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Updated Hazardous Air Pollutants (HAPs) Emissions Estimates and Inhalation Human Health Risk Assessment for U.S. Coal-Fired Electric Generating Units

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1017980

Final Report, December 2009

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This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Updated Hazardous Air Pollutants (HAPs) Emissions Estimates and Inhalation Human Health Risk Assessment for U.S. Coal-Fired Electric Generating Units. EPRI, Palo Alto, CA: 2009. 1017980.

PRODUCT DESCRIPTION

Since the mid-1990s, there has been no comprehensive evaluation of hazardous air pollutants (HAPs) emissions from U.S. coal-fired electric power plants and the risks associated with those emissions. With the exception of mercury, none of the HAPs-classified chemicals has been fundamentally reassessed for more than 15 years. The set of EPRI studies reported on here provides a fundamental reevaluation of potential HAPs emissions from coal-fired power plants based on current data concerning coals burned, controls installed, and new measurements taken in the intervening period. In addition, the human health risks due to inhalation of trace amounts of HAPs emitted from coal-fired power plants are assessed for each individual power plant facility as well as for facilities having stacks located within 50 km of one another. These risk assessments were carried out using current EPA-supported air quality models and archived databases on the location of residents in the vicinity of each power plant stack. This report presents an updated assessment of HAPs emissions and the consequent human health risks by inhalation for all U.S. coal-fired electric generation units.

Results and Findings

HAPs emissions were assessed for a current characterization of the U.S. coal-fired utility industry. In general, the statistical correlations among coal HAPs concentrations and control efficiency for a variety of substances differed little from earlier compilations. Additional information on chemical species emitted permitted a separation of emission rates for chlorine from those for hydrogen chloride, and allowed incorporation of evidence of several organic compounds emitted that were not shown to be present in earlier studies. When U.S. coal-fired power plant HAPs total emissions were tallied by substance, total amounts generally had declined since EPRI's 1994 assessment, *Electric Utility Trace Substances Synthesis Report: Volumes 1-4* (TR-104614). Inhalation risks were found for each plant to be below the health thresholds of interest: for carcinogenicity, all were below 1 in one million; for both chronic (long-term exposure) and acute (shorter exposure) non-cancer health risks, all were below a hazard index of 1. These data demonstrated that the inhalation health risks for each chemical individually, and all emitted chemicals combined, were below any health reference levels.

Challenges and Objective(s)

Regulatory standards require a knowledge of baseline conditions for coal-fired utilities to allow prudent planning of control steps. The objective of this project is to address the essential lack of recent measurement data for all HAPs except mercury, a condition that necessitates a comprehensive evaluation of changes to the statistical relations underlying the emission factors. These emission factors—and the derived emission rates for each U.S. coal-fired power plant—will serve as guideposts for both researchers and regulatory bodies evaluating the distribution of emission rates within the industry. It is important to note that the inhalation risk assessment serves as a comparison baseline for public health risks potentially posed by these facilities. In turn, the risk results can provide a numerical interpretation of the health risks posed by this type of facility in general.

Applications, Values, and Use

The database of emission rates by U.S. power plant provides a baseline for future planning and management, allowing comparisons among plants on the basis of fuel supply, control configuration, and operations. Future changes in coal-fired power plants can be compared to present-day facilities to estimate potential changes in emissions and the resulting risks. The risk outcomes themselves, all below levels of concern, serve as useful utility planning guidance.

EPRI Perspective

This project is designed to serve both as support for proposed regulatory reviews by public agencies and as guidance for additional EPRI research. The approach used in this study was guided and constrained by methods required by regulatory review, but led to additional studies that expanded well beyond those limited requirements. Additionally, the results of the emissions recalculations demonstrated the importance of performing more comprehensive field measurements of HAPs emissions at a variety of present-day facilities, including some measured in earlier research.

Approach

The project team conducted a comprehensive literature search to update the coal-fired power plant HAPs emissions inventory. The team then added these new datasets to the existing EPRI compilation to allow recalculations of statistical associations used to derive emission rates. They next applied these statistical relations to each individual unit at every U.S. coal-fired power plant in order to derive a unit, stack, and facility emission rate for each HAP potentially present. These emission rates, along with physical stack parameters and plant location, were used as input to an air quality model that simulated downwind concentrations at locations within 50 km of each stack. Finally, the team used that correspondence of concentration and location to define the point of highest inhalation risk for long-term exposure for carcinogen and non-carcinogen air toxics, and for short-term exposure for non-carcinogens.

Keywords

Air Pollution Controls
Hazardous Air Pollutants (HAPs)
Emission Estimates
Human Health Risk Assessment
Coal-Fired Power Plants
Mercury

EXECUTIVE SUMMARY

There has been no comprehensive evaluation of the emissions of and risks due to hazardous air pollutants (HAPs) from coal-fired electric utilities since the mid-1990s, and those studies relied on data from 1990 and earlier. With the exception of mercury, none of the HAPs-classified chemicals has been fundamentally re-assessed for more than 15 years. Two recent EPRI studies, reported on here, re-evaluated HAPs emissions from coal-fired utility plants based on updated data, and assessed the potential human health risks by inhalation.

To estimate emissions for all individual coal-fired power plants, a number of data sources were required. The general approach included the following steps:

- Assemble coal composition data for HAPs categorized by coal source;
- Obtain fuel consumption and coal blending data by power plant;
- Characterize power plant configuration and operations representative of the 2007 base year;
- Update existing emission correlations and factors developed earlier for the EPRI Emission Factors Handbook;
- Use these updated correlations and factors for specific HAPs to estimate emissions by stack and by facility.

In particular, approximately 150 newer mercury emissions test datasets were available for coal-fired units. Data on flue gas mercury and associated information regarding coal and ash properties were compiled and incorporated into the previous mercury emission correlations, which were based primarily on the 1999-2000 EPA ICR emissions data. New correlations were also developed for plant configurations not addressed earlier.

Annual emission estimates for each power plant unit were developed using the 2007 base-year plant configuration database, "blended" coal composition data, and the updated emission correlations. Data was compiled for units discharging to common stacks. Emission estimates (mass per unit time) were compiled based on the 2007 fuel firing rate for each unit and each stack, by HAP species.

Emission estimates were prepared for all units > 25 MW selling power to the grid. These emission estimates were subsequently used as inputs to the EPA AERMOD plume dispersion model. The resulting concentration patterns in ambient air were matched with U.S. Census block location data; the inhabited location with the maximum concentration for each HAP was used to calculate inhalation risks.

Inhalation risks were found, for each power plant, to be below the health thresholds of interest. For carcinogenic health effects by inhalation, all risks were below 1 in one million. For both chronic (long-term exposure) and acute (shorter exposure) non-cancer health risks by inhalation, all risks were below a hazard index of 1. That in turn demonstrated that the inhalation health risks for each chemical individually, and all emitted chemicals combined, were below any health reference concentrations.

The overall effort provides a fine-scale portrayal of the "current" operations and control configuration of all coal-fired power plants generating more than 25 MW of electricity, and of their emissions of all detected air toxics at each such plant. In addition, the studies use state-of-the-art air dispersion modeling and standard environmental databases to calculate community risks by inhalation due to each plant's HAPs emissions. These risks are shown to be, in all cases, below levels of concern.

ACKNOWLEDGMENTS

URS gratefully acknowledges the assistance of Jim Marchetti (James Marchetti, Inc.) for supplying the unit characteristics database information, the assistance of Ralph Roberson (RMB Consulting & Research, Inc.) in compilation of the stack parameter information used in this project, and the assistance of AECOM in providing updated stack location coordinates for selected plants.

GLOSSARY

ACI	Activated carbon injection
Btu	British thermal unit
°C	Degrees Celsius
CAA	Clean Air Act
CAMR	Clean Air Mercury Rule
CEM	Continuous emissions monitoring
CFD	Cumulative frequency distribution
CFR	Code of Federal Regulations
DOE	Department of Energy
EEMS	Emission-Economic Modeling System
EFH	Emission factors handbook
EGU	Electric generation unit
EIA	Energy Information Agency
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESPc	Cold-side electrostatic precipitator
ESPh	Hot-side electrostatic precipitator
°F	Degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FBC	Fluidized bed combustor
FCEM	Field chemical emissions monitoring

FF	Fabric filter
FGDd	Dry flue gas desulfurization
FGDw	Wet flue gas desulfurization
HAP	Hazardous air pollutant
Hg	Mercury
HgE	Elemental mercury
HgOx	Oxidized mercury
HgP	Particulate mercury
ICR	Information Collection Request
IGCC	Integrated gasification combined cycle
kg	kilogram
lb	pound
ln	Natural logarithm
MACT	Maximum Achievable Control Technology
MBtu	Million (106) British thermal units
MWe	Megawatt of electricity
SCA	Specific collection area
SCR	Selective catalytic reduction
SD	Spray dryer
SNCR	Selective non-catalytic reduction
TBtu	Trillion (1012) British thermal units
USGS	United States Geological Survey
VS	Venturi scrubber

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BACKGROUND AND INTRODUCTION

This report presents an updated assessment of hazardous air pollutant (HAP) emissions and the consequent human health risks by inhalation for all United States coal-fired electric generation units (EGUs). In the mid-1990s, EPRI compiled and evaluated HAP emissions data as part of the 1994 Synthesis Report (1). Subsequently, EPRI conducted data analyses and developed emission factor correlations for HAPs which were incorporated into the EPA AP-42 database. In addition, EPRI performed an analysis of the 1999 Information Collection Request (ICR) dataset for mercury and chlorine to examine mercury emissions in more detail and developed a set of updated mercury emission factors for various power plant configurations (2). Since that time, additional full-scale emissions information has been generated through various test programs sponsored by organizations such as EPRI, DOE, and in some cases, individual utilities. In particular, there have been full-scale mercury control technology evaluation tests conducted at approximately 150 coal-fired units in which “baseline” (time periods during which no mercury controls such as activated carbon injection or chemical injection, were engaged) mercury emission data were collected. Some of these test programs also included measurements of other HAPs (metals, acid gases, etc.) as part of the work scope. These types of information, collected over the past 10-15 years, provide a significant amount of new data to supplement the information analyzed previously by EPRI. In 2008, EPRI initiated a project to identify and compile these new sources of data and subsequently use these data to supplement and update work previously conducted by EPRI.

One objective of this EPRI program was to prepare revised emission estimates for the current fleet of coal-fired electric generating units for 2007 (the base year selected for this study). These revised emission estimates were then used in a companion EPRI project to conduct stack air dispersion modeling and develop health risk estimates for the current fleet of coal-fired EGUs. To accomplish this objective, additional sources of recent emissions test data were identified from various literature and in-house utility sources, compiled, and analyzed to develop revised methodologies for estimating emissions of mercury and non-mercury HAPs (e.g., trace elements, acid gases, such as HCl, HF, Cl_2, HCN, and select organic compounds). This report provides details regarding the methodology used to develop these revised emission estimates; a summary of the revised emission estimates for coal-fired units; and the methodology and results from the inhalation portion of the health risk assessment. As a result of this herculean effort, many of the emission factors and equations previously published have changed, most with only minor modifications. For mercury, a review of measurement data from units equipped with SCR and SNCR NO_x controls has resulted in the development of emission factors for many new control configurations.

Project Methodology Overview

To estimate emissions for all individual coal-fired power plants, a number of data sources were required. The general approach included the following steps:

- Develop HAPs and mercury concentration datasets for coals combusted by EGUs that are categorized by coal source at the county/state/coal region level.
- Obtain publically available fuel data to develop consumption rates for each coal type specific for each EGU, including EGUs that burn blends of coal.
- Obtain appropriate power plant characteristics representative of the 2007 base year operations (e.g., control technologies in place, physical configurations, stack particulate emission rate, stack parameters necessary for dispersion modeling, etc.).
- Update existing emission correlations and emission factors from previous EPRI work using new sources of data for mercury and non-mercury-HAPs.
- Use these updated correlations and factors for specific HAPs along with fuel consumption data to estimate emissions.

Each step is described in more detail in the following sections.

Coal Composition Dataset

In EPRI's 1994 Synthesis Report, the USGS Coal Quality database (3) was screened to provide HAPs concentrations for 22 major coal regions by state. Since that time, USGS has not updated the dataset. Consequently, the effort from 1994 still represents the best estimate of non-mercury HAPs in as-fired coal and was used to develop the current emission estimates. The EPRI version of the screened USGS database was used to develop the geometric mean values of each dataset, expressed in lb/trillion Btu (lb/TBtu).

For coal mercury, the 1999 EPA ICR dataset was used, as it contains 40,000 as-fired measurements. It is organized by state/county and can be grouped into coal regions as well. The one exception was the ICR data for Gulf Coast lignite, which has been shown to have significant low bias due to the analytical methods used for mercury analysis of these coal samples. An alternative set of more recent coal mercury data for this coal type was identified and used in this analysis.

Given the large number of data points available in the 1999 ICR dataset, county average mercury values by coal rank were used for this effort as opposed to the geometric mean values by state/region that were used for non-mercury HAPs. This methodology results a national total mercury emission estimate that was developed in a way comparable to that used previously as part of the EPRI's 2000 mercury emissions assessment which was based on the 1999 EPA ICR mercury coal and emissions datasets.

Fuel Consumption Data

A comprehensive list of coal-fired power plant stations and units to be included in the emission estimate process were compiled using information from utility plant databases for coal-fired units developed by James Marchetti, Inc. The primary source for these databases is the *Emission-Economic Modeling System* (*EEMS*) Database. The primary information sources used to create and maintain the database are Energy Information Administration (EIA) Forms 423, 767, 860, 906/920, Federal Energy Regulatory Commission (FERC) Form 423, published reports; and discussions with individual electric generator operators.

FERC and EIA Form 423 records from 2007 were used to provide coal delivery data by station with fuel source information at the state and county level. By mapping coal regions to state and counties, fuel delivery records from EIA and FERC forms were used to calculate "blended" coal compositions for individual stations based on the percentage of coal fired for the 2007 base year. The 22 USGS datasets account for over 90% of the coal consumed in the U.S. For the other sources, estimates were derived using appropriate combinations of the 22 USGS datasets.

Power Plant Characteristics

The characteristics of each power plant unit (e.g., air pollution control devices in place, reported or particulate emissions) necessary to estimate HAP emissions were defined using information from the plant databases supplied by James Marchetti, Inc. as referenced above. These 2007 base-year unit characteristic databases for coal and oil units provided current plant configuration information and other key input parameter values necessary to apply the updated emission correlations so as to permit estimates of HAPs emissions for each unit. The plant databases also provided information regarding fuel usage (i.e., trillion Btu fired at the unit and station level) necessary to estimate annual emissions.

Update Emission Correlations

Emission correlations and emission factors for both mercury and non-mercury HAPs have been developed previously for coal-fired units as part of the EPRI Emission Factors Handbook (4). New sources of emissions data were identified as part of this current study and were combined with the previous datasets to develop a set of updated emission correlations.

Mercury - New sources of mercury emissions test data were identified and inventoried by plant configuration type for coal-fired units. Data from approximately 150 test programs were identified from literature and EPRI sources in which baseline flue gas mercury measurements were collected, including stack emission measurements. Baseline flue gas mercury data and associated key information regarding coal and ash properties were extracted from each report and entered into a master spreadsheet for subsequent data analysis and incorporation into the previous mercury emission correlations developed using the ICR mercury emissions dataset. The characteristics of each power plant unit (e.g., air pollution control devices in place, reported or particulate emissions) necessary to estimate HAP emissions were defined using information from the plant databases supplied by James Marchetti, Inc. as referenced above. These 2007 base-year unit characteristic databases for coal and oil units provided current plant configuration information and other key input parameter values necessary to apply the updated emission correlations so as to permit estimates of HAPs emissions for each unit. The plant databases also provided information regarding fuel usage (i.e., trillion Btu fired at the unit and station level) necessary to estimate annual emissions.

Non-Mercury HAPs - New sources of non-mercury HAPs emissions test data were identified and inventoried by plant configuration type. Flue gas data and associated key information regarding fuel properties were extracted from each report and incorporated into emission factor correlations developed previously for trace element HAPs as part of the EPRI Emissions Factors Handbook.

Four sources of new emissions data for organic compounds from coal-fired units were identified as part of the data screening effort, so emission factors for organic compound HAPs for coal-fired units were also updated using these new sources of data.

Estimate Emissions

Annual emission estimates for each power plant unit were developed using the 2007 base-year plant configuration database parameters (control device configuration, total heat input, stack particulate emission rate), “blended” coal composition data, and the updated emission correlations. In cases where flue gas from multiple units is discharged to a common stack, the final set of emission values were estimated for the combined stack emission point. Emission estimates were prepared on a mass/year basis based on the 2007 fuel firing rate for each unit (e.g., trillion Btu fired in 2007). These emission estimates for each stack location were subsequently used as inputs to perform health risk estimates for each power plant.

Emission estimates were developed for mercury, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, selenium, hydrogen chloride, chlorine (Cl_2), hydrogen fluoride, hydrogen cyanide, and selected organic compounds or groups of organic compounds (e.g. polycyclic aromatic compounds). In addition to total mercury, emission estimates for the elemental, oxidized and particulate forms of mercury were also developed.

Development of the Final Emission Estimates and Inhalation Risk Results

Initial emission estimates were prepared for all units > 25 MW selling power to the grid based on plant operational characteristics and stack parameter data compiled from publicly available sources. These emission estimates were subsequently used as inputs to Tier I and Tier II risk assessment analyses based on air dispersion modeling for each of the unique stack emission locations. The resulting risk results were aggregated to the station level to identify those stations that posed an initial estimated cancer risk greater than 0.5 in a million. Chronic and acute health risks were also evaluated, but the cancer risk was used as the critical parameter for determining the need for additional review of emission estimate inputs and stack parameter data. Subsequently, the unit control system characteristics and stack parameters for this short-list of highest risk stations were then reviewed by each of the plant operators and RMB Consulting & Research, Inc. (RMB) to determine the accuracy of various input parameters and whether the information should be modified based on information from other sources. For example, use of actual stack particulate emissions data from the plant stack tests instead of particulate emissions data reported in EIA Form 767 from the unit characteristics database was one type of revision. Another was an update in emission control technology not identified in the plant database, i.e., very recent installation/startup of FGD or NO_x controls. RMB (RMB) contacted various utilities on the short-list of stations to obtain documented data from each utility regarding stack parameter values and/or actual stack emissions test data that could be used to update emission estimates. Based on this updated set of input values, the emission estimates were finalized and additional Tier I and Tier II risk analyses were carried out. This report summarizes the results of the final emission estimates and the inhalation risk assessments for each coal-fired utility power plant.

Report Organization

Section 2 provides details regarding development of the coal-fired plant database and unit configuration characteristics. The methodology for estimating the input fuel compositions and fuel usage are described in Section 3. Sources of emissions test data used in the development of updated emission correlations and factors are presented in Section 4, and details regarding the analysis of the updated emissions datasets used to obtain updated emission correlations are provided in Section 5. Section 6 provides a summary of the final emission estimates. Section 7 is an introduction to and overview of the inhalation risk process followed for this nationwide assessment. Section 8 provides further details on the data used and the modeling methodology applied to derive the inhalation risk assessment results. Finally, Section 9 presents the results of the coal-fired power plant inhalation risk assessment.

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2
PLANT DESIGN AND OPERATIONAL CHARACTERISTICS

Details regarding the development of the characterization database for coal-fired units are provided in this section.

The databases for coal-fired units were developed for EPRI for the purposes of evaluating both mercury and non-mercury HAPs. The primary data source for these databases is the *Emission-Economic Modeling System* (*EEMS*) Database, which is the main input file for *EEMS. EEMS* is a computer model that was initially developed in 1997 by Jim Marchetti (James Marchetti, Inc.), Ed Cichanowicz and Mike Hein to enable the production of accurate emission estimates for power plants with existing/planned air pollution control systems as well as associated economic analyses of proposed environmental policies and regulations impacting the electric utility industry.

The *EEMS* database contains detailed data related to the electric utility sector, including

- unit design,
- heat rates,
- fuel type,
- unit operation (e.g., capacity factor) and production costs,
- current and future air pollution control equipment,
- current combustion byproduct disposal/utilization methods and costs,
- emission control assumptions and costs, and
- unit-specific emission rates

for over 2,500 steam electric units and all operating combustion turbine and combined-cycle units. In addition to current information, the database contains historical unit operational data for steam electric (e.g., fuel consumption & quality, generation) that extends back to 1980. The database is constantly updated as new unit-specific information becomes available.

The primary information sources used to maintain the database are Energy Information Administration (EIA) Forms 423, 767 (which was discontinued after 2005), 860, 906/920; Federal Energy Regulatory Commission (FERC) Form 423; published reports; and discussions with individual operators. It should be noted that much of the information reported in these forms, including EIA Form 767 and 423, will be provided under a new form entitled EIA Form 923 for year 2008. Form 923 information was not available at the time of this project.

Plant Database Development

The initial task was to develop a database for all coal-fired units operating in 2005 (the most recent year for which plant operating characteristics were available at the unit level), with a focus on specific design and operational parameters related to each coal-fired electric generating unit that would be needed to develop the final HAPs emission estimates. For this emission estimation project, an electric generating unit was defined as a unit that had a nameplate capacity greater than 25 MW and sold electricity to the grid. Table 2-1 illustrates the categories and data fields that composed this initial database for the year 2005.

Table 2-1
Design and Operational Data for Coal Generating Unit Database 2005

Categories	Data Fields	Primary Data Sources
Plant Identification	Plant Name, Plant ID, Operator, State, Prime Mover, Generator & Boiler ID, Nameplate Capacity, Boiler & Bottom Type	EIA Form 767 & 860
Coal Type/Quality	Coal Type/Rank, Coal Quality – heat content, sulfur & ash content by rank, Coal Heat Input by Rank	EIA Form 767
NO_x Controls	Existing Combustion and Post-combustion NO_x Controls, SCR & SNCR In-Service Dates	EIA Form 767, EPA CEM Database, Contact with Individual Generators
Particulate Controls	Collector ID, Existing Particulate Controls by Type, In-Service Dates	EIA Form 767, EPA CEM Database, Contact with Individual Generators
Flue Gas Desulfurization (FGD) Systems	FGD ID, Existing FGD Systems by Type and Sorbent, In-Service Date	EIA Form 767, EPA CEM Database, Contact with Individual Generators
Stack Information	Stack ID, Stack Height, Stack Area at the Top, In-Service Date	EIA Form 767
Geography	County, Latitude, Longitude, Zip Code	EIA Form 767, EPA CEM Database

After review by EPRI, it was decided to expand the database to include SO_2, NO_X, and particulate controls that were in place during 2007 so that the database would reflect the targeted base year for the emission estimates. The database includes in-service dates for all SO_2, NO_X and particulate controls, representing both current and planned/projected dates. EIA Form 767, discontinued after 2005; provided unit-specific information on control technologies. Consequently, information in the *EEMS* Database for those technologies installed between 2006 and 2007 was derived from published reports and discussions with operators. To avoid technology omissions, the expanded database was checked against the Environmental Protection Agency's (EPA) 2007 Continuous Emission Monitoring Database. As an example, significant reductions in flue gas concentrations of SO_2 or NO_x relative to historic data would be indicative of new controls being operated.

After updating the in-place/planned control data to 2007, the EPRI project team decided to shift the reporting standard from the generator to the boiler level to allow for calculating emissions at the unit level. Due to this change, those units that had multiple boilers linked to a single generator have much of their data repeated one or more times within the database.

Additional data fields added to the database are listed in Table 2-2.

Table 2-2
Additional Data Fields Added to the Coal Unit Database

Categories	New Data Fields
Plant Identification	Part 75 Boiler ID
Fuel Data	2007 EIA Form 906/920 Plant Level Generation Fuel Heat Input by Rank, 2007 EPA CEM Unit Level Heat Input
Particulate Controls	2004 and 2005 EIA Form 767 Actual Stack Particulate Emission Rates (lb/million Btu)
Stack Information	Part 75 Monitoring Locations, Flues from EIA Form 767, 2007 Part 75 Stack Height, 2007 Part 75 Area at the Top
Comments	Discussion on operational status of some units between 2005 and 2007

As mentioned, EIA Form 906/920 plant level fuel data was used for calendar year 2007 to substitute for the discontinued EIA Form 767 unit level fuel data. The purpose of using Form 906/920 data was to better understand the types and percentages of fuel being consumed at a specific generating unit/facility in 2007. The 2007 Part 75 stack data were used to identify any changes from the 2005 stack data (from EIA Form 767), due to wet FGD retrofits.

In addition to the stack information provided in the EEMS database for coal-fired units, a current stack parameter database compiled by RMB was employed. The EPRI project team concluded that the RMB database (containing stack height, velocity, flow rate, and latitude and longitude) represented a more up-to-date set of information for coal-fired units than that available in the EEMS database; therefore, the RMB data were used in combination with the fuel data to produce the chemical species emission estimates. The RMB stack database was also used as the basis for determining which units were associated with common stack emission locations. AECOM also provided additional latitude/longitude information for selected stack emission points that were used to supplement the data from the RMB information.

Details in the final plant database were used to define the following key unit-level operational parameters necessary for developing the final emission estimates for the 2007 base-year:

- Unit-level control technology class (e.g., ESPc, SCR/ESPc/FGDw);
- Unit-level stack particulate emission rate (lb/million Btu);

- Unit-level total heat input (trillion Btu/yr);
- Mapping of units to common stack emission points;
- Stack latitude and longitude; and
- Stack height, diameter, velocity, and flow rate.

2007 Industry Profile

The coal-fired utility industry was characterized with respect to the following types of air pollution control systems: particulate matter (PM) controls, SO_2 controls, and NO_x controls (SCR/SNCR). Table 2-3 summarizes the basic PM and SO_2 control class profiles for the industry based on information from the plant database. For mercury, it was necessary to establish additional subcategories, as shown in Table 2-4, to account for the presence of SCR, SNCR, and flue gas conditioning, since these systems have been shown to impact mercury oxidation and subsequent mercury removal in downstream FGD systems. Details regarding the rationale for selection of the various control class categories are provided in Section 5.

When the industry profile is characterized with respect to PM and SO_2 control types only, units equipped with PM control only (ESPs or FFs) account for approximately 63% of total coal-fired MW capacity. Units equipped with PM controls in combination with wet or dry FGD systems account for roughly 36% of the total coal-fired MW capacity.

Table 2-4 shows that approximately 39% of the total 2007 nationwide MW capacity (314 of the 1,173 total units) was equipped with either SNCR or SCR NO_x control systems. The combination of SCR with a wet FGD scrubber, an important control class configuration with respect to mercury oxidation and potential for mercury removal in downstream control systems, accounts for approximately 14% of the total installed MW capacity.

Table 2-3
PM and SO_2 Control Class Profile for Coal-Fired Units (>25 MW to grid) – 2007 Base Year

Control Class	Total MW	Number of Units
ESPc	161,208	612
ESPc FBC	80	1
ESPc FGDd	1,512	4
ESPc FGDw	80,443	164
ESPh	23,224	100
ESPh FGDw	9,960	23
FF	24,567	159
FF FBC	1205	13
FF FGDd	11,268	56
FF FGDw	8,150	17
VS FGDw	9,379	22
IGCC	633	2
Total All Units	331,634	1173
Total ESP or FF only	210,284 (63%)	885 (75%)
Total FGDd or FGDw	120,712 (36%)	286 (24%)
IGCC	633	2

Key:
ESPc = cold-side electrostatic precipitator
ESPh = hot-side electrostatic precipitator
FBC = fluidized bed combustion
FF = fabric filter
FGDd = dry flue gas desulfurization
FGDw = wet flue gas desulfurization
IGCC = integrated gasification combined cycle
VS = venturi scrubber

Table 2-4
SCR/SNCR Control Class Profile for Coal-Fired Units (>25 MW to grid) – 2007 Base Year

Control Class	Total MW	Number of Units
ESPc	76,970	367
ESPc CON	30,254	113
ESPc ACI	109	1
ESPc FGDd	1512	4
ESPc FGDw	34,259	76
ESPh	13,434	77
ESPh FGDw	6,925	16
FF	18,012	126
FF ACI	270	3
FF FBC	965	11
FF FGDd	7,583	33
FF FGDw	6,422	13
VS FGDw	5,922	17
SCR ESPc	23,103	51
SCR ESPc CON	21,787	37
SCR ESPc FBC	80	1
SCR ESPc FGDw	40,055	69
SCR ESPc FGDw CON	1,080	1
SCR ESPh	8,496	14
SCR ESPh FGDw	3,035	7
SCR FF	2,681	4
SCR FF ACI	922	1
SCR FF FGDd	2,822	18
SCR FF FGDw	880	2
SCR VS FGDw	3,270	4
SNCR ESPc	8,911	42
SNCR ESPc ACI	74	1
SNCR ESPc FGDw	5,049	18

Table 2-4 (continued)
SCR/SNCR Control Class Profile for Coal-Fired Units (>25 MW to grid) – 2007 Base Year

Control Class	Total MW	Number of Units
SNCR ESPh	1,294	9
SNCR FF	2,682	25
SNCR FF FBC	240	2
SNCR FF FGDd	863	5
SNCR FF FGDw	848	2
SNCR VS FGDw	187	1
IGCC	633	2
Total All Units	331,634	1,173
Total without SCR or SNCR	202,637 (61%)	857 (73%)
Total with SCR	108,211 (33%)	209 (18%)
Total with SNCR	20,148 (6.4%)	105 (8.9%)
IGCC	633	2

Key:

ESPc	cold-side electrostatic precipitator	FGDw	wet flue gas desulfurization
SCR	selective catalytic reduction	VS	venturi scrubber
ESPh	hot-side electrostatic precipitator	FF	fabric filter
SNCR	selective non catalytic reduction	FBC	fluidized bed combustion
FGDd	dry flue gas desulfurization	ACI	activated carbon injection
IGCC	integrated gasification combined cycle	CON	flue gas conditioning

3
FUEL INFORMATION

The composition of the coal fired at each unit is a key input parameter used in the estimation of emissions of inorganic HAPs species (e.g., trace elements, acid gas species, etc.). This section discusses the methodology used to develop the fuel composition input values for each coal-fired unit. The general steps used to develop these fuel composition input values are listed below.

- Obtain/generate a database of coal composition data by major coal region.
- Obtain information regarding the type and quantity of fuel consumed by each coal-fired power plant for the 2007 base year.
- Combine information generated in the first two steps to determine a "blended" coal composition for inorganic HAPs and other key coal parameters (i.e., heating value, sulfur content, coal ash content) which is representative of the coal fired at each unit for 2007.

The following three subsections discuss in detail each step for generating the "blended" coal composition input data used in the emission estimates.

Coal Composition Data (USGS and 1999 ICR)

In the 1994 Synthesis Report (1), the USGS database was screened to provide HAPs coal concentrations and heating values for 22 major coal producing regions by state. From an initial 3300 coal samples, about 2700 samples were used for subsequent analyses. The screening excluded thin and deep (non-economic) coal beds. Data for several specific coal types were then processed using coal cleaning algorithms to produce a final screened USGS coal dataset. The details of the methodology EPRI used to develop the screened USGS database is described in EPRI's 1994 Synthesis Report. Table 3-1 summarizes the major coal producing regions derived from the screened USGS COALQUAL database and the number of coal samples available.

Table 3-1
Summary of Coal Information from the Screened USGS COALQUAL Database

State	Region	Rank	No. Coal Samples
ALABAMA	SOUTHERN APPALACHIAN	BITUMINOUS	150
COLORADO	GREEN RIVER	BITUMINOUS	26
ILLINOIS	EASTERN	BITUMINOUS	15
INDIANA	EASTERN	BITUMINOUS	80
KENTUCKY	EASTERN	BITUMINOUS	116
KENTUCKY	CENTRAL APPALACHIAN	BITUMINOUS	337
MARYLAND	NORTHERN APPALACHIAN	BITUMINOUS	38
NEW MEXICO	SAN JUAN RIVER	BITUMINOUS	3
OHIO	NORTHERN APPALACHIAN	BITUMINOUS	492
PENNSYLVANIA	NORTHERN APPALACHIAN	BITUMINOUS	539
TENNESSEE	CENTRAL APPALACHIAN	BITUMINOUS	12
UTAH	UINTA	BITUMINOUS	22
VIRGINIA	CENTRAL APPALACHIAN	BITUMINOUS	52
WEST VIRGINIA	NORTHERN APPALACHIAN	BITUMINOUS	115
WEST VIRGINIA	CENTRAL APPALACHIAN	BITUMINOUS	266
NORTH DAKOTA	FORT UNION	LIGNITE	56
TEXAS	TEXAS	LIGNITE	54
COLORADO	GREEN RIVER	SUBBITUMINOUS	1
MONTANA	POWDER RIVER	SUBBITUMINOUS	95
NEW MEXICO	SAN JUAN RIVER	SUBBITUMINOUS	104
WYOMING	GREEN RIVER	SUBBITUMINOUS	2
WYOMING	POWDER RIVER	SUBBITUMINOUS	141
Total			2716

Using the screened USGS coal composition database, geometric mean composition values were calculated for each trace element by state, region and coal rank. This database of geometric mean composition values was then used as the basis for calculating the "blended" fuel compositions on a unit-by-unit basis, as described later in this section. A list of the geometric mean coal compositions for each of the 22 major coal producing regions from the USGS is provided in Appendix A.

For coal mercury and chloride, the 1999 ICR data, containing 40,000 as-fired measurements, was used for the emission estimates. It is organized by state/county and further grouped into coal regions. The detailed ICR coal database is documented in EPRI's 2000 mercury emission assessment report (2) and discussed further in Appendix A.

The one exception was the ICR data for Gulf Coast lignite, which has a low bias due to analytical methods used for mercury analysis in most of these coal samples. URS reviewed available coal sample data from the EPRI PISCES Database v2008a (3), as well as data presented by TXU in letters submitted to the EPA docket (4), and more recent data available from various DOE mercury control technology studies at plants firing Texas lignite (5-7). With the exception of one site, only data from samples analyzed using the ASTM D6414 method were included in the dataset. In all, data from 11 different test programs at seven units were included in the final dataset. A statistical summary of the final dataset is shown in Table 3-2. Individual sample results from each plant were used to compute the values presented in Table 3-2. The average mercury value for this dataset is 27 lb/trillion Btu input (0.25 ppmw, dry) with values ranging from 11 to 85 lb/trillion Btu. The average value of 27 lb/trillion Btu is approximately twice the average Texas lignite coal mercury value derived from the 1999 ICR coal mercury data (13.3 lb/trillion Btu).

Table 3-2
Summary of Texas Lignite Coal Mercury Data Used

	Hg (ppmw, dry)	Heating Value (Btu/lb, dry)	Hg (lb/trillion Btu input)
Average	0.25	9,617	27
Maximum	0.71	10,976	85
Minimum	0.11	7,740	11
Median	0.25	9,810	25
Count	69	69	69

For non-coal fuels (e.g., TDF, petcoke), trace element and heating value information was retrieved from the EPRI PISCES database (version 2008a). An average value for each of these fuel types was generated and used in the calculation of "blended" fuel compositions in cases where 2007 fuel records indicated coal was co-fired with these fuels. Composition data for these fuel types are provided in Appendix A.

