment, 2) related materials, 3) field and indirect labor, 4) sales tax, 5) engineering and home office fees, 6) process and project contingencies, 7) retrofit factors, and 9) general facilities. Maintenance costs are also calculated as a percentage of the bare erected cost (e.g., 2%). Section 4.2 fully describes the methodology used to estimate the total installed retrofit capital cost. Section 4.3 defines specific algorithms used calculate specific equipment and installation labor costs.

The **System Economic Model Sheet** calculates mercury control system O&M, total system investment, total system capital requirement, and then levelizes the capital and O&M to establish single value for $/lb of mercury removed. Twenty case studies are handled simultaneously in this sheet. Sections 4.4 and 4.5 fully describe the methodology used to estimate these costs.

4.2 Capital Cost Estimation Basis

The cost of each equipment section, as identified in Section 4.1, is estimated according to the following procedure:

Bare Installed Retrofit Cost = (*Process Equipment* + *Related Field Materials* + *Field Labor* + *Indirect Field Costs* + *Sales Tax)* x *Retrofit Factor*

Equipment, field materials and field labor are specified via algorithms.
Indirect field costs are calculated as percentage of field labor (**7%** currently specified).

Sales tax is calculated as a percentage of the sum of the four cost elements (**0%** currently specified)
Retrofit Factor (accounts for retrofit difficulty) = **1.15** (Specified by EPA on 4/4/00)

Engineering & Home Office Overhead/Fees = *Bare Installed Retrofit Cost* x E&HO Percentage

EH&O Percentage = **10%** (Specified by EPA on 4/4/00)

Process Contingency = *Bare Installed Retrofit Cost* x *Process Contingency Percentage*

Process Contingency Percentage = **5%** (Specified by EPA on 4/4/00)

Project Contingency = (*Bare Installed Retrofit Cost* + *Engineering & Home Office Overhead/Fees* + Process Contingency) x *Project Contingency Percentage*

Project Contingency Percentage = **15%** (Specified by EPA on 4/4/00)

Total Cost of Each Equipment Section = *Bare Installed Retrofit Cost* + *Engineering & Home Office Overhead/Fees* + *Process Contingency* + *Project Contingency*

The total capital cost of the mercury control system is calculated to include the sum of all equipment sections and the total cost of general facilities as follows:

General Facilities Cost = (*Bare Installed Retrofit Cost* x *General Facilities Percentage*

General Facilities Percentage = **5%** (Specified by EPA on 4/4/00)
Project Contingency Percentage defined above

Total Control Capital Cost = Sum of Equipment Section Total Costs + General Facilities Cost

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4.3 Equipment and Installation Labor Cost Estimation

This section of the memo defines the equipment cost algorithms used in the Capital Cost Model Sheet. Each equipment section is defined separately below. Costs are updated from their baseline year values via use of the Chemical Engineering Annual Plant Index (CEI). The costing algorithms relate to a December 1998 baseline for which the CI value equals 389.5. The ratio of the current index value (e.g., December 1999) and the baseline value therefore yields a cost inflator that adjusts control costs to the specified year.

4.3.1 Spray Cooling Water System

<u>Process Equipment (x $1000), $E</u>

$\$E = 1900 \times (GPM/215)^{0.65} \times CEI/389.5$

GPM = Water flow in gallons/minute

<u>Field Materials (x $1000), $FM</u>

$\$FM = 1700 \times (GPM/215)^{0.65} \times CEI/389.5$

Field Labor (x $1000), $FL

$FL = 1500 x (GPM/215)^{0.65} x CEI/389.5

Indirect Field Costs (x $1000), $IF

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

Example: GPM = 27.4 gpm (Cools flue gas from 290 F to 270 F, 472 MWe,net)
CEI = 399.7 (November 1999)

Bare Installed Cost (x $1000) = 511 + 457+ 404 + 28 = 1,611 or $3.41/kW

4.3.2 Solid Sorbent Injection System

Process Equipment (x $1000), $E

$E = 400 x ((SF x 1000/454)/5486)^{0.65} x CEI/389.5

SF = Sorbent Feed, Kg/Hr

Field Materials (x $1000), $FM

$FM = 900 x ((SF x 1000/454)/5486)^{0.65} x CEI/389.5

Field Labor (x $1000), $FL

$FL = 2600 x ((SF x 1000/454)/5486)^{0.65} x CEI/389.5

Indirect Field Costs (x $1000), $IF

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

Example: SF = 157 Kg/Hr (Based on 3.73 lb/MMacf, 472 MWe,net)
CEI = 399.7 (November 1999)

Bare Installed Cost (x $1000) = 68+ 153 + 442 + 31 = 799 or $1.69/kW

4.3.3 Sorbent Recycle System

Process Equipment (x $1000), $E

$E = 1200 x (RR/13) x CEI/389.5

RR = Recycle (sorbent and ash), Tons/Hr

Field Materials (x \$1000), \$FM

\$FM = \$E

Field Labor (x \$1000), \$FL

\$FL = \$E

Indirect Field Costs (x \$1000), \$IF

\$IF = \$FL x 0.07

Bare Installed Cost (x \$1000) = \$E + \$FM + \$FL + \$IF

4.3.4 Pulse-Jet Fabric Filter and Accessories

Process Equipment (x \$1000), \$E

$\$E = 4800 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

GFR = Flue Gas Flow Rate, acfm
ACR = PJFF air/cloth ratio, $ft^3/min/ft^2$

Field Materials (x \$1000), \$FM

$\$FM = 500 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

Field Labor (x \$1000), \$FL

$\$FL = 2700 \times ((GFR/ACR)/84{,}326))^{0.80} \times CEI/389.5$

Indirect Field Costs (x \$1000), \$IF

\$IF = \$FL x 0.07

Bare Installed Cost (x \$1000) = \$E + \$FM + \$FL + \$IF

Example: GFR = 1,547,360 acfm (Based on 472 MWe,net)
ACR = 10 $ft^3/min/ft^2$
CEI = 399.7 (November 1999)

Bare Installed Cost (x \$1000) = 8,006+ 834 + 4,503 + 315 = 15,707 or \$33/kW

4.3.5 Sorbent Disposal System

Process Equipment (x \$1000), \$E

\$E = 100 x (DS/6) x CEI/389.5

DS = Disposal Solids (spent sorbent and ash), Tons/Hr

Field Materials (x $1000), $FM

$FM = 2 x $E

Field Labor (x $1000), $FL

$FL = 6 x $E

Indirect Field Costs (x $1000), $IF

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

4.3.6 CEMS Upgrade

Process Equipment (x $1000), $E

$\$E = 10 \times (MW/290.4)^{0.75} \times CEI/389.5$

MW = Power Plant Application Net Capacity, MWe,net

Field Materials (x $1000), $FM

$FM = 0

Field Labor (x $1000), $FL

$FL = 1.2 x $E

Indirect Field Costs (x $1000), $IF

$IF = $FL x 0.07

Bare Installed Cost (x $1000) = $E + $FM + $FL + $IF

4.4 Mercury Control System O&M Cost Estimation

4.4.1 O&M Cost Parameters

The O&M cost consists of the following labor and maintenance components:

Operating Labor: cost of system operating and administrative personnel; unit labor rates and manpower requirements/shift are specified in the case study O&M table and can be specified independently for each case study.

Maintenance Labor: 40% of the total maintenance cost calculated in the Capital Cost Model Sheet

Maintenance Material: 60% of the total maintenance cost calculated in the Capital Cost Model Sheet

Administrative and Support Labor: Calculated as a percentage (labor overhead charge rate) of the sum of the operating and maintenance labor cost; overhead charge specified in the case study O&M table and can be specified independently for each case study.

Consumable values are taken from the Technical Model Results Sheet. The O&M cost consists of the following consumable components:

Water (for flue gas humidification), gallons/Hr: *unit cost = $/1000 gallons (e.g., 0.80), specified in case study table*

Water quantity is taken from *Combustion Calculations Sheet*.

Sorbent (e.g., Activated Carbon), **tons /Hr**: *unit cost = $/ton (e.g., 1,100), specified in case study table*

Sorbent unit cost is an input in the *Application Input Sensitivity Sheet*

Incremental Power, kW-Hr: *unit cost = $/MW-Hr (e.g., 30), specified in case study table*

Fan power accounts for the added pressure drop across the mercury control equipment, such as the fabric filter. AC injection system power required to transport sorbent to flue gas duct. Humidification system power required to pump water to an injection grid in the ductwork.

Waste Disposal, tons/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*

Waste sorbent is generated by the mercury control system. This mercury-laden sorbent must be disposed of or processed for mercury removal and recovery. For some design configurations, spent sorbent is captured with the fly ash and must be disposed of with the ash at the cost of ash disposal. For some design configurations, spent sorbent is collected with residual ash from the ESP. This material can be disposed of with the rest of the plant's fly ash or it can be processed separately if deemed a hazardous material.

The user specifies sorbent to be hazardous or non-hazardous in the *Application Input Sensitivity Sheet*. Unit costs for both conventional and hazardous waste disposal are also specified there.

Mercury Byproduct, lb/Hr: *unit cost = $/ton (e.g., 30), specified in case study table*

If the spent sorbent is processed for recovery of mercury, then a by-product credit can be applied. This will be applied only if the user has designated the spent AC as hazardous waste material.

4.4.2 Key O&M Cost Parameter Values

Labor:
Operating Labor Rate (base) -- **$25/Hr** (specified by EPA 4/4/00)
Total Operating Jobs **– 0.833 OJ/Shift**

Consumables:
Water **– 0.42 Mills/gallon** (specified by EPA 4/4/00)
Activated Carbon -- **$1/Kg** (specified by EPA 4/4/00)
Sorbent Storage Capacity **– 30 days** (specified by EPA 4/4/00)
Electricity **– 25 Mills/kW-Hr** (specified by EPA 4/4/00)
Waste Disposal (ash, AC, mercury) -- **$30/Ton**
Waste Disposal (Hazardous waste designation) -- **$1700/Ton**

Plant Capacity Factor – **65%** (specified by EPA 4/4/00)

4.5 Total Mercury Control System Capital Requirement

The total calculated investment in the mercury control system includes the total capital investment calculated in the Capital Cost Model Sheet, interest during construction (AFUDC), and the following additional cost components:

Royalty allowance -- possible technology royalty charges may apply

Preproduction Costs -- covers the cost of operator training, equipment checkout, major modifications to equipment, extra maintenance, and inefficient use of consumables. Calculated as 1 month of fixed operating costs (O&M labor, admin and support labor, and maintenance materials); 1 month of variable operating costs (all consumables) at full capacity; and 2 % of the total system investment.

Inventory Capital -- value of initial inventory of activated carbon that is capitalized. This accounts for an initial storage supply of AC (e.g., 30 day supply).

Initial Catalysts and Chemicals Charge -- the initial cost of any catalysts or chemicals contained in the process equipment, but not in storage. Does not apply to the mercury control systems.

4.5.1 Levelized Cost of Mercury Control

The total cost of mercury control must account for the total capital requirement (expressed as $/kW) and the total operating and maintenance expenses (expressed as mills/kW-Hr). In order to calculate an annualized cost that accounts for both of these, the capital requirement is annuitized via use of the "Levelized Carrying Charge Rate." The Levelized Carrying Charge Rate assumes a 30 year operating period and accounts for return on debt, return on equity, income taxes, book depreciation, property tax, and insurance payments. The Levelized Carrying Charge Rate is specified in this sheet in the section called "Financial Data-Factors." It is multiplied times the total system capital requirement to derive the annualized value and converted to units of mills/kW-Hr based on the annual operating hours of the plant (capacity factor x 8,760 hrs/yr).

The first-year O&M costs that are calculated in this sheet are also levelized in order to account for both apparent and real escalation rates of labor, materials, and consumables over the expected operating time period (e.g., 30 years). A levelization factor is specified in this sheet in the section called "Financial Data-Factors." It is multiplied by the total O&M cost.

The levelized carrying charge and the levelized O&M are summed to yield a total annualized cost which is divided by the annual mercury removed in order to derive a unique cost of removal with units of $/ton mercury removed.

4.5.2 Financial Parameter Values

Apparent General Escalation Rate – **2.9%/Year**
Royalty Allowance -- **$0**
Levelized Carrying Charge Rate – **0.133**
Federal Income Tax Rate – **34%**
Weighted Cost of Capital (after tax) – **9.4%**
Design and Construction – **1 year**
Book Life – **30 Years**

ATTACHMENT 2

Description of
Mercury Control Performance Algorithms Used in the National Energy Technology Laboratory Mercury Control Performance and Cost Model

Description of Mercury Control Performance Algorithms Used in the NETL Mercury Control Performance and Cost Model

The purpose of this report is to document the mercury control performance models that are currently incorporated into the NETL Mercury Control Cost Model. CMU staff based on available pilot- and full-scale data has developed these models, in the form of basic curve-fitting algorithms. The algorithms calculate the activated carbon feed (Lb/MMacf basis) required to achieve specified mercury removal efficiency for a particular control method (e.g., activated carbon injection upstream of an existing ESP). The performance prediction is based solely on control method, flue gas temperature and coal type (bituminous vs. subbituminous).

1. Mercury Control Retrofit Configurations: ESP-1, ESP-4, SD/ESP-1, and SD/ESP-2

Description: Activated carbon injected upstream of existing ESP. ESP-1 -- no flue gas temperature control, ESP-4 – flue gas temperature control via water injection.

1.1 Bituminous Coal

Coal Source: Eastern bituminous coal, West Virginia (< 1%S and 0.1% chlorine)

Data Sources:

PROJECT: ADA Technologies/Public Service Electric and Gas Company/EPRI -- Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration

Pilot-Scale Tests: 160 acfm slipstream from the 620 MWe Hudson Generating Station, Unit 2, opposed-fired furnace, Eastern bituminous coal from West Virginia (< 1%S and 0.1% chlorine), ESP SCA = 287 ft^2/Kacfm

Literature Source: Waugh, E., B. Jensen, L. Lapatnick, F. Gibbons, S. Sjostrom, J. Ruhl, R. Slye, and R. Chang, "Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration," EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.

ICR Data: Baseline removal due to ash alone is from preliminary ICR report data compiled by Dennis Smith, DOE/NETL (5/1/00)

- Low sulfur bit coal ash removes constant 57% mercury
- Total removal is 57% from ash and 0 ==> 43% from ACI
- Baseline mercury removal (ash alone) is an average of 2 plants with 250F inlet and 4 plants with >300F inlet, both approximately 57%
- Correlation for 225F not included; no baseline removal available and temperature below H2SO4 dewpoint.

ICR Results and Pilot-Scale Test Results Combined:

- Mercury removal due to ash for both temperatures is 57% and is not a function of ACI
- Mercury removal due to ACI is not a function of ash but is a function of temperature
- The two removals can be combined: 57% from ash and between 0% and 43% from ACI

Algorithm 1: Incorporates ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, °F		
	225	**250**	**275**
a	55.536	159.27	494.64
b	1.4351	3.6838	11.554
c	1	1	1
R^2 (error)	0.99	0.85	0.82
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Algorithm 2: Excludes ICR Results

$$\text{Hg Removal} = 100 - [a/(ACI+b)^c]$$

Coefficient	Flue Gas Temperature, °F		
	225	**250**	**275**
a	128.69	370.98	1218.6
b	1.4284	3.6937	12.14
c	1	1	1
R^2 (error)	0.99	0.85	0.89
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

1.2 Subbituminous Coal

Coal Source: PRB Subbituminous coal
Data Source:

PROJECT: Pilot-Scale Carbon Injection for Mercury Control at Comanche Station

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Pulse-Jet with A/C ratio = 12 ft/min, most fly ash removed upstream, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_x (@ 3% O_2 dry)

Literature Source: AWMA 99-524, S.M. Haythornthwaite, J. Smith, G. Anderson, T. Hunt, M. Fox, R. Chang, T. Brown, 1999

Algorithm:

Hg Removal = 100 – $[a/(ACI+b)^c]$

Coefficient	Flue Gas Temperature, ^oF			
	230	**280**	**300**	**345**
a	1373.11	247.772	296.714	319.587
b	32.1071	3.3867	4.2911	3.6636
c	1	1	1	1
R^2 (error)	-	0.89	0.84	0.83
ACI Range (Lb/MMacf)	0 - 1	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

2. Mercury Control Retrofit Configurations: ESP-3, ESP-6

Description: Pulse-Jet FF (PJFF) retrofitted after existing ESP. Activated carbon injected upstream of PJFF. ESP-3 -- no flue gas temperature control, ESP-6 -- flue gas temperature control via water injection.