Fuel Purchased Information (FERC and EIA 2007)

Fuel purchase information was taken from FERC and EIA Form 423 coal databases for the year 2007 (8,9). These databases contain the monthly fuel purchase records for all US power plants at the station level. These monthly records were combined to produce a yearly total; all oil and natural gas-fired units were excluded. This adjusted database contained data for the tonnage of fuel purchased, rank, source state and county, and heating value, sulfur and ash content for each unique plant.

Combining the Fuel Composition and Fuel Purchase Information

Information from the fuel composition database and the fuel purchase database were combined to calculate the composition of the "blended" fuel (i.e. tonnage weighted composition of all fuel types fired at a given station). Appendix A provides an example calculation for one station. To combine the two databases, the coal source state and county information from the FERC/EIA database was mapped to one of the 22 USGS categories listed in Table 3-1. An additional 44 unique combinations were identified in the station level fuel purchase records that were not explicitly listed in the USGS database. These coals were reviewed and assigned one of the 22 USGS major coal producing regions based on best judgment. As an example, while coal rank is based on heating value, trace element composition is based on geographic location. Therefore subbituminous coal from Virginia was given the Virginia Central Appalachian composition of bituminous coal. Similarly, Kansas bituminous was assigned the composition of Illinois Eastern bituminous coals. Petroleum coke composition was obtained from the PISCES database (v2008a). Imported coal was assigned as Eastern bituminous, or Powder River subbituminous, depending on the reported rank as these represent the two largest sources of coal by rank. The 22 major seams accounted for 92% of the 2007 coal tonnage for all plants.

Once a fuel source was applied to each plant's fuel purchases, the two databases were combined, with appropriate unit conversions, to obtain a composition input value for inorganic species for each plant. For plants with multiple units and multiple types of fuel burned, the calculations assumed that all units burned the same fuel blend. For example if Plant A with two units purchased 50% PRB and 50% bituminous fuel, it was assumed that each unit burned a 50/50 blend, and not that unit 1 burned all PRB and unit 2 burned all bituminous. This simplification is required because fuel consumption by source is not available at the unit level.

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4
EMISSION DATA SOURCES

This section provides background information on the sources of emissions test data used in the emission estimate analyses.

The compilation of data used in the development of emission correlations and emission factors for this study were generally collected during two distinct time periods: the 1990s (including the 1999 EPA mercury ICR) and post-2000. EPRI began gathering HAPs emissions data as part of the Field Chemical Emissions Measurement (FCEM) project in early 1990. In parallel with EPRI's program, the Department of Energy (DOE) had two initiatives which collected similar data during the same timeframe. The Clean Coal Technology program incorporated the measurement of emissions as a project objective at several sites, sometimes in collaboration with EPRI. The second DOE initiative was the Comprehensive Assessment of Emissions project, carried out for eight coal-fired sites in the summer of 1993. Together, these data sources formed the basis of the early- to mid-1990s dataset and were used to develop the emission correlations and emission estimates presented in EPRI's 1994 Electric Utility Trace Substances Synthesis Report. The next major data collection initiative occurred as a result of EPA's 1999 mercury ICR, which generated data for both coal mercury and chloride, as well as stack mercury emissions and speciation data for a subset of coal-fired power plants firing various coal types and equipped with various air pollution control devices. These mercury ICR data were subsequently used by EPRI to conduct an assessment of mercury emissions from U.S. coal-fired power plants (1).

Since 2000, EPRI has conducted a number of field test programs at coal-fired sites equipped with SCR and FGD controls to examine the impact of SCR on the speciation and fate of mercury. As part of some of these test programs, EPRI collected additional data on the fate and emissions of other HAPs (e.g., additional trace elements and acid gas species). A second major source of more recent HAPs emission data, particularly mercury, is data collected as part of DOE-sponsored full-scale mercury control technology test programs (e.g., activated carbon injection), many of which were conducted in collaboration with EPRI. Nearly all of these DOE mercury control test program included collection of mercury speciation and emissions data during baseline conditions, and in some cases, also included measurement of other HAPs species. Finally, some utilities conducted HAPs testing and provided their results to EPRI for use in this project. These more recent EPRI, DOE baseline, and in-house utility data were identified and compiled for use in development of updated emission correlations and factors as part of this project.

Test Program Overview

Table 4-1 compares the number of HAPs test sites from previous data-gathering efforts to the number of test sites identified from various sources in this current study. The total number of tests sites represents the number of non-unique test sites (i.e., count includes sites that were tested more than once as part of various test programs). Table 4-1 also indicates the number of control class configuration datasets generated to illustrate that some test sites were used to generate data for multiple control class groups. Over 150 sites have been sampled for mercury and other HAPs since EPRI's 1994 Synthesis Report and 2000 mercury emissions assessment efforts. Of these newly identified test sites, approximately 60% were studies sponsored by EPRI and 30% were conducted as part of the DOE mercury control testing programs, with the remainder from miscellaneous literature or utility sources.

Table 4-2 provides a comparison of the control class classifications and number of mercury correlation datasets from the 2000 EPRI mercury emissions assessment study and the updated correlations from this current study. As described further in Section 5, a number of new control class designations were developed for this current study (where sufficient data were available) to account for the increased use of both SCR and SNCR controls on coal-fired units over the past 15 years. In addition, as discussed in Section 5, units having ESP controls with and without flue gas conditioning were treated separately with respect to mercury in this current study. The most significant increases in available data occurred for the following control classes: ESPc and ESPc CON, ESPc FGDw, SCR ESPc FGDw, SCR ESPc and SNCR ESPc.

A summary of available data for non-mercury HAPs (non-mercury trace elements, hydrogen chloride, hydrogen fluoride, hydrogen cyanide, volatile organic compounds, polycyclic aromatic compounds, and dioxin/furan compounds) emission correlations and emission factors are summarized in Table 4-3. Anywhere from 10 to 28 additional data points were added to the correlation datasets for the various non-mercury HAPs. Studies having new emissions data for organic compounds were limited to three test sites for volatile organic compounds and one site for polycyclic aromatic compounds. No new test data were identified for dioxin/furan compounds.

Test Sites and Industry Profile Comparison

To provide a reference for test site characteristics relative to the 2007 population of coal-fired units, the number of units tested matching each of the major control class groups was compared to the total number of coal-fired units within each control class. Total units for each control class were developed from the combined unit characteristics database described previously in Section 2 (i.e., >25MW providing power to the grid). This comparison was done separately for the non-mercury HAPs dataset and the mercury dataset since the amount and type of data collected is distinctly different within each group of data. Appendix B provides fuel, site, and measurements characteristics for the units that have been tested and included in the data pool used for this current study.

Table 4-1
Number of Coal-Fired Test Sites by Test Campaign

Test Campaign	Number of Test Sitesa	Number of Control Class Datasetsb
1990-1995 EPRI FCEM and DOE Air Toxics	28	38
1999 EPA Mercury ICR	84	109
Newly Identified Sourcesc	153	153

[a] Number of non-unique test sites. Count may include units tested more than once as part of different test programs.

[b] Some test sites provide datasets for more than one control class configuration (e.g. ESPc FGDw sites can provide data for both ESPc and ESPc FGDw control class groups).

[c] Includes data from DOE mercury control test programs, recent EPRI studies of mercury and other HAPs, and miscellaneous test sites identified from the literature or individual utilities.

Table 4-2
Comparison of Mercury Correlation Data Points

EPRI 2000 Mercury Assessment + New Data Sources		EPRI 2000 Mercury Assessment	
Control Class	**No. Correlation Data Points**	**Control Class**	**No. Correlation Data Points**
ESPc	46	ESPc	29
ESPc CON	23	–	–
ESPc FGDd	6	ESPc FGDd	3
ESPc FGDw	35	ESPc FGDw	12
ESPh	20	ESPh	15
ESPh FGDw	8	ESPh FGDw	6
FF	18	FF	12
FF FBC	7	FF FBC	7
FF FGDd	12	FF FGDd	11
FF FGDw	5	FF FGDw	3
VS FGDw	15	VS FGDw	9
SCR ESPc	18	–	–
SCR ESPc FGDw	25	–	–
SCR VS FGDw	4	–	–
SNCR ESPc	9	–	–
IGCC	2	IGCC	2

Key:
ESPc = cold-side electrostatic precipitator
SCR= selective catalytic reduction
ESPh = hot-side electrostatic precipitator
SNCR = selective non catalytic reduction
FGDd = dry flue gas desulfurization
IGCC = integrated gasification combined cycle
FGDw = wet flue gas desulfurization
VS = venturi scrubber
FF = fabric filter
FBC = fluidized bed combustion
CON = flue gas conditioning

Table 4-3
Summary of Available Coal-Fired Plant Data for Emission Correlations – Non-Mercury HAPs

Analyte	Previous EFH Correlation a	Current Total Data Points
Antimony	8	18
Arsenic	34	51
Beryllium	17	40
Cadmium	9	13
Chromium	38	51
Cobalt	20	48
Lead	33	48
Manganese	37	55
Nickel	25	44
Selenium	29	47
Hydrogen Chloride	38	58
Hydrogen Fluoride	28	41
Hydrogen Cyanide	NA [b]	9
Volatile Organic Compounds [c]	1 – 26	1 - 28
Polycyclic Aromatic Compounds [c]	3 – 22	3 - 23
Dioxin/Furan Compounds	15	15

[a] EPRI 2002 Emission Factors Handbook.

[b] Emission factor for hydrogen cyanide was not developed as part of previous EPRI analyses.

[c] Range of stack data point counts for various organic compound species. Four additional test sites were identified in which volatile organic compounds (3 sites) and polycyclic aromatic compounds (1 site) were measured, resulting in 1 to 3 additional data points per organic compound in some cases.

Non-Mercury HAPs

Table 4-4 provides a summary of the non-mercury HAPs dataset. One or more of the non-mercury HAPs species has been tested at 85 units where sufficient data were generated for use in the emission correlations or emission factors. Note that the number of units tested with a particular control class may include multiple tests at the same unit tested as part of various test programs over the years; thus, the percentages shown in Table 4-4 are an approximate indication of the percentage of total units tested within a particular control class. A higher percentage of units in the ESPc FGDw and FF FGDd control class groups have been tested (12-14%), with the remainder of the control class groups with test data indicating approximately 2-8% of the total units tested.

Table 4-4
Comparison of Number of Units Tested to Coal-Fired Unit Industry Profile – Non-Mercury HAPs

Control Class	Number of Units	Number of Non-Unique Units Tested a	Percent of Total Units
ESPc	612	44	7%
ESPc FBC	1	-	-
ESPc FGDd	4	-	-
ESPc FGDw	164	19	12%
ESPh	100	2	2%
ESPh FGDw	23	-	-
FF	159	10	6%
FF FBC	13	1	8%
FF FGDd	56	8	14%
FF FGDw	17	1	6%
VS FGDw	22	-	-
IGCC	2	-	-
Total All Units	1,173	85	7%

[a] Number of non-unique units tested within each control class group. In some cases, the counts include units that have been tested more than once as part of various test programs; therefore the percent of total units shown is approximate.

Key:
ESPc = cold-side electrostatic precipitator
ESPh = hot-side electrostatic precipitator
FBC = fluidized bed combustion
FF = fabric filter
FGDd = dry flue gas desulfurization
FGDw = wet flue gas desulfurization
IGCC = integrated gasification combined cycle
VS = venturi scrubber

Mercury

Table 4-5 shows the total number of units tested and having sufficient data for use in the mercury correlations within each control class group. Additional subcategories of control class were developed for mercury as discussed in Section 5. Note that some units have been tested for mercury more than once as part of different test programs; each test campaign is included in the overall unit counts. A total of 254 units have been tested and included in the mercury data pool used to develop updated correlations and factors. Units without SCR or SNCR controls have generally been more extensively characterized than units having these types of NOX controls. The SCR ESPc, SCR ESPc FGDw and SNCR ESPc control classes are an exception; Table 4-5 shows 20-35% of the total units have been tested in these groups as a result of EPRI research programs over the past 10 years to investigate the impacts of SCR and SNCR NO_x controls on the fate and emissions of mercury at coal-fired units.

Table 4-5
Comparison of Number of Units Tested to Coal-Fired Unit Industry Profile – Mercury

Control Class	Number of Units	Number of Non-Unique Units Tested a	Percent of Total Units a
ESPc	367	46	13%
ESPc CON	113	23	20%
ESPc ACI	1		
ESPc FGDd	4	6	150%
ESPc FGDw	76	35	47%
ESPh	77	20	26%
ESPh FGDw	16	8	50%
FF	126	18	14%
FF ACI	3		
FF FBC	14	7	50%
FF FGDd	33	12	36%
FF FGDw	13	5	38%
VS FGDw	17	15	88%
SCR ESPc	51	18	35%
SCR ESPc CON	37		
SCR ESPc FBC	1		
SCR ESPc FGDw	69	25	36%
SCR ESPc FGDw CON	1		

Table 4-5 (continued)
Comparison of Number of Units Tested to Coal-Fired Unit Industry Profile – Mercury

Control Class	Number of Units	Number of Non-Unique Units Tested a	Percent of Total Units a
SCR ESPh	14		
SCR ESPh FGDw	7		
SCR FF	4		
SCR FF ACI	1		
SCR FF FGDd	18		
SCR FF FGDw	2		
SCR VS FGDw	4	4	100%
SNCR ESPc	42	9	21%
SNCR ESPc ACI	1		
SNCR ESPc FGDw	18		
SNCR ESPh	9		
SNCR FF	25		
SNCR FF FBC	2		
SNCR FF FGDd	5		
SNCR FF FGDw	2		
SNCR VS FGDw	1		
IGCC	2	2	100%
Total All Units	1,173	254	22%

[a] Number of non-unique units tested within each control class group. The counts includes units that may have been tested more than once as part of various test programs, therefore the percent of total units shown is approximate. For example, the 150% shown for the Epic FGDd control class is an anomaly caused by one unit in this group being tested multiple times and the small number of units in this control class group.

Key:

ESPc = cold-side electrostatic precipitator
SCR = selective catalytic reduction
ESPh = hot-side electrostatic precipitator
SNCR = selective non catalytic reduction
FGDd = dry flue gas desulfurization
IGCC = integrated gasification combined cycle
FGDw = wet flue gas desulfurization
VS = venturi scrubber
FF = fabric filter
FBC = fluidized bed combustion
ACI = activated carbon injection
CON = flue gas conditioning

References

1. An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants, EPRI, Palo Alto, CA: September 2000. TR-1000608
2. Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI, Palo Alto, CA: 2002. 1005402

5
EMISSION CORRELATIONS AND FACTORS

Emission Estimation Approach Overview

This section presents the methods used for estimating trace substance emissions from fossil-fuel-fired power plants. Estimation techniques were derived from test data produced by the Electric Power Research Institute (EPRI) and the Department of Energy (DOE) in the mid- to late-1990s that focused on hazardous air pollutants (HAPs). Recent mercury data collected by the Environmental Protection Agency (EPA), DOE, and individual utilities have also been incorporated. The methodology discussed here was first used by EPRI in the Electric Utility Trace Substances Synthesis Report (1). It is presented to document the inclusion of more recent data. It is important to keep in mind the following caveats when using this information:

- These estimates are based on a significant amount of sampling information. As the basis for industry-wide estimates, the methodologies employed here are believed to be the best available.
- Actual measurements of HAPs emissions may vary significantly from estimated levels. This variability is primarily external to sampling and analytical variability (i.e., it is caused by site-specific differences in plant design and operation and in daily process variability).
- As more data become available and are used in the regressions and averages, the predicted factors may change.
- Much of the data fit log-normal distributions. The resulting correlations and geometric mean values provide an appropriate median emission factor for a single unit.

This section presents emission estimation techniques for the following trace substances:

- Antimony, arsenic, beryllium, cadmium, chromium, cobalt, manganese, mercury, lead, nickel, and selenium;
- Hydrogen cyanide;
- Hydrogen chloride (HCl);
- Chlorine (Cl_2);
- Hydrogen fluoride (HF); and
- Selected organics substances that have been detected in emissions from coal -fired plants.

Background

EPRI and DOE have sponsored programs to conduct a more thorough characterization of trace substance emissions from power plants. These measurement programs provide a comprehensive set of data that can be used to assess the extent of power plant trace substance emissions and to estimate emissions from similar, untested facilities. In this section, trace substance emission estimating techniques that describe these data are presented for coal-fired steam-electric power plants.

Prior to using these techniques for emissions estimates, the reader should be aware of the following facts and observations:

- Analytical results from tests sponsored by EPRI, DOE, and others provided results for a wide range of individual HAPs for 2 to 20% of operating units. These field tests encompassed plants representing each major fuel type and boiler configuration as well as SO_2, NO_X, and particulate control technologies. The resulting database represents data obtained by consistent sampling and analytical protocols to estimate emissions from steam-electric power plants. However, even within this small number of plants, emissions varied significantly among similarly configured plants.
- The measured emissions results have been quite variable, with measurements of some individual specific hazardous air pollutants ranging across several orders of magnitude. Many of the HAPs datasets have been shown to be log-normally distributed. Some results were divided into smaller subsets to account for variables such as fuel type and SO_2 and particulate control technologies.
- The correlations or emission factors suggested in this section are based on specific groups of data and computational approaches. Alternative approaches would produce different statistics. As with all statistical information there is some probability that any given value will be exceeded some of the time.

For coal-fired power plants, the recommended approaches for estimating emissions are summarized below. Appendix C provides additional details regarding development of emission factors and correlations.

Particulate-Phase Trace Elements

A significant fraction of the trace elements present in the fly ash are removed by a particulate control device. The estimation approach used for each particulate-phase trace element emission is a correlation that incorporates the inlet concentration in the coal and the total particulate emission. These regressions are not dependent upon specific control technology devices or coal types. However, the correlation indirectly incorporates the particulate control efficiency. Figure 5-1 is an example of this type of correlation for arsenic. The independent parameter is the coal concentration, divided by the ash content of the coal, and multiplied by the particulate emission level. A power function is used to fit this parameter to the measured emissions. Both values are expressed on a common basis, pounds of the substance per trillion Btus heat input. Note that two regression lines are shown. The thinner red line is the older correlation from the 2002 Emission

Factors Handbook. New correlation constants were generated from the addition of new site results to the database.

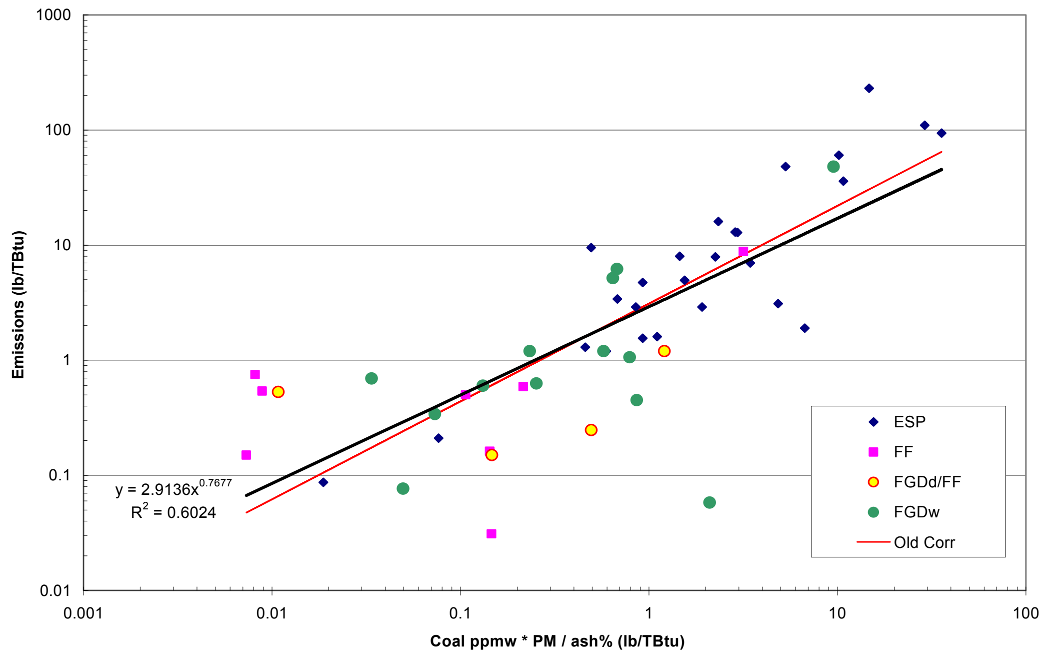


Figure 5-1
Arsenic Emission Correlation

Volatile Inorganic Substances

Certain inorganic substances in the fuel (such as chlorine, fluorine, mercury, and, in some cases, selenium) exist in the flue gas primarily in vapor phase and, thus, are not consistently captured by a particulate control device. The average removal efficiencies for HCl, HF, and selenium are used to estimate these emissions. Mercury emission estimates were developed as a function of the coal chloride content for some of the control technologies. Average values were used for other control class categories. The extensive recent effort to measure mercury emissions also permitted a categorization of results based on the types of NO_x control employed, whether none, SNCR, or SCR. These catalytic processes change the speciation of mercury present in the flue gas, which affects the removal performance of downstream control devices.

Organic Compounds

Some organic substances are either not totally consumed or perhaps created during the combustion process and are generally not well-controlled by particulate or SO_2 control devices. Measured levels of organics are quite variable. In many cases, these measurements are at the detection level. Median (as estimated by the geometric mean) values are provided as emission factor estimates for each substance.

Summary Correlation Results for Coal-Fired Sites

Particulate Metals

Table 5-1 presents the correlation constants and statistics for the nine trace elements that partition to the solid phase and can be estimated using both the coal composition and the particulate emission. Also shown in the table are the number of data pairs for each element, the correlation coefficient, and the prior constants from the 2002 Emission Factors Handbook (2). In most cases, the inclusion of additional data has not changed the predicted values significantly.

Table 5-1
Particulate Metal Correlation Coefficients

Element	a	b	N pairs	r^2	EFH a	EFH b
As	2.91	0.77	51	0.60	3.1	0.85
Be	0.66	0.67	40	0.58	1.2	1.1
Cd	3.99	0.54	13	0.72	3.3	0.5
Co	1.21	0.50	47	0.39	1.7	0.69
Cr	3.74	0.50	51	0.53	3.7	0.58
Mn	4.45	0.50	55	0.37	3.8	0.6
Ni	3.62	0.43	44	0.40	3.4	0.8
Pb	2.77	0.66	48	0.46	4.4	0.48
Sb	0.97	0.60	18	0.55	0.92	0.63

Figure 5-2 shows the relationship for two levels of statistical significance between the correlation coefficient and the number of datasets. As shown in Table 5-1, all of the correlations (r^2) are statistically valid at the 95% confidence level.

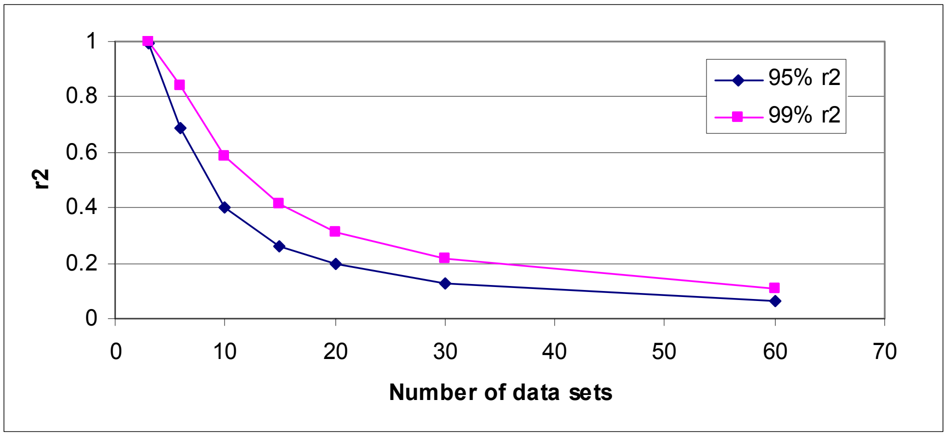


Figure 5-2
Statistical Significance vs. Number of Datasets

Mercury

Numerous measurements were carried out on mercury emissions over the 10 years since the 1999 mercury ICR collection effort. Much of these data have been obtained by EPRI and compared with previous results. The bulk of these measurements has been made during evaluations of various mercury control technology evaluations. The “baseline” measurements have been included here to provide a better understanding of mercury behavior.

One of the effects of more data is the possibility of evaluating the impact of a greater range of conventional control technology combinations. In the last ten years, the use of selective and non-selective catalytic reduction for NO_x control has become more common. In conjunction with the various particulate and SO_2 control technologies available, the number of unique permutations involving air pollution control configurations at power plants has grown. In EPRI’s 2000 Mercury Emissions Assessment, 11 groups of control technologies were developed. We now have over 30. Unfortunately, although these configurations are found in the industry population, not all of them have been sampled to provide performance data. In addition, the standard correlation between coal chlorine and mercury removal and speciation is not always statistically valid because of limited data. In these cases, average values are used to estimate the performance of plants in those categories. Table 5-2 presents the predictive factors for the various control categories. Note that for some categories, a “+” in the dataset column indicates the values for the same numbered dataset were used due to a lack of measurement data (i.e., the ESPcCon data were used for the SCRESPcCon category). The equation is of the form:

$$\%\text{Removal (or \% Elemental)} = \text{Multiplier} * \ln(\text{coal chlorine}) + \text{Constant}$$

If coal chloride was not a good predictor, the average value of the dataset is used to predict performance. Upper and lower bounds were also established for the correlations based on the range of available data and best engineering judgment, as shown in Table 5-2.

Table 5-2
Mercury Emission Predictive Correlations and Factors

Control Class	Dataset	% Removal					% Elemental					%Particulate
		Multiplier	Constant	Minimum	Average	Maximum	Multiplier	Constant	Minimum	Average	Maximum	Average
ESPc	1		25%				-12%	116%	2%	54%	98%	3.50%
ESPc Con	2		50%				-12%	116%	2%	54%	98%	4.00%
ESPcACI	3		90%					54%				3.50%
ESPcFGDd	4		5%					94%				0.40%
ESPcFGDw	5	7%	19%	3%	56%	84%	-3%	102%	60%	85%	98%	0.65%
ESPh	6		3%				-19%	162%	5%	57%	92%	2.50%
ESPhFGDw	7	25%	-110%	0%	20%	74%		91%				2.60%
FF	8	23%	-70%	0%	58%	99%		23%				0.76%
FFACI	9		90%					23%				0.76%
FFFBC	10		86%					56%				2.00%
FFFGDd	11	31%	-131%	5%	42%	99%	-11%	145%	41%	84%	99%	2.80%
FFFGDw	12		86%					74%				5.00%
IGCC	13		4%					96%				0.50%
SCRESPc	14		43%				-16%	120%	1%	26%	73%	0.93%
SCRESPc Con	2+		50%				-12%	116%				4.00%
SCRESPcACI	15		90%					26%				0.93%
SCRESPcFBC	10+		86%					56%				2.00%
SCRESPcFGDw	16	10%	19%	21%	85%	98%		59%				0.80%
SCRESPh	6+		3%					20%				2.50%
SCRESPhFGDw	avg 7+16	17%	-45%					91%				2.60%
SCRFF	8+	23%	-70%					30%				0.76%
SCRFFACI	9+		90%					23%				0.76%
SCRFFFGDd	11+	31%	-131%	5%	42%	99%		30%				0.76%
SCRFFFGDw	12+		86%					74%				5.00%
SCRVSFGDw	17		54%					56%				1.00%
SNCRESPc	18		72%					20%				3.50%
SNCRESPcACI	3+		90%					20%				3.50%
SNCRESPcFGDw	16+	10%	19%	21%	85%	98%		59%				0.80%
SNCRESPh	6+		3%					20%				2.50%
SNCRFF	8+	23%	-70%	0%	58%	99%		23%				0.76%
SNCRFFFBC	10+		86%					56%				2.00%
SNCRFFFGDd	11+	31%	-131%	5%	42%	99%	-11%	145%	41%	84%	99%	2.80%
SNCRFFFGDw	12+		86%					74%				5.00%
SNCRVSFGDw	avg 17+19		38%					75%				1.00%
VSFGDw	19		22%					94%				1.00%

Selenium

Selenium data was grouped according to control technology. A significant relationship was determined only for the fabric filter category versus coal sulfur content (and only because one site had higher coal sulfur levels than the other datasets). The data are plotted in Figure 5-3. As shown, the other three control categories are best represented by average removal efficiencies shown as horizontal lines in Figure 5-3 and subsequent figures.

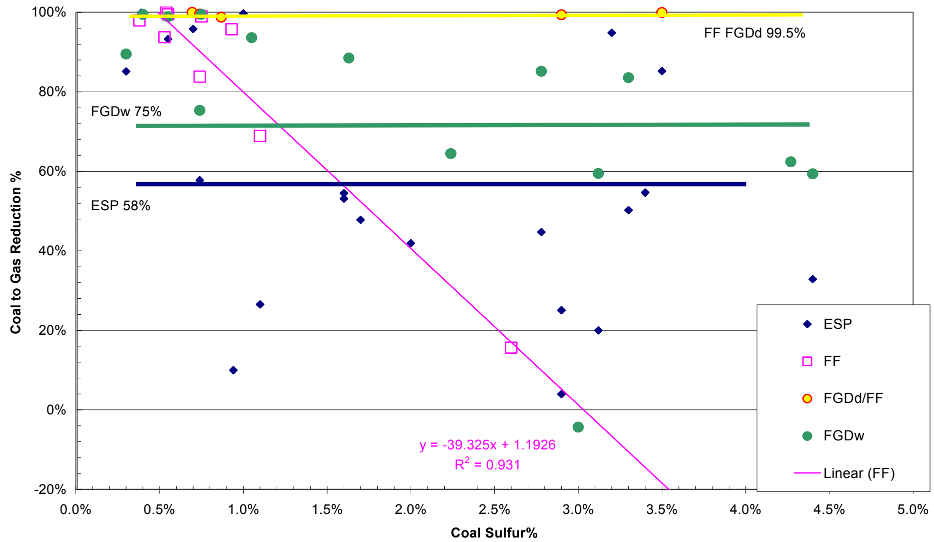


Figure 5-3
Selenium Removal Data

Hydrochloric Acid/Chlorine

Coal-to-gas reduction of total chloride is plotted in Figure 5-4 for several control technologies versus coal sulfur content. The ESP category has a discontinuity in removal efficiency as the coal sulfur drops below 0.7%, therefore two average values are provided. The use of either a dry or wet FGD systems is extremely effective for removing HCl.

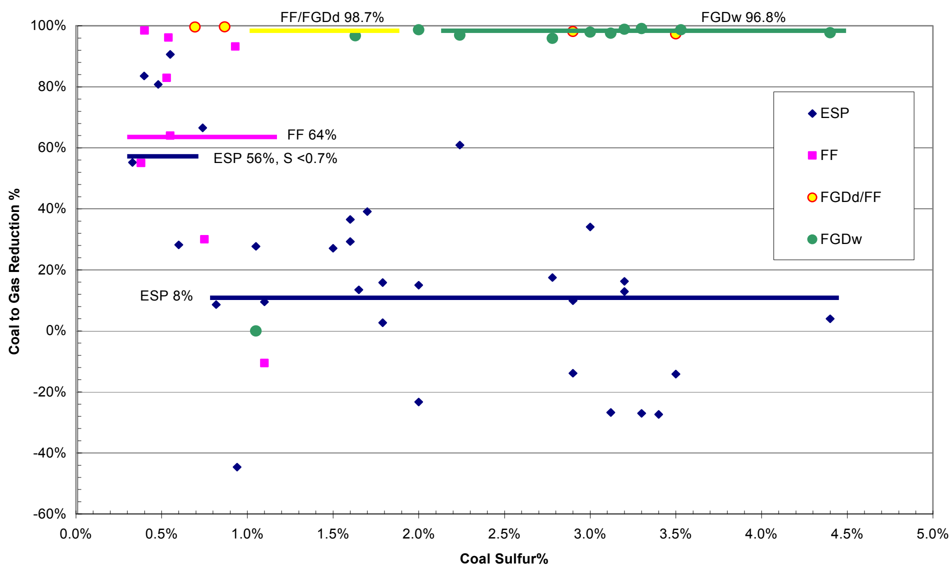


Figure 5-4
HCl Removal Data

Limited data exist for determining the split between HCl and chlorine (Cl_2) in power plant flue gas. Again, coal sulfur levels (which are a weak surrogate for coal chlorine levels) and the presence of FGD systems (which effectively remove HCl, but not Cl_2) are the basis for categorization. Table 5-3 presents the average values of the datasets.

Table 5-3
Chlorine as a Percentage of Total Chloride Emissions

Category	Cl_2/Total Cl
>0.7 wt % Sulfur Coal	4%
< =0.7 wt % Sulfur Coal	50%
Wet FGD	50%
Dry FGD	50%

Hydrofluoric Acid

Coal-to-gas reduction for HF are plotted in Figure 5-5 for several control technologies versus coal sulfur content. The particulate control devices show a break in removal as the coal sulfur drops below 0.7%, therefore two average values are provided. The use of either a dry or wet FGD systems is extremely effective for removing HF.

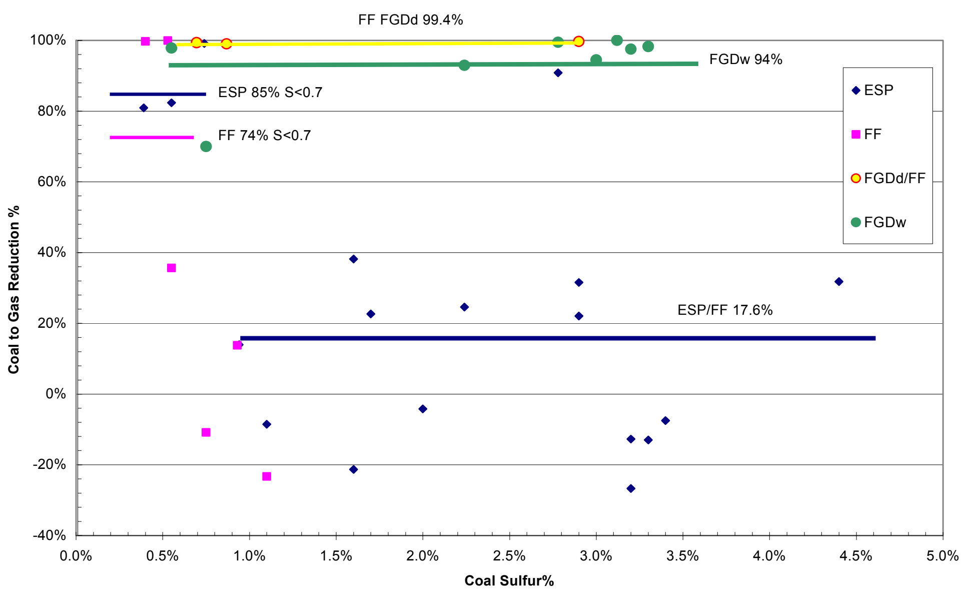


Figure 5-5
HF Removal Data

Organic Compounds

The detection of organic compounds in flue gas is carried out using several different sampling and analytical procedures. These procedures typically involve some form of chromatography in which sample responses are identified by the similarity to known substances. For a given method, a specific list of substances is in the memory of the analyzer. The sample results are then reported as quantified or non-detected values. For the risk assessment effort, only those substances which have been detected at one or more sites are presented in Table 5-4 below. All of the organic compounds are presented in Appendix C with detection levels and sample counts.

The currently accepted WHO toxicity weighting factors (3) were used to update the existing 2,3,7,8-TCDD equivalents emission factor developed from the set of dioxin/furan date for the measurement sites documented in the 2002 Emission Factors Handbook. No new dioxin/furan measurement data were identified for coal-fired units.

For benzo(a)pyrene (B(a)P) equivalents, the emission factor was updated using CalEPA PEF values for the individual PAH compounds (4). Sites where none of the PAH compounds were detected were counted as zero in the average calculation, analogous to the methodology used for dioxin/furan compounds.

For both benzo(a)pyrene equivalents and 2,3,7,8-TCDD equivalents, EPRI selected the arithmetic average of the site B(a)P and 2,3,7,8-TCDD equivalent values rather than the geometric mean to establish the final emission factors used in the emission estimates for coal-fired units.

Table 5-4
Detected Organic Substances in Flue Gas

Chemical Substance	Mean (lb/TBtu)	CAS
1,1-Dichloroethane	0.68	75-34-3
1,2,4-Trichlorobenzene	1.1	120-82-1
1,2-Dibromoethane	2.6	106-93-4
1,3,5-Trimethylbenzene	0.95	108-67-8
1,3-Dichlorobenzene	0.75	541-73-1
1,4-Dichlorobenzene	0.79	106-46-7
1-Naphthylamine	0.011	134-32-7
2,3,7,8-TCDD equivalents	1.41E-06[a]	NA
2,4-Dinitrotoluene	0.2	121-14-2
2,5-Dimethylbenzaldehyde	14	5779-94-2
2,6-Dinitrotoluene	0.11	606-20-2
2-Butanone	2.4	78-93-3

Table 5-4 (continued)
Detected Organic Substances in Flue Gas

Chemical Substance	Mean (lb/TBtu)	CAS
2-Chloronaphthalene	0.0005	91-58-7
2-Hexanone	2.1	591-78-6
2-Methylnaphthalene	0.042	91-57-6
3-Chloropropylene	2.9	107-05-1
4-Ethyl toluene	2.8	622968
4-Methyl-2-pentanone	1.4	108-10-1
4-Methylphenol	1.1	106-44-5
5-Methylchrysene	0.0006	3697-24-3
Acenaphthene	0.021	83-32-9
Acenaphthylene	0.0073	208-96-8
Acetaldehyde	2.6	75-07-0
Acetone	1.0	67-64-1
Acetophenone	1.2	98-86-2
Acrolein	1.9	107-02-8
Anthracene	0.011	120-12-7
B(a)P equivalents	0.00336[a]	NA
Benzaldehyde	4.2	100-52-7
Benzene	3.5	71-43-2
Benzo(a)anthracene	0.0066	56-55-3
Benzo(a)phenanthrene (Chrysene)	0.0049	218-01-9
Benzo(a)pyrene	0.0019	50-32-8
Benzo(b)fluoranthene	0.0083	205-99-2
Benzo(e)pyrene	0.0031	50-32-8
Benzo(g,h,i)perylene	0.0016	191-24-2
Benzoic acid	22	65-85-0
Benzyl alcohol	2	100-51-6
Benzylchloride	0.28	100-44-7
Biphenyl	0.16	92-52-4
bis(2-Ethlyhexyl)phthalate	3.6	117-81-7

Table 5-4 (continued)
Detected Organic Substances in Flue Gas

Chemical Substance	Mean (lb/TBtu)	CAS
Bromomethane	1.1	74-83-9
Butylbenzylphthalate	0.3	85-68-7
Carbon disulfide	1.0	75-15-0
Chlorobenzene	0.14	108-90-7
Chloroethane	0.43	75-00-3
Chloroform	0.64	67-66-3
Chloromethane	1.8	74-87-3
cis-1,3-Dichloropropene	0.59	10061-01-5
Cumene	0.21	98-82-8
Dibenzo(a,h)anthracene	0.00098	53-70-3
Dibenzo(a,j)acridine	0.001	224-42-0
Dibenzofuran	0.61	132-64-9
Dibutylphthalate	0.11	84-72-2
Diethylphthalate	0.2	84-66-2
Dimethylphthalate	0.09	131-11-3
Ethylbenzene	0.65	100-41-4
Ethylene dibromide	0.07	74-95-3
Fluoranthene	0.13	206-44-0
Fluorene	0.13	86-73-7
Formaldehyde	2.4	50-00-0
Hexaldehyde	5.7	66-25-1
Indeno(1,2,3-c,d)pyrene	0.0018	193-39-5
Iodomethane	2	74-88-4
Isophorone	1.2	78-59-1
m/p-Tolualdehyde	3.2	1334-78-7
m/p-Xylene	0.7	1330-20-7
Methyl chloroform (1,1,1-Trichloroethane)	0.44	71-55-6
Methyl methacrylate	1.1	80-62-6
Methylene chloride	3.1	75-09-2

Table 5-4 (continued)
Detected Organic Substances in Flue Gas

Chemical Substance	Mean (lb/TBtu)	CAS
Naphthalene	0.9	91-20-3
n-Butyraldehyde	8.3	123-72-8
n-Hexane	0.48	110-54-3
o-Tolualdehyde	2.9	529-20-4
o-Xylene	0.37	95-47-6
Perylene	0.0033	198-55-0
Phenanthrene	0.40	85-01-8
Phenol	3.3	108-95-2
Propionaldehyde	1.9	123-38-6
Pyrene	0.055	129-00-0
Styrene	0.59	100-42-5
Tetrachloroethylene	0.35	127-18-4
Toluene	1.7	108-88-3
Trichlorofluoromethane	0.72	75-69-4
Valeraldehyde	7.6	110-62-3
Vinyl acetate	0.25	108-05-4
Vinyl chloride	0.58	75-01-4
HCN	13.3	74-90-8

[a] Emission factors for B(a)P equivalents and 2,3,7,8-TCDD equivalents were updated using updated toxicity equivalency factors.

References

1. Electric Utility Trace Substance Synthesis Report, Vol. 1 and 2, Electric Power Research Institute, Palo Alto, CA: November 1994. TR-104614-V1, TR-104614-V2
2. Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI, Palo Alto, CA: 2002. 1005402
3. World Health Organization (WHO), 1995
4. California Environmental Protection Agency, (April 1999a; June 1999b) Air Toxics Hot Spots Program Risk Assessment Guidelines, Part II Technical Support Document for Describing Available Cancer Potency Factors, Office of Environmental Health Hazard Assessment, http://www.oehha.org/air/cancer_guide/hsca2.html (Accessed: January 2001)

6 EMISSION ESTIMATES

The emission estimation procedures used for coal-fired units are described in this section, followed by a summary of the emission estimate results and a discussion of potential uncertainties in the calculations.

Methodology Overview

Using unit configuration and operational characteristics, plant measurements, and fuel analyses, a procedure was developed for estimating power plant emissions of HAPs species. This procedure integrated information from plant databases, data on trace substances in utility fuels, and the emission estimating correlations and factors derived from the updated field test datasets (as described in Section 5). Final emission estimates were developed for the listed HAPs species: mercury, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, selenium, hydrogen chloride, chlorine, hydrogen fluoride, hydrogen cyanide, and selected organic compounds or groups of organic compounds (e.g., volatile organic compounds, polycyclic aromatic compounds, dioxin/furan compounds). In addition to total mercury, estimates for the elemental, oxidized and particulate-bound forms of mercury were also developed.

The calculation of emission estimates for coal-fired units involved the following steps:

1. *The unit characteristics databases were used to determine the operations of individual units for the 2007 base year.* Key unit operational characteristics required as inputs for the emission estimates included air pollution control technology configuration (i.e., control class), stack particulate emission rate, total annual heat input (trillion Btu), and mapping of individual units to common stack emission points at a given power plant station. Section 2 provides a detailed discussion of the various data sources used to compile the unit characteristics databases for coal-fired units.
2. *Blended coal characteristics were assigned to coal-fired units based on coal composition research and 2007 fuel purchase records.* For trace elements other than mercury, coal characteristics from the screened USGS COALQUAL database were used in conjunction with 2007 FERC and EIA coal purchase records for each station to assign a blended fuel compositions for each unit based on the rank and origins of the coals fired at each station. For mercury, the 1999 ICR dataset was used, as it contains 40,000 as-fired coal concentrations. It is organized by state/county and can be grouped into coal regions as well. Section 3 discusses how coal characteristics were assigned to individual units.
3. *Stack particulate emission rates each coal-fired unit were defined.* Stack particulate emission rates, in the form of lb/million Btu input, were established for each unit using data from the unit characteristics database unit characteristics database described in Section 2. The primary

source of the particulate emission data were actual emission rates as reported on 2005 EIA Form 767. The year 2005 was the last for which unit level data were reported. For units where 2005 data were not available, EIA Form 767 data from 2004 were used. When no data was available for 2004 or 2005, an estimate of the particulate emission rate was estimated using a correlation developed between plant MW size and particulate emission rate based on the 2005 EIA Form 767 data for all coal-fired plants in the unit characteristics database. This correlation and underlying dataset is presented in Appendix D.

4. *Initial trace substance emissions for coal-fired units were calculated.* Based on control device configuration, specific emission correlations or emission factors were assigned to individual coal-fired units and initial emission estimates were prepared for each unit and stack emission point. For particulate-phase metals, correlations that relate trace substance concentration in the coal and particulate emission rates to trace substance emission rates were applied. For mercury, control device specific correlations that relate coal chloride concentrations to the coal-to-stack mercury reduction percentage were applied to the total mercury input to the boiler in most cases. Similar correlations were used to estimate emissions for the various speciated forms of mercury (oxidized, elemental, and particulate forms). For selenium, hydrogen chloride, chlorine, hydrogen fluoride, and in some cases mercury, average coal-to-stack reduction factors were applied to the total trace substance boiler input rate based on the control device configuration of the unit and characteristics of the coal fired. For organic compounds and hydrogen cyanide, emission factors (mass of substance emitted per unit heat input) were used. Section 5 provides a detailed discussion of how the various emission correlations equations and factors were derived.

5. Using the appropriate equations or factors, along with the unit characteristics from Step 1, the blended fuel characteristics from Step 2, and the particulate emission rates from Step 3, estimates of trace substance emissions were calculated for each unit. Information from the unit characteristics database was then used to combine unit-level emissions for units that discharge to a common stack emission point. In addition, emission estimates for all stack emission points at a given station were also combined to provide total emission estimates at the station level for each trace substance. Sample emission calculations are provided in Appendix E, and station totals are presented in Appendix F, along with stack information.

6. *Input parameters and plant characteristics information were reviewed/updated, and trace substance emission estimates were finalized.* Initial emission estimates were prepared for all units > 25 MW selling power to the grid based on plant operational characteristics and stack parameter data compiled from publicly available sources as described above. These emission estimates were subsequently used as inputs to the initial Tier I and Tier II risk assessments. The resulting risk results were aggregated to the station level to identify those stations that had an initial estimated cancer risk greater than 0.5 in a million. Subsequently, unit control system characteristics and stack parameters for this short-list of high-interest stations were then reviewed by each of the operating companies and by RMB to determine if the various input parameters were accurate or should be refined. RMB contacted various utilities on the short-list stations to obtain data from each utility regarding actual plant control configurations, stack parameter values and/or actual stack emissions test data that could be used to update the information. Updates to the input data for the short-listed stations included the following types of modifications:

   - updates to stack particulate emission rates based on actual recent stack test data;

- changes in control classification for selected units to account for addition of wet FGD scrubber and/or NO_x systems between 2007 and 2009;
- changes in stack latitude/longitude and various stack parameters (gas exit velocity, volumetric emission rate, stack height, etc.) to correct errors in the initial stack parameter database, and
- updates to information regarding common stack emission points for various units.

Minor computational errors noted in the initial emission estimates were also corrected. Based on this new set of input values, the emission estimates were finalized and additional risk analyses were carried.

A summary of the emission estimate results for coal-fired units is provided in the following sections.

Emission Summary

Normalized Emission Rates

Table 6-1 summarizes estimated emission rates of inorganic non-mercury HAPs substances from coal-fired units normalized on a lb/TBtu heat input basis. Results are presented for all units, for units with PM control only, and for units with PM+SO_2 controls. Median, mean, maximum, and minimum values are presented for each substance. As expected, significant differences are seen in the normalized emission rates for HCl, Cl_2, HF, Hg and Se for units with particulate only controls compared to units with particulate+SO_2 controls.

Figure 6-1 provides a cumulative frequency distribution of emission rate estimates across all coal-fired units for arsenic and chromium to illustrate the typical distribution of emission factor values across all units. The highest normalized arsenic and chromium emission rates were 36 lb/TBtu and 24 lb/TBtu, respectively. By comparison, the highest estimated normalized emission rate for HCl and HF were 124,000 lb/TBtu and 7,300 lb/TBtu, respectively.

Estimated lb/TBtu emission rates for particulate phase metals at each unit were also plotted against the particulate emission rate reported for each unit in the unit characteristics database to illustrate whether particulate emissions may provide a potential surrogate for particulate phase metals emissions.

Table 6-1
Emission Rate Summary for Coal-Fired Units – Non-Mercury HAPs (lb/TBtu input basis)

	As	Be	Cd	HCl	Cl2	Co	Cr	HF	Mn	Ni	Pb	Sb	Se
All Units													
Median	3.6	0.3	0.6	3,020	1,471	1.2	6.4	1,678	11.9	5.4	3.4	0.3	51.5
Mean	5.5	0.4	0.7	22,189	2,357	1.3	7.1	2,410	13.3	6.1	4.1	0.4	57.3
Max	35.8	2.7	4.9	123,973	32,435	4.8	24.4	7,277	58.3	43.8	19.2	1.8	262
Min	0.1	0.024	0.049	34.1	16.1	0.2	0.9	20.9	1.3	1.1	0.3	0.0	0.0
Particulate Control Only													
Median	3.9	0.3	0.6	13,669	1,979	1.3	6.6	3,130	12.6	5.6	3.8	0.3	63.5
Mean	5.8	0.4	0.7	29,945	2,975	1.4	7.4	3,147	14.0	6.3	4.3	0.4	63.8
Max	35.8	2.7	4.9	123,973	32,435	4.8	24.4	7,277	47.8	39.4	19.2	1.8	262
Min	0.1	0.027	0.073	1,073	58.4	0.2	1.0	948	1.6	1.1	0.4	0.0	0.0
Particulate and SO_2 Controls													
Median	2.8	0.3	0.5	553	551	1.0	5.2	308	9.6	4.7	2.8	0.3	40.2
Mean	4.7	0.4	0.6	662	656	1.1	6.2	285	11.3	5.6	3.5	0.3	39.4
Max	33.5	2.2	3.4	2,202	2,202	3.8	20.9	731	58.3	43.8	14.5	1.8	180
Min	0.3	0.024	0.049	34.1	16.1	0.2	0.9	20.9	1.3	1.1	0.3	0.0	0.4

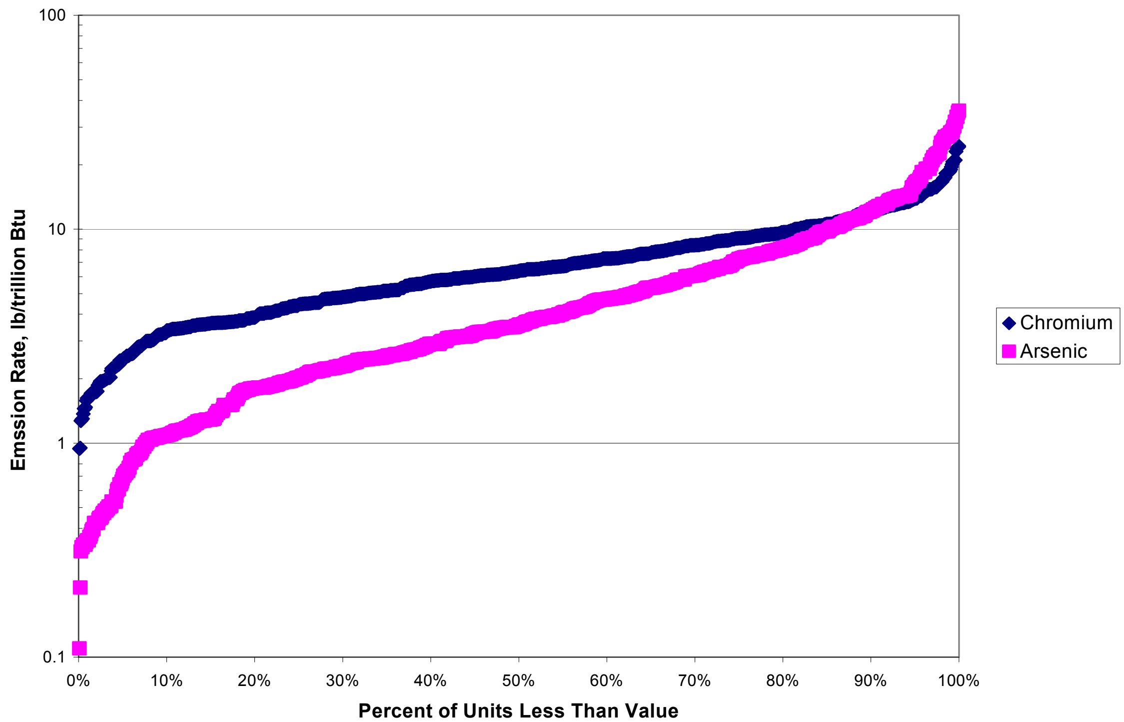


Figure 6-1
Cumulative Frequency Distribution of Arsenic and Chromium Emission Rates for Individual Coal-Fired Units

Figures 6-2 and 6-3 show the results for arsenic and chromium, the two trace element HAPs that were shown to be the largest contributors to cancer health risk, respectively. For both of these particulate phase metals, the lb/TBtu individual unit emission rate values increase with increasing particulate emission rate. For arsenic, the range of estimated emission values at a given particulate emission rate varies by as much as a factor of 40, reflecting the variability in geometric mean coal arsenic compositions across units with a given particulate emission rate. For example, units emitting 0.01 lb/million Btu of particulate exhibit estimated arsenic emissions ranging from 0.2 to 8 lb/TBtu. Similar trends are observed for chromium; however, the range of estimated emission values for a given particulate emission rate is narrower. Chromium values vary by a factor of 10 at 0.01 lb/million Btu particulate emissions (1.3 to 14 lb/TBtu). Although emissions of particulate phase metals do trend with particulate emissions, coal composition also has a significant impact on the estimated emission rates.

For more volatile species (mercury, selenium, hydrogen chloride, chlorine, and hydrogen fluoride), normalized emission rates are primarily a function of the coal composition and class of control technology, so similar trends with particulate emissions are not evident.

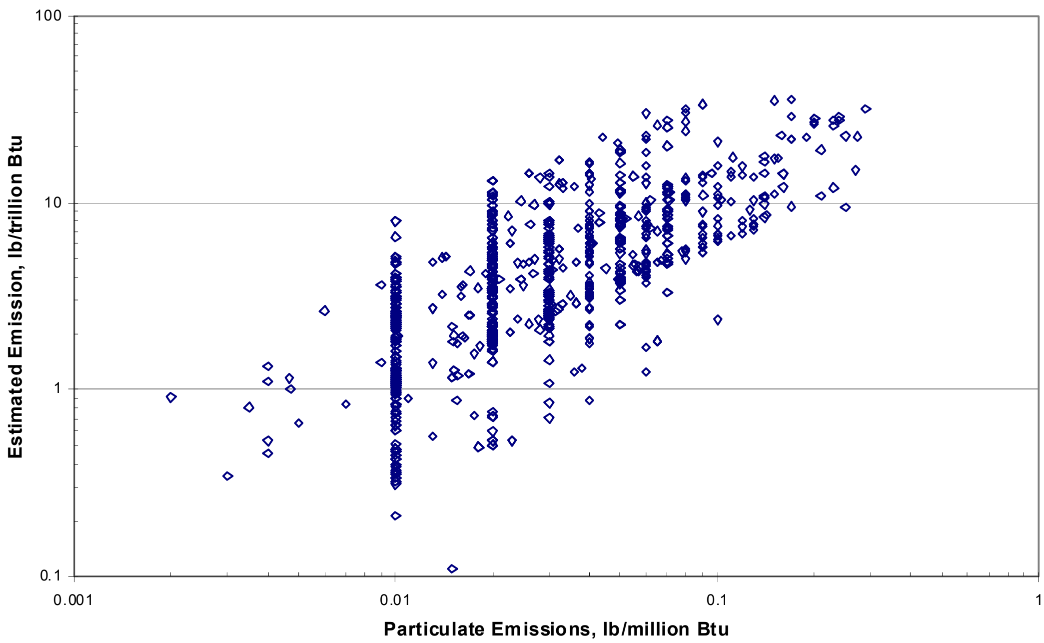


Figure 6-2
Estimated Arsenic Emission Rate by Unit as a Function of Particulate Emission Rate

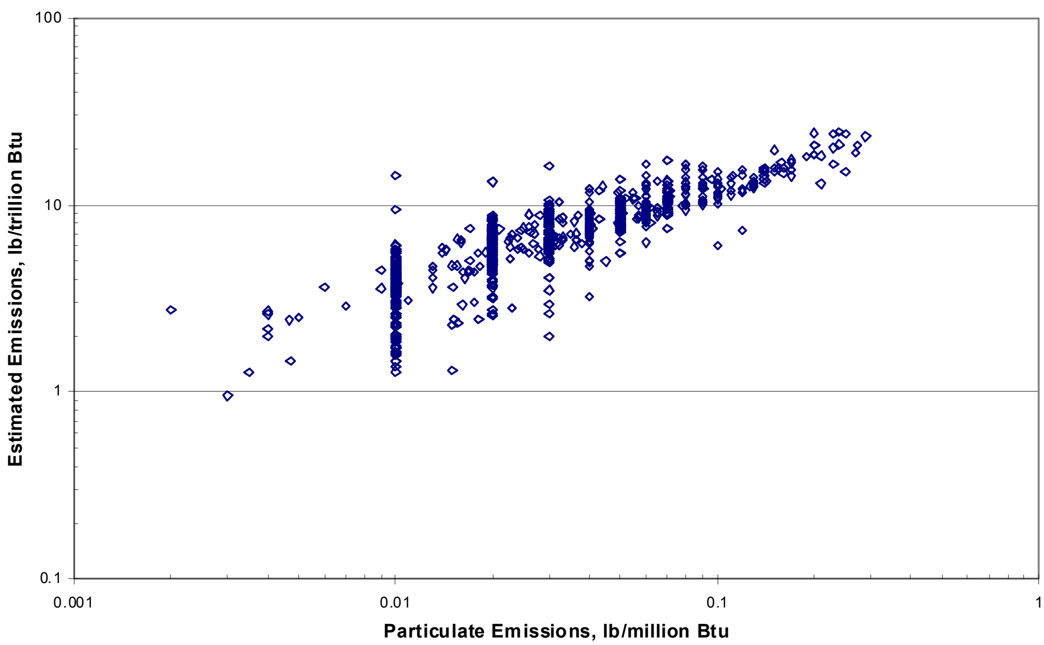


Figure 6-3
Estimated Chromium Emission Rate by Unit as a Function of Particulate Emission Rate

Table 6-2 summarizes estimated normalized emission rates for mercury for all coal-fired units within a specified control class. Speciated forms of mercury are presented as a percentage of total mercury emissions in each control class. Results are presented for all units within each of the 35 control technology class categories defined for this study. The mean normalized emission rate for mercury across all units is 4.2 lb/TBtu with an overall coal-to-stack reduction of 51 percent. Cumulative estimated mercury emissions for all units are approximately 44 tons (40 metric tons). The impact of using SCR in combination with wet FGD systems is evident by comparing normalized mercury emission rates for selected control classes with and without SCR. The SCR ESPc FGDw control class shows a mean emission factor of 1.2 lb/TBtu (88% reduction) compared to 4.1 lb/TBtu (58% reduction) for ESPc FGDw. Mean emission factors for control class groups making up approximately 70% of the total MW capacity (ESPc, ESPc CON, ESPc FGDw, FF, SCR ESPc, SCR ESPc CON, and SCR ESPc FGDw) ranged from 1.2 lb/TBtu to 5.8 lb/TBtu.

Annual Emissions

Table 6-3 summarizes results of the emissions estimates on an annual basis for the 2007 base year aggregated at the station level for 462 operating stations (808 stack emission points). For each electric utility steam generating unit, the emissions of each trace substance were estimated as described above. Unit-level emissions, aggregated to the stack serving each unit, and then aggregated to the power-plant station level, served as the emission inputs to the subsequent dispersion modeling and health risk assessment. Station-level emission estimates for all of the detected organic compounds listed previously in Section 5 (Table 5-4) were developed; however, only selected organic compounds or compound groups are summarized in Table 6-3. Appendix F provides a detailed listing of the estimated total annual emission values for each station as well as a detailed listing of the stack parameter values (latitude/longitude, height, temperature, etc.) for stack emission points at each station. Annual emission estimates for organic species not listed in Table 6-3 can be derived the emission factors from Table 5-4 and the annual total trillion Btu heat input values for each station or stack emission provided in Appendix F.

Table 6-2
Summary of Unit-Level Mercury Emissions by Control Technology Class

Control Class	MW	# Units	TBtu Input	Coal Hg (lb/yr)	Stack Hg (lb/yr)	% Reduction	Stack Hg (lb/TBtu)b	% Elemental	% Oxidized	% Particulate
ESPc	76,970	367	4,414	34,367	25,775	25%	5.8	44.2%	52.3%	3.5%
ESPc CON	30,254	113	1,930	14,805	7,402	50%	3.8	45.8%	50.2%	4.0%
ESPc ACI	109	1	5	29	3	90%	0.6	54.0%	42.5%	3.5%
ESPc FGDd	1,512	4	112	683	649	5%	5.8	94.0%	5.6%	0.4%
ESPc FGDw	34,259	76	2,416	23,926	10,006	58%	4.1	87.8%	11.6%	0.7%
ESPh	13,434	77	794	5,458	5,294	3%	6.7	62.6%	34.9%	2.5%
ESPh FGDw	6,925	16	504	2,740	2,572	6%	5.1	91.0%	6.4%	2.6%
FF	18,012	126	1,216	13,548	5,731	58%	4.7	23.0%	76.2%	0.8%
FF ACI	270	3	20	92	9	90%	0.5	23.0%	76.2%	0.8%
FF FBC	1,235	14	57	462	65	86%	1.1	56.0%	42.0%	2.0%
FF FGDd	7,583	33	543	3,352	2,342	30%	4.3	92.9%	4.3%	2.8%
FF FGDw	6,422	13	476	2,295	321	86%	0.7	74.0%	21.0%	5.0%
VS FGDw	5,922	17	443	2,660	2,075	22%	4.7	94.0%	5.0%	1.0%
SCR ESPc	23,103	51	1,337	9,557	5,409	43%	4.0	20.9%	78.1%	0.9%
SCR ESPc CON	21,787	37	1,351	10,871	5,435	50%	4.0	39.8%	56.2%	4.0%
SCR ESPc FBC	80	1	9	53	7	86%	0.9	56.0%	42.0%	2.0%
SCR ESPc FGDw	40,055	69	2,590	27,146	3,206	88%	1.2	59.0%	40.2%	0.8%
SCR ESPc FGDw CON	1,080	1	68	481	241	50%	3.5	29.7%	66.3%	4.0%
SCR ESPh	8,496	14	500	5,944	5,766	3%	11.5	20.0%	77.5%	2.5%
SCR ESPh FGDw	3,035	7	194	1,499	436	71%	2.2	91.0%	6.4%	2.6%
SCR FF	2,681	4	171	1,043	685	34%	4.0	30.0%	69.2%	0.8%
SCR FF ACI	922	1	90	546	55	90%	0.6	23.0%	76.2%	0.8%
SCR FF FGDd	2,822	18	184	1,413	551	61%	3.0	30.0%	69.2%	0.8%
SCR FF FGDw	880	2	68	425	59	86%	0.9	74.0%	21.0%	5.0%
SCR VS FGDw	3,270	4	192	1,590	731	54%	3.8	56.0%	43.0%	1.0%
SNCR ESPc	8,911	42	512	5,351	1,498	72%	2.9	20.0%	76.5%	3.5%

Table 6-2 (continued)
Summary of Unit-Level Mercury Emissions by Control Technology Class

Control Class	MW	# Units	TBtu Input	Coal Hg (lb/yr)	Stack Hg (lb/yr)	% Reduction	Stack Hg (lb/TBtu)b	% Elemental	% Oxidized	% Particulate
SNCR ESPc ACI	74	1	5	27	3	90%	0.6	20.0%	76.5%	3.5%
SNCR ESPc FGDw	5,049	18	305	3,553	440	88%	1.4	59.0%	40.2%	0.8%
SNCR ESPh	1,294	9	72	400	388	3%	5.4	20.0%	77.5%	2.5%
SNCR FF	2,682	25	169	3,438	629	82%	3.7	23.0%	76.2%	0.8%
SNCR FF FBC	240	2	14	89	12	86%	0.9	56.0%	42.0%	2.0%
SNCR FF FGDd	863	5	54	2,113	681	68%	12.7	76.5%	20.7%	2.8%
SNCR FF FGDw	848	2	58	336	47	86%	0.8	74.0%	21.0%	5.0%
SNCR VS FGDw	187	1	8	61	38	38%	4.8	75.0%	24.0%	1.0%
IGCC	633	2	27	151	145	4%	5.3	96.0%	3.5%	0.5%
Total	**331,634**	**1,173**	**20,908**	**180,504**	**88,706**[c]	**51%**	**4.2**	**50.4%**	**47.1%**	**2.5%**

[a] Calculated based on the total coal mercury input (lbs/yr) and the total stack mercury emissions (lbs/yr) for a given control class category.

[b] Calculated based on the total trillion Btu input and the total stack mercury emissions (lbs/yr) for a given control class category.

[c] Equivalent to 44 tons or 40 metric tons.

Key:

ESPc = cold-side electrostatic precipitator
SCR= selective catalytic reduction
ESPh = hot-side electrostatic precipitator
SNCR= selective non catalytic reduction
FGDd = dry flue gas desulfurization
IGCC = integrated gasification combined cycle
FGDw = wet flue gas desulfurization
VS = venturi scrubber
FF = fabric filter
FBC = fluidized bed combustion
ACI = activated carbon injection
CON = flue gas conditioning

Table 6-3
Annual Emission Summary at the Station Level

	Annual Emissions at Station Level (lb/yr)			
	Median	**Mean**	**Max**	**Min**
As	104	214	2950	1.0
Be	9	16	185	0.1
Cd	17	27	253	0.1
Co	34	54	472	0.1
Cr	178	293	2270	1.0
Mn	358	575	3960	2.0
Ni	157	249	3330	1.0
Pb	100	164	1280	1.0
Sb	9	15	148	0.04
HCl	98,600	762,000	16,500,000	252
Cl_2	33,100	95,700	2,790,000	14
HF	39,700	85,200	1,180,000	109
HCN	376	601	3,490	1.1
Se	1,360	2,490	30,000	0
Hg (total)	93	192	3,300	0.47
Hg (elemental)	41	97	1740	0.1
Hg (oxidized)	40	91	2350	0
Hg (particulate)	2	5	119	0
Benzene	99	158	919	0.28
Toluene	48	77	446	0.14
Formaldehyde	68	108	630	0.19
B(a)P Equivalents	9.5E-02	1.5E-01	8.8E-01	2.7E-04
2,3,7,8-TCDD Equivalents	4.0E-05	6.4E-05	3.7E-04	1.1E-07

Estimated annual emissions (lbs/yr) at the station level are also presented graphically in Figures 6-4 through 6-7 as cumulative frequency distribution plots. Figure 6-4 presents estimated annual emissions for particulate phase metals, Figure 6-5 show estimates for acid gas species (HCl, Cl_2, HF, and Se), Figure 6-6 shows estimates for total and speciated forms of mercury, and Figure 6-7 includes selected organic compounds and organic compound groups (benzene, toluene, formaldehyde, polycyclic aromatic compounds as B(a)P equivalents, and dioxin/furan compounds as 2,3,7,8-TCDD equivalents).