2.1 Bituminous Coal

Coal Source: Eastern bituminous coal, West Virginia (< 1%S and 0.1% chlorine)

Data Source:

PROJECT: ADA Technologies/Public Service Electric and Gas Company/EPRI -- Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration

Pilot-Scale Tests: 4,000 acfm slipstream from the 620 MWe Hudson Generating Station, Unit 2, opposed-fired furnace, Eastern bituminous coal from West Virginia (< 1%S and 0.1% chlorine), Pulse-jet FF installed downstream of cold ESP, A/C ratio = 12 ft/min, tests conducted with AC and fly ash

Literature Source: Waugh, E., B. Jensen, L. Lapatnick, F. Gibbons, S. Sjostrom, J. Ruhl, R. Slye, and R. Chang, "Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration," EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.

ICR Results and Pilot-Scale Test Results Combined:

- Mercury removal due to ash for both temperatures is 57% and is not a function of ACI
- Mercury removal due to ACI is not a function of ash but is a function of temperature
- The two removals can be combined: 57% from ash and between 0% and 43% from ACI

Algorithm 1: Incorporates ICR Results

Hg Removal = 100 – [a/(ACI+b)^c]

Coefficient	Flue Gas Temperature, ^oF		
	240	**285**	**285**
a	51.038	159.4	159.4
b	1.3194	3.5606	3.5606
c	1	1	1
R^2 (error)	0.73	0.66	0.66
ACI Range (Lb/MMacf)	0 - 5	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

Algorithm 2: Excludes ICR Results

Hg Removal = 100 – [a/(ACI+b)^c]

Coefficient	Flue Gas Temperature, ^oF	
	240	**285**
a	118.69	370.69
b	1.3194	3.5606
c	1	1
R^2 (error)	0.73	0.66
ACI Range (Lb/MMacf)	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

2.2 Subbituminous Coal

Coal Source: PRB Subbituminous coal

Data Source:

PROJECT: ADA Technologies/PS Colorado/EPRI/NETL – Pilot-Scale Demonstration of Dry Carbon-Based Sorbent Injection for Hg Control in Utility ESPs and FFs – Phase I

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Pulse-Jet with A/C ratio = 12 ft/min, most fly ash removed upstream, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_X (@ 3% O_2 dry)

Literature Source: Ebner, T., J. Ruhl, R. Slye, J. Smith, T. Hunt, R. Chang, and T. Brown, " Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses," EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997.

Algorithm:

$$\text{Hg Removal} = 100 - [a/(\text{ACI}+b)^c]$$

Coefficient	Flue Gas Temperature, ^oF		
	250	**280**	**300**
a	4.2774	27.5595	148.0419
b	0.04793	0.31345	0.92051
c	1	1	1
R^2 (error)	0.99	0.8	0.96
ACI Range (Lb/MMacf)	0 – 3	0 – 3	0 – 3

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

3. Mercury Control Retrofit Configurations: FF-1, FF-2, SD/FF-1, and SD/FF-2

Description: Activated carbon injected upstream of existing reverse-gas baghouse. FF-1 -- no flue gas temperature control, FF-2 – flue gas temperature control via water injection.

3.1 Bituminous Coal

No data for bituminous coal applications.

3.2 Subbituminous Coal

Coal Source: PRB coal from Belle Ayr mine

Data Source:

PROJECT: ADA Technologies/PS Colorado/EPRI/NETL – Pilot-Scale Demonstration of Dry Carbon-Based Sorbent Injection for Hg Control in Utility ESPs and FFs

Pilot-Scale Tests: 600 acfm slipstream from the 350 MWe Comanche Station, Unit 2 PSCo, opposed-fired furnace, PRB coal from Belle Ayr mine, Flue gas contained little HCl, 275 to 325 ppm SO_2 (@ 3% O_2 dry), 180 to 250 ppm NO_x (@ 3% O_2 dry)

Literature Source: AWMA 99-524, S.M. Haythornthwaite, J. Smith, G. Anderson, T. Hunt, M. Fox, R. Chang, T. Brown, 1999

Algorithm:

Hg Removal = 100 – [a/(ACI+b)^c]

Coefficient	Flue Gas Temperature, ^oF		
	230	**275**	**330**
a	266.119	23.20196	27.9742
b	11.1359	0.43006	0.31913
c	1	1	1
R^2 (error)	0.03	0.88	0.87
ACI Range (Lb/MMacf)	0 - 1	0 - 5	0 - 5

Where, a,b,c = numerical coefficients
ACI = Activated Carbon Injection Feed rate, Lb/MMacf
Hg Removal = % total mercury removed, inlet to outlet

4. Mercury Control Retrofit Configurations: WS-1

Description: Existing ESP for particulate control and wet FGD for SO_2 control.

4.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000

Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for bituminous coal (Section 1.1)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

4.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:
Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

5. Mercury Control Retrofit Configurations: WS-2

Description: Existing SNCR for NOx control, existing ESP for particulate control and wet FGD for SO_2 control.

5.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:

Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SNCR: Not specified

Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm (Section 1.1)
- SNCR installation increases oxidized Hg by 0% (e.g., 70% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

5.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:

Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SNCR: Not specified

Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- SNCR installation increases oxidized Hg by 0% (e.g., 25% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

6. Mercury Control Retrofit Configurations: WS-3

Description: Existing SCR for NO_X control, existing ESP for particulate control and wet FGD for SO_2 control.

6.1 Bituminous Coal

Coal Source: Bituminous coal
Data Source:

Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SCR: Mercury control phone meeting 4/28/2000

Methodology:

- Hg speciation for Bituminous coal: 70% oxidized, 30% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm (Section 1.1)
- SCR installation increases oxidized Hg by 35% (e.g., 94.5% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

6.2 Subbituminous Coal

Coal Source: Subbituminous coal
Data Source:

Mercury Speciation and Wet FGD removal: Memo from D. Smith, DOE/NETL, 4/29/2000
Impact of SCR: Mercury control phone meeting 4/28/2000

Methodology:

- Hg speciation for subbituminous coal: 25% oxidized, 75% elemental
- Existing ESP assumed to remove Hg at rate predicted by ESP-1, ESP-4 algorithm for subbituminous coal (Section 1.2)
- SCR installation increases oxidized Hg by 35% (e.g., 33.75% total)
- Wet FGD removes 100% of oxidized Hg and 0% elemental Hg

7. Mercury Control Retrofit Configurations: ESP-7, Combined AC + Lime Sorbent

Description: Pulse-Jet FF (PJFF) retrofitted after existing ESP. Combined activated carbon/Lime sorbent injected upstream of PJFF.

7.1 Bituminous Coal

Coal Source: Bituminous coal

Data Source:

Butz, J.R., R. Chang, E.G. Waugh, "Use of Sorbents for Air Toxics Control in a Pilot-Scale COHPAC Baghouse," paper presented at the Air and Waste Management Association's 92nd annual meeting and exhibition, June 20-24, 1999, St. Louis, Mo.

Methodology:

- Assumes AC:Lime ratio = 2:19
- Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
- 1- 4 lb/MMacf Sorbent Concentration yields 90-95% Hg Removal

ATTACHMENT 3

Summary of Mercury Control Cases Analyzed with National Energy Technology Laboratory Mercury Control Performance and Cost Model

Summary of Mercury Control Cases Analyzed with NETL's Mercury Control Performance and Cost Model

The purpose of this document is to summarize the mercury control cases evaluated with NETL's Mercury Control Performance and Cost Model.

1. Original Cases Designated by EPA

Table 1 identifies the original matrix of cases that were designated by EPA for evaluation. Of those designated in the table, the following model plant types were actually evaluated: 1, 4, 7, 8, 10, 13, 16, and 17. The others were not assessed due to lack of control performance data or similarity to another model plant type. Table 2 describes the mercury control retrofit scenario configurations used in Table 1.

2. EPA Evaluation Requirements

For each combination of model plant and pertinent mercury control technology (see Tables 1 and 2), EPA requested estimates of capital cost ($/kW), fixed O&M cost (mills/kWh), and variable O&M cost (mills/kWh) using the EPRI TAG methodology. These cost estimates were in 1999 constant dollars. EPA also designated the following analysis assumptions:

(1) Mercury removal of 50%, 60%, 70%, 80%, and 90% for each of the model plants;

(2) Flue gas temperature at activated carbon injection location of 150 C for cases without spray cooling (SC) and an approach to saturation of 10 degrees celsius (18 degrees F) for cases with SC;

(3) plant capacity factor of 65%;

(4) activated carbon cost of $1.0/kg;

(5) water cost of 0.42 mills/gallon;

(6) energy cost 25 mills/kWh;

(7) 30 days of sorbent storage;

(8) labor cost of $25/h; and

(6) other economic assumptions
- (i) general facilities – 5% of direct process capital (DPC)
- (ii) engineering and home office expense – 10% of DPC
- (iii) process contingency – 5% of DPC
- (iv) project contingency – 15% of DPC + (i) + (ii) + (iii)
- (v) pre-production cost – 2% of total plant investment (TPI)
- (vi) retrofit factor – 1.15
- (vii) fixed O&M – 1.5% of TPI

TABLE 1
ORIGINAL MERCURY CONTROL CASES DESIGNATED BY EPA

MODEL PLANT #	POWER PLANT SIZE (MW)	COAL		EXISTING PLANT EMISSION CONTROLS	MERCURY CONTROL(S)	CO-BENEFIT CASE(S) with
		Type[a]	**S%**			
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3 Same as 1	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	SCR
5	975	Bit	0.6	FF	FF-2	SCR
6 Same as 4	975	Bit	0.6	HESP	HESP-1	SCR
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	SCR
8	975	Subbit	0.5	FF	FF-2	SCR
9	975	Subbit	0.5	HESP	HESP-1	SCR
10	100	Bit	3	SD + ESP	SD/ESP-1	
11	100	Bit	3	SD + FF	SD/FF-1	
12	100	Bit	3	HESP + FGD	HESP-1	
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15 Same as 13	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18 Same as 16	100	Subbit	0.5	HESP	HESP-1	

a. Bit = bituminous coal; Subbit = subbituminous coal.

Table 2
Mercury Control Technology Retrofit Scenarios

CASE	EXISTING EQUIPMENT	RETROFIT SCENARIO
ESP-1	Cold-side ESP (ESP)	ACI
ESP-3		ACI + PFF
ESP-4		SC + ACI
ESP-6		SC + ACI + PFF
ESP-7		SC + AC + lime + PFF
ESP-8		SC + ACI + CFBA
ESP-9		SC + AC + lime + CFBA
HESP-1	Hot-side ESP (HESP)	SC + ACI + PFF
FF-1	Fabric filter (FF)	ACI
FF-2		SC + ACI
FF-3		SC + AC + lime + PFF
SD/FF-1	Spray dryer (SD) + FF	ACI
SD/ESP-1	SD + ESP	ACI
WS-1	ESP + wet scrubber (WS)	
WS-2	SNCR + ESP + WS	
WS-3	SCR + ESP + WS	
SCR-SD-1	SCR + SD + FF	

3. Sensitivity Cases

In addition to the original cases described above, EPA also requested five sensitivity cases that are described below.

3.1 Power Plant Size

The purpose of this sensitivity analysis was to add 500 MWe cases for Model Plant Applications 1, 4, 7, 8.

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.2 Mercury Control Operating Temperature

The purpose of this sensitivity analysis was to change the mercury control operating temperature to: Acid Dew Point (ADP) + 40 F for the following cases:

Plant 4, 500 MW
Plant 7, 500 MW
Plant 8, 500 MW
Plant 13, 100 MW
Plant 16, 100 MW
Plant 17, 100 MW

High sulfur cases are not impacted by the change. 975 MW cases were not run.

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.3 COHPAC with Recycle

The purpose of this sensitivity analysis was to add 20% recycle of AC to the COHPAC-type mercury control scenarios (ESP-3 and ESP-6). This sensitivity applies only to retrofit scenarios ESP-3 and ESP-6. Mercury control temperature was set at ADP+18 F (ADP+40 F cases were not run) for the following model plant applications:

Plant 1, 500 MW (ESP-3)
Plant 4, 500 MW (ESP-6)
Plant 7, 500 MW (ESP-6)
Plant 13, 100 MW (ESP-6)
Plant 16, 100 MW (ESP-6)

This work was originally completed on 6/6/2000. The sensitivity runs were updated on 6-14-2000 to correct a programming error. The results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls**."

3.4 Addition of Ductwork to Increase Flue Gas Residence Time

The purpose of this sensitivity analysis was to add the capital cost of additional ductwork to the cost of mercury control for a specified model plant application. The model plant application that was selected was Plant 4, ESP-4, 500 MW. The following assumptions were used to complete this effort:

Application: Plant 4, ESP-4, Ductwork added upstream of ESP
Results presented with and without added ductwork
Plant sizes: 975, 500 and 100 MWe
Type of ductwork: carbon steel, polymer-lined, insulated (reflects a conservative selection of material)
Cost of ductwork: $134/sq ft
Installation labor: 0.8 hrs/sq ft
Number of ducts: 2
Duct gas velocity: 2800 ft/min
Retrofit factor: 1.3
Gas residence time in new duct: 1 second

This work was completed on 6/14/2000. The capital costing results indicate the following:

975 MW application: **$2.51/kW** for 2 ducts @ 47 feet long (22.3 ft x 22.3 ft)
500 MW application: **$3.50/kW** for 2 ducts @ 47 feet long (16 ft x 16 ft)
100 MW application: **$5.54/kW** for 2 ducts @ 47 feet long (10 ft x 10 ft)

The complete cost results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls" (Plant 4, W&WO Added Ductwork)**.

3.5 Use of a Combined AC/Lime Sorbent

The purpose of this sensitivity analysis was to assess the potential economic impact of using a sorbent consisting of AC and lime. The assumptions were:

Application: Model Plant 4, ESP-6, AC sorbent (50-90% Removal); Model Plant 4, ESP-7, AC-Lime Sorbent (90%+ removal)
Plant size: 500 MWe
AC sorbent Cost = $908/Ton
AC+Lime Sorbent Cost = $149/Ton, Assumes AC:Lime ratio = 2:19
ESP-7 Sensitivity Cases Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
ESP-7 Sensitivity Cases run for 1, 2, 3, and 4 lb/MMacf Sorbent Concentration
ESP-6 Comparison Cases Run for 50, 60, 70, 80, 90% Hg Removal

The complete cost results are presented via table and graphs in Excel file "**Mercury Control Results 6-15-00.xls" (Plant 4, 500 MW, Lime-AC Sorbent)**.

ATTACHMENT 4

Results of all Model Runs

Table 1. Mercury Control Technology Retrofit Configurations		
Mercury Control	**Existing Equipment (a,b)**	**Retrofit Technology (a)**
ESP-1	ESP	ACI
ESP-3		ACI + PFF
ESP-4		SC + ACI
ESP-6		SC + ACI + PFF
ESP-7		SC + AC + lime + PFF
ESP-8		SC + ACI + CFBA
ESP-9		SC + AC + lime + CFBA
HESP-1	HESP	
	SC + ACI + PFF	
FF-1	FF	ACI
FF-2		SC + ACI
FF-3		SC + AC + lime + PFF
SD/FF-1	SD + FF	ACI
SD/ESP-1	SD + ESP	ACI

a. ESP = cold-side electrostatic precipitator; HESP = hot-side electrostatic precipitator; FF= fabric filter; SD = spray dryer; ACI = activated carbon injection; PFF = polishing fabric filter.
b. Existing equipment may include wet scrubber and NOx controls such as selective catalytic reduction (SCR).

Table 2. Mercury Control Technology Applications and Cobenefits Definition						
Model Plant #	**Power Plant Size, MWe**	**Coal Type**	**Coal Sulfur Content, %S**	**Existing Controls**	**Mercury Controls**	**CoBenefit Case(s) with**
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	
5	975	Bit	0.6	FF	FF-2	
6	975	Bit	0.6	HESP	HESP-1	
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	
8	975	Subbit	0.5	FF	FF-2	
9	975	Subbit	0.5	HESP	HESP-1	
10	100	Bit	3	SD + ESP	SD/ESP-1	SCR
11	100	Bit	3	SD + FF	SD/FF-1	SCR
12	100	Bit	3	HESP + FGD	HESP-1	SCR
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18	100	Subbit	0.5	HESP	HESP-1	

a. Bit = bituminous coal; Subbit = subbituminous coal.
b. Mercury controls are shown in Table 1.