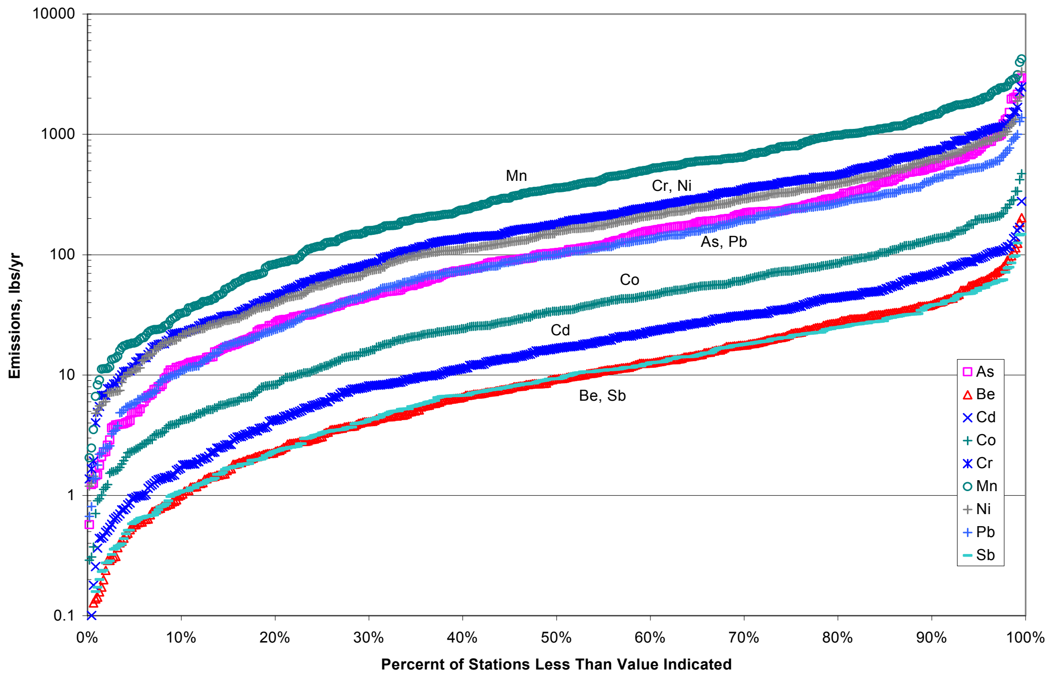


Figure 6-4
Cumulative Frequency Distribution of Station-Level Annual Emissions for Particulate Phase Metals

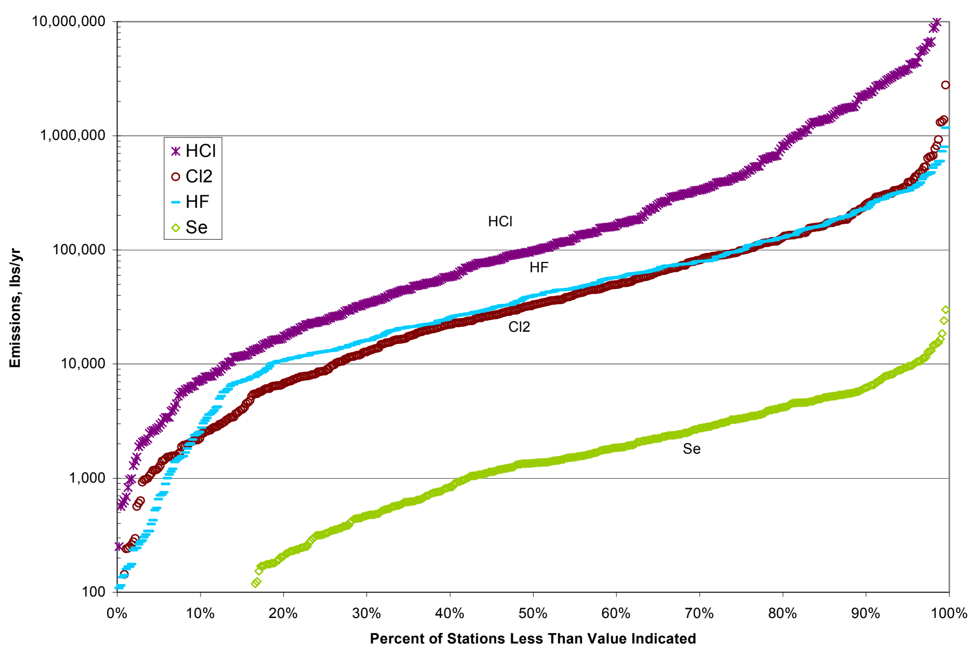


Figure 6-5
Cumulative Frequency Distribution of Station-Level Annual Emissions for Acid Gas Species

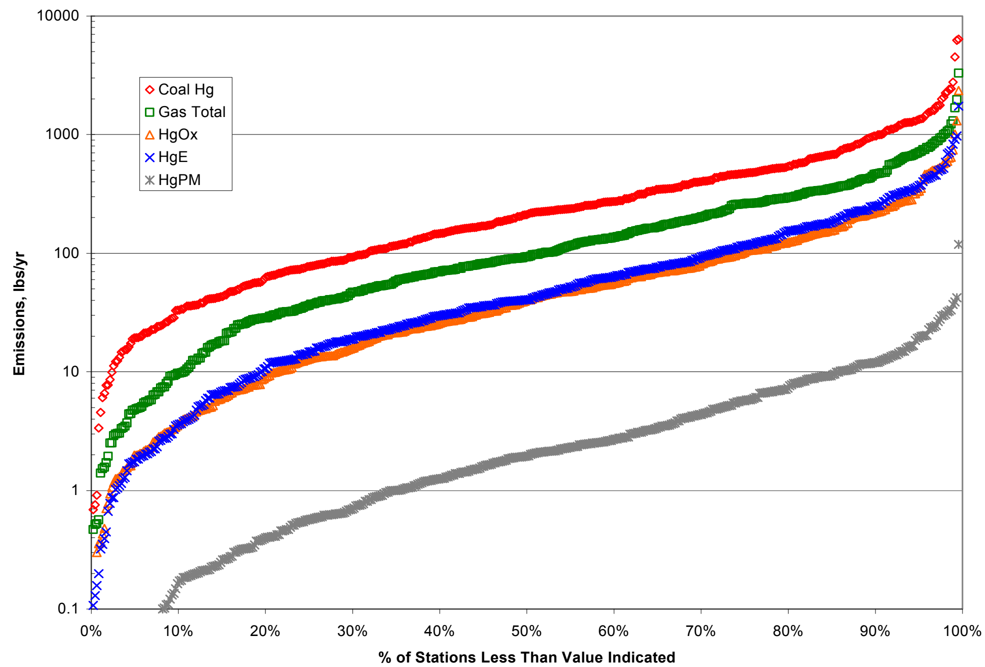


Figure 6-6
Cumulative Frequency Distribution of Station-Level Annual Emissions for Total and Speciated Mercury

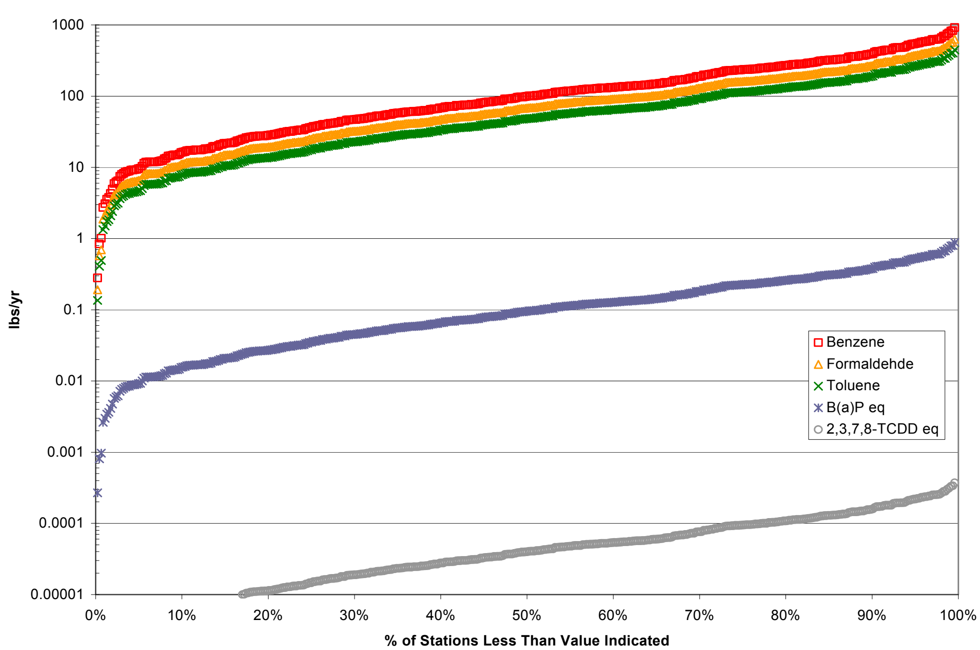


Figure 6-7
Cumulative Frequency Distribution of Station-Level Annual Emissions for Organic Compounds

Figure 6-8 presents results of the annual mercury emission calculations on a station and individual unit basis. The estimated pounds per year of mercury entering the plant in the fuel is plotted against the predicted stack emissions for the 1,173 units and 470 stations. A line representing 50% removal is shown on the figure as a reference point. As shown previously in Table 6-2, the average removal for all plants is about 51 percent, calculated based on the estimated total annual coal mercury input (180,500 lbs/yr) and the estimated total annual mercury emissions (88,700 lbs/yr).

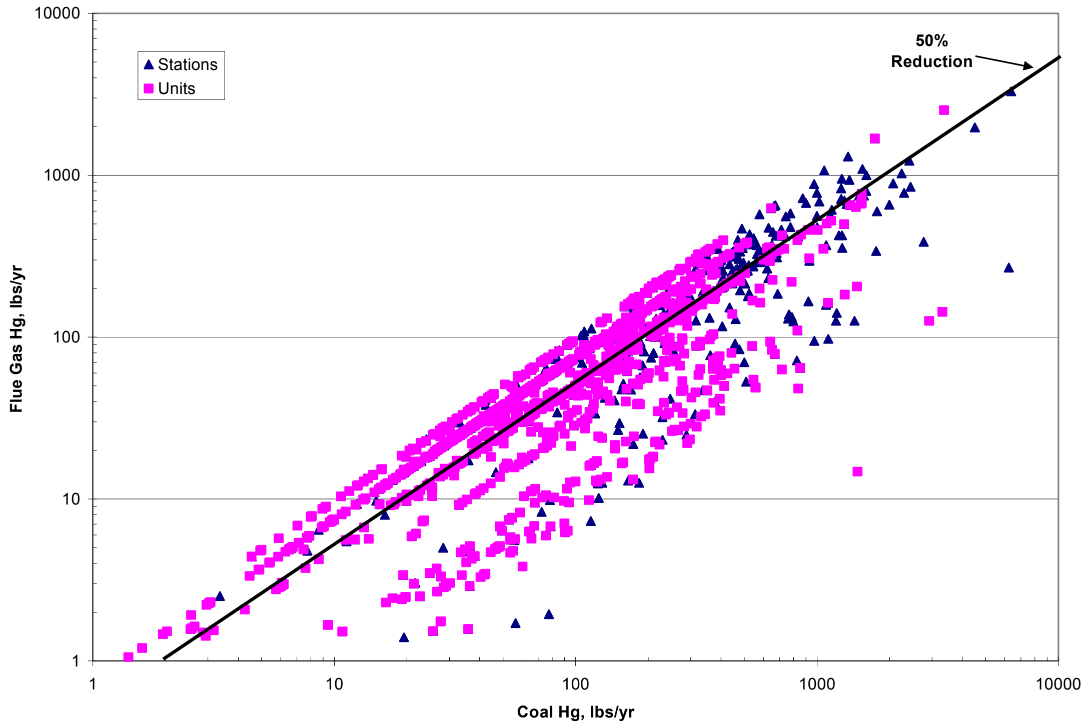


Figure 6-8
Mercury Reduction by Units and Stations

Figure 6-9 presents the cumulative frequency distribution for mercury for individual unit emissions and the cumulative total emissions for all units. This figure can be used to determine how many individual units contribute certain tonnages of annual emissions. The total amount of mercury emissions is estimated to be 44 tons (40 metric tons) for 2007. Figure 6-9 show that 50 percent of the individual units emit less than 41 pounds of mercury per year, for a cumulative total of 5 tons (4.5 metric tons). Conversely, the remaining 50 percent of the units account for approximately 39 of the 44 tons (35 of 40 metric tons) per year of mercury emissions. Approximately 80% of all units account for 39% of the total annual mercury emissions (17 of 44 tons). The smallest 25% of units emit less than about 17 pounds each for a cumulative total of 1 ton (0.9 metric ton) per year.

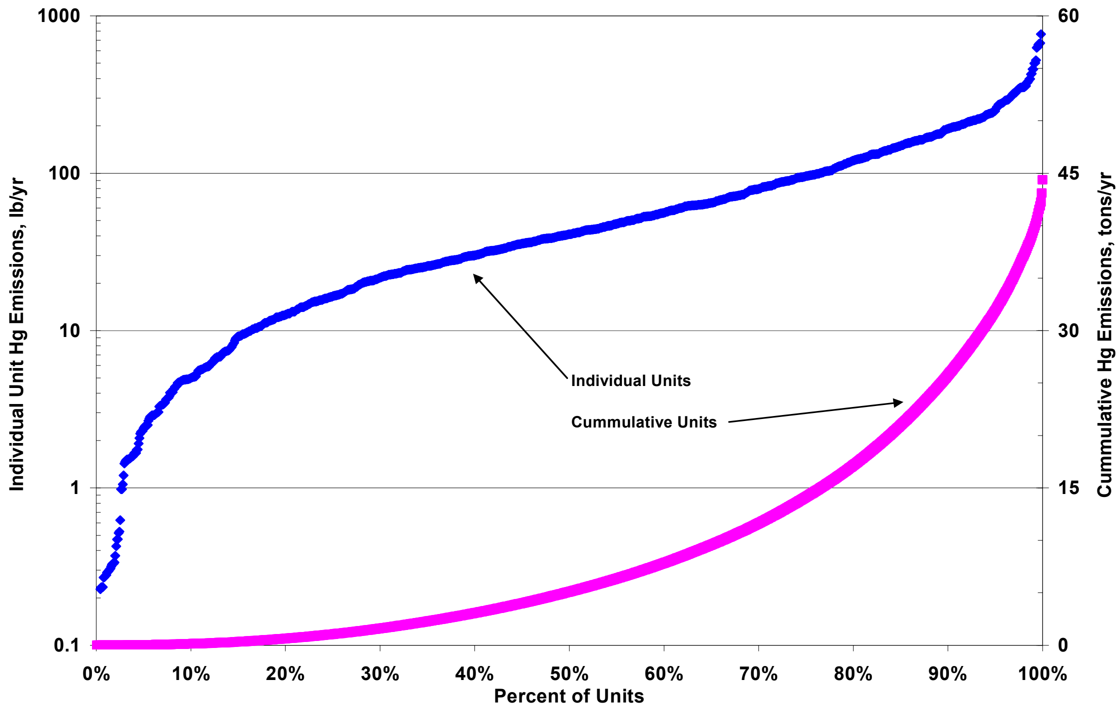


Figure 6-9
Distribution of Annual Mercury Emissions by Individual Units

Uncertainty in Emission Estimates

All of the emissions estimates calculated in this current study contain uncertainties due to numerous assumptions in their derivation. The degree to which these assumptions impact the calculated values used in the risk assessment models are discussed below in both qualitative and quantitative terms. The basic premise of the estimates is that measurements made at a subset of the utility boiler population can be used to represent the non-tested sites. If the subset is representative, then more specific issues arise as to the appropriateness of the sampling and analysis methods. Lastly, the long-term variability of input parameters and/or control device performance needs to be considered.

Test Sample Population

There are about 1100 individual coal-fired units that require emission estimates. These units are the furnaces which produce steam for electrical production. At some stations, multiple furnaces provide steam to one turbine. For the most part, the flue gas from a furnace is treated by a unique series of control devices, before being exhausted through a single stack or being combined with other exhaust streams. The compilation of streams at a single stack requires that each unique furnace has its emissions calculated.

As discussed in Section 4, for most of the HAPs, about 50 sites have been tested in total. Mercury is an exception with about 250 sets of test data. This indicates that about 4% to 20% of the units have been sampled and are currently included in the datasets used to develop the various emission correlations or emission factors. More data obviously provides a better estimate, however the cost of obtaining data is not insignificant.

Table 4-5 in Section 4 provides a profile of the number of units tested for mercury relative to the various control class groups identified for this study. For control class groups that have tested units, most indicate approximately 20% to 50% of the total units have been tested, so a substantial amount of test data is available for development of emission correlations or factors in these cases. However, for other control class groups no test data were available, so correlations from other control class groups with test data (or combinations of correlations) were assumed to apply to control class groups without test data. These assumptions, documented in detail in Section 5 and Appendix C, contribute to the uncertainty in emission estimates for these control class groups.

The emission estimation procedure employed here does not use the actual measured emissions of sites that have been tested. This is because the test periods are quite short, ranging from a few hours to a few days. The mass rate entering the system for many of the substances of concern is known to vary over a year. This variability is shown in the coal composition discussion later (mean versus standard deviation values) in this section. Since the chemistry of trace substances does not vary greatly for similar configurations, the use of correlations that are based on long-term average input parameters is a reasonable way to estimate emissions. For example, the behavior of arsenic, whether present in the coal at 5 or 50 ppm, remains the same as the coal is combusted, the flue gas cooled, ash removed, and finally the flue gas stream is scrubbed. Only the total mass rate varies. For this reason, long term input parameters, using correlated datasets, should provide reasonable emission values for use in risk assessment analyses.

Sampling and Analytical Methods

Since the early 1990's, the procedures for collecting and analyzing most analytes in stack emissions have remained essentially the same, with the exception of mercury, although there have been improvements in analytical method sensitivities for some trace elements. Mercury measurements have evolved to determine the various species present, and some of the organic methods have developed more sensitive detection levels, but in general, the reliability of the methods is not a major concern. For any given sample, the collection portion of the procedure is expected to be accurate within 10% of the actual amount, while the uncertainty in the analysis procedure typically exceeds the sampling uncertainty. The 1994 EPRI Synthesis Report discussed sampling and analytical issues associated with trace substance measurements at power plants in great detail (2). Since that time, some issues have been further addressed, specifically low-level chlorine analyses for coal, and mercury levels in Texas lignite. However, the bulk of the reference gas stream measurement methods published by EPA have not been changed, except for minor procedural modifications. The multi-metals and mercury speciation methods have been validated by EPA's Method 301 procedure.

HAPs Metals

The predictive equation for the HAPs metallic elements is of the form:

$$Emissions = a(coal\ ppm/ash\% \times PM)^b$$

This regression has readily obtained input parameters: the coal composition and the particulate emission level for a specific unit. As an example, for the arsenic dataset, the constants a and b are 2.91 and 0.77 respectively for 51 data pairs, with an r^2 of 0.60.

To illustrate the potential variability in coal trace element compositions and ash content, data from the USGS coal quality database were examined. The arsenic found in 116 samples of Eastern Kentucky bituminous coal has a geometric mean of 6 ppmw. The lower and upper geometric standard deviations range from 2 to 17 ppmw. Figure 6-10 is a plot of the coal ash weight-percent versus the coal arsenic level. As can be seen, there is no valid correlation between these two parameters. Figure 6-11 is a plot of the reported arsenic concentrations, showing the cumulative distribution frequency. The coal ash content averages 12%, with a standard deviation of 4 percent.

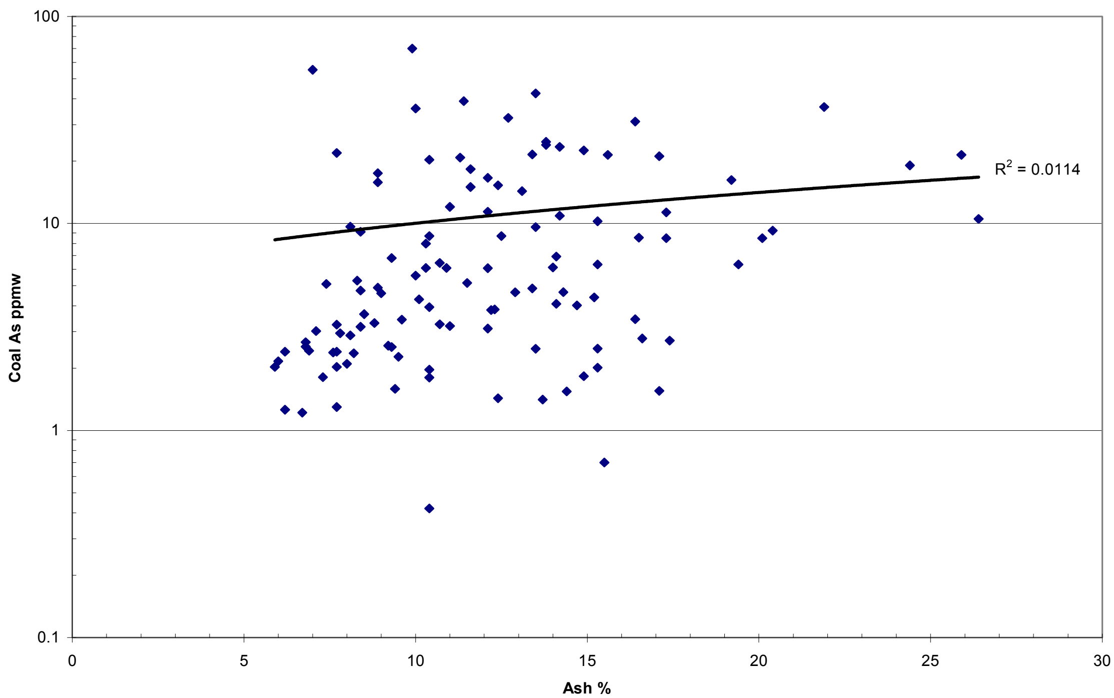


Figure 6-10
Ash vs. Arsenic Concentrations for Eastern Kentucky Coal

For most sites, the particulate emission level is accurate within 20% or less, i.e., a device designed for 0.02 lb/million Btu will typically not exceed that level, and may be as low as 0.016

lb/million Btu. Table 6-4 shows the effect of these uncertainties versus the calculated emission factor. The "most likely" emission factor, using the geometric mean values, is 2.2 lbs/TBtu. However, the first and second upper standard deviation values are significantly higher. This indicates that short-term measurements at a site can differ significantly from a predicted value obtained using the correlations. Consequently, the use of larger datasets (i.e., the screened USGS coal quality database) can offer a more realistic long-term input value than actual short-term test measurements. However, the USGS regions span large geographical areas, and if plants have coal analysis that shows consistent compositions, these values should be used.

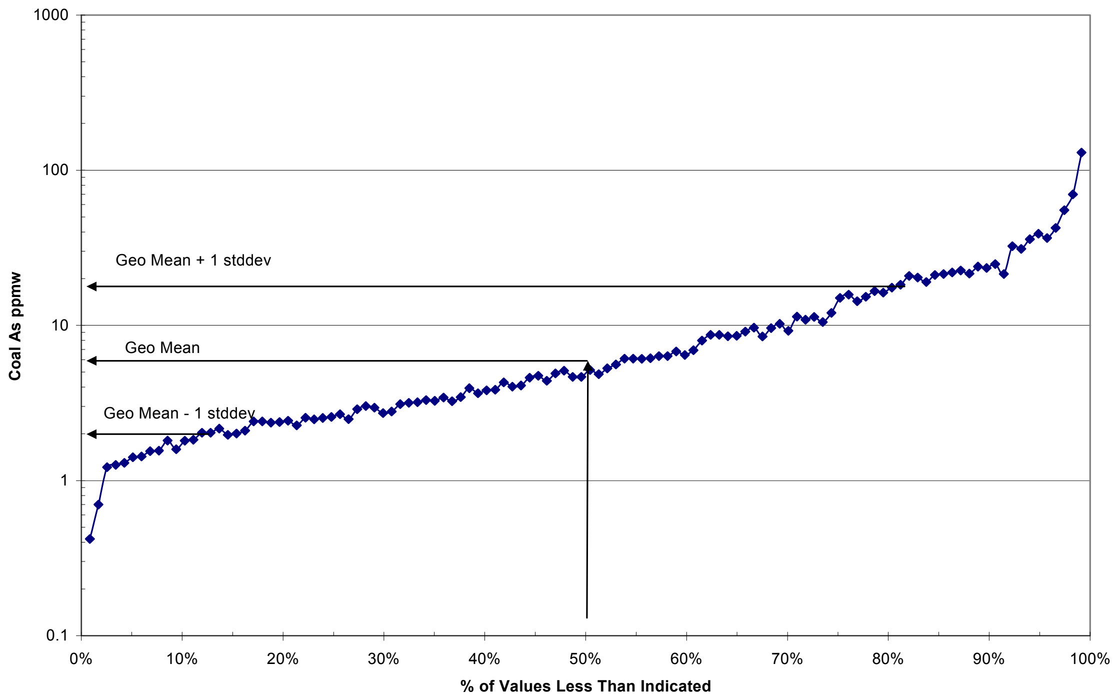


Figure 6-11
Eastern Kentucky Coal Arsenic Distribution

Table 6-4
Uncertainty in Arsenic Emission Factor Estimates

	Coal As ppmw	Coal Ash wt%	Particulate Matter (lb/MBtu)	Emission Factor (lb/TBtu)
Geometric Mean	6	12	0.02	2.2
-1 std dev	2	16	0.02	0.6
+1 std dev	17	8	0.02	9.5
+2std dev	49	8	0.02	27.4

Table 6-5 presents the geometric mean and one upper standard deviation concentration for the HAPs elements by coal region developed from the screened USGS coal dataset used in the emission estimates. Note that most upper standard deviation values are two to three times the mean value, which can lead to significant uncertainty when comparing measured to predicted values.

Table 6-5
Eastern Kentucky Coal Concentrations (ppmw)

Element	Geometric Mean	+ 1 standard deviation
Arsenic	6.0	17
Beryllium	2.0	3.2
Cadmium	0.12	0.34
Cobalt	3.0	5.2
Chromium	14	23
Manganese	34	72
Nickel	11	23
Lead	5.4	13
Antimony	0.5	1.6
Selenium	2.0	3.2

Mercury

EPRI's assessment of ICR mercury data conducted in 2000 (1) provided a detailed evaluation of emission estimate uncertainty, including an evaluation of variability of mercury and chloride in coal samples from the ICR dataset. This previous study also addressed the issue of analytical uncertainty for mercury and chloride analyses of solid fuels. Since the current emission estimate effort for mercury used a similar correlation methodology and similar ICR coal data inputs as was used in the 2000 mercury assessment, much of the previous analysis held for the current estimates, at least at a qualitative level.

As part of the 1999 ICR, 40,000 coal samples were analyzed for mercury. Since the removal efficiency of mercury by most control technologies is not dependent on the concentration of mercury in the flue gas, the fuel mercury concentration and, in some cases, coal chloride concentrations are the predominant predictors of the mercury emission level.

Figure 6-12 is a cumulative distribution plot of the mercury distribution in the three major coal ranks. As opposed to the other trace metals, mercury concentration does not exhibit as wide a concentration range. Note that 95% of the values reported are between 2 and 30 lb/TBtu. The other trace elements typically span several orders of magnitude in concentration over 95% of the values.

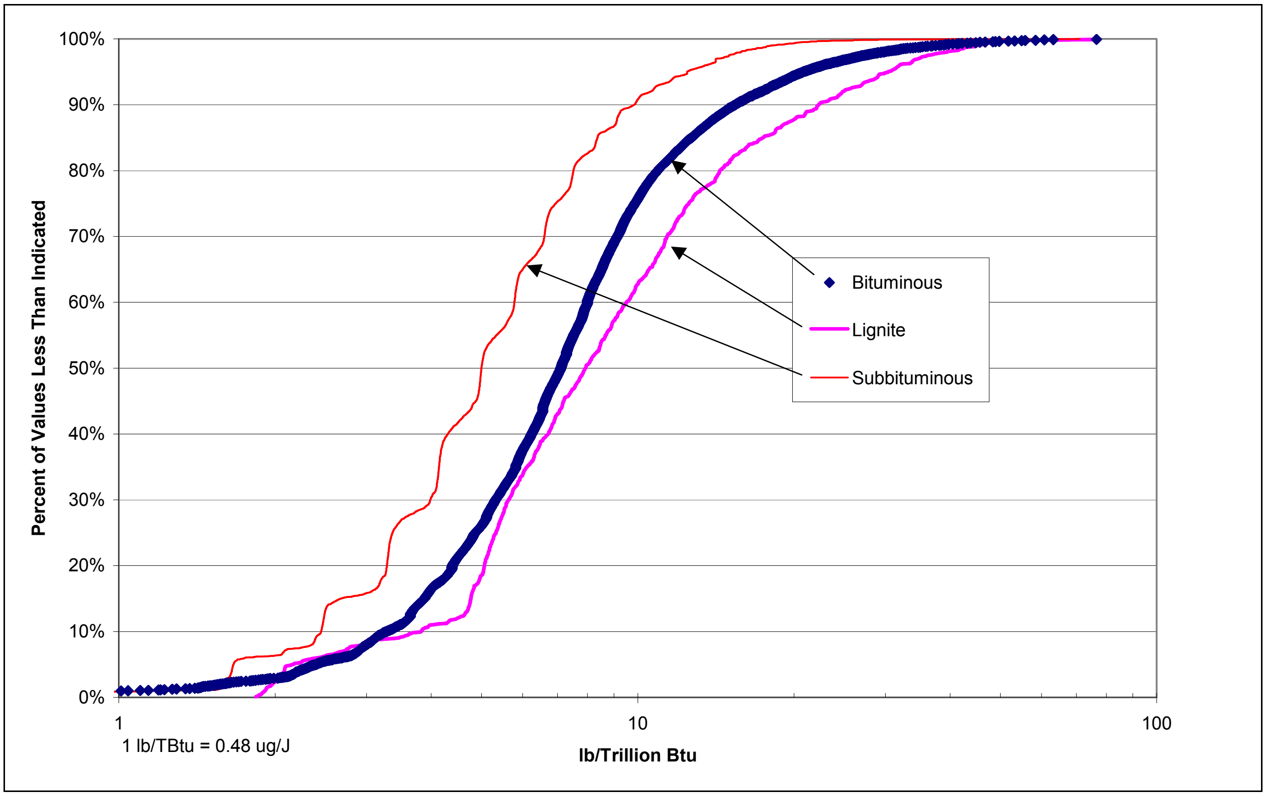


Figure 6-12
Mercury Distribution by Coal Rank, 1999 ICR Data

With respect to uncertainties in the analytical methods used for mercury, the 2000 EPRI mercury emissions assessment concluded that the total mercury levels entering power plants may have been overestimated by 5 percent. Potential bias in the ICR coal chloride values for low chloride coals (< 200 ppmw) was also identified in the previous EPRI study since chloride concentrations at this level are near the limits of quantitation for most analytical methods used for the 1999 ICR samples. Using the calculation approach for the current emissions estimate, varying all coal chloride levels for units with concentrations below 200 ppmw by ±50% results in total annual mercury emission of 43.4 to 45.6 tons per year compared to the total of 44 tons per year calculated using the "as reported" ICR coal chloride and mercury values.

Organic Compounds

For organic compounds, the lognormal mean emission factors were calculated based on anywhere from 2 to 30 individual field measurement values for all coal-fired units. The measurement variability of trace organic substances is often very large. The distribution of individual measurements for a given substance typically ranged over 2-4 orders of magnitude. The lower and upper 95% confidence intervals for the geometric mean emission factors of substances used in this study typically exhibited values in the range of 0.3 to 3 times the mean emission factor.

References

1. An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants, EPRI, Palo Alto, CA: September 2000. TR-1000608
2. Electric Utility Trace Substance Synthesis Report, Vol. 1 and 2, Electric Power Research Institute, Palo Alto, CA: November 1994. TR-104614-V1, TR-104614-V2

7

INTRODUCTION TO THE INHALATION RISK ASSESSMENT

Background

The Electric Power Research Institute (EPRI) has instituted a broad look at the potential risks posed to human health, as well as to welfare and ecosystem indicators, from coal-fired electric utility generating facility stack emissions. To assist in this endeavor, EPRI and its research contractor, AECOM Environment, conducted a risk assessment of hazardous air pollutant emissions from coal-fired electric utilities in the United States based on present-day configurations. This report discusses the methods and results of the tiered inhalation health risk assessment, which essentially following U.S. EPA guidelines.

The purpose of the assessment is twofold. The first goal is to provide the U.S. Environmental Protection Agency (EPA) with information regarding acute and chronic inhalation risks, multi-pathway human health risk and ecological risk associated with electric generation by coal-fired electrical generating units (EGUs). It is anticipated that EPA will use this information in consideration of the extent to which the level of human health risk associated with coal-fired utility HAP emissions warrants continued classification of that source category as a significant HAPs source. Secondly, the risk assessment results are helping to guide focused areas of EPRI research on HAPs sources, fate and transport and their basic health effects. A number of projects have begun taking advantage of the risk assessment results and the data used to guide the assessment. This report is focused on the numerical results of the assessment.

Study Approach

EPRI and AECOM have worked cooperatively with EPA's Office of Air Quality Planning and Standards (OAQPS) in the development of a study approach, including modeling requirements and risk assessment methods. The tiered approach developed in coordination with Ted Palma of EPA OAQPS generally follows guidelines of the EPA Air Toxics Risk Assessment Reference Library (EPA, 2004). A Tier 1 screening-level inhalation risk assessment was conducted for all HAPs that in a companion EPRI study (URS, 2009) were determined to be emitted from 470 coal-fired power plants throughout the U.S. Three types of inhalation risks were evaluated: chronic non-cancer risk, acute non-cancer risk and cancer risk. A Tier 2 screening assessment which used the AERMOD version of the Human Exposure Model (HEM3-AERMOD) was applied to a subset of the power plants for which the Tier 1 assessment resulted in higher modeled risk. In addition to the risk associated with individual power plants, inhalation risks associated with power plants located within a 50 kilometer radius of one another were evaluated.

8

INHALATION RISK ASSESSMENT METHODOLOGY

Source Data

Stack parameters and annual emission estimates data were developed by EPRI (URS 2009) for individual stacks at 470 coal-fired power plants. The list of the power plants is provided with the results in Table 9-1. Physical source parameters included the location, stack height, inner stack diameter, exit temperature and exit velocity. Each of the 470 power plants had from 1 to 10 stacks, for a total of 825 stacks. Annual emissions of a large number of stack-gas constituents that have been measured in coal-fired power plant exhaust were quantified by URS (2009) and all HAPs for which EPA OAQPS has established dose-response factors (EPA 2007) were evaluated.

Inhalation Dose-Response Data

Table 8-1 lists the HAPs and their corresponding dose-response factors provided by EPA OAQPS (2007). For each HAP, three values related to risk due to inhalation are listed: Chronic Toxic Endpoint ($\mu g/m^3$) for non-cancer human health effects, Acute Toxic Endpoint ($\mu g/m^3$) for peak 1-hour concentrations and Unit Risk Estimate [$(\mu g/m^3)^{-1}$] for cancer effects. For chromium, the cancer dose-response factor listed in Table 8-1 assumes per EPA guidance that 12% of the emissions are in the hexavalent form. Emissions of dioxin and furan congeners are represented by 2,3,7,8-TCDD toxic equivalents. Likewise, polycyclic aromatic compounds are collectively represented as benzo(a)pyrene toxic equivalents. The chronic dose-response factors inherently assume that there is a continuous exposure of at least one year and the cancer unit risk estimates inherently assume 70 years of exposure. These long-term dose response factors are based on a 20 kg body weight and 20 m^3 inhalation rate. For the acute toxic endpoints EPA has compiled information from a variety of sources, but does not provide written recommendations on which value to select. For this program the hierarchy applied in EPA's residual risk program is followed. According to EPA (2009a) the hierarchy is REL, MRL, AEGL-1-2, ERPG-1-2 and if none of these values are provided, the acute effects for that HAP are not evaluated.

For this screening-level inhalation assessment it is assumed that the all HAP contributions to risk are additive. Acute and chronic risks are evaluated by computing hazard quotients, defined as the ratio of the modeled concentrations to the corresponding toxic endpoint. The hazard index (HI) is the sum of the hazard quotients among all modeled HAPs. A hazard index of less than 1.0 is threshold used by EPA to establish whether non-cancer health effects associated with a modeled exposure are unlikely. Lifetime incremental inhalation cancer risk associated each carcinogenic HAP is computed by multiplying the modeled long-term average concentration by the Unit Risk Estimate. The total inhalation cancer risk is computed by summing the cancer risk among all carcinogenic HAPs.

Tier 1 Risk Inhalation Assessment Methodology

The purpose of a Tier 1 assessment is to apply highly conservative methods to estimate risk such that it can be assured that the modeled risk is much greater than the risk resulting from a more refined assessment using site-specific inputs. Tier 1 screening was conducted for all 470 coal-fired power plants in the U.S. Tier 1 is a highly conservative screening technique that was applied to initially assess chronic, carcinogenic and acute health effects. Tier 1 involved the application of EPA's SCREEN3 model, which is based on the dispersion algorithms from ISCST3 and applies a generic set of meteorological conditions to estimate the maximum 1-hour average ground-level concentration occurring anywhere in the vicinity of a source. SCREEN3 was applied in the rural dispersion environment mode with flat terrain. To estimate maximum long-term average concentrations required to assess chronic and carcinogenic risk, EPA recommends that the maximum modeled 1-hour concentration from each stack be multiplied by a factor of 0.1. This factor is based on EPA's screening guidance (EPA, 1992), which indicates that maximum annual average concentrations can be computed from maximum modeled 1-hour concentrations from SCREEN3 by multiplying the modeled 1-hour concentration by a factor ranging from 0.06 to 0.10. For this assessment the upper limit to the range of averaging time conversion factors recommended by the EPA screening guidance (0.10) was selected to compensate for the potential effects of terrain and downwash, which are not included in the SCREEN3 assessment.

In the Tier 1 analysis the risks associated with each stack at a power plant are computed so that the total risk is the sum of the individual risks for each stack. This is considered conservative, since it assumes that the location of maximum modeled concentration for each stack is the same. Each stack at a power plant was modeled at a unit emission rate (1 g/sec) and the modeled maximum annual average dispersion factor ($\mu g/m^3$ per g/sec). For the risk computation a spreadsheet-based program was developed whereby the SCREEN3 dispersion factor is multiplied by the emission rate for each HAP (g/sec) to estimate the short-term HAP concentration. For the chronic HI and cancer risk computation the annual average emission estimates were applied. For acute effects, EPA guidance (EPA 2004) suggests that the annual average emission rates be adjusted to account for intermittent operations. An adjustment was made for each power plant based on its 2005 annual capacity factor provided in eGRID (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html). For example if the capacity factor were 50%, the short-term emission rate is two times the annual emission rate. The acute risk for each HAP was then computed and summed over all of the stacks to estimate the acute HI. The chronic HI and lifetime cancer risk for each power plant was computed and summed based on the annual emissions.

Tier 2 Inhalation Risk Assessment Methodology

A Tier 2 analysis was applied to the power plants for which Tier 1 screening indicated the possibility of acute, chronic or cancer risk of significance. Because only a few power plants had Tier 1 acute and chronic hazard indices exceeding 1.0, all of these plants were modeled with Tier 2 methods. It is well known that there is a high degree of conservatism from Tier 1 compared to Tier 2. A limited number of exploratory Tier 2 analyses were undertaken to assess the distribution of Tier 2 to Tier 1 risk ratios. Twenty power plants were selected for this comparison using the top five Tier 1-risk plants as well as 15 randomly selected plants. The comparison of the twenty Tier 2 and Tier 1 risks indicated that all modeled Tier 2 cancer risks were less than about 25% of the same plant's Tier 1-modeled risks and, on average, the Tier 2 risks were only about 10% of the Tier 1 risks. Based on this comparison it was concluded that Tier 2-modeled cancer risks for any power plant would almost assuredly be less than 50% of the Tier 1-modeled risk. Therefore, all power plants with modeled Tier 1 inhalation cancer risk exceeding 2×10^{-6} were selected for the Tier 2 analysis.

For Tier 2, the Human Exposure Model, Version 3 with the AERMOD option (HEM3-AERMOD) was applied. This model simulates annual average concentrations and maximum 1-hour concentrations for a full year of meteorology. For this assessment AERMOD-ready surface and upper-air meteorological data available on the HEM3 website was used. This dataset is comprised of 122 one-year hourly wind speed and direction and atmospheric stability datasets (mostly for 1991) at measured locations shown in Figure 8-1. The closest station to each power plant was selected from this database included in the HEM3 archive. HEM3 estimates the chronic hazard index and inhalation cancer risk at prescribed population-based receptors which represent the centroids of the year 2000 census blocks. Receptor data included terrain elevation. For cancer risk and chronic HI, HEM3 computes the risk at each receptor following the same methodology as described for Tier 1. HEM3 was applied using the concentration-response factors supplied with the program and default model parameters. Facility-specific source information included stack location and base elevation, stack height, stack inner diameter, exit velocity and exit temperature.

For the acute assessment, the maximum 1-hour average concentration of each HAP at any off-site location is evaluated. The acute assessment uses a polar receptor grid, centered on the stack, generated by HEM3-AERMOD with receptors at 100, 160, 260, 420, 680, 1110, 1800, 3000, 5300, 9300, 16300, 28600, and 50000 m, which conservatively ignores the power plant fence line or property boundary. Because HEM3 does not directly compute an acute HI, a spreadsheet was developed to link the modeled maximum 1-hour concentrations with the acute toxic endpoints. In computing the acute HI, as described for Tier 1, the concentrations were scaled by the inverse of the capacity factor to reflect maximum rather than average HAP emissions.

The long-term cancer and non-cancer risk, toxic endpoints and unit risk estimates in the HEM3 library were applied for this assessment. These are generally consistent with EPA's Air Toxics guidance values listed in Table 8-1. An exception is that the HEM3 library assumes that nickel compounds are assigned a unit risk estimate equal to 25% of the unit risk estimate of nickel subsulfide. The assumption that 25% of nickel compounds from coal combustion are as toxic as nickel subsulfide is likely to be conservative for coal combustion. However, the assumption is inconsequential because the inhalation risk results show that nickel does not substantially contribute to inhalation risk from coal-fired utility boilers.

In comparing the modeled screening-level Tier 1 and refined Tier 2 long-term risks for each plant, it was noted that on-average the Tier 2 risk was less than 10% of the Tier 1 risk and that at the 95th percentile level the Tier 2 risk was 24.1% of the corresponding Tier 1 risk. This confirms the appropriateness of the criterion used to select Tier 2 plants because a plant with a Tier 1 risk of 2.0×10^{-6} would have a 95th percentile upper-bound risk of about 0.48×10^{-6}. So that the modeled risk for Tier 1 and Tier 2 plants can be more readily compared, a "Tier 1.5" risk was calculated by multiplying the Tier 1 risks by 0.241 to represent the 95th percentile upper limit estimate of Tier 2 risks for each plant. Therefore, rather than listing Tier 1 long-term risk results, which have been demonstrated to grossly overestimate revised risk estimates,, the results provided in Section 3 include only the Tier 1.5 and Tier 2 risk estimates, as applicable. For acute risks it was determined that the disparity between Tier 1 and Tier 2 was much less, with Tier 2 on average equal to 60% of Tier 1. Thus, acute risks were not included in the Tier 1.5 assessment.

Combined Long-Term Inhalation Risk From Nearby Power Plants

Even if all Tier 2 results for individual power plants indicate insignificant risk, there is the possibility that overlapping plumes from power plants within local distance scales from one another could result in higher air concentrations and thus higher inhalation risks. This is not a concern for acute risk because it is nearly impossible for the maximum 1-hour impacts from separate but adjacent facilities to occur at the same time and location since both facilities are reasonably certain to be subject to essentially identical wind patterns. Because the range of HEM3 applicability is 50 km, the first step in this assessment was to determine the location of the 470 power plants to establish local groups where the 50 km stack-centered radii intersect. A nationwide plot of these overlapping circles is provided in Figure 8-2. Individual group plots are shown in Appendix A. Over 100 facility groups were identified, each group consisting of from two to 10 power plants. As shown in the figure, the national map was divided into 13 regions and groups were identified by map number and group number within each region. In areas such as the Ohio Valley where coal-fired power plants are numerous, some power plants are included in more than one group. A two-level approach was applied in addressing the maximum combined risk associated with these groups.

Level 1 Screen

In the Level 1 Screen the maximum risk associated with each power plant within a group (represented either by Tier 1.5 or Tier 2 risks) was summed with the equivalent risk value for the other plants in the group. This method is highly conservative because the maximum risk is always located within a few kilometers of the source location, whereas most facilities are separated by much greater distances. If after a first pass the combined chronic HI exceeded 1.0 or cancer risk exceeded 1×10^{-6}, the contribution of each plant was examined to determine if any major contributors were based on the highly conservative Tier 1.5 risk estimates. If this was the case then additional power plants in the affected groups were modeled with Tier 2 methods until modeled combined risks were shown to be insignificant. This conservative Level 1 analysis indicated that one group of power plants within 50 km had a combined chronic hazard index exceeding 1.0 and 21 groups of power plants had the potential for combined cancer risk to exceed 1×10^{-6}.

Level 2 Analysis

For these 22 groups a refined Level 2 analysis was conducted. Rather than sum the maximum risk from each facility, the combined risk was computed by modeling the risk at the specific population centroid HEM3 model receptors associated with all power plants in a group. This refined analysis required that Tier 2 modeling be conducted for all of the power plants that contributed substantially to the risk in each group. HEM3-ARMOD risk results were imported into a spreadsheet, risks from all power plants in the group were added for all modeled population centroid receptors, and the model receptor location with the highest risk was determined.

Table 8-1
U.S. EPA OAQPS Toxic Endpoints Used in the Inhalation Risk Assessment

HAP	CAS	Chronic Toxic Endpoint (µg/m^3)	Acute Toxic Endpoint (µg/m^3)	Basis of Acute Toxic Endpoint	Unit Risk Estimate (µg/m^3)$^{-1}$
Arsenic (As)	7440-38-2	0.030	0.19	REL	4.30E-03
Beryllium (Be)	7440-41-7	0.020	25.00	ERPG-2	2.40E-03
Cadmium (Cd)	7440-43-9	0.020			1.80E-03
Hydrogen Chloride (HCl)	7647-01-0	20.000	2100.00	REL	
Chlorine (Cl2)	7782-50-5	0.200	210.00	REL	
Cobalt (Co)	7440-48-4	0.100			
Chromium (Cr) (12% Cr VI)	7440-47-3	0.833			1.44E-03
Hydrogen Fluoride (HF)	7664-39-3	14.000	240.00	REL	
Mercury (total) (Hg)	7439-97-6	0.300	1.80	REL	
Manganese (Mn)	7439-96-5	0.050			
Nickel Compounds (Ni)	7440-02-0	0.090	6.00	REL	
Lead (Pb)	7439-92-1	0.150			
Antimony (Sb)	7440-36-0	0.200			
Selenium (Se)	7782-49-2	20.000			
1,1-Dichloroethane	75-34-3	500.000			1.60E-06
1,2,4-Trichlorobenzene	120-82-1	200.000			
1,2-Dibromoethane	106-93-4	9.000	35000.00	AEGL-1 (8hr)	6.00E-04
1,4-Dichlorobenzene	106-46-7	800.000	12000.00	MRL	1.10E-05
2,3,7,8-TCDD equivalents	1746-01-6	0.000			3.30E+01
2,4-Dinitrotoluene	121-14-2	7.000			8.90E-05
2-Chloronaphthalene	91-58-7				
2-Methylnaphthalene	91-57-6				
3-Chloropropylene	107-05-1	1.000	9400.00	ERPG-1	6.00E-06
4-Methyl-2-pentanone	108-10-1	3000.000			
4-Methylphenol	106-44-5				

Table 8-1 (continued)
U.S. EPA OAQPS Toxic Endpoints Used in the Inhalation Risk Assessment

HAP	CAS	Chronic Toxic Endpoint (µg/m^3)	Acute Toxic Endpoint (µg/m^3)	Basis of Acute Toxic Endpoint	Unit Risk Estimate (µg/m^3)$^{-1}$
5-Methylchrysene	3697-24-3				1.10E-03
Acetaldehyde	75-07-0	9.000	81000.00	ERPG-1	2.20E-06
Acetophenone	98-86-2				
Acrolein	107-02-8	0.020	0.19	REL	
B(a)P equivalents	NA				1.10E-03
Benzene	71-43-2	30.000	29.00	MRL	7.80E-06
Benzylchloride	100-44-7		240.00	REL	4.90E-05
Biphenyl	92-52-4		28000.00	AEGL2-8hr	
bis(2-Ethlyhexyl)phthalate	117-81-7	10.000			2.40E-06
Bromomethane	74-83-9	5.000	190.00	MRL	
Carbon disulfide	75-15-0	700.000	6200.00	REL	
Chlorobenzene	108-90-7	1000.000	46000.00	AEGL1-8hr	
Chloroethane	75-00-3	10000.000	40000.00	MRL	
Chloroform	67-66-3	98.000	150.00	REL	
Chloromethane	74-87-3	90.000	1000.00	MRL	
Cumene	98-82-8	400.000	250000.00	AEGL1-1hr	
Ethylbenzene	100-41-4	1000.000			
Formaldehyde	50-00-0	9.800	49.00	MRL	5.50E-09
Iodomethane	74-88-4		150000.00	ERPG-1	
Isophorone	78-59-1	2000.000			2.70E-07
m/p-Xylene	1330-20-7	100.000	8700.00	MRL	
Methyl chloroform	71-55-6	1000.000	11000.00	MRL	
Methyl methacrylate	80-62-6	700.000	70000.00	AEGL1-1hr	
Methylene chloride	75-09-2	1000.000	2100.00	MRL	4.70E-07
Naphthalene	91-20-3	3.000			3.40E-05
n-Hexane	110-54-3	700.000	12000000.00	AEGL2-1hr	
o-Xylene	95-47-6				

Table 8-1 (continued)
U.S. EPA OAQPS Toxic Endpoints Used in the Inhalation Risk Assessment

HAP	CAS	Chronic Toxic Endpoint (µg/m^3)	Acute Toxic Endpoint (µg/m^3)	Basis of Acute Toxic Endpoint	Unit Risk Estimate (µg/m^3)$^{-1}$
Phenol	108-95-2	200.000	5800.00	REL	
Propionaldehyde	123-38-6		110000.00	AEGL1-1hr	
Styrene	100-42-5	1000.000	21000.00	REL	
Tetrachloroethylene	127-18-4	270.000	1400.00	MRL	5.90E-06
Toluene	108-88-3	5000.000	3800.00	MRL	
Vinyl acetate	108-05-4	200.000	18000.00	ERPG-1	
Vinyl chloride	75-01-4	100.000	1300.00	MRL	8.80E-06
Hydrogen Cyanide	74-90-8	3.000	340.00	REL	

Notes: Chronic Toxic Endpoints and Unit Risk Estimates obtained from Table 1. Prioritized Chronic Dose-Response Values (6/12/2007) accessed at http://www.epa.gov/ttn/atw/toxsource/summary.html

Acute Toxic Endpoints obtained from Table 2. Acute Dose-Response Values for Screening Risk Assessments (6/12/2007) accessed at http://www.epa.gov/ttn/atw/toxsource/summary.html.

Key:

Blank = no value provided in Table 1 or Table 2
REL = California EPA reference exposure level for no adverse effects
AEGL = Acute exposure guideline levels for mild effects (AEGL-1) and moderate effects (AEGL-2) for 1- and 8-hour exposures.
MRL = ATSDR minimum risk levels for no adverse effects for 1 to 14-day exposures.
ERPG = US DOE Emergency Removal Program guidelines for mild or transient effects (ERPG-1) for 1-hour exposures.

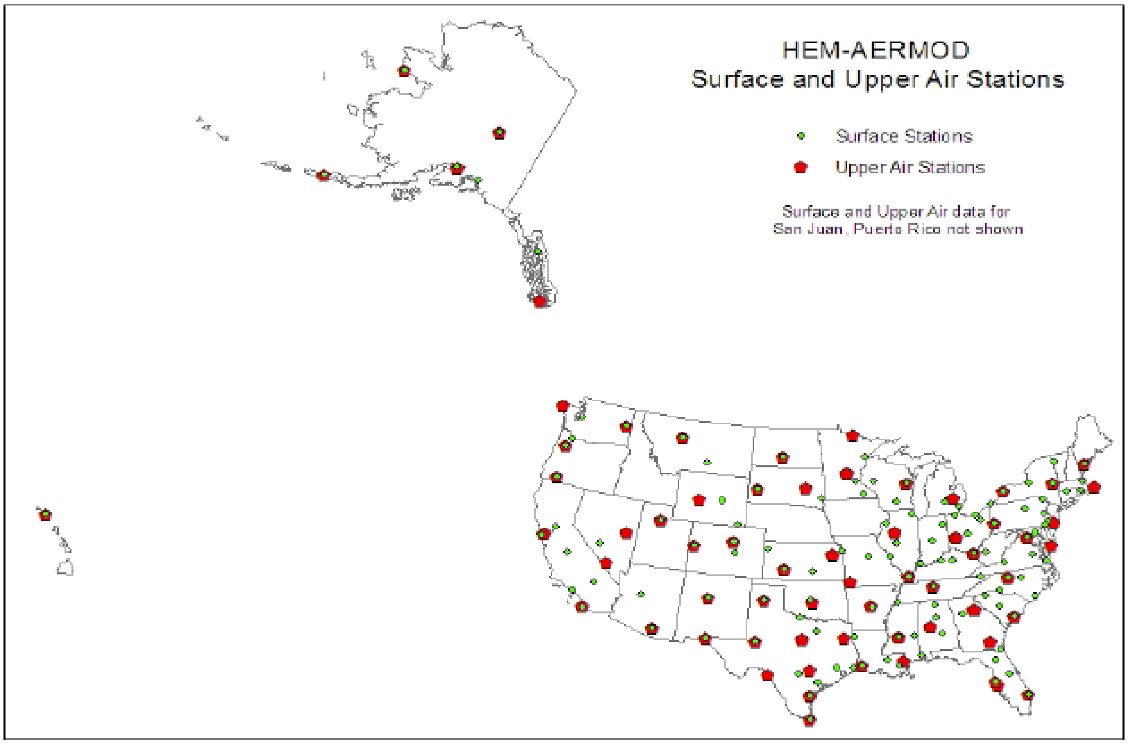


Figure 8-1
Location of Surface and Upper Air Stations in the HEM-AERMOD Database

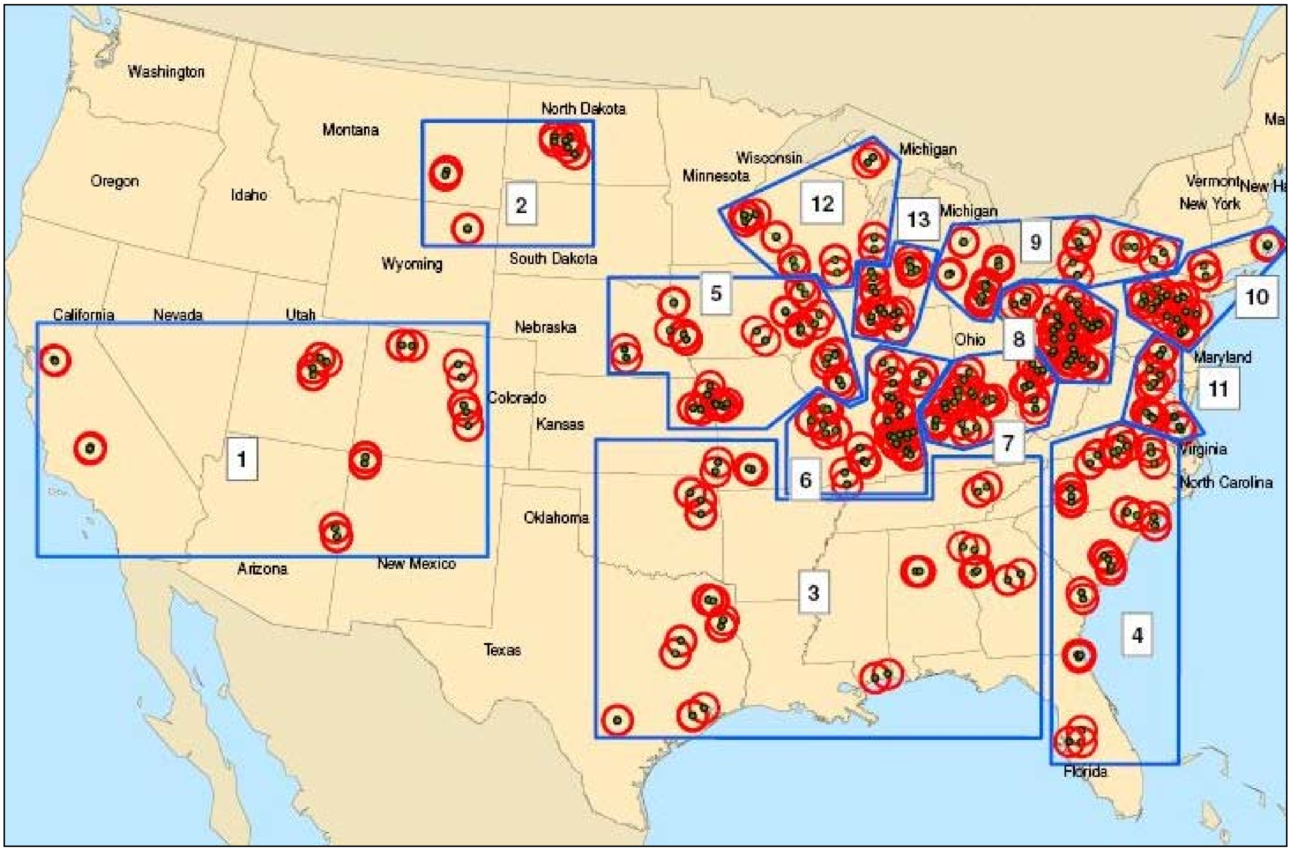


Figure 8-2
Regions (boxes) and Groups of Facilities (50 km circles) with Overlapping Modeling Domains

References

1. Screening Procedures for Estimating the Air Quality. Impact of Stationary Sources, Revised, U.S. EPA U.S. EPA Office of air Quality Planning and Standards, October 1992 (EPA-454/R-92-019)
2. Air Toxics Risk Assessment Reference Library, Volume 2, Facility-Specific Assessment. U.S. EPA Office of air Quality Planning and Standards (EPA-453-04-001B), April 2004

9

INHALATION RISK ASSESSMENT RESULTS

Results for all 470 coal-fired power plants are shown in Table 9-1. At the completion of the combined power plant assessment, a total of 198 facilities underwent a Tier 2 analysis using HEM3-AERMOD. Acute and chronic hazard indices and cancer risks associated with these power plants are indicated in bold. Among the remaining 272 power plants, the acute values correspond to Tier 1 and the chronic hazard index and cancer risk values correspond to Tier 1.5. No individual power plant assessment resulted in a modeled hazard index exceeding 1 or a cancer risk exceeding 1 x 10^{-6}. Tables 9-2, 9-3 and 9-4 provide information on the 10 power plants with the highest cancer risk, chronic inhalation risk, and acute risk, respectively.

Table 9-2 indicates that nearly all of the cancer risk associated with these coal-fired power plants is due to arsenic (average of 76%) and hexavalent chromium (17%). Other metals are minor contributors to the risk, contributing on average about 7%, combined.

Table 9-3 indicates that chlorine dominates the chronic hazard index, accounting on average for over 97% of the hazard index. Hydrogen chloride contributes about 1 %.

Table 9-4 indicates that arsenic (average of 52%) and acrolein (9%) are typically the largest contributors, with substantial contributions from hydrogen chloride, chlorine and hydrogen fluoride.

The results of the combined analysis are provided in Table 9-5 for cancer risk and Table 9-6 for Chronic Hazard Index. Two types of results are provided, a screening assessment where maximum modeled risks from all facilities in the group were added together and a refined analysis where HEM3-ARMOD results were imported into a spreadsheet and risks were summed on a receptor-by-receptor basis using spreadsheet pivot tables. All but 22 groups demonstrate insignificant risks using the screening level assessment. Among the 22 groups for which a refined analysis was conducted, all but two groups had results less than the significance levels. The two groups of facilities, one along the Illinois-Indiana border and the other along the Ohio-Pennsylvania border, had combined modeled cancer risks marginally above 1x10-6. The contributions of each power plant for these two groups are shown in Table 9-7. Given the conservative aspects of this analysis, such as the assumed 70-year lifetime exposure at fixed outdoor locations, the actual inhalation risks are probably well below the significance level.

In summary, a tiered inhalation risk assessment using EPA-prescribed methodologies has demonstrated that no coal-fired power plant or combination of power plants results in significant risks.

Table 9-1
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
1	VECTREN(SIGE)	A. B. Brown	**0.022**	**0.014**	**1.58E-07**
2	Trona Operating Partners	ACE Cogeneration Plant	0.001	0.001	1.59E-08
3	AES Beaver Valley	AES BV Partners Beaver Valley	**0.065**	**0.211**	**9.52E-07**
4	AES-CAYUGA	AES Cayuga (NY)	**0.070**	**0.295**	**6.49E-07**
5	AES Deepwater Inc	AES Deepwater	0.006	0.008	1.25E-07
6	AES GREENIDGE	AES Greenidge	**0.008**	**0.008**	**1.29E-08**
7	AES HAWAII	AES Hawaii, Inc.	0.023	0.011	5.02E-08
8	AES-HICKLING	AES Hickling	0.000	0.000	0.00E+00
9	AES JENNISON	AES Jennison	0.000	0.000	0.00E+00
10	Applied Energy Systems	AES Shady Point, Inc.	0.022	0.037	1.44E-07
11	AES SOMERSET	AES Somerset (NY)	**0.034**	**0.022**	**2.77E-07**
12	AES THAMES	AES Thames, Inc.	0.021	0.016	8.10E-08
13	AES WARRIOR	AES Warrior Run	0.011	0.017	8.14E-08
14	AES-WESTOVER	AES Westover	0.035	0.038	2.52E-07
15	ALLEGHENY	Albright	0.033	0.017	1.99E-07
16	TVA	Allen Fossil Plant	**0.262**	**0.060**	**7.83E-08**
17	XCEL	Allen S. King	0.011	0.002	3.83E-08
18	DAIRYLAND	Alma	0.024	0.004	6.09E-08
19	LG&E Power Serv Inc	Altavista Power Station	0.012	0.025	1.02E-07
20	AMES	Ames	0.060	0.029	8.99E-08
21	BASIN ELECTRIC	Antelope Valley Station	**0.003**	**0.000**	**5.76E-08**
22	AZ ELEC COOP	Apache Station	**0.004**	**0.001**	**3.65E-08**
23	XCEL	Arapahoe	0.004	0.009	1.01E-07
24	ALLEGHENY	Armstrong	**0.018**	**0.018**	**5.63E-08**
25	EMPIRE DISTRICT	Asbury	0.025	0.024	2.12E-07
26	PROGRESS ENERGY	Asheville	**0.281**	**0.063**	**9.49E-07**
27	FIRST ENERGY	Ashtabula	0.050	0.009	4.91E-08
28	RELIANT ENERGY - MIDWEST	Avon Lake	**0.046**	**0.039**	**2.32E-07**
29	PEPCO HOLDINGS (to RC Cape May Holdings - 1Q-07)	B L England	0.027	0.012	1.88E-07
30	CMS	B.C. Cobb	0.142	0.018	2.44E-07

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
31	NIPSCO(NISOURCE)	Bailly	**0.010**	**0.010**	**8.44E-08**
32	DYNEGY MIDWEST	Baldwin	**0.073**	**0.032**	**1.46E-07**
33	SOUTHERN	Barry	**0.155**	**0.033**	**1.92E-07**
34	XCEL	BAY FRONT 6	0.064	0.096	4.16E-07
35	FIRST ENERGY	Bay Shore	**0.052**	**0.019**	**1.22E-07**
36	DUKE ENERGY CAROLINAS	Belews Creek	**0.054**	**0.034**	**2.07E-07**
37	DTE ENERGY	Belle River Power Plant	0.086	0.009	1.53E-07
38	TECO	Big Bend	**0.021**	**0.021**	**4.70E-07**
39	LUMINANT (TXU)	Big Brown	**0.101**	**0.031**	**8.65E-08**
40	LA GEN(NRG)	Big Cajun 2	0.208	0.018	3.02E-07
41	AEP	Big Sandy	0.134	0.017	1.99E-07
42	OTTER TAIL	Big Stone	0.043	0.005	6.52E-08
43	GE/Goldman Sachs	Birchwood Power Facility	**0.011**	**0.010**	**1.51E-07**
44	XCEL	Black Dog	0.031	0.004	7.00E-08
45	MG&E	Blount Street	0.012	0.033	1.51E-07
46	INDEPENDENCE	Blue Valley	0.018	0.031	6.01E-08
47	PORTLAND G&E	Boardman	0.087	0.009	8.65E-08
48	DESERT	Bonanza	0.022	0.018	1.37E-07
49	SOUTHERN	Bowen	**0.046**	**0.080**	**2.17E-07**
50	CONSTELLATION PWR SOURCE	Brandon Shores	0.181	0.043	3.45E-07
51	DOMINION	Brayton Point	**0.186**	**0.039**	**2.27E-07**
52	DOMINION VA POWER	Bremo Power Station	0.089	0.080	2.12E-07
53	PSE&G	Bridgeport Harbor	**0.019**	**0.031**	**1.68E-07**
54	FIRST ENERGY	Bruce Mansfield	**0.042**	**0.053**	**4.05E-07**
55	PPL CORP	Brunner Island	**0.069**	**0.012**	**4.38E-07**
56	DUKE ENERGY CAROLINAS	Buck	**0.446**	**0.062**	**9.64E-08**
57	TVA	Bull Run Fossil Plant	0.086	0.016	1.09E-07
58	ALLIANT	Burlington	0.067	0.026	2.48E-07
59	NRG Huntley Operations Inc	C. R. Huntley	0.123	0.025	3.43E-07
60	CONSTELLATION PWR SOURCE	C.P. Crane	**0.024**	**0.063**	**3.24E-07**
61	Cambria CoGen Co	Cambria CoGen	**0.053**	**0.019**	**5.38E-08**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
62	XCEL	Cameo	0.044	0.016	2.79E-08
63	SCANA	Canadys Steam	**0.094**	**0.103**	**7.97E-07**
64	LGE ENERGY (POWER GEN)	Cane Run	**0.061**	**0.238**	**6.30E-07**
65	PROGRESS ENERGY	Cape Fear	**0.118**	**0.079**	**3.83E-07**
66	PACIFICORP(SCOTTISH PWR)	Carbon	0.237	0.034	1.05E-07
67	CARDINAL(AEP)	Cardinal	**0.044**	**0.032**	**1.03E-07**
68	JAMESTOWN	CARLSON 5	0.039	0.057	1.89E-07
69	NEGT (to GOLDMAN SACHS IN 05)	Carneys Point Generating Plant	**0.010**	**0.011**	**1.41E-07**
70	DUKE ENERGY INDIANA	Cayuga (IN)	**0.057**	**0.049**	**2.58E-07**
71	NEGT (to GOLDMAN SACHS IN 05)	Cedar Bay Generating Co, L.P.	0.020	0.009	6.34E-08
72	Delta Power Co	Central Power and Lime, Inc.	0.009	0.006	4.00E-08
73	TRANS ALTA	Centralia	0.017	0.011	2.54E-07
74	MIRANT-MID-ATLANTIC	Chalk Point	**0.029**	**0.022**	**9.11E-08**
75	CEN ELEC PWR COOP	Chamois	0.012	0.053	2.02E-07
76	ALEC	Charles R. Lowman	**0.013**	**0.019**	**1.70E-07**
77	XCEL	Cherokee	0.012	0.007	6.65E-08
78	DOMINION VA POWER	Chesapeake Energy Center	**0.629**	**0.081**	**3.77E-07**
79	DOMINION VA POWER	Chesterfield Power Station	**0.106**	**0.093**	**4.19E-07**
80	RELIANT ENERGY - MID-ATLANTIC	Cheswick	**0.025**	**0.037**	**1.92E-07**
81	AZ PUB SERV	Cholla	0.108	0.081	2.73E-07
82	ALLETE(MIN PWR)	Clay Boswell	**0.009**	**0.002**	**2.05E-07**
83	DUKE ENERGY CAROLINAS	Cliffside	0.124	0.064	3.16E-07
84	OVEC	Clifty Creek	**0.011**	**0.027**	**7.91E-08**
85	AEP	Clinch River	0.068	0.042	3.48E-07
86	DOMINION VA POWER	Clover Power Station	**0.046**	**0.013**	**1.45E-07**
87	GREAT RIVER ENG	Coal Creek	0.023	0.014	1.45E-07
88	AMEREN ENERGY GEN	Coffeen	0.204	0.011	2.64E-07
89	SCANA	Cogen South	**0.009**	**0.012**	**4.98E-08**
90	Goldman Sachs	Cogentrix Hopewell	0.015	0.087	2.07E-07
91	Goldman Sachs	Cogentrix of Richmond, INC.	0.075	0.137	4.41E-07
92	Goldman Sachs	Cogentrix Portsmouth	0.062	0.125	2.82E-07