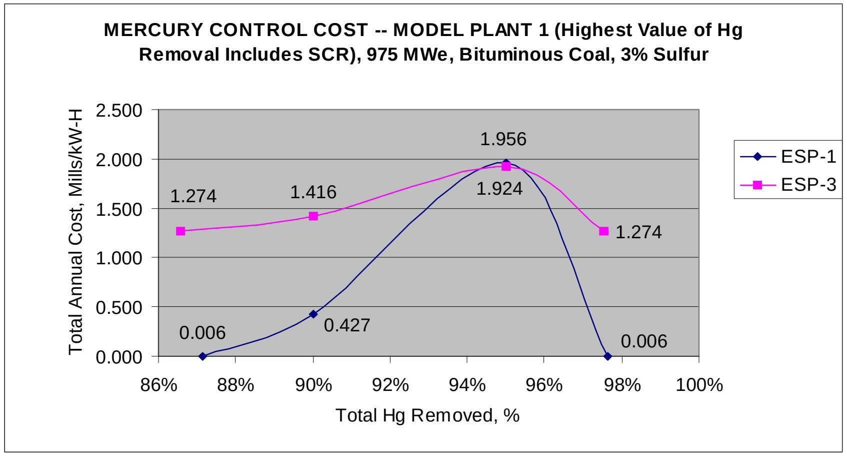
RESULTS FOR MODEL PLANTS 1 AND 4 **DATE: 5/22/00**
(Accounts for ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 87% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 97.6% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 86.6% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 97.6% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
5) Model Plant 4, ESP-4: Minimum Hg removal = 58% for ESP with Eastern Bituminous Coals
7) Model Plant 4, ESP-6: Minimum Hg removal = 61.3% for ESP with Eastern Bituminous Coals

See plot of results below table

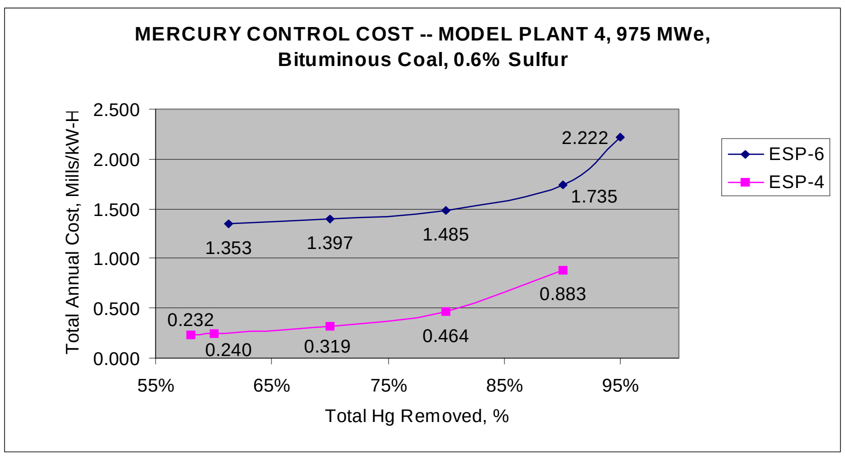
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	975	87.16%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	3.29	2.48	0.058	0.040	0.022	0.307	0.427
1	975	95.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	18.12	8.54	0.200	0.048	0.026	1.683	1.956
1	975	97.64%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	86.58%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	43.45	1.015	0.116	0.063	0.080	1.274
1	975	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	1.22	44.59	1.041	0.118	0.064	0.193	1.416
1	975	95.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	6.00	47.10	1.100	0.121	0.065	0.637	1.924
1	975	97.54%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	43.45	1.015	0.116	0.063	0.080	1.274
4	975	58.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	5.88	0.137	0.047	0.025	0.022	0.232
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.06	6.01	0.140	0.047	0.025	0.027	0.240
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.79	6.67	0.156	0.048	0.026	0.088	0.319
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.24	7.54	0.176	0.050	0.027	0.211	0.464
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	6.61	9.53	0.223	0.052	0.028	0.580	0.883
4	975	61.30%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	46.02	1.075	0.121	0.065	0.092	1.353
4	975	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.38	46.50	1.086	0.122	0.065	0.124	1.397
4	975	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.23	47.11	1.100	0.122	0.066	0.196	1.485
4	975	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.78	48.46	1.132	0.124	0.067	0.412	1.735
4	975	95.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	8.89	50.59	1.182	0.127	0.068	0.845	2.222

ECONOMIC RESULTS -- GRAPHICAL FORMAT

MODEL PLANT #1



MODEL PLANT #4



RESULTS FOR MODEL PLANTS 1 AND 4 (ADP+40) **DATE: 6/6/00**

(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)

Comments:

1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals

2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals

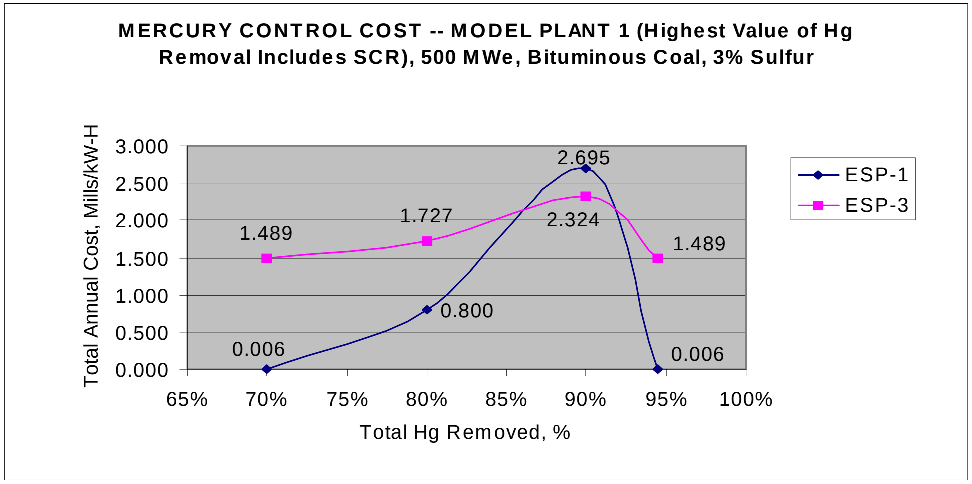
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

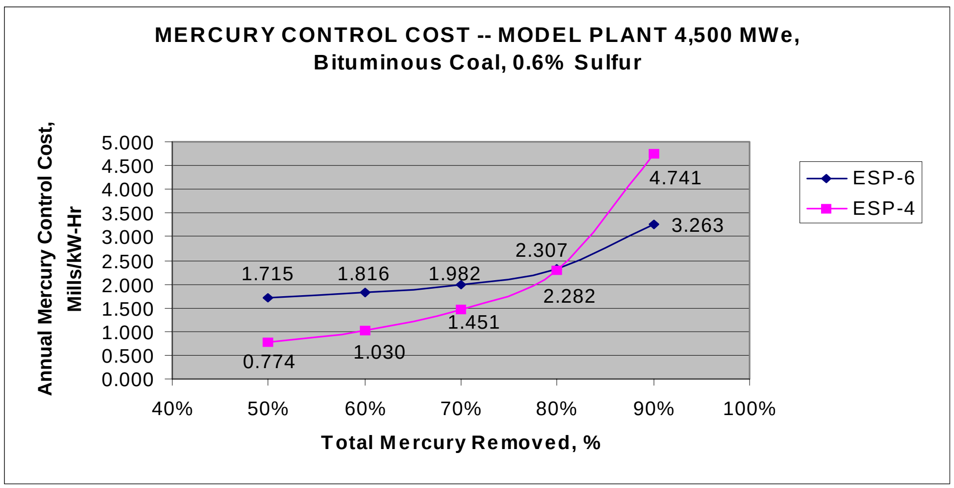
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.64	1.206	0.166	0.089	0.266	1.727
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.83	1.281	0.170	0.091	0.782	2.324
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	5.31	7.95	0.186	0.084	0.045	0.459	0.774
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	7.96	9.22	0.215	0.086	0.046	0.683	1.030
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	12.37	11.13	0.260	0.088	0.048	1.055	1.451
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.19	14.55	0.340	0.093	0.050	1.800	2.282
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	47.64	23.42	0.547	0.103	0.056	4.035	4.741
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	1.98	51.91	1.212	0.166	0.089	0.248	1.715
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	2.98	52.53	1.227	0.167	0.090	0.333	1.816
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	4.65	53.46	1.249	0.168	0.090	0.474	1.982
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	8.00	55.10	1.287	0.170	0.092	0.758	2.307
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	18.05	59.25	1.384	0.176	0.095	1.609	3.263

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



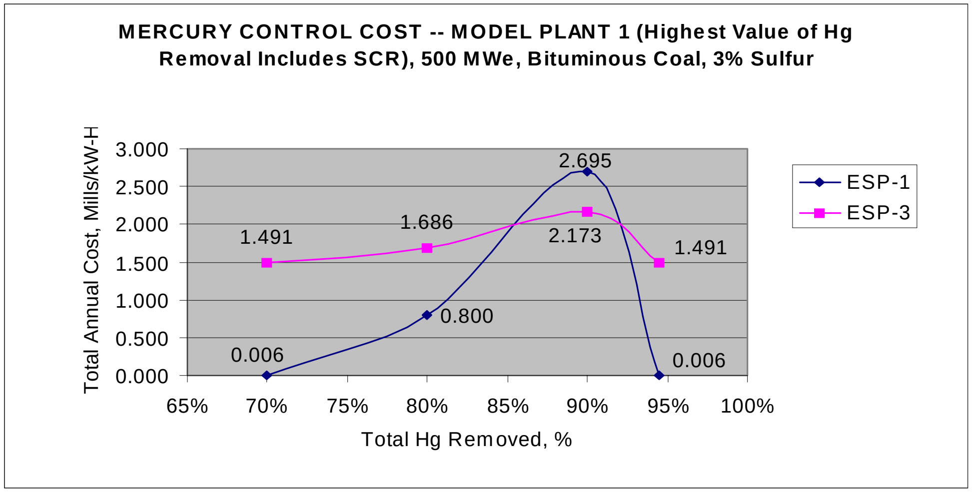
RESULTS FOR MODEL PLANTS 1 AND 4 (w Recycle for ESP-3 and ESP-6) **06/06/2000**
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

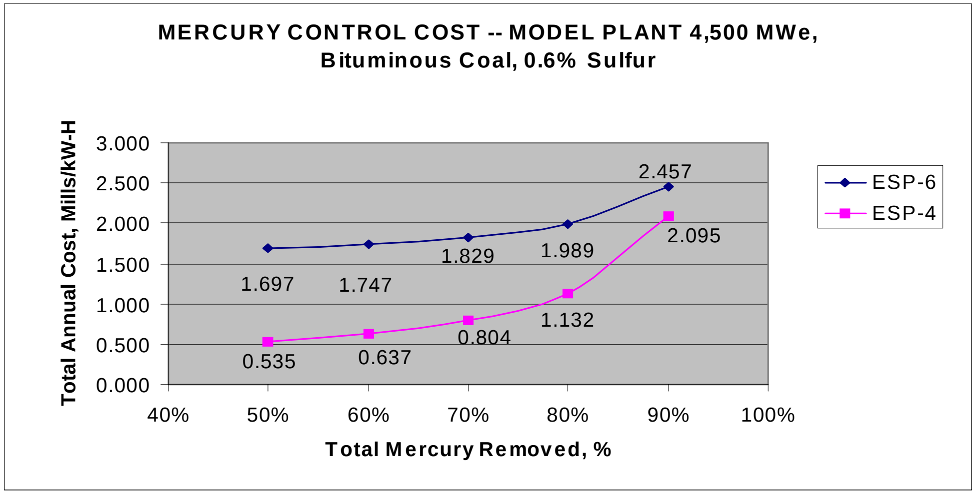
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.67	1.160	0.163	0.088	0.081	1.491
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.39	1.200	0.165	0.089	0.231	1.686
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.15	1.265	0.169	0.091	0.648	2.173
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.67	1.160	0.163	0.088	0.081	1.491
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.216	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.230	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.252	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.291	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.388	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.33	1.269	0.170	0.092	0.166	1.697
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.71	1.278	0.171	0.092	0.206	1.747
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.26	1.291	0.172	0.093	0.274	1.829
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.23	1.313	0.173	0.093	0.409	1.989
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	58.64	1.370	0.177	0.095	0.816	2.457

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



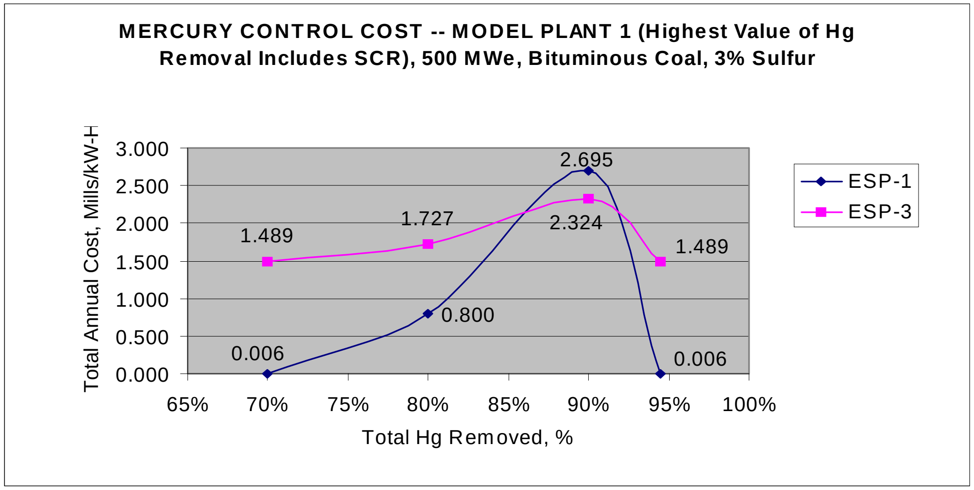
RESULTS FOR MODEL PLANTS 1 AND 4 **06/05/2000**
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

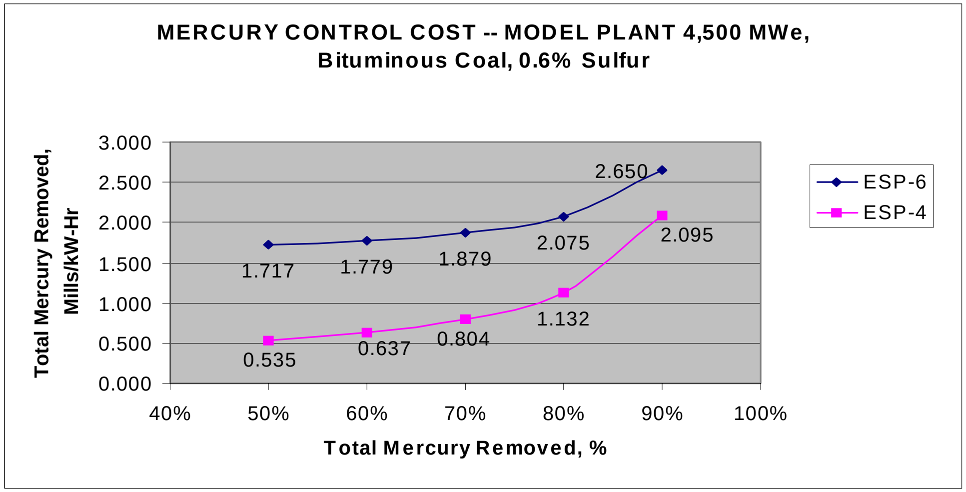
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	500	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	4.61	0.108	0.078	0.042	0.572	0.800
1	500	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	12.54	0.293	0.089	0.048	2.266	2.695
1	500	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.12	0.003	0.000	0.000	0.003	0.006
1	500	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
1	500	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	51.64	1.206	0.166	0.089	0.266	1.727
1	500	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	54.83	1.281	0.170	0.091	0.782	2.324
1	500	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	49.65	1.160	0.163	0.088	0.080	1.489
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.216	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.230	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.252	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.291	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.388	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.48	1.273	0.171	0.092	0.182	1.717
4	500	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.91	1.283	0.171	0.092	0.232	1.779
4	500	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.55	1.298	0.172	0.093	0.316	1.879
4	500	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.67	1.324	0.174	0.094	0.484	2.075
4	500	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	59.46	1.389	0.178	0.096	0.987	2.650