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
93	Goldman Sachs	Cogentrix Roxboro	**0.004**	**0.005**	**7.84E-08**
94	Goldman Sachs	Cogentrix Southport	0.025	0.049	1.11E-07
95	TVA	Colbert Fossil Plant	0.134	0.025	2.36E-07
96	WEST KY ENG (to BIG RIVERS in 2007)	Coleman	**0.039**	**0.044**	**5.24E-07**
97	INTERNATIONAL POWER PLC	Coleto Creek	0.074	0.009	1.30E-07
98	Rosebud Operating Services Inc	Colstrip Energy Ltd Partnership	0.004	0.020	1.52E-08
99	PPL GLOBAL	Colstrip	**0.008**	**0.028**	**1.99E-07**
100	ALLIANT	Columbia	0.126	0.013	2.51E-07
101	A C Power Colver Operations	Colver Power Project	**0.017**	**0.008**	**2.86E-08**
102	XCEL	Comanche	0.087	0.011	1.08E-07
103	RELIANT ENERGY - MID-ATLANTIC	Conemaugh	**0.038**	**0.119**	**3.93E-07**
104	AEP	Conesville	**0.039**	**0.049**	**2.46E-07**
105	EAST KY PWR COOP	Cooper	**0.048**	**0.290**	**4.93E-07**
106	SCANA	Cope	0.032	0.023	2.12E-07
107	SRP	Coronado	0.014	0.008	1.30E-07
108	MIDAMER(BERK HATH)	Council Bluffs	**0.284**	**0.041**	**6.10E-07**
109	MDU	Coyote	**0.003**	**0.010**	**6.56E-08**
110	TRI-STATE G&T	Craig	**0.004**	**0.001**	**4.80E-08**
111	MIDWEST GEN	Crawford	**0.057**	**0.013**	**1.53E-07**
112	SOUTHERN	Crist	0.049	0.027	2.63E-07
113	EXELON GENERATION	Cromby Generating Station	**0.022**	**0.034**	**3.43E-07**
114	SANTEE	Cross Generating Station	**0.164**	**0.068**	**5.04E-07**
115	PROGRESS ENERGY	Crystal River	**0.063**	**0.109**	**1.81E-07**
116	TVA	Cumberland Fossil Plant	**0.035**	**0.022**	**1.54E-07**
117	WEST KY ENG (to BIG RIVERS in 2007)	D. B. Wilson	**0.016**	**0.010**	**8.70E-08**
118	EAST KY PWR COOP	Dale	0.083	0.093	4.47E-07
119	SPRING-IL	Dallman	0.131	0.060	4.69E-07
120	CMS	Dan E. Karn	0.126	0.023	1.94E-07
121	DUKE ENERGY CAROLINAS	Dan River	**0.055**	**0.031**	**1.87E-07**
122	DYNEGY NORTHEAST	Danskammer	0.221	0.063	4.02E-07
123	PACIFICORP(SCOTTISH PWR)	Dave Johnston	**0.037**	**0.040**	**1.79E-07**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
124	PEPCO HOLDINGS	Deepwater	**0.021**	**0.009**	**7.57E-08**
125	GAINESVILLE	Deerhaven	**0.285**	**0.016**	**6.58E-08**
126	MIRANT-MID-ATLANTIC	Dickerson	0.130	0.048	2.84E-07
127	CLECO	Dolet Hills Power Station	0.018	0.010	1.86E-07
128	ALLIANT	Dubuque	0.060	0.040	1.08E-07
129	AMEREN ENERGY RESOURCES GENERATING CO	Duck Creek	0.019	0.010	8.27E-08
130	NRG Dunkirk Operations Inc	Dunkirk	0.132	0.035	3.35E-07
131	Goldman Sachs	Dwayne Collier Battle Cogen	0.042	0.088	3.31E-07
132	AMEREN ENERGY RESOURCES GENERATING CO	E. D. Edwards	0.111	0.018	3.15E-07
133	LGE ENERGY (POWER GEN)	E. W. Brown	0.108	0.042	3.57E-07
134	AES (IPALCO)	E. W. Stout	**0.052**	**0.033**	**5.94E-07**
135	CORN BELT	Earl F. Wisdom	0.002	0.008	2.47E-08
136	DUKE ENERGY OHIO (to UNION LIGHT HEAT & PWR)	East Bend Station	**0.015**	**0.005**	**4.13E-08**
137	FIRST ENERGY	Eastlake	0.072	0.029	4.59E-07
138	Power Systems Operations Inc	Ebensburg Power Company	**0.018**	**0.010**	**1.97E-08**
139	LANSING	Eckert Station	0.073	0.018	1.95E-07
140	EXELON GENERATION	Eddystone	**0.041**	**0.077**	**7.14E-07**
141	PEPCO HOLDINGS	Edge Moor	**0.483**	**0.160**	**1.95E-07**
142	ALLIANT	Edgewater (WI)	0.109	0.014	2.11E-07
143	DUKE ENERGY INDIANA	Edwardsport	**0.011**	**0.013**	**1.09E-07**
144	WPS POWER DEV	EJ STONEMAN 2	**0.004**	**0.126**	**1.73E-08**
145	NORTH CAROLINA POWER HOLDINGS	Elizabethtown	0.000	0.003	8.33E-09
146	OWENSBORO	Elmer Smith	**0.010**	**0.014**	**2.13E-07**
147	RELIANT ENERGY - MID-ATLANTIC	Elrama	**0.038**	**0.028**	**3.70E-07**
148	MI SO CEN	Endicott	0.057	0.118	2.49E-07
149	LANSING	Erikcson	0.066	0.016	6.29E-08
150	TRI-STATE G&T	Escalante	0.016	0.020	8.12E-08
151	VECTREN(SIGE)	F. B. Culley	**0.013**	**0.027**	**3.66E-07**
152	CEN IA PWR COOP	Fair Station	0.014	0.033	1.16E-07
153	LCRA	Fayette (Seymour)	0.174	0.023	4.74E-07
154	MIDWEST GEN	Fisk	**0.022**	**0.007**	**6.92E-08**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
155	AEP	Flint Creek	0.076	0.009	1.44E-07
156	Black River Power LLC	Fort Drum H.T.W. Cogeneration	0.014	0.046	2.05E-07
157	ALLEGHENY	Fort Martin	**0.063**	**0.134**	**4.66E-07**
158	El Paso Merchant Energy Co	Foster Wheeler Mt. Carmel, Inc.	**0.007**	**0.003**	**3.30E-08**
159	AZ PUB SERV	Four Corners	0.048	0.085	4.05E-07
160	HOOSIER	Frank E. Ratts	**0.019**	**0.063**	**6.12E-07**
161	DUKE ENERGY CAROLINAS	G.G. Allen	**0.138**	**0.026**	**4.81E-07**
162	SOUTHERN	Gadsden	0.010	0.015	1.05E-07
163	TVA	Gallatin Fossil Plant	0.079	0.032	1.86E-07
164	SOUTHERN	Gaston	0.038	0.015	3.31E-07
165	AEP	Gen J. M. Gavin	**0.041**	**0.052**	**3.91E-07**
166	DAIRYLAND	Genoa	0.061	0.012	2.31E-07
167	MIDAMER(BERK HATH)	George Neal North	**0.046**	**0.035**	**1.91E-07**
168	MIDAMER(BERK HATH)	George Neal South	0.073	0.006	1.23E-07
169	NPPD	Gerald Gentlemen Station	0.165	0.020	1.94E-07
170	LGE ENERGY (POWER GEN)	Ghent	**0.081**	**0.054**	**5.24E-07**
171	TMPA	Gibbons Creek	**0.007**	**0.023**	**2.61E-07**
172	DUKE ENERGY INDIANA	Gibson Generating Station	**0.065**	**0.118**	**9.78E-07**
173	AEP	Glen Lyn	0.041	0.034	2.12E-07
174	SOUTHERN	Gorgas	0.048	0.019	2.57E-07
175	SANTEE	Grainger Generating Station	**0.062**	**0.038**	**4.84E-07**
176	Edison Mission Op & Maintenance	Grant Town Power Plant	**0.004**	**0.009**	**3.36E-08**
177	GRDA	GRDA	0.114	0.037	4.19E-07
178	LGE ENERGY (POWER GEN)	Green River	**0.008**	**0.016**	**9.37E-08**
179	SOUTHERN	Greene County	0.028	0.012	1.40E-07
180	PROGRESS ENERGY	H B Robinson	0.069	0.049	2.93E-07
181	CONSTELLATION PWR SOURCE	H.A. Wagner	0.163	0.083	1.60E-07
182	EAST KY PWR COOP	H.L. Spurlock	**0.035**	**0.023**	**2.11E-07**
183	AES (IPALCO)	H.T. Pritchard	0.025	0.028	3.13E-07
184	HAMILTON	Hamilton	**0.020**	**0.010**	**1.17E-07**
185	SOUTHERN	Hammond	0.073	0.012	1.92E-07

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
186	Hanford Ltd Partnership	Hanford	0.065	0.074	3.82E-08
187	DTE ENERGY	Harbor Beach Power Plant	0.006	0.005	2.31E-08
188	ROCKY MOUNTAIN POWER	HARDIN GENERATING	0.005	0.023	1.01E-07
189	SOUTHERN	Harllee Branch	0.110	0.014	3.00E-07
190	XCEL	Harrington Station	0.167	0.027	3.85E-07
191	ALLEGHENY	Harrison	**0.017**	**0.020**	**1.11E-07**
192	ALLEGHENY	Hatfield's Ferry	**0.062**	**0.063**	**2.84E-07**
193	DYNEGY MIDWEST	Havana	0.078	0.010	1.19E-07
194	KCP&L(GREAT PLAINS ENERGY)	Hawthorn	0.007	0.009	1.09E-07
195	XCEL	Hayden	0.012	0.007	6.00E-08
196	GOLDEN VALLEY	Healy	0.007	0.018	6.04E-08
197	HENDERSON	HENDERSON ONE 6	**0.001**	**0.000**	**2.85E-08**
198	WEST KY ENG (to BIG RIVERS in 2007)	HENDERSON TWO	**0.014**	**0.014**	**1.25E-07**
199	DYNEGY MIDWEST	Hennepin	0.087	0.025	2.73E-07
200	XCEL	High Bridge	0.020	0.003	5.11E-08
201	SUNFLOWER	Holcomb	0.007	0.011	1.42E-07
202	ED MISSION(GE CAPITAL)	Homer City	**0.108**	**0.095**	**5.38E-07**
203	OTTER TAIL	Hoot Lake	0.042	0.019	1.91E-07
204	PSE&G	Hudson	**0.209**	**0.037**	**1.32E-07**
205	WEST FARMERS	Hugo	0.079	0.009	7.88E-08
206	UGI	Hunlock Power Station	**0.016**	**0.081**	**1.56E-07**
207	PACIFICORP(SCOTTISH PWR)	Hunter	0.038	0.034	3.25E-07
208	PACIFICORP(SCOTTISH PWR)	Huntington	0.038	0.019	2.06E-07
209	AMEREN ENERGY GEN	Hutsonville	**0.046**	**0.016**	**1.22E-07**
210	KCP&L(GREAT PLAINS ENERGY)	Iatan	0.065	0.006	1.13E-07
211	ENTERGY	Independence	0.080	0.003	1.73E-07
212	NRG Indian River Operations Inc	Indian River	**0.524**	**0.058**	**4.12E-07**
213	NEGT (to GOLDMAN SACHS IN 05)	Indiantown Cogeneration Facility	0.021	0.010	9.65E-08
214	INTERMOUNTAIN/LADWP	Intermountain	0.022	0.007	1.45E-07
215	TUCSON	Irvington	0.025	0.012	3.06E-08
216	DAIRYLAND	J P Madgett	0.044	0.007	1.37E-07

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
217	DP&L	J. M. Stuart	**0.070**	**0.069**	**1.79E-07**
218	CMS	J.C. Weadock	**0.115**	**0.020**	**6.81E-08**
219	PPL GLOBAL	J.E. Corette	0.060	0.032	4.15E-07
220	CMS	J.H. Campbell	**0.116**	**0.020**	**5.24E-08**
221	SAPSB	J.K. Spruce	0.014	0.011	1.66E-07
222	CMS	J.R. Whiting	**0.194**	**0.045**	**4.54E-07**
223	SAPSB	J.T. Deely	0.067	0.007	2.00E-07
224	SOUTHERN	Jack McDonough	0.067	0.018	3.63E-07
225	SOUTHERN	Jack Watson	**0.201**	**0.032**	**2.73E-07**
226	HOLLAND	James De Young	0.143	0.061	8.52E-08
227	SPRING-MO	James River Power Station	**0.222**	**0.030**	**6.57E-07**
228	GRAND HAVEN	JB SIMS 3	0.017	0.014	1.34E-07
229	SANTEE	Jefferies Generating Station	**0.068**	**0.060**	**7.19E-07**
230	WESTSTAR ENERGY	Jeffrey Energy Center	**0.012**	**0.022**	**1.96E-07**
231	PACIFICORP(SCOTTISH PWR)	Jim Bridger	**0.004**	**0.023**	**4.48E-08**
232	Gilberton Power Co	John B. Rich Memorial Power St.	**0.027**	**0.006**	**2.49E-08**
233	AEP	John E Amos	0.164	0.014	2.29E-07
234	TVA	John Sevier Fossil Plant	0.057	0.028	1.72E-07
235	TVA	Johnsonville Fossil Plant	0.065	0.007	1.66E-07
236	MIDWEST GEN	JOLIET 6	**0.022**	**0.007**	**6.55E-08**
237	MIDWEST GEN	Joliet	**0.044**	**0.019**	**1.20E-07**
238	EEI	Joppa Steam	**0.123**	**0.021**	**2.33E-07**
239	AEP	Kammer	**0.012**	**0.024**	**9.80E-08**
240	AEP	Kanawha River	0.065	0.021	1.27E-07
241	RELIANT ENERGY - MID-ATLANTIC	Keystone	**0.011**	**0.071**	**3.99E-07**
242	DP&L	Killen	**0.189**	**0.036**	**3.67E-08**
243	KINCAID(DOM RES)	Kincaid Generation, L.L.C.	0.064	0.003	6.29E-08
244	TVA	Kingston Fossil Plant	**0.333**	**0.025**	**8.79E-08**
245	Northeastern Power Company	Kline Township Cogen Facility	**0.167**	**0.014**	**3.83E-08**
246	SOUTHERN	Kraft	0.126	0.018	1.81E-07
247	OVEC	Kyger Creek	**0.008**	**0.022**	**5.75E-08**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
248	PROGRESS ENERGY	L V Sutton	0.082	0.038	4.58E-07
249	KCP&L(GREAT PLAINS ENERGY)	La Cygne	**0.046**	**0.021**	**1.61E-07**
250	AMEREN-UE	Labadie	**0.074**	**0.035**	**1.30E-07**
251	CLEVELAND	LAKE ROAD (OH) 11	0.000	0.000	0.00E+00
252	AQUILA(GREAT PLAINS ENERGY)	Lake Road Plant	0.077	0.025	9.53E-08
253	FIRST ENERGY	Lake Shore	0.102	0.026	2.11E-07
254	SPRING-IL	Lakeside	0.039	0.026	4.44E-08
255	ALLIANT	Lansing	0.100	0.048	2.89E-07
256	SOUTHERN	Lansing Smith	0.032	0.029	2.11E-07
257	BASIN ELECTRIC	Laramie River Station	0.043	0.038	4.06E-07
258	ALLETE(MIN PWR)	Laskin Energy Center	0.013	0.065	3.41E-07
259	WESTSTAR ENERGY	Lawrence	**0.056**	**0.035**	**4.35E-07**
260	PROGRESS ENERGY	Lee	0.064	0.026	1.87E-07
261	BASIN ELECTRIC	Leland Olds Station	0.021	0.015	1.45E-07
262	MDU	Lewis & Clark	0.011	0.049	2.11E-07
263	LG&E Power Serv Inc	LG&E - Westmoreland Hopewell	0.167	0.071	4.05E-08
264	NRG ENERGY	Limestone	0.047	0.022	2.57E-07
265	NEGT (to GOLDMAN SACHS IN 05)	Logan Generating Plant	**0.017**	**0.003**	**7.56E-08**
266	FREEMONT	Lon Wright	**0.080**	**0.020**	**3.26E-07**
267	MIDAMER(BERK HATH)	Louisa	0.005	0.003	9.33E-08
268	MIRANT-NY	Lovett	**0.185**	**0.033**	**2.76E-08**
269	NORTH CAROLINA POWER HOLDINGS	Lumberton	0.000	0.004	1.00E-08
270	MANITOWOC	MANITOWOC 9	0.008	0.094	1.03E-07
271	SO IL PWR COOP	Marion	0.103	0.071	2.26E-07
272	DUKE ENERGY CAROLINAS	Marshall	**0.160**	**0.083**	**9.01E-07**
273	COL SPRINGS	Martin Drake	0.223	0.043	7.54E-08
274	LUMINANT (TXU)	Martin Lake	0.060	0.017	2.87E-07
275	PPL CORP	Martins Creek	**0.013**	**0.136**	**1.61E-07**
276	DTE ENERGY	Marysville Power Plant	0.000	0.000	0.00E+00
277	PROGRESS ENERGY	Mayo	**0.174**	**0.020**	**8.50E-08**
278	LAKELAND	MCINTOSH (FL) 3	0.044	0.025	2.71E-07

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
279	SOUTHERN	McIntosh	0.099	0.019	1.20E-07
280	SCANA	McMeekin	0.030	0.035	1.29E-07
281	UAE Mecklenburg Cogeneration	Mecklenburg Power Station	**0.026**	**0.005**	**7.60E-08**
282	AMEREN-UE	Meramec	0.216	0.044	2.74E-07
283	PSE&G	Mercer	**0.668**	**0.052**	**3.62E-07**
284	AMEREN ENERGY GEN	Meredosia	0.196	0.024	1.58E-07
285	HOOSIER	Merom	**0.010**	**0.013**	**9.29E-08**
286	NU	Merrimack	**0.083**	**0.077**	**3.44E-07**
287	DUKE ENERGY OHIO	Miami Fort Station	**0.053**	**0.038**	**2.60E-07**
288	NIPSCO(NISOURCE)	Michigan City	**0.045**	**0.019**	**1.20E-07**
289	LGE ENERGY (POWER GEN)	Mill Creek	**0.096**	**0.045**	**5.14E-07**
290	SOUTHERN	Miller	0.228	0.012	2.18E-07
291	ALLIANT	Milton L. Kapp	0.059	0.025	2.66E-07
292	MINNKOTA	Milton R. Young	0.031	0.024	2.12E-07
293	SOUTHERN	Mitchell (GA)	0.021	0.013	6.52E-08
294	ALLEGHENY	Mitchell (PA)	**0.012**	**0.048**	**1.72E-07**
295	AEP	Mitchell (WV)	**0.011**	**0.018**	**1.14E-07**
296	SO CAL ED/AES	Mohave	0.000	0.000	0.00E+00
297	DTE ENERGY	Monroe Power Plant	**0.188**	**0.051**	**6.90E-08**
298	LUMINANT (TXU)	Monticello	**0.109**	**0.042**	**2.56E-07**
299	PPL CORP	Montour	**0.073**	**0.091**	**9.67E-07**
300	KCP&L(GREAT PLAINS ENERGY)	Montrose	**0.039**	**0.019**	**1.64E-07**
301	Dominion Energy Services Co	Morgantown Energy Facility	**0.012**	**0.023**	**3.21E-08**
302	MIRANT-MID-ATLANTIC	Morgantown	**0.023**	**0.071**	**4.71E-07**
303	NU (Sell to Energy Capital Partners end of 2006)	Mount Tom	0.125	0.059	4.67E-07
304	AEP	Mountaineer	**0.029**	**0.022**	**2.06E-07**
305	POLARIS POWER GROUP	Mt. Poso Cogeneration Plant	0.048	0.018	4.50E-08
306	DOMINION VA POWER	Mt. Storm Power Station	**0.020**	**0.019**	**1.17E-07**
307	MUSCATINE	Muscatine	0.064	0.048	2.04E-07
308	AEP	Muskingum River	**0.019**	**0.035**	**1.32E-07**
309	OG&E	Muskogee	**0.208**	**0.031**	**3.63E-07**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
310	PACIFICORP(SCOTTISH PWR)	Naughton	**0.010**	**0.060**	**8.85E-08**
311	SRP	Navajo	0.043	0.035	3.89E-07
312	AUSTIN-MN	NE Station	0.021	0.027	5.72E-08
313	KCBPU	Nearman Creek	0.070	0.014	9.63E-08
314	OPPD	Nebraska City	0.067	0.006	1.14E-07
315	BLACK HILLS	NEIL SIMPSON 6 (II 2)	0.009	0.021	1.14E-07
316	ALLIANT	Nelson Dewey	0.014	0.027	3.24E-07
317	RELIANT ENERGY - MID-ATLANTIC	New Castle	**0.009**	**0.009**	**4.33E-08**
318	ASSOCIATED	New Madrid	0.077	0.005	2.10E-07
319	AMEREN ENERGY GEN	Newton	0.166	0.019	3.95E-07
320	RELIANT ENERGY - MIDWEST	Niles	**0.020**	**0.006**	**8.55E-08**
321	DOMINION VA POWER	North Branch Power Station	0.005	0.008	3.79E-08
322	OPPD	North Omaha	**0.085**	**0.029**	**1.49E-07**
323	SIERRA RES	North Valmy Generating Station	0.065	0.017	1.51E-07
324	Northampton Generating Co LP (Goldman Sachs)	Northampton Generating Co. L.P.	**0.190**	**0.018**	**3.47E-08**
325	AEP PSO	Northeastern	0.178	0.026	2.42E-07
326	JEA	NORTHSIDE 2	0.031	0.080	3.46E-07
327	TRI-STATE G&T	Nucla	0.026	0.013	2.13E-08
328	DP&L	O. H. Hutchings	0.051	0.030	9.11E-08
329	AEP PSO	Oklaunion	0.018	0.018	2.21E-07
330	ALLIANT	Ottumwa	0.072	0.007	1.29E-07
331	Constellation Oper Services	Panther Creek Energy Facility	**0.064**	**0.014**	**2.16E-08**
332	TVA	Paradise Fossil Plant	**0.034**	**0.061**	**2.31E-07**
333	XCEL	Pawnee	0.074	0.009	8.96E-08
334	PELLA	PELLA 6	0.022	0.020	4.12E-08
335	AES (IPALCO)	Petersburg	**0.026**	**0.048**	**4.27E-07**
336	AEP	Philip Sporn	**0.067**	**0.032**	**1.38E-07**
337	AEP	Picway	0.013	0.016	1.16E-07
338	Piney Creek L P	Piney Creek Project	0.016	0.036	1.25E-07
339	SIERRA RES	Pinone Pine	0.000	0.000	0.00E+00
340	AEP	Pirkey	**0.016**	**0.030**	**3.69E-07**

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
341	GRAND ISLAND	Platte	0.049	0.020	7.56E-08
342	WE ENERGIES	Pleasant Prairie	0.021	0.013	1.97E-07
343	ALLEGHENY	Pleasants	**0.032**	**0.034**	**4.14E-07**
344	Tampa Electric Co	Polk	0.002	0.004	5.73E-08
345	Mt Poso Cogeneration Co	Port of Stockton District Energy	0.038	0.014	2.77E-08
346	RELIANT ENERGY - MID-ATLANTIC	Portland	**0.037**	**0.046**	**3.23E-07**
347	MIRANT-MID-ATLANTIC	Potomac River	**0.079**	**0.079**	**2.87E-07**
348	MIDWEST GEN	Powerton	0.078	0.004	1.11E-07
349	ALLIANT	Prairie Creek	0.084	0.044	2.08E-07
350	WE ENERGIES	Presque Isle	0.161	0.022	1.58E-07
351	WPS	Pulliam	0.073	0.012	1.93E-07
352	KCBPU	Quindaro	0.081	0.028	9.40E-08
353	Entergy Gulf States Inc	R S Nelson	**0.026**	**0.040**	**4.05E-07**
354	WEST KY ENG (to BIG RIVERS in 2007)	R. D. Green	**0.030**	**0.026**	**1.97E-07**
355	SO MISS ELEC PWR	R. D. Morrow, Sr.	0.058	0.016	2.23E-07
356	FIRST ENERGY	R. E. Burger	**0.007**	**0.009**	**3.73E-08**
357	DUKE ENERGY INDIANA	R. Gallagher Station	**0.013**	**0.023**	**1.46E-07**
358	ALLEGHENY	R. Paul Smith	0.028	0.091	3.96E-07
359	MDU	R.M. Heskett Station	0.043	0.011	5.05E-08
360	NIPSCO(NISOURCE)	R.M. Schahfer	**0.036**	**0.039**	**2.70E-07**
361	Entergy Gulf States Inc	R.S. Nelson 6	0.018	0.013	2.66E-07
362	PLATTE RIVER	Rawhide	0.006	0.010	9.14E-08
363	COL SPRINGS	Ray D. Nixon	0.047	0.009	5.64E-08
364	Choctaw Generating LP	Red Hills Generation Facility	**0.139**	**0.031**	**3.71E-08**
365	SIERRA RES	Reid Gardner	0.025	0.052	3.23E-07
366	AMP	Richard H. Gorsuch	0.036	0.015	1.07E-07
367	Constellation Oper Services	Rio Bravo Jasmin	0.019	0.101	6.28E-08
368	Constellation Oper Services	Rio Bravo Poso	0.019	0.104	6.35E-08
369	DTE ENERGY	River Rouge Power Plant	**0.109**	**0.014**	**2.94E-08**
370	DUKE ENERGY CAROLINAS	Riverbend	**0.062**	**0.029**	**1.15E-07**
371	XCEL	Riverside	0.005	0.015	7.89E-08

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
372	MIDAMER(BERK HATH)	Riverside	0.034	0.009	8.03E-08
373	XCEL	Riverside	0.053	0.013	1.20E-07
374	EMPIRE DISTRICT	Riverton	0.016	0.057	2.87E-07
375	ALLEGHENY	Rivesville	**0.052**	**0.067**	**2.01E-07**
376	WEST KY ENG (to BIG RIVERS in 2007)	Robert Reid	**0.006**	**0.007**	**2.58E-08**
377	ENERGY EAST	Rochester 7	0.000	0.000	0.00E+00
378	AEP	Rockport	**0.028**	**0.012**	**2.77E-08**
379	CLECO	Rodemacher Power Station	0.097	0.012	9.21E-08
380	PROGRESS ENERGY	Roxboro	**0.258**	**0.045**	**8.06E-07**
381	Rumford Cogeneration Co	Rumford Cogeneration	0.026	0.002	1.99E-08
382	AMEREN-UE	Rush Island	0.126	0.011	1.49E-07
383	DOMINION	Salem Harbor	0.174	0.044	2.53E-07
384	PSNM	San Juan	**0.005**	**0.001**	**3.84E-08**
385	SAN MIGUEL	San Miguel	0.082	0.014	1.73E-07
386	LUMINANT (TXU)	Sandow	0.052	0.015	1.94E-07
387	SOUTHERN	Scherer	0.238	0.011	2.95E-07
388	NU	Schiller	**0.226**	**0.037**	**4.27E-07**
389	SOUTHERN	Scholz	0.032	0.032	7.54E-08
390	Buzzard Power Corporation	Scrubgrass Generating	0.029	0.024	8.06E-08
391	SEMINOLE	Seminole	**0.049**	**0.023**	**1.40E-07**
392	RELIANT ENERGY - MID-ATLANTIC	Seward	**0.012**	**0.027**	**2.79E-08**
393	TVA	Shawnee Fossil Plant	0.108	0.010	2.06E-07
394	RELIANT ENERGY - MID-ATLANTIC	Shawville	**0.045**	**0.102**	**2.47E-07**
395	NPPD	Sheldon	0.087	0.030	1.10E-07
396	XCEL	Sherburne County	0.026	0.018	3.99E-07
397	MARQUETTE	Shiras	0.007	0.077	2.54E-07
398	AQUILA(GREAT PLAINS ENERGY)	Sibley	0.108	0.012	9.87E-08
399	SIKESTON	Sikeston	0.010	0.011	1.24E-07
400	ROCHESTER	Silver Lake	0.021	0.049	2.61E-07
401	AMEREN-UE	Sioux	0.056	0.024	2.10E-07
402	ALLIANT	SIXTH STREET (IA) 8	0.021	0.008	1.96E-08

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
403	NRG Somerset Power LLC	Somerset	0.086	0.022	1.42E-07
404	OG&E	Sooner	0.160	0.021	3.19E-07
405	WE ENERGIES	South Oak Creek	0.125	0.014	1.57E-07
406	LG&E Power Serv Inc	Southampton Power Station	0.021	0.047	1.77E-07
407	SPRING-MO	Southwest Power Station	0.019	0.057	3.05E-07
408	TUCSON	Springerville	0.019	0.023	2.21E-07
409	DTE ENERGY	St Clair Power Plant	**0.083**	**0.029**	**1.34E-07**
410	JEA	St. Johns River Power Park	0.057	0.015	2.88E-07
411	Schuylkill Energy Resource Inc	St. Nicholas Cogeneration Project	**0.039**	**0.026**	**2.67E-08**
412	ORLANDO	Stanton Energy	0.166	0.061	4.72E-07
413	GREAT RIVER ENG	Stanton Station	0.054	0.026	1.55E-07
414	DOMINION	State Line	**0.034**	**0.012**	**8.69E-08**
415	ArcLight Capital Partners	Stockton Cogen Company	0.004	0.010	4.29E-08
416	CEDAR FALLS	Streeter Station	0.009	0.020	8.59E-08
417	SUNDBURY(WPS-PDI)	Sunbury	**0.053**	**0.088**	**3.42E-07**
418	Sunnyside Operations Associate	Sunnyside Cogeneration	0.109	0.022	1.37E-08
419	ALLIANT	Sutherland	0.149	0.106	3.28E-07
420	ALLETE(MIN PWR)	Taconite Harbor Energy Center	0.115	0.078	4.24E-07
421	AEP	Tanners Creek	**0.434**	**0.035**	**2.24E-07**
422	WESTSTAR ENERGY	Tecumseh	0.113	0.059	3.24E-07
423	TES Filer City Station LP	TES Filer City Station	0.017	0.059	1.68E-07
424	ASSOCIATED	Thomas Hill	0.199	0.036	3.72E-07
425	RELIANT ENERGY - MID-ATLANTIC	Titus	**0.041**	**0.141**	**1.67E-07**
426	SEMPRA GENERATION (to PNM RESOURCES 2006)	TNP-One	0.018	0.036	1.69E-07
427	XCEL	Tolk Station	0.109	0.013	2.17E-07
428	DTE ENERGY	Trenton Channel Power Plant	**0.126**	**0.019**	**1.07E-07**
429	Trigen-Syracuse Energy Corp	Trigen Syracuse	0.006	0.010	7.57E-08
430	LGE ENERGY (POWER GEN)	Trimble County	**0.024**	**0.019**	**1.73E-07**
431	LGE ENERGY (POWER GEN)	Tyrone	0.022	0.012	6.41E-08
432	SCANA	Urquhart	**0.045**	**0.008**	**8.65E-07**
433	WE ENERGIES	Valley	0.094	0.023	5.59E-08

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
434	XCEL	Valmont	0.005	0.004	2.87E-08
435	DYNEGY MIDWEST	Vermilion	0.046	0.013	8.74E-08
436	SOUTHERN	Victor J. Daniel	0.232	0.012	1.77E-07
437	NRG ENERGY	W A Parish	**0.062**	**0.040**	**1.02E-07**
438	PROGRESS ENERGY	W H Weatherspoon	**0.145**	**0.064**	**5.89E-07**
439	FIRST ENERGY	W. H. Sammis	**0.317**	**0.052**	**2.25E-07**
440	DUKE ENERGY OHIO	W. H. Zimmer Station	**0.041**	**0.014**	**1.70E-07**
441	DUKE ENERGY CAROLINAS	W. S. Lee	**0.122**	**0.059**	**5.15E-07**
442	DUKE ENERGY INDIANA	Wabash River	0.034	0.014	3.28E-07
443	DUKE ENERGY OHIO	Walter C. Beckjord	**0.140**	**0.060**	**5.05E-07**
444	SOUTHERN	Wansley	**0.012**	**0.034**	**1.25E-07**
445	ALCOA	Warrick Power Plant	**0.015**	**0.022**	**9.36E-08**
446	SCANA	Wateree	0.131	0.073	4.50E-07
447	TVA	WATTS BAR COAL 4	0.000	0.000	0.00E+00
448	MIDWEST GEN	Waukegan	0.167	0.033	3.20E-07
449	AEP	Welsh	**0.182**	**0.053**	**4.16E-07**
450	LG&E Power Services	Westmoreland Roanoke Valley 1	0.014	0.008	4.91E-08
451	LG&E Power Services	Westmoreland Roanoke Valley 2	0.011	0.018	6.11E-08
452	WPS	Weston	0.111	0.042	2.86E-07
453	WPS POWER DEV	Westwood	**0.004**	**0.011**	**1.02E-07**
454	Wheelabrator Environmental Systems	Wheelabrator Frackville Energy	**0.072**	**0.007**	**2.22E-08**
455	HASTINGS	Whelan Energy Center	0.047	0.018	4.68E-08
456	ENTERGY	White Bluff	0.093	0.004	8.29E-08
457	RICHMOND	Whitewater Valley	0.015	0.045	4.02E-07
458	TVA	Widows Creek Fossil Plant	0.085	0.034	4.61E-07
459	MIDWEST GEN	Will County	**0.074**	**0.021**	**1.31E-07**
460	SCANA	Williams	**0.012**	**0.017**	**3.68E-08**
461	ALLEGHENY	Willow Island	0.029	0.051	2.10E-07
462	SANTEE	Winyah Generating Station	**0.123**	**0.037**	**4.89E-07**
463	DYNEGY MIDWEST	Wood River	0.123	0.034	1.77E-07
464	WPS POWER DEV	WPS POWER Niagara	0.010	0.024	5.93E-08

Table 9-1 (continued)
Inhalation Risk Result

Plant ID	Owner	Facility	Chronic HI*	Acute HI	Cancer Risk*
465	WYANDOTTE	WYANDOTTE 7&8	**0.018**	**0.013**	**6.87E-08**
466	BLACK HILLS	WYGEN 1	0.006	0.027	8.47E-08
467	PACIFICORP(SCOTTISH PWR)	Wyodak	0.012	0.011	8.54E-08
468	SOUTHERN	Yates	**0.021**	**0.079**	**4.85E-07**
469	DOMINION VA POWER	Yorktown Power Station	0.065	0.039	3.05E-07

* Bold values indicate Tier 2 modeling.

For chronic HI and cancer risk the non-bold values are Tier 1.5 results applying the 95th percentile Tier 2/Tier 1 ratio.

For Acute the non-bold values indicate Tier 1.

Table 9-2
Facilities with the Highest Cancer Risk Results

ID	Owner	Facility	Tier 2 Cancer Risk	Highest Contributor		2nd Highest Contributor		3rd Highest Contributor		4th Highest Contributor		5th Highest Contributor	
172	DUKE ENERGY INDIANA	Gibson	**9.78E-07**	Arsenic	63.9%	Chromium (VI)	24.7%	Cadmium	3.4%	Beryllium	3.4%	Ethylene dibromide	2.6%
299	PPL CORP	Montour	**9.67E-07**	Arsenic	83.0%	Chromium (VI)	12.7%	Beryllium	1.4%	Cadmium	1.0%	Ethylene dibromide	0.9%
3	AES	Beaver Valley	**9.52E-07**	Arsenic	79.0%	Chromium (VI)	15.4%	Ethylene dibromide	1.5%	Beryllium	1.5%	Cadmium	1.2%
26	PROGRESS ENERGY	Asheville	**9.49E-07**	Arsenic	60.7%	Chromium (VI)	26.8%	Ethylene dibromide	4.9%	Beryllium	3.0%	Nickel	2.0%
272	DUKE ENERGY CAROLINAS	Marshall	**9.01E-07**	Arsenic	62.3%	Chromium (VI)	26.3%	Ethylene dibromide	4.1%	Beryllium	2.7%	Nickel	2.2%
432	SCANA	Urquhart	**8.65E-07**	Arsenic	83.4%	Chromium (VI)	12.0%	Beryllium	1.6%	Cadmium	1.3%	Ethylene dibromide	0.9%
380	PROGRESS ENERGY	Roxboro	**8.06E-07**	Chromium (VI)	50.2%	Arsenic	28.2%	Beryllium	6.8%	Ethylene dibromide	5.6%	Cadmium	5.0%
63	SCANA	Canadys	**7.97E-07**	Arsenic	72.6%	Chromium (VI)	19.6%	Beryllium	2.9%	Ethylene dibromide	1.7%	Cadmium	1.6%
229	SANTEE	Jefferies	**7.19E-07**	Arsenic	74.5%	Chromium (VI)	18.6%	Beryllium	3.3%	Cadmium	1.5%	Nickel	1.2%
140	EXELON GENERATION	Eddystone	**7.14E-07**	Arsenic	75.4%	Chromium (VI)	18.0%	Beryllium	2.1%	Cadmium	1.8%	Ethylene dibromide	1.4%

Table 9-3
Facilities with the Highest Chronic Inhalation Risk Results

ID	Owner	Facility	Tier 2 Chronic HI	Highest Contributor		2nd Highest Contributor		3rd Highest Contributor		4th Highest Contributor		5th Highest Contributor	
283	PSE&G	Mercer	**0.668**	Chlorine	98.14%	HCl	0.98%	Arsenic	0.25%	Manganese	0.25%	Nickel	0.08%
78	DOMINION VA POWER	Chesapeake	**0.629**	Chlorine	97.44%	HCl	0.97%	Manganese	0.51%	HF	0.27%	Arsenic	0.26%
212	NRG Indian River Operations Inc	Indian River	**0.524**	Chlorine	97.74%	HCl	0.98%	Arsenic	0.42%	Manganese	0.33%	HF	0.13%
141	PEPCO	Edge Moor	**0.483**	Chlorine	98.29%	HCl	0.98%	Arsenic	0.20%	Manganese	0.19%	HF	0.09%
56	DUKE ENERGY	Buck	**0.446**	Chlorine	98.50%	HCl	0.99%	Manganese	0.13%	Acrolein	0.09%	Arsenic	0.08%
421	AEP	Tanners Creek	**0.434**	Chlorine	97.86%	HCl	0.98%	Manganese	0.35%	Arsenic	0.23%	HF	0.16%
244	TVA	Kingston	**0.333**	Chlorine	98.29%	HCl	0.98%	Manganese	0.19%	HF	0.14%	Acrolei n	0.13%
439	FIRST ENERGY	W. H. Sammis	**0.317**	Chlorine	97.40%	HCl	0.97%	Manganese	0.50%	Arsenic	0.31%	HF	0.24%
125	GAINESVILLE	Deerhaven	**0.285**	Chlorine	98.47%	HCl	0.98%	Manganese	0.12%	Acrolein	0.10%	Arsenic	0.09%
108	MIDAMER(BERK HATH)	Council Bluffs	**0.284**	Chlorine	92.54%	Manganese	2.74%	HF	1.00%	HF	0.93%	Arsenic	0.82%

Table 9-4
Facilities with the Highest Acute Risk Results

ID	Owner	Facility	Tier 2 Acute HI	Highest Contributor		2nd Highest Contributor		3rd Highest Contributor		4th Highest Contributor		5th Highest Contributor	
4	AES	Cayuga (NY)	**0.295**	As	75.1%	Acrolein	12.7%	Cl2	7.1%	HF	1.8%	Ni	1.4%
105	EAST KY PWR	Cooper	**0.290**	As	60.3%	HCl	16.6%	HF	10.8%	Acrolein	5.3%	Cl2	3.4%
64	LGE ENERGY	Cane Run	**0.238**	As	65.8%	Acrolein	19.4%	Cl2	6.6%	Hg0	2.5%	Ni	2.5%
3	AES	Beaver Valley	**0.211**	As	82.5%	Acrolein	8.4%	Cl2	4.5%	Hg0	1.6%	Ni	1.2%
141	PEPCO	Edge Moor	**0.160**	Cl2	62.5%	As	20.7%	HCl	6.3%	Acrolein	5.2%	HF	3.4%
425	RELIANT ENERGY	Titus	**0.141**	As	37.6%	HCl	30.3%	HF	10.0%	Hg0	9.0%	Acrolein	6.2%
275	PPL CORP	Martins Creek	**0.136**	As	65.1%	HCl	13.9%	HF	9.2%	Acrolein	4.9%	Hg0	3.2%
157	ALLE-GHENY	Fort Martin	**0.134**	As	51.5%	HCl	20.8%	HF	13.9%	Acrolein	7.6%	Cl2	4.3%
144	WPS POWER	EJ STONEMAN 2	**0.126**	HCl	33.9%	As	26.4%	HF	18.5%	Acrolein	10.8%	Cl2	6.9%
103	RELIANT ENERGY	Conemaugh	**0.119**	As	67.4%	Acrolein	18.1%	Cl2	5.9%	Hg0	3.5%	HF	2.8%

Table 9-5
Cancer Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Risk*	Screening Combined Risk**
1	1	Northern CA	2		7.06E-08
1	2	Southern CA	3		1.71E-07
1	3	AZ/NM Border	2		3.51E-07
1	4	Four Corners	2		4.43E-07
1	5	Central UT	4		6.50E-07
1	6	NW Colorado	2		1.08E-07
1	7	Boulder, CO Area	2		1.30E-07
1	8	Colorado Springs	3		2.39E-07
2	1	SE MT	3		2.84E-07
2	2	NE WY	2		2.14E-07
2	3	Central ND	7		8.30E-07
3	1	TX	2		3.66E-07
3	2	SE TX	2		2.26E-07
3	3	TX	2		3.43E-07
3	4	NE TX	2		6.56E-07
3	5	NE TX	2		6.72E-07
3	6	Eastern OK	3		7.14E-07
3	7	KS/MO Border	2		4.99E-07
3	8	SW MO	2		9.62E-07
3	9	Coastal MS	2		4.50E-07
3	10	Central AL	2		4.75E-07
3	11	NW GA	2		4.08E-07
3	12	Western GA	2		6.11E-07
3	13	Central GA	2		5.94E-07
3	14	Eastern TN	2		1.97E-07
4	1	Central FL	3		7.97E-07
4	2	NE FL	3		6.96E-07

Table 9-5 (continued)
Cancer Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Risk*	Screening Combined Risk**
4	3	GA/SC Border	2		3.00E-07
4	4	Central SC	4	**7.67E-07**	1.31E-06
4	5	Coastal NC	2		5.68E-07
4	6	Southern NC	3		6.07E-07
4	7	Western NC	3	**9.31E-07**	1.50E-06
4	8	Northern NC	2		3.95E-07
4	9	NC/VA Border	5	**8.20E-07**	1.19E-06
4	10	Eastern NC	3		4.41E-07
5	1	NE/IA Border (North)	2		3.13E-07
5	2	NE/IA Border (South)	3	**6.23E-07**	1.09E-06
5	3	Eastern KS	2		7.59E-07
5	4	KS/MO Border	4		3.98E-07
5	5	Western MO	5		4.70E-07
5	6	Central IA	2		1.70E-07
5	7	Eastern IA	2		2.27E-07
5	8	IA/WI Border	2		1.25E-07
5	9	IA/IL Border (North)	2		3.46E-07
5	10	IA/IL Border (South)	3		4.12E-07
5	11	Western IL (North)	4		6.27E-07
5	12	Western IL (South)	3		5.76E-07
5	13	NE	2		1.22E-07
6	1	IL/MO Border (North)	2		3.87E-07
6	2	IL/MO Border (South)	4		6.99E-07
6	3	IL/KY Border	3		6.65E-07
6	4	IL/IN Border A	2		3.45E-07
6	5	IL/IN Border B	3		7.08E-07
6	6	IL/IN Border C	5	**8.11E-07**	1.36E-06

Table 9-5 (continued)
Cancer Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Risk*	Screening Combined Risk**
6	7	IL/IN Border D	4	***1.03E-06***	2.13E-06
6	8	West Central IN	2		9.07E-07
6	9	Northern KY	7		9.73E-07
6	10	KY/IN Border	10	**5.66E-07**	1.76E-06
7	1	KY/IN Border	3	**7.80E-07**	1.29E-06
7	2	KY/IN Border	6	**5.63E-07**	1.30E-06
7	3	KY/IN/OH Border	6	**5.36E-07**	1.67E-06
7	4	SW OH	2		2.08E-07
7	5	KY/OH Border	3		4.27E-07
7	6	KY/OH Border	3		7.12E-07
7	7	Central KY	3		8.67E-07
7	8	KY/OH Border	5	**5.41E-07**	1.20E-06
8	1	Northern OH	3		9.01E-07
8	2	NE WV	3		3.54E-07
8	3	WV/Southwest PA	6	**5.00E-07**	1.13E-06
8	4	Southwest PA	4	**4.22E-07**	1.02E-06
8	5	OH/WV Border	6		9.82E-07
8	6	OH/PA Border	5	***1.21E-06***	1.71E-06
8	7	Western PA	3		2.61E-07
8	8	Western PA	7	**9.17E-07**	1.64E-06
8	9	Western PA	7	**8.88E-07**	1.46E-06
9	1	Central MI	2		2.57E-07
9	2	NE MI	2		2.62E-07
9	3	Eastern MI (North)	3		2.87E-07
9	4	Eastern MI (South)	6		8.51E-07
9	5	Western NY (South)	2		5.24E-07
9	6	Western NY (North)	3		6.79E-07

Table 9-5 (continued)
Cancer Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Risk*	Screening Combined Risk**
9	7	Central NY	2		6.62E-07
9	8	Central NY	2	**2.51E-07**	3.94E-07
10	1	SE MA	2	**3.70E-07**	2.55E-07
10	2	SE NY	2	**4.29E-07**	5.96E-07
10	3	DE/NJ/PA Border	6	**7.14E-07**	1.37E-06
10	4	NJ/Eastern PA	6	**3.95E-07**	1.25E-06
10	5	Eastern PA	6	**7.14E-07**	1.59E-06
10	6	PA/NJ Border	4	**5.41E-07**	5.40E-07
10	7	East-Northeast PA	9	**9.67E-07**	1.68E-06
11	1	Eastern VA	3		9.72E-07
11	2	DC/MD/PA Border	4	**4.71E-07**	1.00E-06
11	3	Eastern MD	3		8.28E-07
11	4	Coastal VA	3		9.64E-07
12	1	Northern MI	2		4.12E-07
12	2	Eastern WI	2		3.13E-07
12	3	Central WI	2		4.01E-07
12	4	WI/IA/MN Border	2		5.19E-07
12	5	WI/MN Border	2		1.98E-07
12	6	Eastern MN	5		3.58E-07
13	1	Western MI	4		5.15E-07
13	2	WI/IL Border	4		7.29E-07
13	3	NE IL	6		6.25E-07
13	4	IL/IN Border	5		5.13E-07
13	5	NW IN	2		3.55E-07

Table 9-6
Chronic Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Hazard Index*	Screening Combined Hazard Index**
1	1	Northern CA	2		0.04
1	2	Southern CA	3		0.09
1	3	AZ/NM Border	2		0.03
1	4	Four Corners	2		0.05
1	5	Central UT	4		0.42
1	6	NW Colorado	2		0.02
1	7	Boulder, CO Area	2		0.01
1	8	Colorado Springs	3		0.36
2	1	SE MT	3		0.03
2	2	NE WY	2		0.01
2	3	Central ND	7		0.18
3	1	TX	2		0.08
3	2	SE TX	2		0.07
3	3	TX	2		0.15
3	4	NE TX	2		0.08
3	5	NE TX	2		0.29
3	6	Eastern OK	3		0.42
3	7	KS/MO Border	2		0.04
3	8	SW MO	2		0.24
3	9	Coastal MS	2		0.43
3	10	Central AL	2		0.28
3	11	NW GA	2		0.12
3	12	Western GA	2		0.03
3	13	Central GA	2		0.35
3	14	Eastern TN	2		0.42
4	1	Central FL	3		0.07
4	2	NE FL	3		0.11

Table 9-6 (continued)
Chronic Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Hazard Index*	Screening Combined Hazard Index**
4	3	GA/SC Border	2		0.22
4	4	Central SC	4		0.25
4	5	Coastal NC	2		0.11
4	6	Southern NC	3		0.15
4	7	Western NC	3		0.36
4	8	Northern NC	2		0.11
4	9	NC/VA Border	5		0.51
4	10	Eastern NC	3		0.07
5	1	NE/IA Border (North)	2		0.12
5	2	NE/IA Border (South)	3		0.45
5	3	Eastern KS	2		0.17
5	4	KS/MO Border	4		0.29
5	5	Western MO	5		0.25
5	6	Central IA	2		0.09
5	7	Eastern IA	2		0.11
5	8	IA/WI Border	2		0.06
5	9	IA/IL Border (North)	2		0.09
5	10	IA/IL Border (South)	3		0.08
5	11	Western IL (North)	4		0.29
5	12	Western IL (South)	3		0.23
5	13	NE	2		0.10
6	1	IL/MO Border (North)	2		0.06
6	2	IL/MO Border (South)	4		0.49
6	3	IL/KY Border	3		0.33
6	4	IL/IN Border A	2		0.10
6	5	IL/IN Border B	3		0.14
6	6	IL/IN Border C	5		0.11

Table 9-6 (continued)
Chronic Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Hazard Index*	Screening Combined Hazard Index**
6	7	IL/IN Border D	4		0.12
6	8	West Central IN	2		0.08
6	9	Northern KY	7		0.12
6	10	KY/IN Border	10		0.18
7	1	KY/IN Border	3		0.17
7	2	KY/IN Border	6		0.62
7	3	KY/IN/OH Border	6		0.74
7	4	SW OH	2		0.07
7	5	KY/OH Border	3		0.29
7	6	KY/OH Border	3		0.37
7	7	Central KY	3		0.21
7	8	KY/OH Border	5		0.68
8	1	Northern OH	3		0.22
8	2	NE WV	3		0.06
8	3	WV/Southwest PA	6		0.21
8	4	Southwest PA	4		0.14
8	5	OH/WV Border	6		0.43
8	6	OH/PA Border	5		0.45
8	7	Western PA	3		0.06
8	8	Western PA	7		0.23
8	9	Western PA	7		0.26
9	1	Central MI	2		0.14
9	2	NE MI	2		0.24
9	3	Eastern MI (North)	3		0.17
9	4	Eastern MI (South)	6		0.69
9	5	Western NY (South)	2		0.17
9	6	Western NY (North)	3		0.17

Table 9-6 (continued)
Chronic Risk Results, Facility Groups with Overlapping Plume Domains

Map ID	Group ID	Location	Number of Facilities in Group	Refined Combined Hazard Index*	Screening Combined Hazard Index**
9	7	Central NY	2		0.08
9	8	Central NY	2		0.12
10	1	SE MA	2		0.37
10	2	SE NY	2		0.23
10	3	DE/NJ/PA Border	6		0.22
10	4	NJ/Eastern PA	6	**0.67**	1.00
10	5	Eastern PA	6		0.79
10	6	PA/NJ Border	4		0.12
10	7	East-Northeast PA	9		0.44
11	1	Eastern VA	3		0.18
11	2	DC/MD/PA Border	4		0.14
11	3	Eastern MD	3		0.37
11	4	Coastal VA	3		0.76
12	1	Northern MI	2		0.17
12	2	Eastern WI	2		0.12
12	3	Central WI	2		0.14
12	4	WI/IA/MN Border	2		0.16
12	5	WI/MN Border	2		0.07
12	6	Eastern MN	5		0.12
13	1	Western MI	4		0.42
13	2	WI/IL Border	4		0.41
13	3	NE IL	6		0.25
13	4	IL/IN Border	5		0.17
13	5	NW IN	2		0.05

Table 9-7
Facility Groups with Cancer Risk Exceeding 1 x 10^{-6}

Map ID	6	8
Group ID	7	6
Location	IL/IN border	OH/PA border
Number of Facilities in Group	4	5
Combined Risk	***1.03E-06***	***1.21E-06***
Contributing Power Plants		
Facility 1 ID	143	439
Owner	Duke Energy Indiana	First Energy
Location	Edwardsport	W. H. Sammis
Maximum Risk	1.09E-07	2.25E-07
Facility 2 ID	160	54
Owner	Hoosier	First Energy
Location	Frank E. Ratts	Bruce Mansfield
Maximum Risk	6.12E-07	4.05E-07
Facility 3 ID	335	3
Owner	AES (IPALCO)	AES
Location	Petersburg	Beaver Valley
Maximum Risk	4.27E-07	9.57E-07
Facility 4 ID	172	317
Owner	Duke Energy Indiana	Reliant Energy-Mid-Atlantic
Location	Gibson Generating Station	New Castle
Maximum Risk	9.78E-07	4.33E-08
Facility 5 ID		320
Owner		Reliant Energy-Midwest
Location		Niles
Maximum Risk		8.55E-08

A

SAMPLE CALCULATIONS FOR BLENDED COAL COMPOSITION INPUTS

This appendix describes the general methodology for how the blended coal compositions were generated for each power plant. As an example, specific calculations are shown for the Clay Boswell Station.

As described in Section 3, the USGS database was screened to provide approximately 2700 coal composition records for 22 major coal-producing regions in the United States. Fuel compositions for these 22 regions are shown in Table A-1. Surveying the fuel purchasing records for coal-fired stations from the FERC and EIA database, an additional 44 unique types of fuel were identified that were not explicitly listed in 22 USGS coal-producing regions. These additional 44 types were then mapped onto the 22 major regions from the USGS database, as shown in Table A-2. Coal mercury and chloride concentrations were not taken from the USGS database, but instead came from the 1999 EPA mercury ICR database of over 40,000 coal samples organized by coal rank, state, and county. These ICR data for coal mercury and chloride are documented in EPRI's 2000 Assessment of Mercury Emissions (1). Table A-3 provides the geometric mean composition data for petroleum coke and tired derived fuel (TDF) developed from data taken from the EPRI PISCES Database (Version 2008a).

Table A-1
Fuel Compositions for USGS Coal Regions

State	Coal Supply Region	Rank	No. Samples	Geometric Mean Concentration (lb/TBtu)										
				As	Be	Cd	Co	Cr	F	Mn	Ni	Pb	Sb	Se
ALABAMA	SOUTHERN APPALACHIAN	Bit	150	877	146	3.8	452	1,677	8,390	2,035	1,104	376	109	113
COLORADO	GREEN RIVER	Bit	26	65	66	4.9	100	231	8,183	800	190	450	20	79
ILLINOIS	EASTERN	Bit	15	265	146	64	204	1,196	4,704	3,879	826	590	41	160
INDIANA	EASTERN	Bit	80	550	233	14	341	1,206	4,688	2,366	1,192	470	77	161
KENTUCKY	EASTERN	Bit	116	504	170	9.9	259	1,204	4,634	2,839	893	455	42	173
KENTUCKY	CENTRAL APPALACHIAN	Bit	337	636	204	4.3	446	1,076	6,314	1,292	1,091	422	78	269
MARYLAND	NORTHERN APPALACHIAN	Bit	38	1,021	139	6.7	572	1,781	5,702	719	1,166	477	51	197
NEW MEXICO	SAN JUAN RIVER	Bit	3	46	87	4.8	191	331	11,574	980	478	279	31	81
OHIO	NORTHERN APPALACHIAN	Bit	492	1,487	168	9.1	283	1,088	6,752	2,496	1,092	348	40	233
PENNSYLVANIA	NORTHERN APPALACHIAN	Bit	539	2,017	163	6.5	447	1,423	5,208	1,804	1,326	662	71	206
TENNESSEE	CENTRAL APPALACHIAN	Bit	12	1,304	70	5.8	254	586	3,201	686	497	221	48	201
UTAH	UINTA	Bit	22	75	45	6.9	116	639	4,659	673	313	311	19	155
VIRGINIA	CENTRAL APPALACHIAN	Bit	52	725	119	3.7	389	804	4,752	1,277	715	348	57	197
WEST VIRGINIA	NORTHERN APPALACHIAN	Bit	115	977	153	5.7	482	1,214	4,243	1,833	953	433	52	278
WEST VIRGINIA	CENTRAL APPALACHIAN	Bit	266	280	175	7.6	425	863	3,608	650	819	392	60	246

Table A-1 (continued)
Fuel Compositions for USGS Coal Regions

State	Coal Supply Region	Rank	No. Samples	Geometric Mean Concentration (lb/TBtu)										
				As	Be	Cd	Co	Cr	F	Mn	Ni	Pb	Sb	Se
NORTH DAKOTA	FORT UNION	Lig	56	989	88	12	145	603	3,313	10,097	337	500	54	104
TEXAS	TEXAS	Lig	54	410	183	15	392	1,414	6,596	15,205	851	597	100	718
COLORADO	GREEN RIVER	Sub	1	65	60	6	105	125	5,708	1,150	92	506	23	110
MONTANA	POWDER RIVER	Sub	95	408	74	10	125	421	6,734	3,557	446	378	55	84
NEW MEXICO	SAN JUAN RIVER	Sub	104	143	226	16	262	605	7,022	3,367	450	1,484	98	209
WYOMING	GREEN RIVER	Sub	2	290	29	9.2	157	806	4,268	4,128	314	616	71	143
WYOMING	POWDER RIVER	Sub	141	165	35	5.6	158	512	6,131	2,289	379	250	22	86

Table A-2
USGS Coal Region Used for Unique Coal Types

Actual Coal Type Reported			USGS Coal Type Assigned		
State	Coal Supply Region	Rank	State	Coal Supply Region	Rank
Wyoming	Green River	Bituminous	Colorado	Green River	Bituminous
Utah	Uinta	Waste Coal	Utah	Uinta	Bituminous
Utah	Uinta	Synthetic Coal	Utah	Uinta	Bituminous
Wyoming	Powder River	Lignite	Wyoming	Powder River	Subbituminous
Wyoming	Powder River	Bituminous	Wyoming	Powder River	Subbituminous
Kansas	Eastern	Bituminous	Illinois	Eastern	Bituminous
Illinois	Eastern	Synthetic Coal	Illinois	Eastern	Bituminous
Illinois	Eastern	Subbituminous	Illinois	Eastern	Bituminous
West Virginia	Central Appalachian	Synthetic Coal	West Virginia	Central Appalachian	Bituminous
West Virginia	Central Appalachian	Subbituminous	West Virginia	Central Appalachian	Bituminous
West Virginia	Central Appalachian	Waste Coal	West Virginia	Central Appalachian	Bituminous
Montana	Powder River	Bituminous	Montana	Powder River	Subbituminous
Montana	Powder River	Lignite	Montana	Powder River	Subbituminous
Montana	Powder River	Synthetic Coal	Montana	Powder River	Subbituminous
Montana	Powder River	Waste Coal	Montana	Powder River	Subbituminous
Indonesian	Powder River	Subbituminous	Average	Powder River	Subbituminous
Imported	Powder River	Subbituminous	Average	Powder River	Subbituminous
Indiana	Powder River	Subbituminous	Average	Powder River	Subbituminous
-	Powder River	Subbituminous	Average	Powder River	Subbituminous
Louisiana	Texas	Lignite	Texas	Texas	Lignite
Columbian	Eastern	Bituminous	Average	Eastern	Bituminous
Indonesian	Eastern	Bituminous	Average	Eastern	Bituminous
Imported	Eastern	Bituminous	Average	Eastern	Bituminous
Missouri	Eastern	Bituminous	Average	Eastern	Bituminous
Oklahoma	Eastern	Bituminous	Average	Eastern	Bituminous
Other	Eastern	Bituminous	Average	Eastern	Bituminous
Venezuelan	Eastern	Bituminous	Average	Eastern	Bituminous
Venezuelan	Eastern	Waste Coal	Average	Eastern	Bituminous
Kentucky	Eastern	Waste Coal	Kentucky	Eastern	Bituminous
Indiana	Eastern	Synthetic Coal	Indiana	Eastern	Bituminous
Kentucky	Central Appalachian	Synthetic Coal	Kentucky	Central Appalachian	Bituminous
Virginia	Central Appalachian	Synthetic Coal	Virginia	Central Appalachian	Bituminous

Table A-2 (continued)
USGS Coal Region Used for Unique Coal Types

Actual Coal Type Reported			USGS Coal Type Assigned		
State	**Coal Supply Region**	**Rank**	**State**	**Coal Supply Region**	**Rank**
Virginia	Central Appalachian	Subbituminous	Virginia	Central Appalachian	Bituminous
Alabama	Southern Appalachian	Synthetic Coal	Alabama	Southern Appalachian	Bituminous
Mississippi	Southern Appalachian	Lignite	Alabama	Southern Appalachian	Bituminous
West Virginia	Northern Appalachian	Waste Coal	West Virginia	Northern Appalachian	Bituminous
-	Central Appalachian	Bituminous	Average	Central Appalachian	Bituminous
-	Northern Appalachian	Waste Coal	Average	Northern Appalachian	Bituminous
-	Northern Appalachian	Synthetic Coal	Average	Northern Appalachian	Bituminous
-	Northern Appalachian	Bituminous	Average	Northern Appalachian	Bituminous
Pennsylvania	Northern Appalachian	Synthetic Coal	Pennsylvania	Northern Appalachian	Bituminous
Pennsylvania	Northern Appalachian	Waste Coal	Pennsylvania	Northern Appalachian	Bituminous
Pennsylvania	Northern Appalachian	Subbituminous	Pennsylvania	Northern Appalachian	Bituminous

Table A-3
Petroleum Coke and Tire Derived Fuel Composition Data

Fuel [a]	No. Samples	Geometric Mean Concentration (lb/TBtu)												
		As	**Be**	**Cd**	**Cl**	**Co**	**Cr**	**F**	**Mn**	**Hg**	**Ni**	**Pb**	**Sb**	**Se**
Pet Coke	4-7	85	31	3	18,171	232	436	7,332	232	5.4	7,632	192	63	45
TDF	1-4	533	2.7	213	No Data	12,670	3,533	No Data	973	2.2	417	5,960	33	271

[a] Composition data for petroleum coke (Pet Coke) and tire derived fuel (TDF) were derived from data in EPRI's PISCES Database, version 2008a.

For each power plant the monthly fuel purchase records from the FERC and EIA coal database were retrieved and totaled. Fuels used for start-up only (oil, natural gas, etc) were not included in this total. Table A-4 shows the fuel purchase records for Clay Boswell for 2007.

Table A-4
Coal Types Purchased at Clay Boswell

Coal Source State	Coal Source County	Coal Type	USGS Region	Amount (tons)	Avg Btu Content (Btu/lb)	Avg Sulfur (wt %)	Avg Ash Content (wt %)
MT	Rosebud	Sub	Subbituminous Montana Powder River	1,980,050	8,675	0.655	8.93
MT	Bighorn	Sub	Subbituminous Montana Powder River	1,973,380	9,390	0.341	4.46
WY	Campbell	Sub	Subbituminous Wyoming Powder River	26,720	8,315	0.32	4.7
Total				3,980,150			

It was assumed that each unit at a station burned the same blend of coals which was estimated based on the tonnages of coal purchased in 2007. Blended fuel compositions were generated by first calculating the total amount of each element by coal type. The equation below uses arsenic as a sample element:

$$As_{Coal1} = Conc_{As} * BTU_{Coal1} * \mathrm{Mass}_{\mathrm{Coal}}$$

Where $\mathrm{As}_{\mathrm{Coal}}$ is the total annual arsenic from coal type 1, $\mathrm{Conc}_{\mathrm{As}}$ is the geometric mean coal arsenic composition in lbs/TBtu for coal type 1, and $\mathrm{BTU}_{\mathrm{Coal}}$ is the average heat content of coal type 1 in Btu/lb as reported in the FERC/EIA fuel purchase database, and $\mathrm{Mass}_{\mathrm{Coal}}$ is the amount of coal type 1 purchased in 2007 in tons. Using information from Table A-4 and the geometric mean coal composition values derived from the screened USGS database, the equation for Clay Boswell becomes:

$$As_{Rosebud} = 408.22 * 8{,}675 * 1{,}980{,}050 * 2000 / 10^{12} = 14{,}021 \frac{lbsAs}{yr}$$

Table A-5 shows the results for the all fuel types at Clay Boswell.

Table A-5
Elements combusted at Clay Boswell by Fuel Type

Coal Name	Element Mass (lbs)												
	As	Se	Cd	Cl	Co	Cr	F	Hg	Mn	Ni	Pb	Sb	Se
Rosebud	14,021	2,524	328	168,227	4,287	14,454	231,292	201	122,171	15,319	12,968	1,877	2,893
Bighorn	15,127	2,723	353	337,494	4,625	15,594	249,544	178	131,812	16,528	13,991	2,025	3,121
Campbell	73	15	2	4,750	70	227	2725	2.8	1,017	169	111	9.6	38
Total	**29,221**	**5,262**	**684**	**510,471**	**8,982**	**30,275**	**483,560**	**382**	**255,000**	**32,014**	**27,070**	**3,912**	**6,053**

For other coal information (sulfur, heating value, and ash content) the following equation was used to calculate a total annual consumption. The equation below is specifically for sulfur, but the equation is analogous for the others.

$$S_{Coal} = S_{WT\%} * Mass_{Coal1}$$

$$\text{S}_{Rosebud} = \text{Coal}_{\text{S}} * \text{Mass}_{Coal}$$

Where, $\text{S}_{\text{Rosebud}}$ = sulfur content of coal type 1 (wt fraction), and

$\text{Mass}_{\text{Coal}}$ = amount of coal type 1 purchased in 2007 (tons).

For Clay Boswell Rosebud coal this becomes:

$$S_{Rosebud} = 0.655 * 1{,}980{,}050 = 1{,}296{,}933 tonsS$$

Table A-6 shows the results for the remaining characteristics and coal types at Clay Boswell.

Table A-6
Annual Sulfur, Ash, and Energy Content of Coal Purchased at Clay Boswell

Coal Type	Sulfur (tons)	Ash (tons)	Energy Content (Million Btu)
Rosebud	1,296,933	17,688,447	34,346,607
Bighorn	672,594	8,806,208	37,056,952
Campbell	8,550.4	125,584	444,461
Total	1,978,077	26,620,239	71,848,020

The total element mass values for the entire plant were then divided by the total mass of fuel burned by the plant to get a blended fuel concentration, as shown for arsenic in the equation below:

$$Blend_{As} = \frac{As_{Total}}{Coal_{Total}} * 10^6$$

Where Blend $_{As}$ = blended fuel composition in ppmw, As_{Total} = total annual arsenic input with all fuel types in lbs, and $Coal_{Total}$ = total annual fuel purchased in tons.

For Clay Boswell this becomes:

$$Blend_{As} = \frac{29{,}211}{3{,}980{,}150 * 2000} * 10^6 = 3.67\, ppm\,\mathrm{w}$$

Table A-7 shows the results for all elements at Clay Boswell.

Table A-7
Blended Fuel Composition at Clay Boswell

Element Concentration (ppmw)												
As	Se	Cd	Cl	Co	Cr	F	Hg	Mn	Ni	Pb	Sb	Se
3.7	0.7	0.09	64.1	1.1	3.8	60.7	0.048	32.0	4.0	3.4	0.5	0.8

A similar equation is used for sulfur, ash, and heat content, except without the factor of 10^6 to convert to ppmw and the factor of 2000 to convert tons to pounds. The results for Clay Boswell are shown in Table A-8.

Table A-8
Sulfur, Ash, and Heat Content of Blended Coal Combusted at Clay Boswell

Sulfur (wt%)	**Ash (wt %)**	**Heat Content (Btu/lb)**
0.5	6.7	9,026

References

. + An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants, EPRI, Palo Alto, CA: September 2000. TR-1000608

B
TABULATION OF COAL-FIRED TEST SITES

Table B-1 presents information about the test sites sampled for non-mercury HAPs. The information includes the control technology, coal type, suite of analytes and year tested. Table B-2 provides similar information for the plants sampled during the 1999 ICR for mercury emissions. Table B-3 presents similar information for the more recent mercury test data.