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



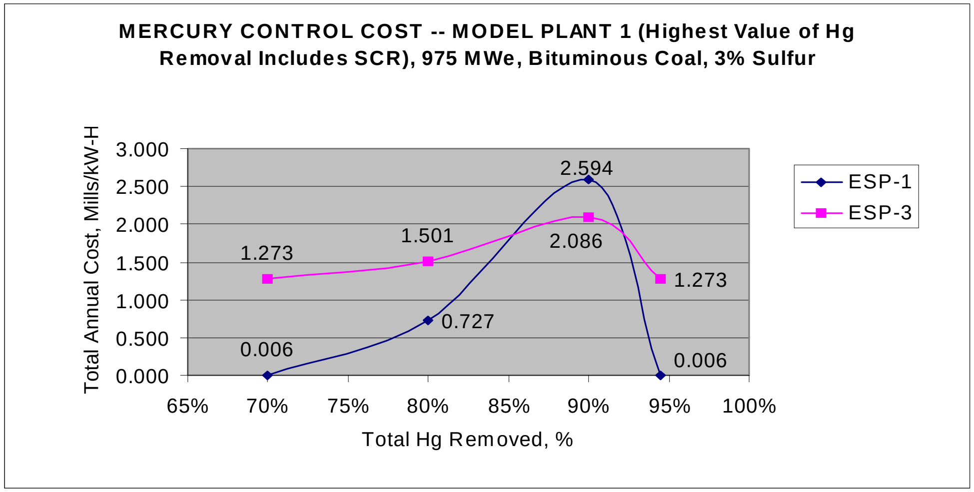
RESULTS FOR MODEL PLANTS 1 AND 4 **05/22/2000**
(Utilizes Original Performance Algorithms -- Excludes ICR Data Modification)
Comments:
1) Model Plant 1, ESP-1: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
2) Model Plant 1, ESP-1: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals
3) Model Plant 1, ESP-3: Minimum Hg removal = 70% for ESP and FGD Combination with Eastern Bituminous Coals
4) Model Plant 1, ESP-3: Minimum Hg removal = 94.5% for ESP, FGD, and SCR Combination with Eastern Bituminous Coals

See plot of results below table

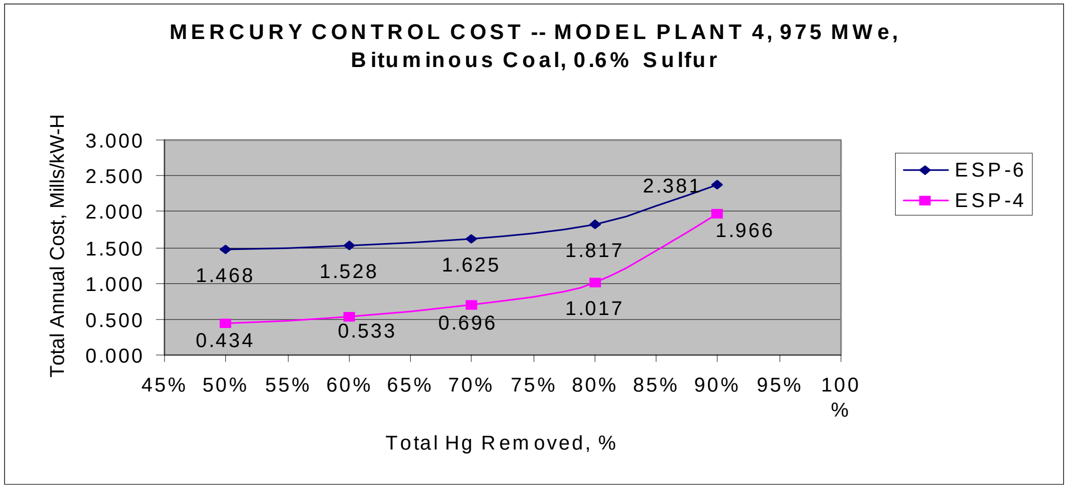
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
1	975	70.00%	Bit	3	ESP, FGD	ESP-1	None	N/A	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	80.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	6.14	3.85	0.090	0.042	0.023	0.572	0.727
1	975	90.00%	Bit	3	ESP, FGD	ESP-1	SI System	N/A	No FG Cooling	24.42	10.73	0.251	0.050	0.027	2.266	2.594
1	975	94.50%	Bit	3	ESP, FGD	ESP-1	SI System	SCR	No FG Cooling	0.00	0.11	0.002	0.000	0.000	0.003	0.006
1	975	70.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	0.00	43.43	1.014	0.116	0.063	0.080	1.273
1	975	80.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	2.00	45.08	1.053	0.119	0.064	0.266	1.501
1	975	90.00%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	N/A	No FG Cooling	7.56	47.78	1.116	0.122	0.066	0.782	2.086
1	975	94.50%	Bit	3	ESP, FGD	ESP-3	SI System, PJFF	SCR	No FG Cooling	0.00	43.43	1.014	0.116	0.063	0.080	1.273
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	7.37	0.172	0.049	0.027	0.185	0.434
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	7.90	0.185	0.050	0.027	0.271	0.533
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	8.70	0.203	0.051	0.028	0.414	0.696
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	10.10	0.236	0.053	0.029	0.700	1.017
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	13.72	0.320	0.057	0.031	1.557	1.966
4	975	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	47.00	1.098	0.122	0.066	0.182	1.468
4	975	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	47.37	1.106	0.123	0.066	0.232	1.528
4	975	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	47.90	1.119	0.124	0.067	0.316	1.625
4	975	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	48.84	1.141	0.125	0.067	0.484	1.817
4	975	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	51.23	1.197	0.128	0.069	0.988	2.381

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 1



MODEL PLANT # 4



RESULTS FOR MODEL PLANTS 7 AND 8 (w Recycle for ESP-6) **DATE: 6/6/00**

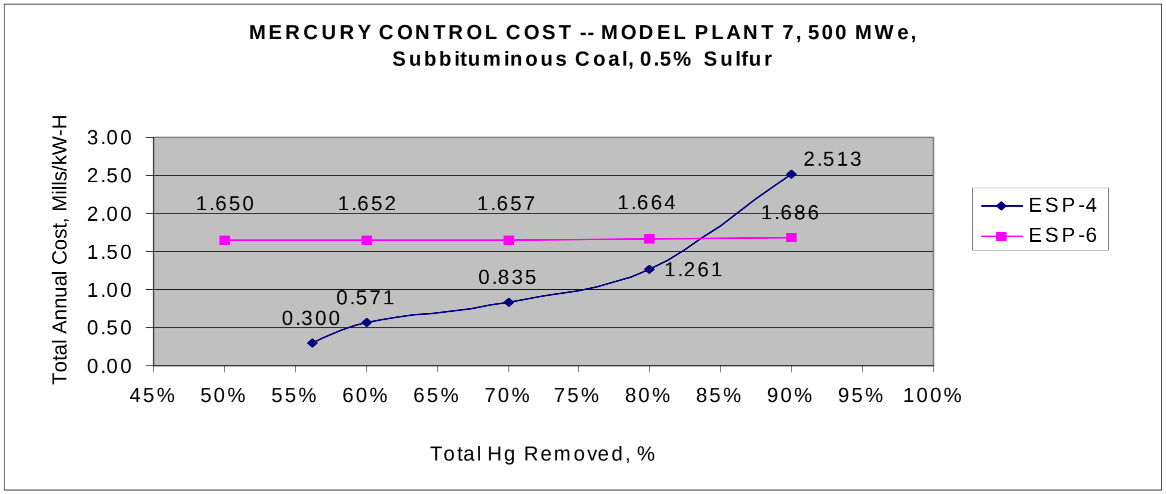
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

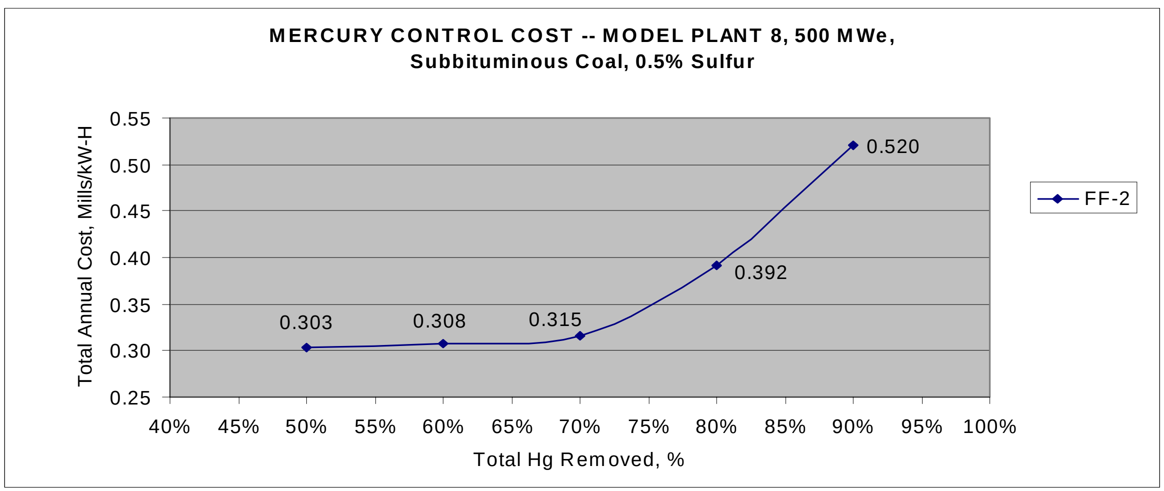
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	6.59	0.154	0.083	0.045	0.019	0.300
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	8.79	0.205	0.086	0.046	0.233	0.571
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	10.27	0.240	0.088	0.048	0.459	0.835
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	12.34	0.288	0.091	0.049	0.833	1.261
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	17.55	0.410	0.098	0.053	1.953	2.513
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	55.15	1.288	0.172	0.093	0.097	1.650
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	55.19	1.289	0.172	0.092	0.099	1.652
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	55.25	1.290	0.172	0.093	0.101	1.657
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	55.34	1.293	0.172	0.093	0.107	1.664
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	55.57	1.298	0.173	0.093	0.122	1.686
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	6.65	0.155	0.083	0.045	0.020	0.303
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	6.74	0.157	0.083	0.045	0.023	0.308
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	6.84	0.160	0.083	0.045	0.027	0.315
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	7.56	0.177	0.085	0.046	0.085	0.392
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	8.47	0.198	0.086	0.046	0.190	0.520

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 **DATE: 06/06/2000**

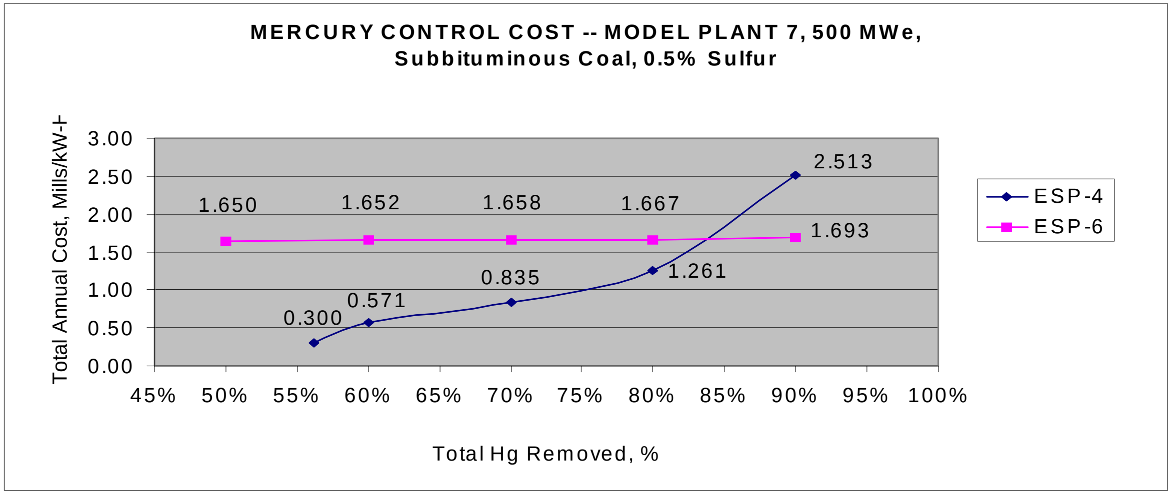
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

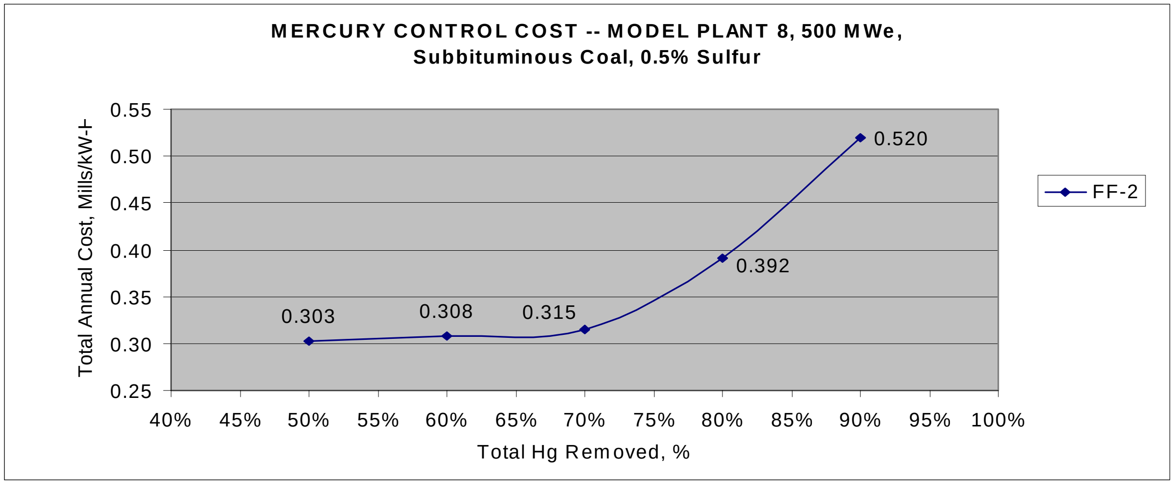
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	6.59	0.154	0.083	0.045	0.019	0.300
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	8.79	0.205	0.086	0.046	0.233	0.571
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	10.27	0.240	0.088	0.048	0.459	0.835
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	12.34	0.288	0.091	0.049	0.833	1.261
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	17.55	0.410	0.098	0.053	1.953	2.513
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	55.15	1.288	0.172	0.093	0.097	1.650
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	55.20	1.289	0.172	0.092	0.099	1.652
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	55.26	1.291	0.172	0.093	0.102	1.658
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	55.37	1.293	0.172	0.093	0.108	1.667
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	55.64	1.300	0.173	0.093	0.128	1.693
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	6.65	0.155	0.083	0.045	0.020	0.303
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	6.74	0.157	0.083	0.045	0.023	0.308
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	6.84	0.160	0.083	0.045	0.027	0.315
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	7.56	0.177	0.085	0.046	0.085	0.392
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	8.47	0.198	0.086	0.046	0.190	0.520

ECONOMIC RESULTS S GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 (ADP+40) **DATE: 6/6/00**

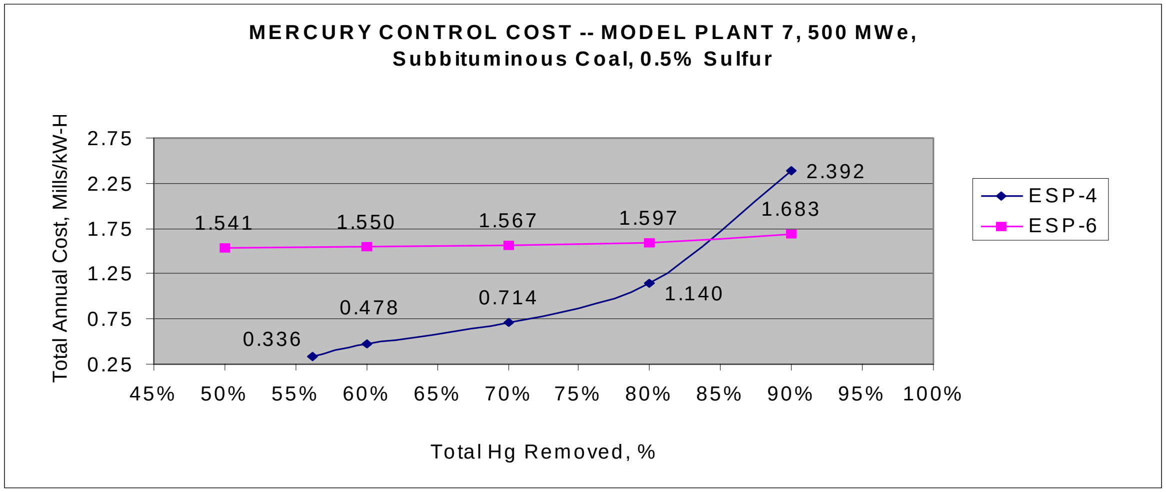
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

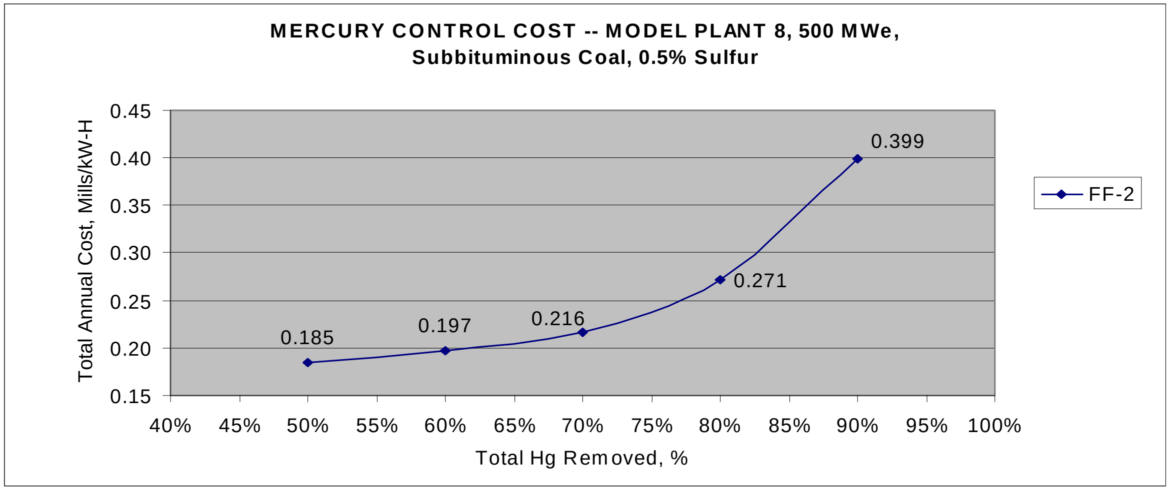
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	500	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	0.00	3.92	0.092	0.078	0.042	0.125	0.336
7	500	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	2.36	4.83	0.113	0.079	0.043	0.243	0.478
7	500	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	4.87	6.15	0.144	0.081	0.044	0.446	0.714
7	500	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	9.00	8.22	0.192	0.084	0.045	0.820	1.140
7	500	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.39	13.42	0.313	0.090	0.049	1.939	2.392
7	500	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.04	51.17	1.195	0.165	0.089	0.093	1.541
7	500	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.06	51.28	1.198	0.164	0.089	0.100	1.550
7	500	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.09	51.44	1.201	0.165	0.089	0.111	1.567
7	500	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.17	51.70	1.208	0.166	0.089	0.134	1.597
7	500	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.38	52.36	1.223	0.167	0.090	0.204	1.683
8	500	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.01	2.57	0.060	0.076	0.041	0.009	0.185
8	500	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.04	2.75	0.064	0.076	0.041	0.017	0.197
8	500	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.09	2.95	0.069	0.076	0.041	0.030	0.216
8	500	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.73	3.44	0.080	0.077	0.041	0.072	0.271
8	500	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	1.89	4.35	0.102	0.078	0.042	0.177	0.399

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 7 AND 8 **DATE: 05/22/2000**

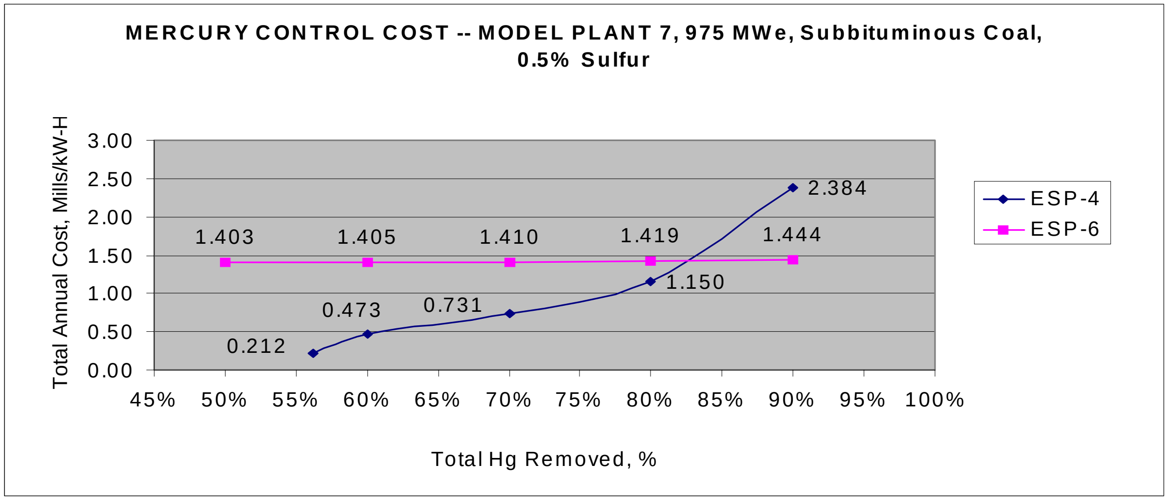
Comments:
1) Model Plant 7, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 8, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

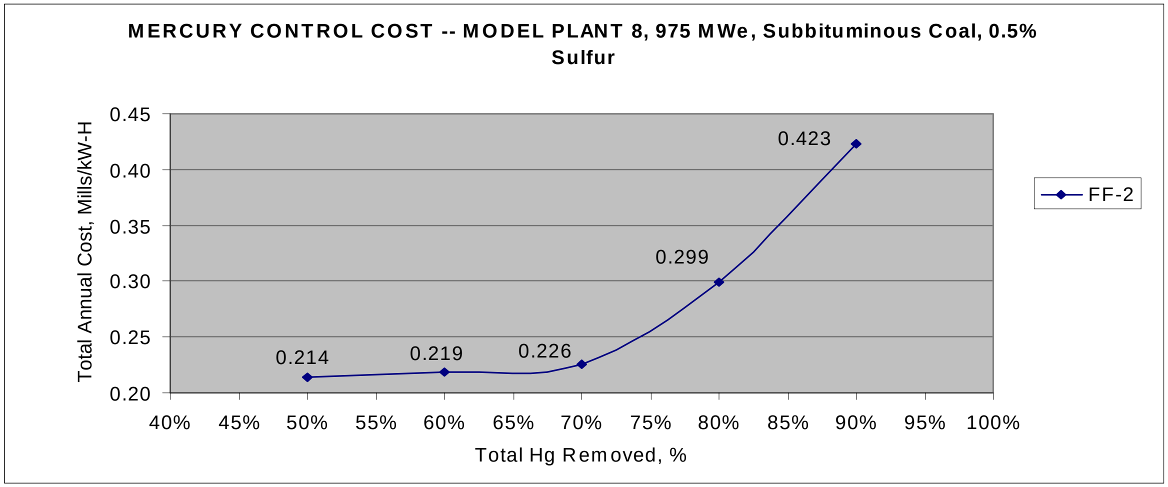
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
7	975	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	5.25	0.123	0.046	0.025	0.019	0.212
7	975	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	7.07	0.165	0.049	0.026	0.233	0.473
7	975	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	8.32	0.194	0.050	0.027	0.459	0.731
7	975	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	10.09	0.236	0.053	0.028	0.833	1.150
7	975	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	14.61	0.341	0.058	0.031	1.953	2.384
7	975	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	47.74	1.115	0.124	0.067	0.097	1.403
7	975	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	47.78	1.116	0.124	0.067	0.099	1.405
7	975	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	47.83	1.117	0.124	0.067	0.102	1.410
7	975	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	47.92	1.119	0.124	0.067	0.109	1.419
7	975	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	48.14	1.124	0.125	0.067	0.128	1.444
8	975	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	5.30	0.124	0.046	0.025	0.020	0.214
8	975	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	5.37	0.125	0.046	0.025	0.023	0.219
8	975	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	5.45	0.127	0.046	0.025	0.027	0.226
8	975	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	6.04	0.141	0.047	0.025	0.085	0.299
8	975	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	6.80	0.159	0.048	0.026	0.190	0.423

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 7



MODEL PLANT # 8



RESULTS FOR MODEL PLANTS 10 AND 13 **DATE: 5/22/00**

Comments:

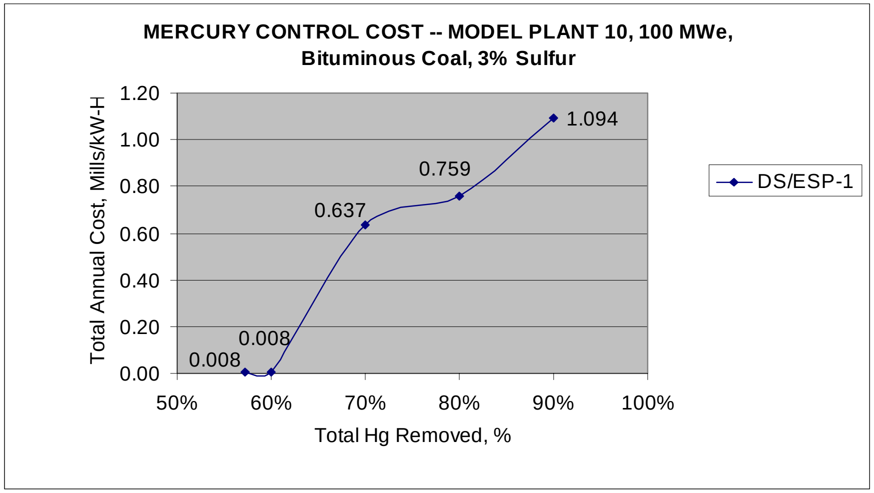
1) Model Plant 10, DS/ESP-1: Minimum Hg removal = 57.2% for DS/ESP Combination with Eastern Bituminous Coals
2) Model Plant 10: Capital Cost Only Includes Sorbent Injection Equipment (accounts for storage/transfer of sorbent)
3) Model Plant 13, ESP-4: Minimum Hg removal = 58.8% for ESP with Eastern Bituminous Coals
4) Model Plant 13, ESP-6: Minimum Hg removal = 61.3% for ESP with Eastern Bituminous Coals

See plot of results below table

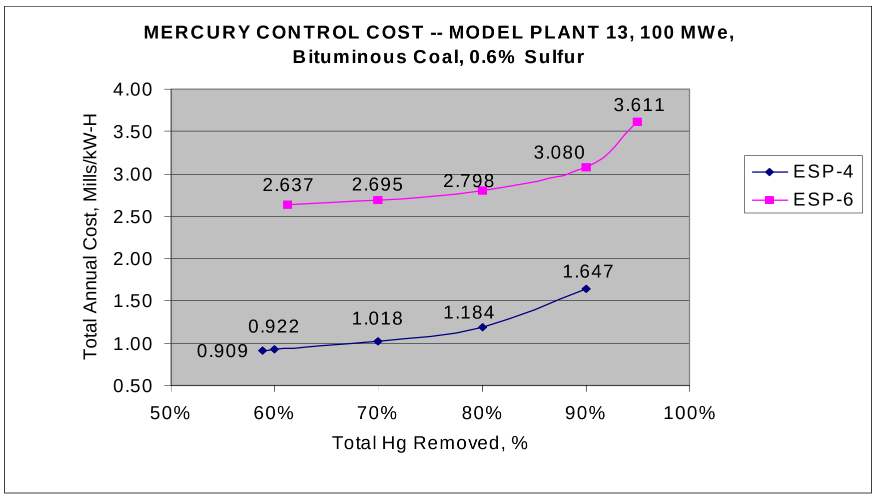
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	57.20%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.00	0.18	0.004	0.000	0.000	0.003	0.008
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.00	0.18	0.004	0.000	0.000	0.003	0.008
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.42	1.58	0.037	0.363	0.195	0.042	0.637
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.34	2.95	0.069	0.365	0.197	0.128	0.759
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	4.12	5.84	0.136	0.370	0.199	0.388	1.094
13	100	58.80%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	13.11	0.306	0.378	0.203	0.022	0.909
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.06	13.39	0.313	0.378	0.204	0.027	0.922
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.79	14.72	0.344	0.381	0.205	0.088	1.018
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.24	16.40	0.383	0.383	0.206	0.211	1.184
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	6.61	20.05	0.468	0.389	0.210	0.580	1.647
13	100	61.30%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	76.37	1.784	0.495	0.266	0.092	2.637
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.38	77.36	1.807	0.497	0.267	0.124	2.695
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.23	78.56	1.835	0.499	0.268	0.196	2.798
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.78	81.10	1.894	0.503	0.271	0.412	3.080
13	100	95.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	8.89	84.94	1.984	0.509	0.274	0.844	3.611

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 10 AND 13 (ADP+40) **DATE: 6/6/00**

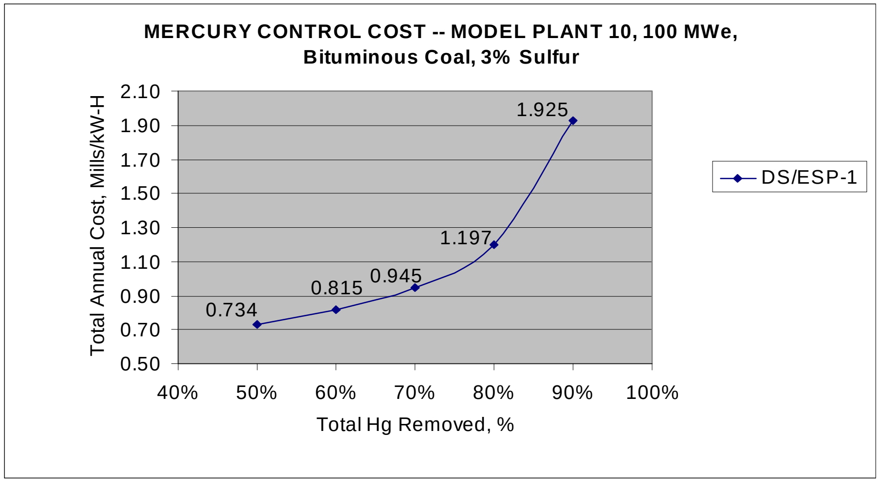
Comments:

See plot of results below table

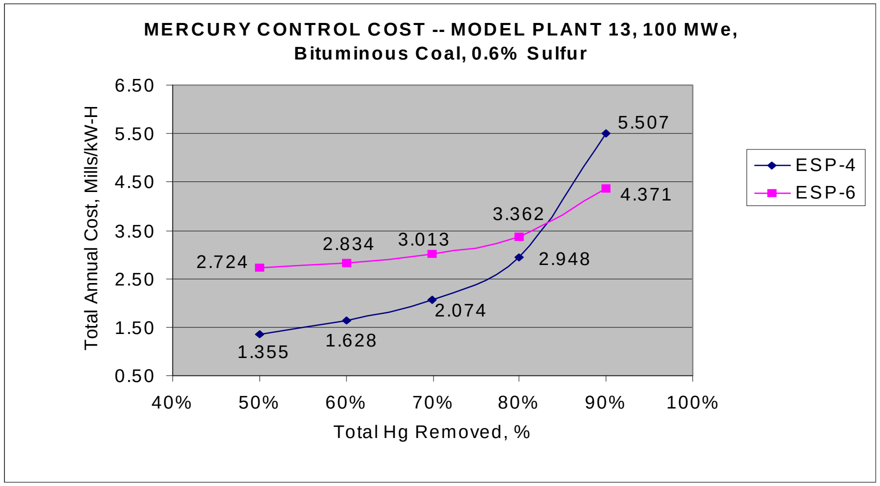
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	5.31	13.49	0.315	0.377	0.203	0.459	1.355
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	7.96	15.43	0.360	0.380	0.205	0.683	1.628
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	12.37	18.31	0.428	0.385	0.207	1.055	2.074
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.19	23.36	0.546	0.392	0.211	1.800	2.948
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	47.64	36.04	0.842	0.410	0.221	4.035	5.507
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	1.98	73.77	1.723	0.490	0.264	0.248	2.724
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	2.98	74.76	1.746	0.491	0.264	0.333	2.834
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	4.65	76.20	1.780	0.493	0.266	0.474	3.013
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	8.00	78.71	1.839	0.497	0.268	0.758	3.362
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	18.05	84.91	1.983	0.506	0.273	1.609	4.371

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



Sensitivity Results: Plants 4, ESP-4, W & WO Ductwork for Added Residence Time **DATE: 6/14/00**

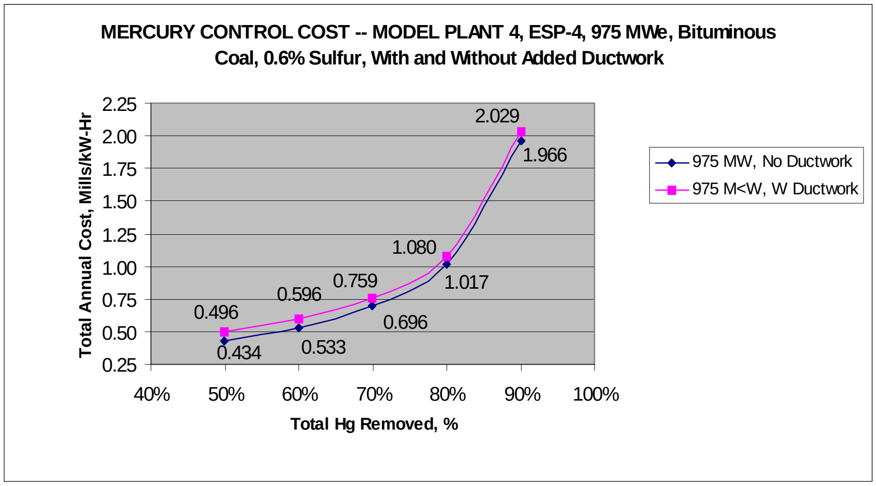
Comments:
Application: Plant 4, ESP-4, Ductwork added upstream of ESP
Results presented with and without added ductwork
Plant sizes: 975, 500 and 100 MWe
Type of ductwork: carbon steel, polymer-lined, insulated (reflects a conservative selection of material)
Cost of ductwork: $134/sq ft
Installation labor: 0.8 hrs/sq ft
Number of ducts: 2
Duct gas velocity: 2800 ft/min
Retrofit factor: 1.3
Gas residence time in new duct: 1 second

See plot of results below table

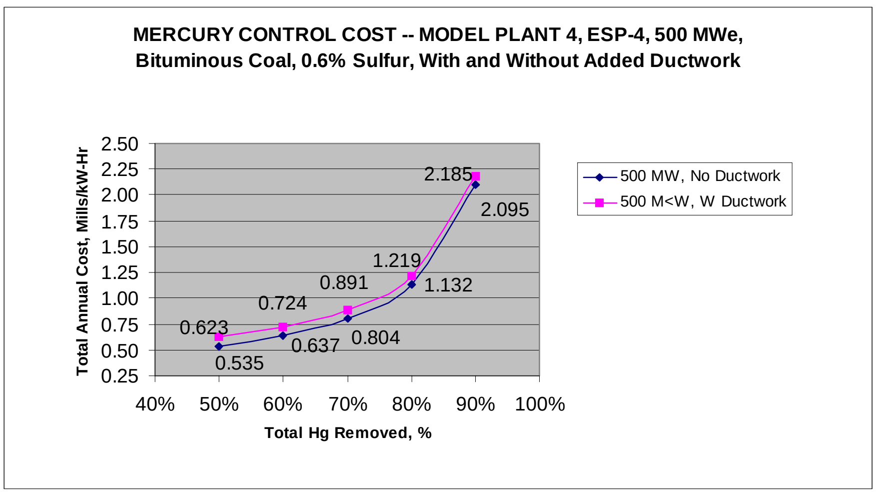
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	7.37	0.17	0.049	0.027	0.185	0.434
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	7.90	0.18	0.050	0.027	0.271	0.533
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	8.70	0.20	0.051	0.028	0.414	0.696
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	SCR	FG Cooling, ADP+18F	8.03	10.10	0.24	0.053	0.029	0.700	1.017
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	13.72	0.32	0.057	0.031	1.557	1.966
4	975	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	10.04	0.23	0.050	0.027	0.185	0.496
4	975	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	10.57	0.25	0.050	0.027	0.271	0.596
4	975	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	11.37	0.27	0.051	0.028	0.414	0.759
4	975	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	12.77	0.30	0.053	0.029	0.700	1.080
4	975	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	16.39	0.38	0.058	0.031	1.557	2.029
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	9.23	0.22	0.087	0.047	0.185	0.535
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	9.86	0.23	0.088	0.047	0.271	0.637
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	10.79	0.25	0.090	0.048	0.414	0.804
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	12.44	0.29	0.092	0.049	0.700	1.132
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	16.62	0.39	0.097	0.052	1.557	2.095
4	500	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	12.95	0.30	0.088	0.047	0.185	0.623
4	500	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	13.58	0.32	0.088	0.048	0.271	0.724
4	500	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	14.52	0.34	0.090	0.048	0.414	0.891
4	500	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	16.17	0.38	0.092	0.050	0.700	1.219
4	500	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	20.43	0.48	0.098	0.053	1.557	2.185
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.38	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.40	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.43	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	SCR	FG Cooling, ADP+18F	8.03	21.06	0.49	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.64	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	1.94	21.98	0.51	0.383	0.206	0.185	1.288
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	2.95	22.97	0.54	0.385	0.207	0.271	1.400
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	4.64	24.43	0.57	0.387	0.209	0.414	1.580
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	8.03	26.96	0.63	0.391	0.211	0.700	1.931
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System, Ductwork	N/A	FG Cooling, ADP+18F	18.17	33.19	0.78	0.400	0.216	1.557	2.948

ECONOMIC RESULTS S GRAPHICAL FORMAT

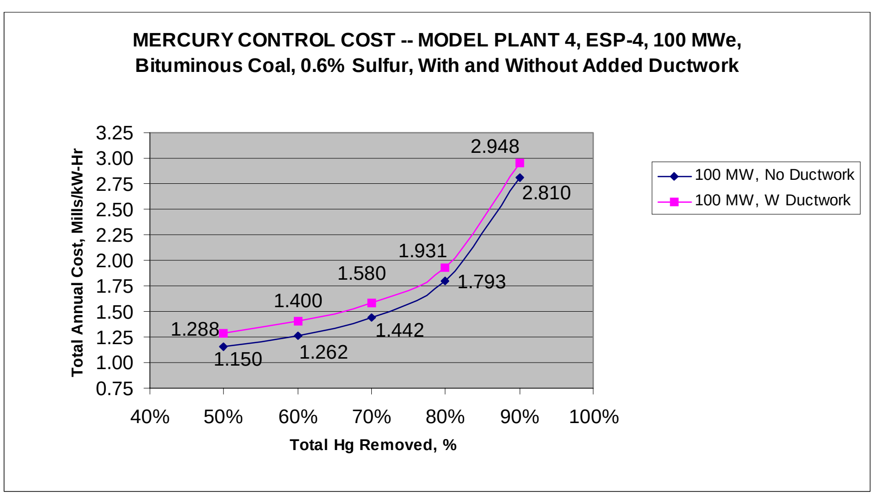
MODEL PLANT # 4, 975 MW



MODEL PLANT #4, 500 MW



MODEL PLANT #4, 100 MW



RESULTS FOR MODEL PLANTS 10 AND 13 (Recycle for ESP-6) **DATE: 6/6/00**

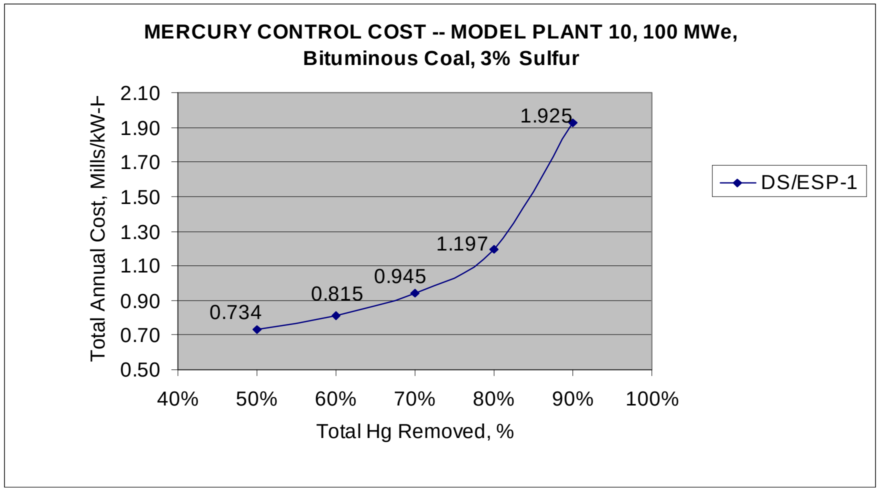
Comments:

See plot of results below table

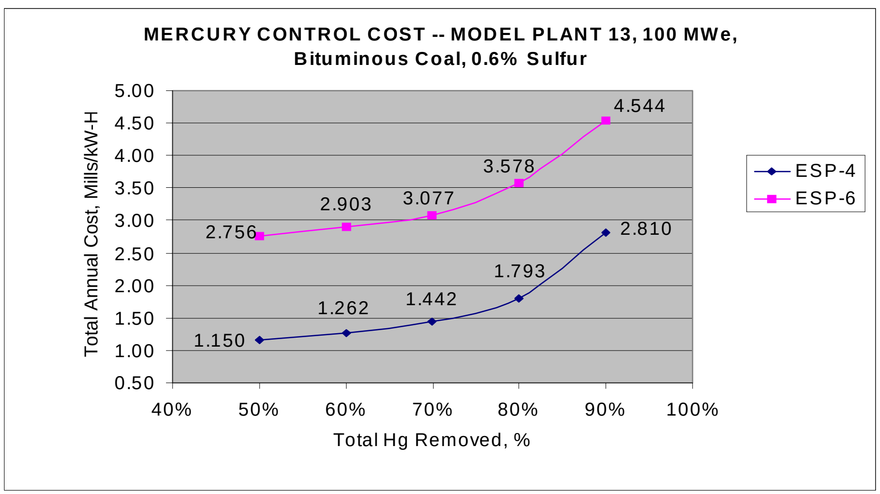
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.11	1.824	0.498	0.268	0.166	2.756
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	79.59	1.859	0.500	0.269	0.274	2.903
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.10	1.894	0.503	0.271	0.409	3.077
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	84.78	1.980	0.508	0.274	0.816	3.578
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	90.73	2.119	0.517	0.279	1.629	4.544

ECONOMIC RESULTS — GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 10 AND 13 **DATE: 5/22/00**

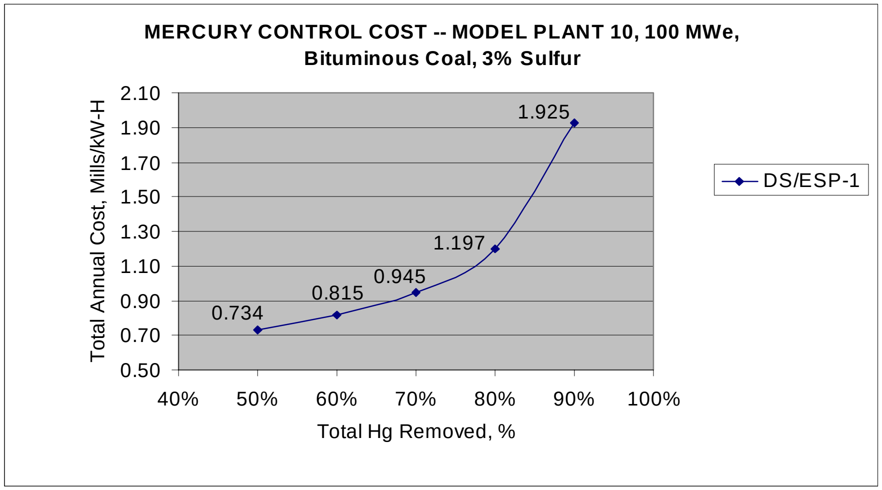
Comments:

See plot of results below table

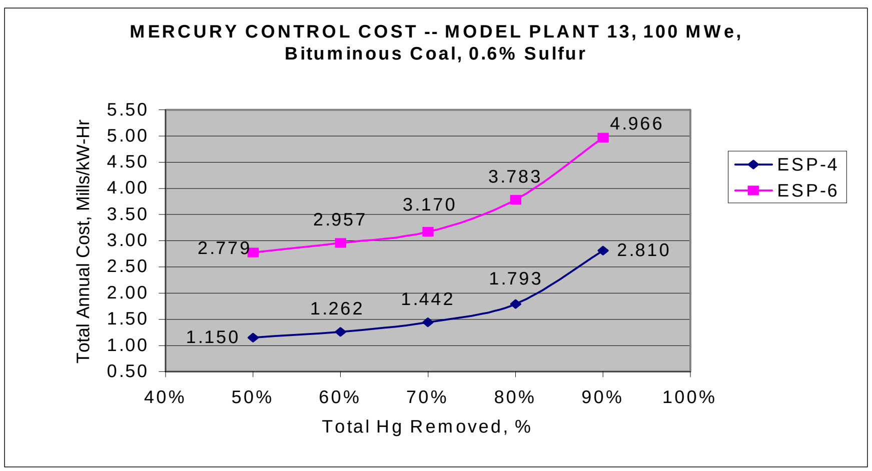
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.15	2.69	0.063	0.365	0.196	0.110	0.734
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	1.79	3.49	0.081	0.366	0.197	0.170	0.815
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	2.86	4.64	0.108	0.368	0.198	0.270	0.945
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	5.01	6.62	0.155	0.371	0.200	0.471	1.197
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	11.44	11.49	0.268	0.379	0.204	1.073	1.925
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.36	1.830	0.498	0.268	0.182	2.779
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	80.07	1.870	0.501	0.270	0.316	2.957
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.81	1.911	0.504	0.271	0.484	3.170
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	86.06	2.010	0.510	0.275	0.987	3.783
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	92.95	2.171	0.520	0.280	1.994	4.966

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 10



MODEL PLANT # 13



RESULTS FOR MODEL PLANTS 16 AND 17 **05/22/2000**

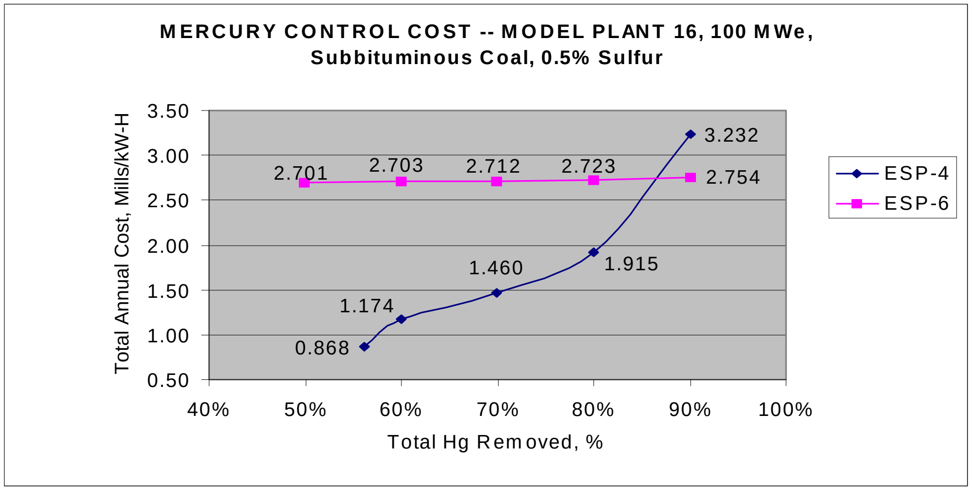
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 75.7% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

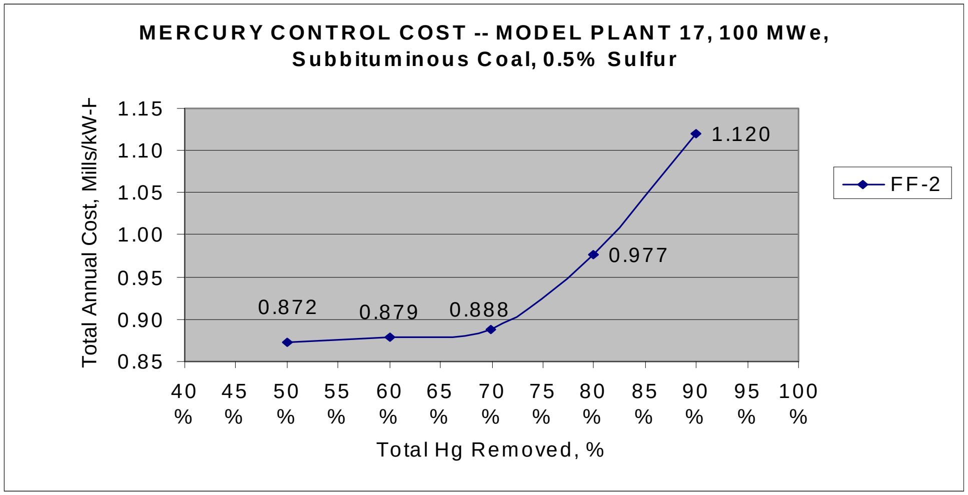
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	11.63	0.272	0.375	0.202	0.019	0.868
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	15.21	0.355	0.381	0.205	0.232	1.174
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	17.52	0.409	0.385	0.207	0.459	1.460
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	20.68	0.483	0.390	0.210	0.832	1.915
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	28.38	0.663	0.401	0.216	1.953	3.232
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	78.65	1.837	0.499	0.269	0.097	2.701
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	78.73	1.839	0.498	0.268	0.099	2.703
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	78.84	1.841	0.499	0.269	0.102	2.712
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	79.02	1.846	0.500	0.269	0.108	2.723
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	79.46	1.856	0.500	0.269	0.128	2.754
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	11.73	0.274	0.376	0.203	0.019	0.872
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	11.88	0.278	0.376	0.203	0.022	0.879
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	12.05	0.282	0.377	0.203	0.027	0.888
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	13.25	0.310	0.379	0.204	0.085	0.977
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	14.71	0.344	0.381	0.205	0.189	1.120

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



RESULTS FOR MODEL PLANTS 16 AND 17 (Recycle for ESP-6) **DATE: 6/6/00**

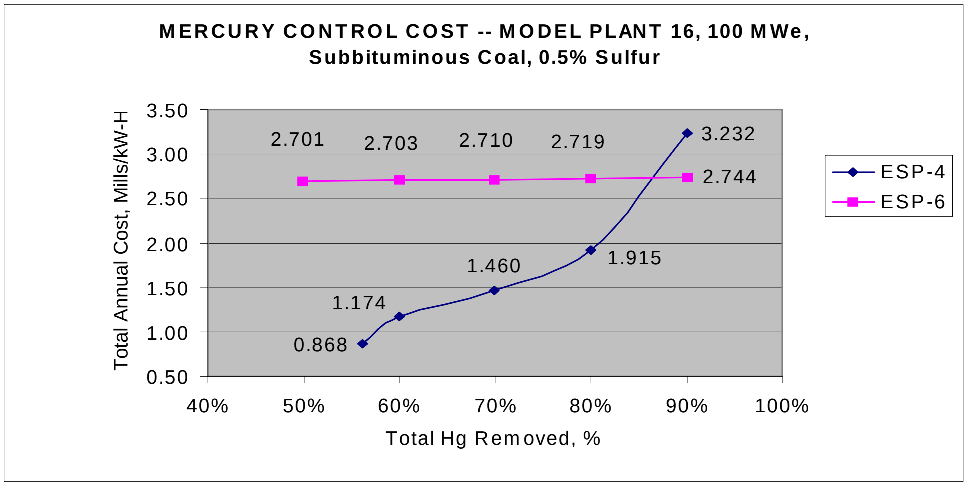
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 75.7% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

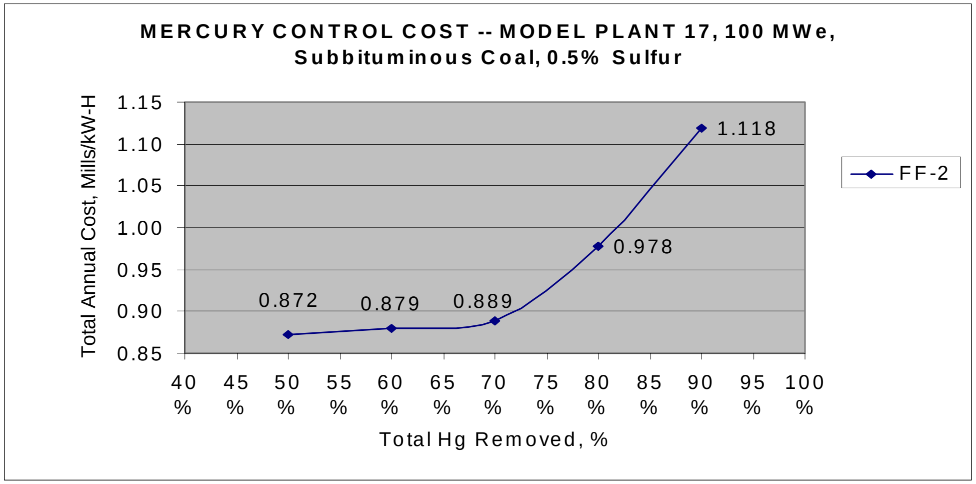
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	11.63	0.272	0.375	0.202	0.019	0.868
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.36	15.21	0.355	0.381	0.205	0.232	1.174
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.87	17.52	0.409	0.385	0.207	0.459	1.460
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	9.00	20.68	0.483	0.390	0.210	0.832	1.915
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	21.39	28.38	0.663	0.401	0.216	1.953	3.232
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.04	78.64	1.837	0.499	0.269	0.097	2.701
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.06	78.70	1.838	0.498	0.268	0.099	2.703
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.09	78.80	1.841	0.499	0.269	0.101	2.710
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.17	78.96	1.844	0.500	0.269	0.106	2.719
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+18F	0.38	79.30	1.852	0.500	0.269	0.122	2.744
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.01	11.73	0.274	0.376	0.203	0.019	0.872
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.04	11.88	0.278	0.376	0.203	0.022	0.879
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.09	12.07	0.282	0.377	0.203	0.027	0.889
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	0.73	13.28	0.310	0.379	0.204	0.085	0.978
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+18F	1.89	14.67	0.343	0.381	0.205	0.189	1.118

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



RESULTS FOR MODEL PLANTS 16 AND 17 (ADP+40) **05/22/2000**

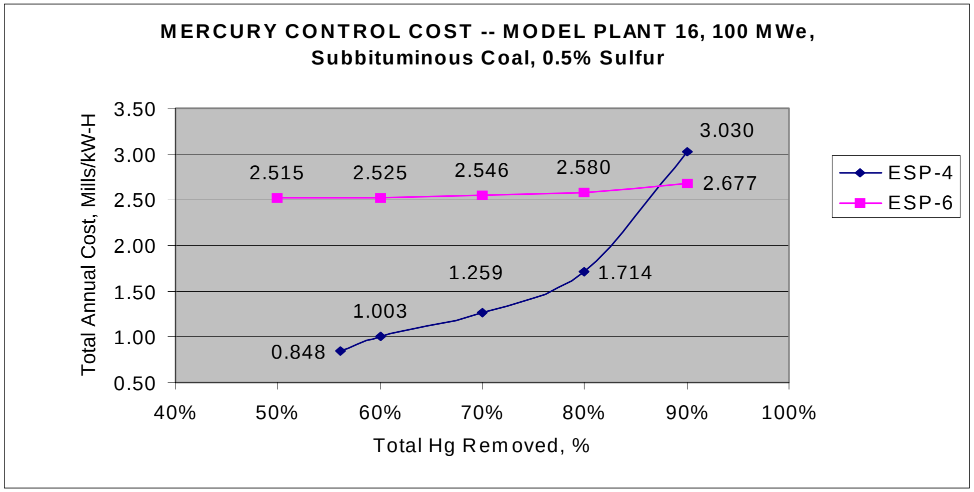
Comments:
1) Model Plant 16, ESP-4: Minimum Hg removal = 56.2% for ESP with Western Subbituminous Coals
2) Model Plant 17, FF-2: Minimum Hg removal = 50% for Reverse-Gas FF with Western Subbituminous Coals

See plot of results below table

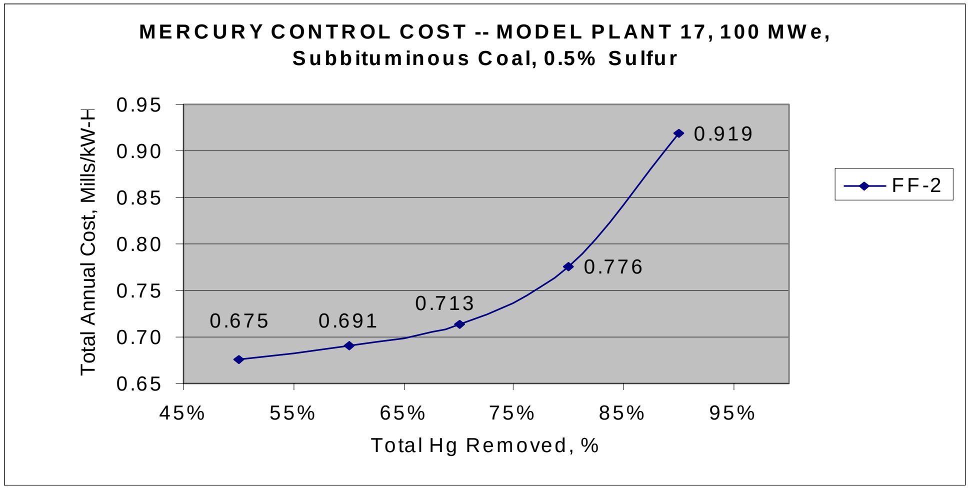
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
16	100	56.20%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	1.32	6.84	0.160	0.366	0.197	0.125	0.848
16	100	60.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	2.62	8.28	0.194	0.368	0.198	0.243	1.003
16	100	70.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	4.87	10.33	0.241	0.372	0.200	0.446	1.259
16	100	80.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	9.00	13.49	0.315	0.376	0.203	0.820	1.714
16	100	90.00%	Subbit	0.5	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.39	21.18	0.495	0.388	0.209	1.939	3.030
16	100	50.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.13	71.70	1.675	0.486	0.262	0.093	2.515
16	100	60.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.21	71.89	1.679	0.485	0.261	0.100	2.525
16	100	70.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.34	72.15	1.685	0.487	0.262	0.111	2.546
16	100	80.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	0.59	72.59	1.696	0.488	0.263	0.134	2.580
16	100	90.00%	Subbit	0.5	ESP	ESP-6	SI System, WI System, PJFF	N/A	FG Cooling, ADP+40F	1.36	73.65	1.720	0.489	0.264	0.204	2.677
17	100	50.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.03	4.63	0.108	0.363	0.195	0.009	0.675
17	100	60.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.11	4.92	0.115	0.364	0.196	0.016	0.691
17	100	70.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.26	5.26	0.123	0.364	0.196	0.030	0.713
17	100	80.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	0.73	6.06	0.142	0.366	0.197	0.072	0.776
17	100	90.00%	Subbit	0.5	FF	FF-2	SI System, WI System	N/A	FG Cooling, ADP+40F	1.89	7.52	0.176	0.368	0.198	0.177	0.919

ECONOMIC RESULTS § GRAPHICAL FORMAT

MODEL PLANT # 16



MODEL PLANT # 17



Sensitivity Results: Plant 4, ESP-6 & ESP-7, No ICR Mod, Combined Lime-Carbon Sorbent **DATE: 6/14/00**
500 MW

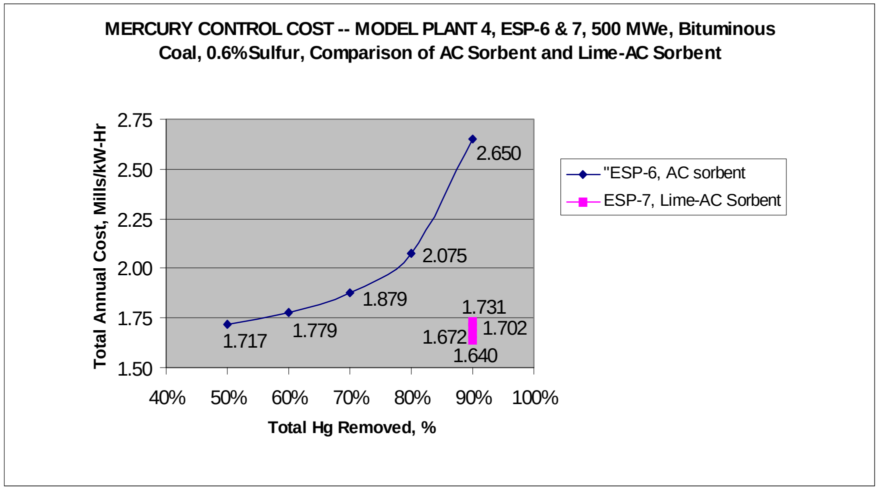
Comments:
Application: Plant 4, ESP-6, AC sorbent (50-90% Removal); Plant 4, ESP-7, AC-Lime Sorbent (90%+ removal)
Plant size: 500 MWe
AC sorbent Cost = $908/Ton
AC-Lime Sorbent Cost = $149/Ton, Assumes C:Lime ratio = 2:19
ESP-7 Sensitivity Cases Assume 90%+ Hg Removal based on ADA Technologies tests at PSE&G
ESP-7 Sensitivity Cases run for 1, 2, 3, 4 lb/Mmacf Sorbent Concentration
ESP-6 Comparison Cases Run for 50, 60, 70, 80, 90% Hg Removal

See plot of results below table

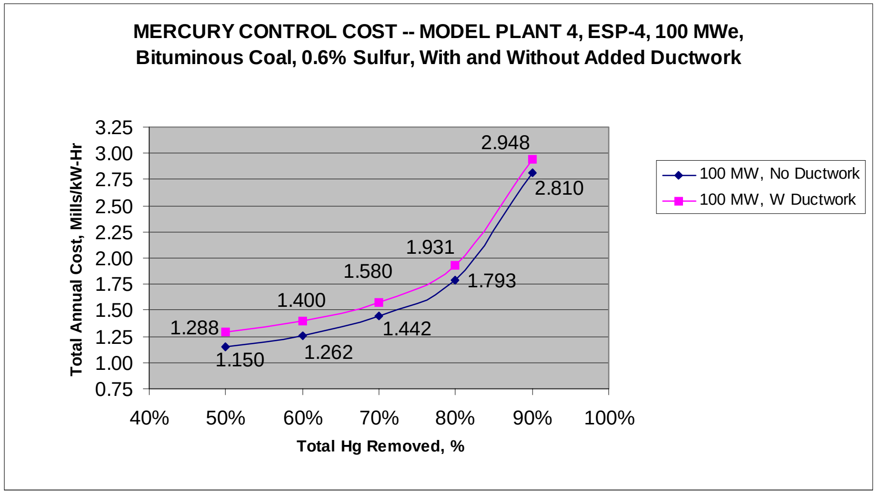
Model Plant #	Plant Size, MWe	Total Mercury Removed, %	Coal Type	Coal Sulfur Content, % by Wt	Existing Pollutant Controls	Hg Control Configuration	Added Equipment for Hg Control	Co-Benefit Cases with	Comments	MERCURY SORBENT INJECTION RATIO lb/MMacf	Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
4	500	50.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	54.48	1.27	0.171	0.092	0.182	1.717
4	500	60.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	1.66	54.91	1.28	0.171	0.092	0.232	1.779
4	500	70.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	55.55	1.30	0.172	0.093	0.316	1.879
4	500	80.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	56.67	1.32	0.174	0.094	0.484	2.075
4	500	90.00%	Bit	0.6	ESP	ESP-6	SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	59.46	1.39	0.178	0.096	0.988	2.650
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.00	54.33	1.27	0.171	0.092	0.108	1.640
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.00	54.94	1.28	0.172	0.092	0.125	1.672
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.00	55.46	1.30	0.173	0.093	0.141	1.702
4	500	90.00%	Bit	0.6	ESP	ESP-7	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.00	55.93	1.31	0.173	0.093	0.158	1.731

ECONOMIC RESULTS $ GRAPHICAL FORMAT

MODEL PLANT # 4, 500 MW, Comparison of ESP-6 and ESP-7



MODEL PLANT # 4, 100 MW



Performance and Cost of Mercury emission Control Technology Applications on Electric utility Boilers

The attached sheets were taken out from the NETL Letter dated August 11,200 transmitting test data relating to the subject and were replaced with revised sheets.

Skb/9-12-00

RESULTS FOR MODEL PLANTS 10 AND 13 DATE: 5/22/00

Comments:
1) Model Plant 10, DS/ESP-1: Minimum Hg removal = 57.2% for DS/ESP Combination with Eastern Bituminous Coals
2) Model Plant 10: Capital Cost Only includes Sorbent Injection Equipment (accounts for storage/transfer of sorbent)
3) Model Plant 13, ESP-4: Minimum Hg removal = 58.8% for ESP with Eastern Bituminous Coals
4) Model Plant 13, ESP-6: Minimum Hg removal = 61.3% for ESP with Eastern Bituminous Coals

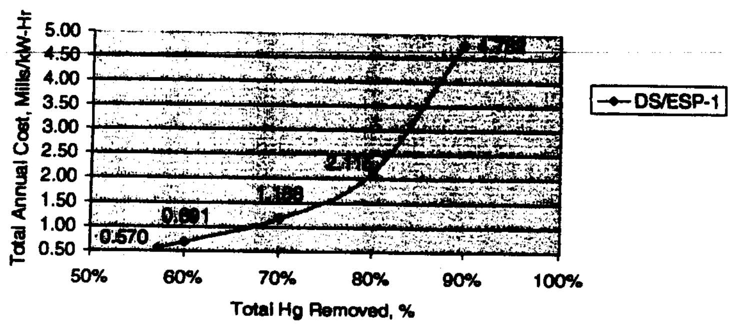
See plot of results below table

[redacted]											Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	57.20%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.00	0.50	0.012	0.361	0.194	0.003	0.570
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	0.81	2.23	0.052	0.364	0.196	0.079	0.691
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	4.93	6.56	0.153	0.371	0.200	0.464	1.188
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	13.18	12.63	0.295	0.380	0.205	1.235	2.115
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	37.91	26.55	0.620	0.400	0.215	3.547	4.782
13	100	58.80%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	13.11	0.306	0.378	0.203	0.022	0.909
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.06	13.39	0.313	0.378	0.204	0.027	0.922
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	0.79	14.72	0.344	0.381	0.205	0.088	1.018
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.24	16.40	0.383	0.383	0.206	0.211	1.184
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	6.61	20.05	0.468	0.389	0.210	0.580	1.647
13	100	61.30%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.00	76.37	1.784	0.495	0.266	0.092	2.637
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	0.38	77.36	1.807	0.497	0.267	0.124	2.695
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.23	78.56	1.835	0.499	0.268	0.196	2.798
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	3.78	81.10	1.894	0.503	0.271	0.412	3.080
13	100	95.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	8.89	84.94	1.984	0.509	0.274	0.844	3.611

ECONOMIC RESULTS – GRAPHICAL FORMAT

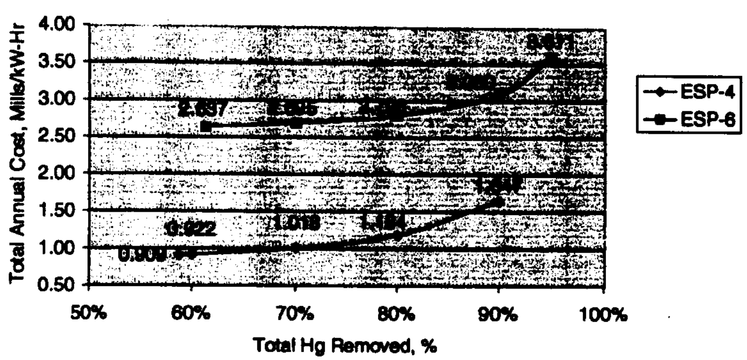
MODEL PLANT #10

MERCURY CONTROL COST – MODEL PLANT 10, 100 MWe, Bituminous Coal, 3% Sulfur



MODEL PLANT #13

MERCURY CONTROL COST – MODEL PLANT 13, 100 MWe, Bituminous Coal, 0.6% Sulfur



RESULTS FOR MODEL PLANTS 10 AND 13 (ADP+40)　　　　DATE: 6/6/00

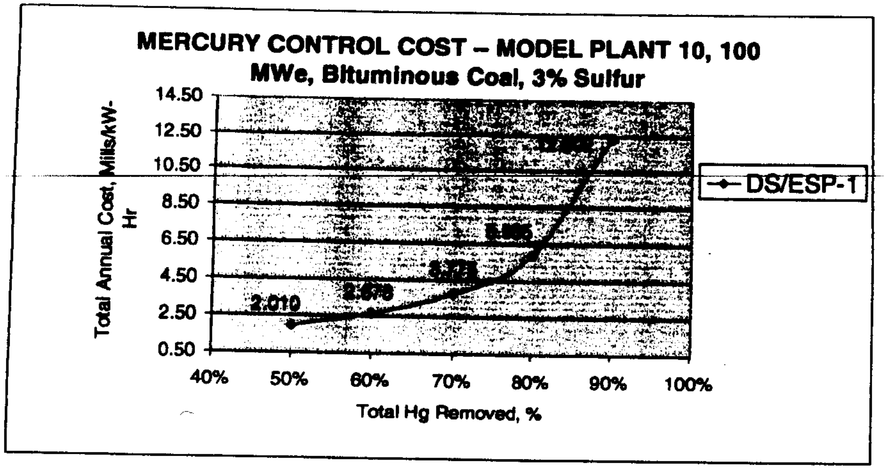
Comments:

~~See plot of results below table~~

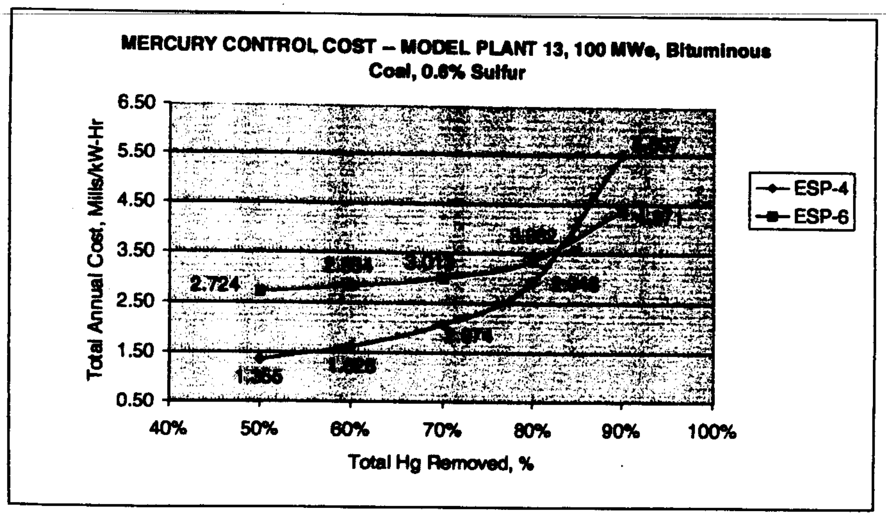
											Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	12.23	12.01	0.280	0.379	0.204	1.146	2.010
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	18.32	15.87	0.371	0.385	0.207	1.716	2.678
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	28.48	21.64	0.505	0.393	0.212	2.665	3.775
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	48.79	31.86	0.744	0.407	0.219	4.565	5.935
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	109.72	58.02	1.355	0.440	0.237	10.269	12.302
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	5.31	13.49	0.315	0.377	0.203	0.459	1.355
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	7.96	15.43	0.360	0.380	0.205	0.683	1.628
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	12.37	18.31	0.428	0.385	0.207	1.055	2.074
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	21.19	23.36	0.546	0.392	0.211	1.800	2.948
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+40F	47.64	36.04	0.842	0.410	0.221	4.035	5.507
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	1.98	73.77	1.723	0.490	0.264	0.248	2.724
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	2.98	74.76	1.746	0.491	0.264	0.333	2.834
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	4.65	76.20	1.780	0.493	0.266	0.474	3.013
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	8.00	78.71	1.839	0.497	0.268	0.758	3.362
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+40F	18.05	84.91	1.983	0.506	0.273	1.609	4.371

ECONOMIC RESULTS -- GRAPHICAL FORMAT

MODEL PLANT #10



MODEL PLANT #13



RESULTS FOR MODEL PLANTS 10 AND 13 (Recycle for ESP-6) DATE: 6/6/00

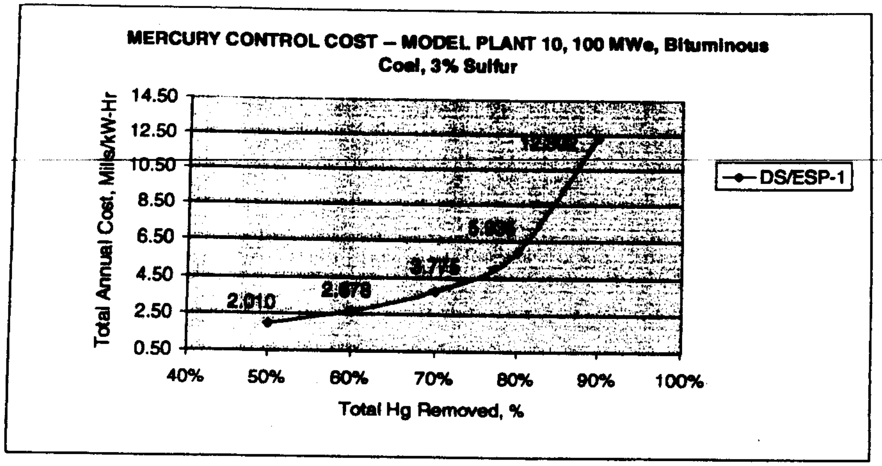
Comments:

See plot of results below table

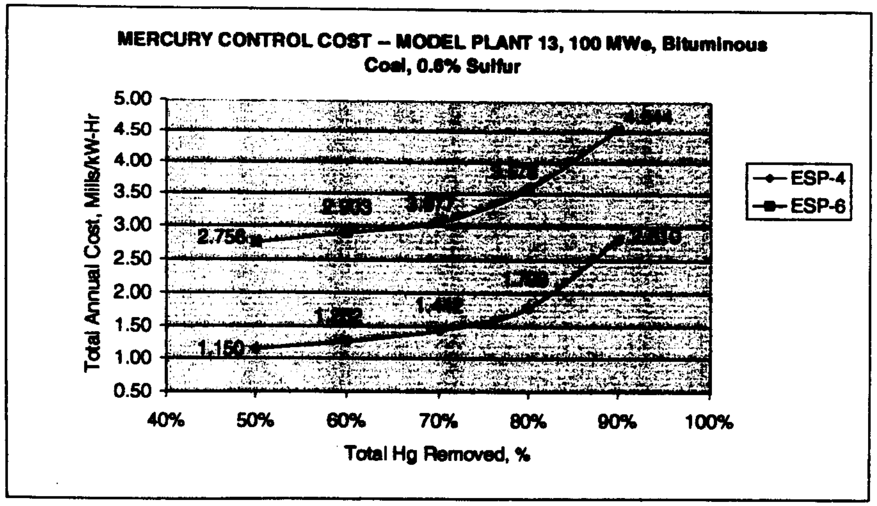
[redacted]											Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	12.23	12.01	0.280	0.379	0.204	1.146	2.010
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	16.32	15.87	0.371	0.385	0.207	1.716	2.678
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	28.48	21.64	0.505	0.393	0.212	2.665	3.775
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	48.79	31.86	0.744	0.407	0.219	4.565	5.935
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	109.72	58.02	1.355	0.440	0.237	10.269	12.302
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.08	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.11	1.824	0.498	0.268	0.166	2.756
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	79.59	1.859	0.500	0.269	0.274	2.903
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.10	1.894	0.503	0.271	0.409	3.077
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	84.78	1.980	0.508	0.274	0.816	3.578
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	90.73	2.119	0.517	0.279	1.629	4.544

ECONOMIC RESULTS – GRAPHICAL FORMAT

MODEL PLANT #10



MODEL PLANT #13



RESULTS FOR MODEL PLANTS 10 AND 13 DATE: 5/22/00

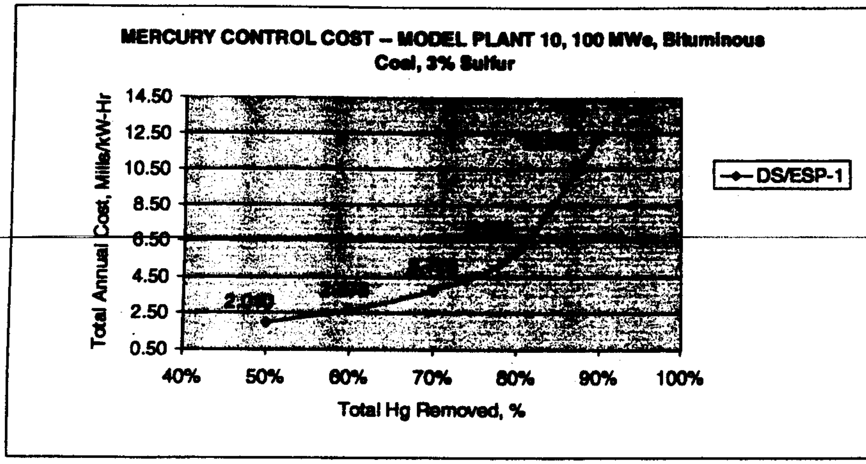
Comments:

See plot of results below table

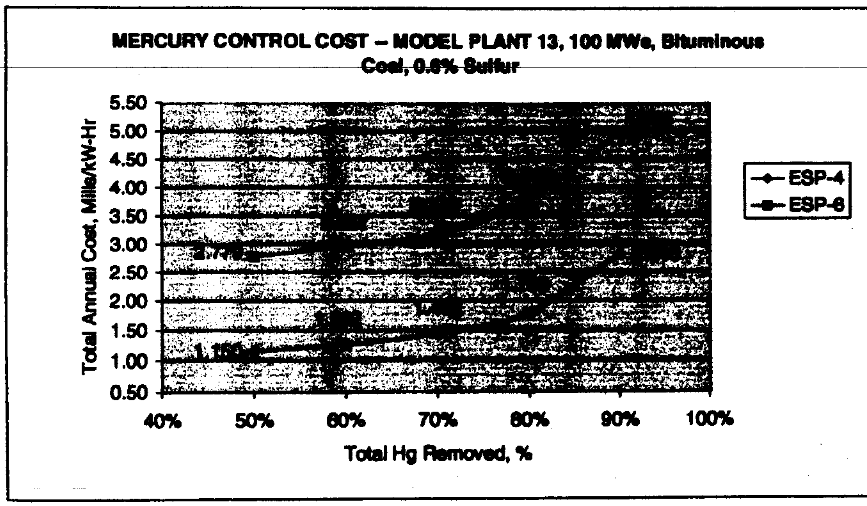
[redacted]											Capital Cost, $/kW	Levelized Carrying Charges, Mills/kW-Hr	Fixed O&M Cost, Mills/kW-Hr	Variable O&M Cost, Mills/kW-Hr	Consumables, Mills/kW-Hr	Total Annual Cost, Mills/kW-Hr
10	100	50.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	12.23	12.01	0.260	0.379	0.204	1.146	2.010
10	100	60.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	18.32	15.87	0.371	0.385	0.207	1.716	2.678
10	100	70.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	28.48	21.64	0.505	0.393	0.212	2.665	3.775
10	100	80.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	48.79	31.86	0.744	0.407	0.219	4.565	5.935
10	100	90.00%	Bit	3	DS, ESP	DS/ESP-1	SI System	N/A	Costs for SI Equipment Only	109.72	58.02	1.355	0.440	0.237	10.269	12.302
13	100	50.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	1.94	16.06	0.376	0.383	0.206	0.185	1.150
13	100	60.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	2.95	17.08	0.399	0.385	0.207	0.271	1.262
13	100	70.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	4.64	18.54	0.433	0.387	0.208	0.414	1.442
13	100	80.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	8.03	21.06	0.492	0.391	0.210	0.700	1.793
13	100	90.00%	Bit	0.6	ESP	ESP-4	SI System, WI System	N/A	FG Cooling, ADP+18F	18.17	27.30	0.638	0.400	0.215	1.557	2.810
13	100	50.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	1.07	78.36	1.830	0.498	0.268	0.182	2.779
13	100	60.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	2.65	80.07	1.870	0.501	0.270	0.316	2.957
13	100	70.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	4.63	81.81	1.911	0.504	0.271	0.484	3.170
13	100	80.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	10.58	86.06	2.010	0.510	0.275	0.987	3.783
13	100	90.00%	Bit	0.6	ESP	ESP-6	PJFF, SI System, WI System	N/A	FG Cooling, ADP+18F	22.47	92.95	2.171	0.520	0.280	1.994	4.966

ECONOMIC RESULTS -- GRAPHICAL FORMAT

MODEL PLANT #10



MODEL PLANT #13



TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/R-01-109	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report		5. REPORT DATE December 2001
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) J.Kilgroe, C.Sedman, R.Srivastava, J.Ryan, C.Lee, and S.Thorneloe		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS See Block 12		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. NA (Inhouse)
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		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES APPCD project officer is James D. Kilgroe, Mail Drop 65, 919/541-2854.

16. ABSTRACT
The report provides additional information on mercury (Hg) emissions control following the release of "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units--Final Report to Congress" in February 1998. Chapters 1-3 describe EPA's December 2000 decision to regulate Hg under the National Emission Standards for Hazardous Air Pollutants (NESHAP) provisions of the Clean Air Act, coal use in electric power generation, and Hg behavior in coal combustion. Chapters 4-9 report new information on current electric utility fuels, boilers, and emission control technologies; Hg emissions associated with these diverse technology combinations; results and implications of tests to evaluate the performance of Hg control technologies and strategies; retrofit control cost modeling; and Hg behavior in solid residues from coal combustion. Chapter 10 summarizes current research and identifies future efforts needed to ensure the cost-effective control of Hg emissions. A list of references is provided at the conclusion of each chapter.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Mercury (Metal)	Stationary Sources	07B
Emission		14G
Coal		21D
Combustion		21B
Electric Power Plants		10B
Utilities		

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