Table B-1
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
XX-FC-012	12	Confid	-	FCEM/DOE	Bit	ESPc FGDw	Comp [a]	M, A, VO, SVO, AL	1990, 1992
XX-FC-012	12	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A, VO, SVO, AL	1990, 1992
XX-FC-014	14	Confid	-	FCEM/DOE	Bit	SD/FF	Comp	M, A, SVO, AL	1990
XX-FC-015	15	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A, VO, SVO, AL	1993
XX-FC-016	16	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A, VO, SVO, AL	1991
XX-FC-016	16	Confid	-	FCEM/DOE	Bit	ESPc (LNB)	Comp	M, A, VO, SVO, AL	1993
XX-FC-018	18	Confid	-	FCEM/DOE	Bit	ESPc	Coal, Stack	M, A	1992
XX-FC-018	18	Confid	-	FCEM/DOE	Bit	ESPc PJFF (pilot)	Coal, Gas In/Out	M, A	1992
XX-FC-019	19	Confid	-	FCEM/DOE	Bit	ESPc	Coal, Gas In/Out	M, A	1992
XX-FC-021	21	Confid	-	FCEM/DOE	Bit	ESPc FGDw	Coal, Gas In/Out	M, A, SVO	1992
XX-FC-110	110	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A, VO, SVO, AL	1991
XX-FC-110	110	Confid	-	FCEM/DOE	Bit	ESPc (LNB)	Comp	M, A, VO, SVO, AL	1992

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
XX-FC-114	114	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A	1992
XX-FC-114	114	Confid	-	FCEM/DOE	Bit	ESPc (reburn)	Comp	M, A	1992
XX-FC-116	116	Confid	-	FCEM/DOE	Bit	ESPc	Comp	M, A, D	1993
XX-FC-116	116	Confid	-	FCEM/DOE	Bit	SNRB (pilot)	Comp	M, A	1993
XX-FC-122	122	Confid	-	FCEM/DOE	Bit	ESPc	Coal, Stack	M, D	1993
XX-FC-125	125	Confid	-	FCEM/DOE	Bit	ESPc FGDw	Coal, Stack	M, A	1993
XX-D-002	DOE2	Niles	2	FCEM/DOE	Bit	ESPc	Comp	Comp [c]	1993
XX-D-002	DOE2	Niles	2	FCEM/DOE	Bit	FF	Comp	Comp	1993
XX-D-003	DOE3	Baldwin	2	FCEM/DOE	Bit	ESPc	Comp	Comp	1993
XX-D-004	DOE4	Yates	1	FCEM/DOE	Bit	ESPc	Comp	Comp	1993
XX-D-004	DOE4	Yates	1	FCEM/DOE	Bit	ESPc FGDw	Comp	Comp	1993
XX-D-005	DOE5	Cardinal	1	FCEM/DOE	Bit	ESPc	Comp	Comp	1993
XX-FC-20	20	Confid	-	FCEM/DOE	Lig	ESPc	Comp	M, A	1993
XX-FC-20	20	Confid	-	FCEM/DOE	Lig	ESPc FGDw	Comp	M, A	1993
XX-D-006	DOE6	Coal Creek	1	FCEM/DOE	Lig	ESPc	Comp	Comp	1993
XX-D-006	DOE6	Coal Creek	1	FCEM/DOE	Lig	ESPc FGDw	Comp	Comp	1993

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
XX-FC-010	10	Confid	-	FCEM/DOE	Sub	FF FBC	Comp	M, A, VO, SVO, AL	1990
XX-FC-011	11	Confid	-	FCEM/DOE	Sub	ESPc	Comp	M, A, VO, SVO, AL	1990, 1992, 1993
XX-FC-011	11	Confid	-	FCEM/DOE	Sub	ESPc FGDw	Comp	M, A, VO, SVO, AL	1990, 1992, 1993
XX-FC-022	22	Confid	-	FCEM/DOE	Sub	ESPc	Comp	M, A, SVO, D	1993
XX-FC-101	101	Confid	-	FCEM/DOE	Sub	FF	Comp	M, A	1994
XX-FC-101	101	Confid	-	FCEM/DOE	Sub	FF FGDw	Comp	M, A, VO	1994
XX-FC-102	102	Confid	-	FCEM/DOE	Sub	ESPc	Comp	M, D	1991
XX-FC-111	111	Confid	-	FCEM/DOE	Sub	SD/FF	Comp	M, A, VO, SVO	1991
XX-FC-111R	111R	Confid	-	FCEM/DOE	Sub	FF	Comp	M, A	1997
XX-FC-111R	111R	Confid	-	FCEM/DOE	Sub	SD/FF	Comp	M, A	1997
XX-FC-115	115	Confid	-	FCEM/DOE	Sub	FF	Comp	M, A, R	1992, 1993
XX-FC-115	115	Confid	-	FCEM/DOE	Sub	FF (Urea)	Comp	M, A, R	1992, 1993
XX-D-007	DOE7	Springerville	2	FCEM/DOE	Sub	SD/FF	Comp	Comp	1993
XX-D-008	DOE8	Boswell	2	FCEM/DOE	Sub	FF	Comp	Comp	1993
XX-D-010	Presque Isle	Presque Isle	9	FCEM/DOE	Sub	ESPh	Stack	D	2001
XX-00037	Sherco 1/2	Confid	1+2	FCEM/DOE	Sub	ESPc FGDw	Stack	D	2000
XX-00037	Sherco 3	Confid	3	FCEM/DOE	Sub	SD/FF	Stack	D	2000

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
XX-FC-102R	Site 102 New	Confid	-	FCEM/DOE	Sub	ESPc	Stack	D	2000
XX-FC-025	25	Confid	-	NEW - EPRI	Bit	ESPc	Stack	VO, AL	1995
XX-D-001	DOE1 U7	Bailey	7	NEW – DOE	Bit	ESPc	Comp	Comp	1993
XX-D-001	DOE1 U8	Bailey	8	NEW – DOE	Bit	ESPc	Comp	Comp	1993
E343	Yates U1 (2008)	Confid	-	NEW – EPRI	Bit	ESPc	Coal, ESP out	A	2007
E010	Yates U2 (2007)	Yates	2	NEW – DOE Hg	Bit	ESPc	Stack	A	2004
XX-D-009	Milliken	Milliken	2	NEW – DOE	Bit	ESPc FGDw	Comp	M, A, SVO, D	1996
XX-D-001	DOE1	Bailey	7+8	NEW – DOE	Bit	ESPc FGDw	Comp	Comp	1993
XX-FC-E29	Site E29	Confid	-	NEW – EPRI	Bit	ESPc FGDw	Comp	M	1998
E048	Widows Creek U7 (2006)	Widows Creek	7	NEW – EPRI	Bit	ESPc FGDw	Coal, Gas In/Out	A	2006
XX-FC-111R	Site 111R U1 Valmy	Confid	1	NEW – EPRI	Bit	FF	Comp	M, A	1997
E031a	Mill Creek U4 (2007)	Confid	-	NEW – EPRI	Bit	SCR ESPc	Comp	M, A	2007
E034	Mitchell U1 (2008)	Confid	-	NEW – EPRI	Bit	SCR ESPc	Comp	M, A	2008

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
E034	Dallman U33 (2007)	Confid	-	NEW – EPRI	Bit	SCR ESPc	Comp	M, A	2007
E033	Pleasant Prairie U1 (2007)	Confid	-	NEW – Util	Bit	SCR ESPc	Comp	M, A	2007
E016	Homer City U1 (2003)	Homer City	1	NEW – DOE Hg	Bit	SCR ESPc	Coal, ESP out	A	2001
E016	Homer City U3 (2003)	Homer City	3	NEW – DOE Hg	Bit	SCR ESPc	Coal, ESP out	A	2001
E031[a]	Mill Creek U4 (2007)	Confid	-	NEW – EPRI	Bit	SCR ESPc FGDw	Comp	M, A	2004
E034	Mitchell U1 (2008)	Confid	-	NEW – EPRI	Bit	SCR ESPc FGDw	Comp	M, A	2008
E034	Dallman U33 (2007)	Confid	-	NEW – EPRI	Bit	SCR ESPc FGDw	Comp	M, A	2007
E033	Pleasant Prairie U1 (2007)	Confid	-	NEW – Util	Bit	SCR ESPc FGDw	Comp	M, A	2007
E036	Salem Harbor U1 (2004)	Salem Harbor	1	NEW –DOE Hg	Bit	SNCR ESPc	Coal, Gas In/Out	M, A	2008
E024	Monticello U3 (2007)	Monticello	3	NEW – DOE Hg	Lig	ESPc FGDw	Coal, Stack	A	2007
XX-00036	CR, baseline	Confid	-	NEW - Lit	Sub	ESPc	Coal, Stack	M	1996
E018	Meramec U2 (2005)	Meramec	2	NEW- DOE Hg	Sub	ESPc	Coal, Gas In/Out	M, A	2004

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
E012	Pleasant Prairie U2 (2003)	Pleasant Prairie	2	NEW – DOE Hg	Sub	ESPc	Stack	M	2001
XX-FC-SCR H050	A1, Unit B, baseline	Confid	-	NEW – EPRI	Sub	ESPc	Coal, Stack	A	2001
XX-FC-SCR H050	S1, baseline	Confid	-	NEW – EPRI	Sub	ESPc	Coal, Stack	A	2001
E340	Miller U4 (2007)	Confid	-	NEW - EPRI	Sub	ESPc	Coal, Stack	A	2006
E045	Laramie River U3 (2006)	Laramie River	3	NEW - Lit	Sub	ESPc FGDw	Comp	M	1994
E038	Louisa U1 (2006)	Louisa	1	NEW – DOE Hg	Sub	ESPh	Coal, Stack	A	2006
E015	Harrington U3 (2008)	Confid	-	NEW – EPRI	Sub	FF	Comp	M	2007
E046	Holcomb U1 (2005)	Holcomb	1	NEW – DOE Hg	Sub	FF	Coal, Gas In/Out	M, A	2004
XX-D-012 H062	Blount Unit 9	Blount	9	NEW –DOE	Sub	MC ESPc	Coal, Stack	A	2000
E339	Holcomb 2002	Confid	-	NEW - EPRI	Sub	SD/FF	Stack	VO, A, AL	2002
E013	St Clair U1 (2005)	St Clair	1	NEW – DOE Hg	Sub/Bit	ESPc	Stack	A	2004
E026	Limestone U1 (2009)	Limestone	1	NEW – DOE Hg	Sub/Bit	ESPc	Coal, ESP out	A	2008

Table B-1 (continued)
Test Site Characteristics: Non-Mercury HAPs

Report Ref.	Site ID	Unit Name	Unit	Data Group	Coal Type	Control Class	Streams Sampled	Analyte Groups b	Year Tested
XX-FC-SCR H050	A1, Unit A, baseline	Confid	-	NEW – EPRI	Sub/Bit	ESPc	Coal, Stack	A	2001
XX-FC-111R	Site 111R U2 Valmy	Confid	-	NEW – EPRI	Sub/Bit	SD/FF	Comp	M, A	1997 Retest

[a] Comprehensive streams are input, output, and major intermediate streams.

[b] M = metals, A = anions, VO = volatile organic compounds, SVO = semivolatile organic compounds, AL = aldehydes, D = dioxin/furan compounds, R = radionuclides

[c] Comprehensive analyses includes metals, anions, volatile organic compounds, semi volatile organic compounds, dioxin/furan compounds, radionuclides, and hydrogen cyanide.

Table B-2
Test Site Characteristics: 1999 ICR Mercury Sites

Report Ref.	Plant Name	City	State	Unit	MWe	Boiler Type	Coal Type	NOx Control	SO2 Control	PM Control	Test Date
I075	Bay Front Plant Generating	Ashland	WI	5	32	Cyclone	Bituminous	–	–	Multiclone	10/26/99
I078	Brayton Point	Somerset	MA	1	241	Tangential fired	Bituminous	LNB	–	ESPc	9/1/99
I078	Brayton Point	Somerset	MA	3	650	Tangential fired	Bituminous	LNB	–	ESPc	9/9/99
I096	George Neal south	Sioux City	IA	4	640	Wall fired	Subbituminous	OFA	–	ESPc	9/14/99
I097	Gibson Generating Station	Owensville	IN	3	668	Wall fired	Bituminous	LNB	–	ESPc	10/14/99
I099	Jack Watson	Gulfport	MS	4	250	Wall fired	Bituminous	LNB	–	ESPc	1/20/00
I106	Leland Olds Station	Stanton	ND	2	440	Cyclone	ND Lignite	–	–	ESPc	7/15/99
I111	Meramec	St. Louis	MO	4	359	Wall fired	Bit/sub	LNB	–	ESPc	7/29/99
I114	Montrose	Clinton	MO	1	170	Tangential fired	Subbituminous	CC	–	ESPc	1/18/00
I117	Newton	Newton	IL	2	617	Tangential fired	Subbituminous	LNB	–	ESPc	8/2/99
I368	Port Washington	Port Washington	WI	4	80	Vertical fired	Bituminous	–	Sorbent Injection	ESPc	11/17/99
I123	Presque Isle	Marquette	MI	6	90	Wall fired	Bituminous	–	–	ESPc	7/15/99
I122	Presque Isle	Marquette	MI	5	90	Wall fired	Bituminous	–	–	ESPc	7/12/99
I127	Salem Harbor	Salem	MA	3	153	Wall fired	Bituminous	LNB & SNCR	–	ESPc	8/25/99
I133	St Clair Power Plant	East China Twp	MI	4	169	Wall fired	Sub/Bit	–	–	ESPc	11/3/99
I134	Stanton Station	Stanton	ND	1	140	Wall fired	ND Lignite	LNB	–	ESPc	8/24/99
I142	Widows Creek Fossil Plant	Stevenson	AL	6	141	Wall fired	Bituminous	–	–	ESPc	10/20/99
I369	AES Cayuga (NY)	Lansing	NY	2	167	Tangential fired	Bituminous	LNB	FGDw	ESPc	8/8/96
I074	Bailly	Chesterton	IN	7	194	Cyclone	Bituminous	–	FGDw	ESPc	12/9/99
I075	Bailly	Chesterton	IN	8	422	Cyclone	Bituminous	–	FGDw	ESPc	12/9/99
I076	Big Bend	North Ruskin	FL	BB03	446	Wall fired	Bituminous	CC	FGDw	ESPc	12/1/99
I147	Coal Creek	Underwood	ND	2	546	Tangential fired	ND Lignite	LNB	FGDw	ESPc	8/3/98
I094	Duck Creek	Canton	IL	1	370	Wall fired	Bituminous	LNB	FGDw	ESPc	7/15/98
I100	Jim Bridger	Point of Rocks	WY	BW 73	561	Tangential fired	Subbituminous	LNB & OFA	FGDw	ESPc	3/29/00
I103	Laramie River Station	Wheatland	WY	1	600	Wall fired	Subbituminous	LNB	FGDw	ESPc	–
I108	Limestone	Jewett	TX	LIM1	813	Tangential fired	TX Lignite	OFA	FGDw	ESPc	11/16/99
I146	Milton R. Young	Center	ND	B2	439	Cyclone	ND Lignite	–	FGDw	ESPc	5/20/98
I113	Monticello	Mount Pleasant	TX	3	793	Wall fired	TX Lignite	–	FGDw	ESPc	2/23/00
I128	Sam Seymour	La Grange	TX	3	475	Tangential fired	Subbituminous	–	FGDw	ESPc	12/2/98
I073	Antelope Valley Station	Beulah	ND	B1	435	Tangential fired	ND Lignite	LNB & OFA	FGDd	FF	7/13/99

Table B-2 (continued)
Test Site Characteristics: 1999 ICR Mercury Sites

Report Ref.	Plant Name	City	State	Unit	MWe	Boiler Type	Coal Type	NOx Control	SO2 Control	PM Control	Test Date
I090	Coyote	Beulah	ND	1	450	Cyclone	ND Lignite	–	FGDd	FF	9/28/99
I092	Craig	Craig	CO	C3	446	Wall fired	Subbituminous	LNB	FGDd	FF	10/4/99
I145	Dwayne Collier Battle Cogeneration Facility	Battleboro	NC	2B	37.5	Stoker	Bituminous	SC	FGDd	FF	11/17/99
I109	Logan Generating Plant	Swedesboro	NJ	GEN 1	230	Wall fired	Bituminous	LNB & SCR	FGDd	FF	8/11/99
I110	Mecklenburg Cogeneration Facility	Clarksville	VA	GEN 1	70	Wall fired	Bituminous	LNB & OFA	FGDd	FF	10/12/99
I118	Northern States Power - Sherburne County Generating Plant	Becker	MN	#3	855	Wall fired	Subbituminous	LNB	FGDd	FF	1/25/00
I126	Rawhide	Wellington	CO	101	285	Tangential fired	Subbituminous	OFA	FGDd	FF	8/25/99
I131	SEI - Birchwood Power Facility	Sealston	VA	1	240	Tangential fired	Bituminous	LNB & SCR	FGDd	FF	9/15/99
I135	Stanton Station	Stanton	ND	10	60	Tangential fired	ND Lignite	LNB	FGDd	FF	8/24/99
I098	GRDA	Chouteau	OK	2	520	Wall fired	Subbituminous	LNB	FGDd	ESPc	9/22/99
I104	Laramie River Station	Wheatland	WY	3	600	Wall fired	Subbituminous	LNB	FGDd	ESPc	9/22/99
I143	Wyodak	Gillette	WY	BW 91	362	Wall fired	Subbituminous	LNB	FGDd	ESPc	9/29/99
I077	Big Brown	Fairfield	TX	1	593	Tangential fired	TX Lignite	–	–	FF	11/9/99
I082	Clay Boswell	Cohasset	MN	2	75	Wall fired	Subbituminous	LNB	–	FF	3/23/00
I088	Comanche	Pueblo	CO	2	375	Wall fired	Subbituminous	OFA	–	FF	10/12/98
I112	Monticello	Mount Pleasant	TX	1	593	Tangential fired	TX Lignite	–	–	ESP & FF	2/22/00
I122	Presque Isle	Marquette	MI	1	37.5	Tangential fired	Bituminous	–	–	FF	7/16/99
I132	Shawnee Fossil Plant	West Paducah	KY	3	175	Wall fired	Bituminous	LNB	–	FF	10/28/99
I138	Valley	Milwaukee	WI	3	136	Wall fired	Bituminous	LNB	–	FF	11/30/99
I139	Valmont	Boulder	CO	5	179	Tangential fired	Bituminous	LNB	–	FF	11/2/99
I140	W. H. Sammis	Stratton	OH	1	190	Wall fired	Bituminous	LNB	–	FF	9/24/99
I085	Clover Power Station	Clover	VA	2	465	Tangential fired	Bituminous	LNB	FGDw	FF	12/1/99
I147	Intermountain	Delta	UT	2SGA	820	Wall fired	Bituminous	LNB	FGDw	FF	10/13/99
I370	Reid Gardner	Moapa	NV	4	270	Wall fired	Subbituminous	LNB	FGDw	FF	–
I371	AES Hawaii, Inc.	Kapolei	HI	B	102	FBC	Subbituminous	SNCR	Limestone Injection	FF	1/11/00
I372	Kline Township Cogen Facility	McAdoo	PA	GEN 1	58	FBC	Waste Anthracite	–	Limestone Injection	FF	10/28/99
I373	R.M. Heskett Station	Mandan	ND	B2	75	FBC	ND Lignite	–	Limestone Injection	ESPc	7/1/99

Table B-2 (continued)
Test Site Characteristics: 1999 ICR Mercury Sites

Report Ref.	Plant Name	City	State	Unit	MWe	Boiler Type	Coal Type	NOx Control	SO2 Control	PM Control	Test Date
I374	Scrubgrass Generating Company, L.P.	SAME as 3	PA	Gen 1/1	95	FBC	Waste Bituminous	–	Limestone Injection	FF	9/16/99
I374	Scrubgrass Generating Company, L.P.	SAME as 3	PA	Gen 1/2	95	FBC	Waste Bituminous	–	Limestone Injection	FF	9/16/99
I375	Stockton Cogen Company	Stockton	CA	GEN 1	56	FBC	Bit/Pet Coke	SNCR	Limestone Injection	FF	10/20/99
I376	TNP-One	Bremond	TX	U2	175	FBC	ND Lignite	FBC	Limestone Injection	FF	10/7/99
I081	Cholla	Joseph City	AZ	3	280	Tangential fired	Bit/Sub	–	–	ESPh	11/4/99
I083	Cliffside	Cliffside	NC	1	40	Tangential fired	Bituminous	–	–	ESPh	9/1/99
I084	Clifty Creek	Madison	IN	6	217	Wall fired	Subbituminous	OFA	–	ESPh	11/2/99
I087	Columbia	Portage	WI	1	512	Tangential fired	Subbituminous	OFA	–	ESPh	10/19/99
I093	Dunkirk	Dunkirk	NY	2	96	Tangential fired	Bituminous	LNB	–	ESPh	10/12/99
I095	Gaston	Wilsonville	AL	1	272	Wall fired	Bituminous	LNB	–	ESPh	11/10/99
I106	Nelson Dewey	Cassville	WI	1	100	Cyclone	Sub/Coke	–	–	ESPh	2/8/00
I119	Platte	Grand Island	NE	1	109	Tangential fired	Subbituminous	LNB	–	ESPh	8/18/99
I122	Presque Isle	Marquette	MI	9	90	Wall fired	Subbituminous	LNB	–	ESPh	7/12/99
I080	Charles R. Lowman	Leroy	AL	2	236	Wall fired	Bituminous	–	FGDw	ESPh	1/26/00
I089	Coronado	St. John's	AZ	U1B	456	Wall fired	Subbituminous	OFA	FGDw	ESPh	10/19/99
I091	Craig	Craig	CO	C1	446	Wall fired	Subbituminous	LNB	FGDw	ESPh	9/28/99
I115	Navajo	Page	AZ	3	803	Tangential fired	Subbituminous	–	FGDw	ESPh	10/25/99
I124	R. D. Morrow, Sr. Generating Plant	Purvis	MS	2	203	Wall fired	Bituminous	LNB	FGDw	ESPh	10/28/99
I129	San Juan	Waterflow	NM	2	369	Wall fired	Subbituminous	OFA	FGDw	ESPh	10/21/99
I079	Bruce Mansfield	Shippingport	PA	1	914	Wall fired	Bituminous	LNB	FGDw	WS	9/21/99
I081	Cholla	Joseph City	AZ	2	280	Tangential fired	Bit/Sub	–	FGDw	WS	11/3/99
I082	Clay Boswell	Cohasset	MN	3	364	Tangential fired	Subbituminous	–	–	WS	3/21/00
I082	Clay Boswell	Cohasset	MN	4	558	Tangential fired	Subbituminous	OFA	FGDw	WS	3/27/00
I086	Colstrip	Rosebud City	MT	3	778	Tangential fired	Subbituminous	OFA	FGDw	WS	9/29/99
I102	La Cygne	LaCygne	KS	1	688	Cyclone	Subbituminous	CC	FGDw	WS	11/17/99
I105	Lawrence	Lawrence	KS	4	114	Tangential fired	Subbituminous	–	FGDw	WS	10/25/99
I107	Lewis & Clark	Sidney	MT	B1	58	Tangential fired	ND Lignite	LNB	–	WS	4/11/00

Table B-2 (continued)
Test Site Characteristics: 1999 ICR Mercury Sites

Report Ref.	Plant Name	City	State	Unit	MWe	Boiler Type	Coal Type	NOx Control	SO2 Control	PM Control	Test Date
I377	Paradise Fossil Plant	Drakesboro	KY	1	704	Cyclone	Bituminous	OFA	FGDw	ESPc	10/25/94
I378	Polk	Mulberry	FL	1	25	IGCC	Bituminous	–	IGCC	IGCC	11/2/99
I379	Wabash River coal gasification repowering project #1 and1A	West Terre Haute	IN	1 + 1A	307	IGCC	Bituminous	LNB	IGCC	IGCC	10/12/99

Table B-3
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
E001	Brayton Point	–	1	245	Bituminous	LNB	–	CS ESP (SO3 conditioning)	ESPc
E002	Portland Unit	–	1	172	Bituminous	LNB/OFA	–	CS ESP	ESPc
H050	Miami Fort	x	6	170	Bituminous	–	–	CS ESP	ESPc
H050	Miami Fort	x	6	170	Bituminous	–	–	CS ESP	ESPc
H050	Montour	x	1	750	Bituminous	–	–	CS ESP	ESPc
E003	D.E. Karn	x	1	222	Bituminous	SCR	–	CS ESP (with conditioning)	ESPc
E003	D.E. Karn	x	2	310	Bituminous	SCR LNB OFA	–	CS ESP (with conditioning)	ESPc
E003	J.C. Weadock	x	7	156	Bituminous	–	–	CS ESP (with conditioning)	ESPc
E003	J.C. Weadock	x	8	156	Bituminous	–	–	CS ESP (with conditioning)	ESPc
E003	J.R. Whiting	x	1	106	Bituminous	LNB	–	CS ESP (with conditioning)	ESPc
E003	J.H. Campbell	x	2	404	Bituminous	LNB	–	CS ESP (with conditioning)	ESPc
E003	B.C. Cobb	x	4	156	Bituminous	–	–	CS ESP (with conditioning)	ESPc
E005	State Line	X	4	209	Sub bituminous	OFA	–	CS ESP	ESPc
E004	Chesterfield	X	3	113	Bituminous	–	–	CS ESP	ESPc
E006	White Bluff	X	–	850	Sub bituminous	OFA	–	CS ESP	ESPc
E006	Independence	X	–	850	Sub bituminous	OFA	–	CS ESP	ESPc
E006	Nelson	X	–	100	Sub bituminous	OFA	–	CS ESP	ESPc
E007	Schaffer	X	15	556	Bituminous	LNB	–	CS ESP	ESPc
E008	Frank E Ratts	X	1	125	Bituminous	LNB/OFA	–	CS ESP	ESPc
E009	Miami Fort	–	6	185	Bituminous	–	–	CS ESP	ESPc
E010	Yates Unit	–	2	100	Bituminous	–	–	CS ESP	ESPc
E011	Leland Olds Unit	–	1	216	ND Lignite	LNB	–	CS ESP	ESPc
E012	Pleasant Prairie	–	2	600	Sub/Bit	–	–	CS ESP	ESPc
H053	Monroe	–	2	820	Sub/Bit	LNB	–	CS ESP	ESPc

Table B-3 (continued)
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
H050	Nanticoke	X	A	500	Sub/Bit	LNB	–	CS ESP	ESPc
H050	Nanticoke	X	A	500	Sub/Bit	LNB	–	CS ESP	ESPc
E013	StClair Unit	–	1	145	Sub/Bit	–	–	CS ESP	ESPc
E014	Monroe	–	4	775	Sub/Bit	SCR (off)	–	CS ESP	ESPc
E015	Harrington	X	1	369	Sub bituminous	LNB	–	CS ESP	ESPc
H054	Pleasant Prairie	–	1	617	Sub bituminous	LNB	–	CS ESP	ESPc
E016	Joliet	–	7	531	Sub bituminous	LNB	–	CS ESP	ESPc
E017	Arapahoe	–	1	45	Sub bituminous	–	–	CS ESP	ESPc
E018	Meramac	–	2	140	Sub bituminous	OFA/LNB	–	CS ESP	ESPc
H051	Bowen	X	4	900	Bituminous	LNB	–	CS ESP	ESPc
H051	Bowen	X	2	700	Bituminous	–	Wet FGD	CS ESP	ESPc
H050	Nanticoke	X	B	500	Sub bituminous	LNB	–	CS ESP	ESPc
H050	Nanticoke	X	B	500	Sub bituminous	LNB	–	CS ESP	ESPc
H050	New Madrid	X		650	Sub bituminous	–	–	CS ESP	ESPc
E019	Baldwin	–	3	630	Sub bituminous	LNB/OFA	–	CS ESP (SO3 conditioning)	ESPc
H065	Rock River	X	1	75	Bituminous	–	–	CS ESP	ESPc
E020	Heskett	–	2	85	ND Lignite	–	FBC	CS ESP	ESPc
E021	Martin Lake	–	2	793	TX Lignite	LNB/OFA	Wet FGD	CS ESP (SO3 conditioning)	ESPc FGDw
E021	Martin Lake	–	2	793	TX Lignite	LNB/OFA	Wet FGD	CS ESP (SO3 conditioning)	ESPc FGDw
E022	Zimmer	–	–	1300	Bituminous	–	Wet FGD	CS ESP	ESPc FGDw
E022	Endicott	–	–	55	Bituminous	–	Wet FGD	CS ESP	ESPc FGDw
H060	Miliken	–	2	150	Bituminous	LNB	Wet FGD	CS ESP	ESPc FGDw
H051	Harrision	X	2	684	Bituminous	LNB	Wet FGD	CS ESP	ESPc FGDw
H070	Unknown	–	–	1330	Bituminous	–	Wet FGD	CS ESP	ESPc FGDw
H050	Gavin	X	2	1360	Bituminous	–	Wet FGD	CS ESP	ESPc FGDw
E007	Schaffer	–	17	424	Bituminous	LNB OFA	FGDw	CS ESP	ESPc FGDw
E007	Bailly	–	7	190	Bituminous	OFA	FGDw	CS ESP	ESPc FGDw
E010	Yates	–	1	100	Bituminous	LNB	Wet FGD (JBR)	CS ESP (SO3 conditioning)	ESPc FGDw
E023	Yates	–	1	100	Bituminous	LNB	Set FGD (JBR)	CS ESP (SO3 conditioning)	ESPc FGDw
E024	MR Young	–	2	450	TX Lignite	OFA	Wet FGD	CS ESP	ESPc FGDw
E025	Monticello	–	3	793	Sub/TX Lig	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw
E025	Monticello	–	3	793	Sub/TX Lig	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw
E024	Monticello	–	3	793	Sub/TX Lig	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw
E025	Sandow	–	4	591	TX Lignite	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw

Table B-3 (continued)
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
E025	Martin Lake	–	3	793	TX Lignite	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw
E025	Martin Lake	–	3	793	Sub/TX Lig	–	Wet FGD	CS ESP (NH3 conditioning)	ESPc FGDw
H069	Trimble	X	–	566	Bituminous	SCR (bypassed)	Wet FGD	CS ESP	ESPc FGDw
H068	Mill Creek	X	4	544	Bituminous	SCR (bypassed)	Wet FGD	CS ESP	ESPc FGDw
H064	Confidential	–	–	585	Sub bituminous	–	Wet FGD	CS ESP	ESPc FGDw
E016	Homer City	–	3	692	Bituminous	SCR/LNB	Wet FGD	CS ESP	ESPc FGDw SCR
H050	Gavin	X	1	1360	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H050	Gavin	X	1	1360	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H050	Gavin	X	2	1360	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H051	Gavin	X	2	1360	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H051	Harrision	X	1	684	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H052	Gavin	X	2	1360	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H055	Cumberland	X	1	1300	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H056	Gavin	X	2	1300	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E027	Harrison	X	1	640	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H068	Mill Creek	X	4	544	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E028	Petersburg	–	2	455	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H069	Trimble	X	–	566	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E008	Merom	X	–	508	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H067	Stanton	X	2	–	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E029	Pleasants	–	1	684	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E004	Mount Storm	–	3	–	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E007	Bailly	–	8	413	Bituminous	OFA SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E030	Cumberland	X	1	1300	Bituminous	SCR LNB	Wet FGD	CS ESP	ESPc FGDw SCR
E031	Mill Creek	X	4	530	Bituminous	LNB/SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E032	Dallman	–	33	200	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H066	Merom	–	–	507	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H050	Paradise	X	1	705	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR

Table B-3 (continued)
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
H051	Paradise	X	1	705	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E033	Pleasant Prairie	X	1	640	Sub bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E034	AEP Mitchell	–	1	200	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
H067	Stanton	x	1	–	Bituminous	SCR	Wet FGD	CS ESP	ESPc FGDw SCR
E014	Monroe	–	4	775	Sub/Bit	SCR	–	CS ESP	ESPc SCR
E016	Homer City	–	1	660	Bituminous	SCR/LNB	–	CS ESP	ESPc SCR
E003	D.E. Karn	X	2	310	Bituminous	SCR LNB OFA	–	CS ESP (with conditioning)	ESPc SCR
E003	Kincaid	X	2	660	Sub bituminous	SCR OFA	–	CS ESP	ESPc SCR
E004	Chesterfield	X	4	188	Bituminous	SCR	–	CS ESP	ESPc SCR
E004	Chesterfield	X	5	359	Bituminous	SCR LNB OFA	–	CS ESP	ESPc SCR
E004	Chesterfield	X	6	694	Bituminous	SCR LNB OFA	–	CS ESP	ESPc SCR
E004	Chesapeake	X	3	185	Bituminous	SCR LNB	–	CS ESP	ESPc SCR
E004	Chesapeake	X	4	239	Bituminous	SCR	–	CS ESP	ESPc SCR
E007	Michigan City	X	12	540	Sub bituminous	SCR OFA	–	CS ESP (with conditioning)	ESPc SCR
E007	Schaffer	X	14	540	Bituminous	SCR OFA	–	CS ESP	ESPc SCR
H050	Montour	X	1	750	Bituminous	SCR	–	CS ESP	ESPc SCR
H050	Montour	X	2	750	Bituminous	SCR	–	CS ESP	ESPc SCR
H053	Monroe	–	1	820	Sub/Bit	LNB/SCR	–	CS ESP	ESPc SCR
H054	Pleasant Prairie	–	2	617	Sub bituminous	LNB/SCR	–	CS ESP	ESPc SCR
H050	New Madrid	X	–	650	Sub bituminous	SCR	–	CS ESP	ESPc SCR
H051	Bowen	X	2	700	Bituminous	SCR	–	CS ESP	ESPc SCR
H050	New Madrid	X	–	650	Sub bituminous	SCR	–	CS ESP	ESPc SCR
E036	Salem Harbor	–	1	88	Bituminous	LNB/SNCR	–	CS ESP	ESPc SNCR
H050	Miami Fort	X	6	170	Bituminous	SNCR	–	CS ESP	ESPc SNCR
E004	Chesapeake	X	1	113	Bituminous	SNCR OFA	–	CS ESP	ESPc SNCR
E004	Chesapeake	X	2	113	Bituminous	SNCR OFA	–	CS ESP	ESPc SNCR
E004	Chesapeake	X	2	113	Bituminous	SNCR OFA	–	CS ESP	ESPc SNCR
E004	Yorktown	X	1	188	Bituminous	SNCR OFA LNB	–	Cyclone /ESP	ESPc SNCR
E004	Yorktown	X	2	188	Bituminous	SNCR OFA LNB	–	CS ESP	ESPc SNCR
H050	Miami Fort	X	6	170	Bituminous	SNCR	–	CS ESP	ESPc SNCR
E010	Shawville	–	3	175	Bituminous	SNCR	–	CS ESP	ESPc SNCR
E037	Cliffside	–	2	40	Bituminous	–	–	HS ESP	ESPh
E038	Louisa	–	1	700	Sub/Bit	–	–	HS ESP	ESPh
E004	Bremo	–	3	69	Bituminous	–	–	HS ESP	ESPh
E004	Bremo	–	4	185	Bituminous	LNB	–	HS ESP	ESPh

Table B-3 (continued)
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
E016	Will County	–	3	278	Subbituminous	LNB	–	HS ESP	ESPh
E040	Gaston	–	3	270	Bituminous	LNB	–	HS ESP (COHPAC)	ESPh FF (COHPAC)
E041	San Juan	x	2	369	Subbituminous	OFA	Wet FGD	HS ESP (with conditioning)	ESPh FGDw
E041	San Juan	x	4	555	Subbituminous	LNB OFA	FGDw	HS ESP (with conditioning)	ESPh FGDw
E015	Harrington	x	3	385	Subbituminous	LNB	–	FF	FF
E042	Valmont	–	5	189	Bituminous	LNB	–	FF	FF
E017	Cherokee	–	3	150	Bituminous	LNB	–	FF	FF
E017	Hayden	–	1	200	Bituminous	LNB	–	FF	FF
E043	Tolk	–	1	565	Sub bituminous	OFA	–	FF	FF
E017	Comanche	–	2	375	Sub bituminous	OFA	–	FF	FF
	North Valmy	–	1	275	Bituminous	LNB	–		FF
E005	State Line	–	3	125	Sub bituminous		–	FF	FF
E017	Arapahoe	–	4	110	Subbituminous	OFA/LNB	–	FF	FF
E025	Big Brown	–	1	593	Sub bituminous	–	–	FF/ESP	FF ESP
E025	Big Brown	–	1	593	Sub bituminous	–	–	FF/ESP	FF ESP
E044	Big Brown	–	2	593	Sub bituminous	–	–	FF/ESP	FF ESP
E044	Big Brown	–	2	593	Sub/Tx Lig	–	–	FF/ESP	FF ESP
E025	Monticello	–	1	593	Sub/Tx Lig	–	–	FF/ESP	FF ESP
E025	Monticello	–	1	593	Sub/Tx Lig	–	–	FF/ESP	FF ESP
H063	Intermountain Power Project	–	–	950	Bituminous	LNB/OFA	Wet FGD	FF	FF FGDw
H057	Parish	x	–	615	Sub bituminous	LNB/OFA	Wet FGD	FF	FF FGDw
H057	Parish	x	–	615	Sub bituminous	LNB/OFA/SCR	Wet FGD	FF	FF FGDw SCR
H062	Blount	–	9	58	Bituminous	LNB	–	MC/CS ESP	MC ESPc
E045	Laramie River	–	3	550	Sub bituminous	LNB	SD	CS ESP	SD/ESP
E045	Laramie River	–	3	550	Sub bituminous	LNB	SD	CS ESP	SD/ESP
E045	Laramie River	–	3	550	Sub bituminous	LNB	SD	CS ESP	SD/ESP
H071	Stanton	–	10	60	ND Lignite	LNB/OFA	SD	FF	SD/FF
E046	Holcomb	–	1	360	Sub bituminous	LNB	SD	FF	SD/FF
H063	Birchwood	–	–	260	Bituminous	SCR	SD	FF	SD/FF SCR
H058	Indiantown	–	1	330	Bituminous	SCR	SD	FF	SD/FF SCR
H059	Carneys Point	–	2	245	Bituminous	SCR	SD	FF	SD/FF SCR
E047	Colstrip	–	3	805	Sub bituminous	–	Wet FGD	Venturi	VS
H061	Paradise	–	–	700	Bituminous	–	Wet FGD	CS ESP	VS

Table B-3 (continued)
Test Site Characteristics: Recent Mercury Test Sites

Report Ref	Site Name	Confidential	Unit	Unit MW	Coal Rank	NOx Control	SO2 Control	PM Control	Control Class
H061	Paradise	–	–	700	Bituminous	–	Wet FGD	CS ESP	VS
H050	Paradise	x	1	705	Bituminous	—	Wet FGD	CS ESP	VS
H051	Paradise	x	1	705	Bituminous	–	Wet FGD	CS ESP	VS
E048	Widows Creek	x	7	500	Bituminous	–	Wet FGD	Venturi	VS SCR
E049	Widows Creek	x	8	500	Bituminous	SCR	Wet FGD	Venturi	VS SCR
E049	Widows Creek	x	7	500	Bituminous	SCR	Wet FGD	Venturi	VS SCR

C

CORRELATION AND EMISSION FACTOR DEVELOPMENT FOR COAL-FIRED UNITS

The correlations presented in this appendix have been previously discussed in many documents. They have been updated with new data and may have changed slightly. A listing of previous similar documents is as follows:

- Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, TR-105611, November 1995.
- Emission Factors Handbook Addendum: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, TR-105611, September 1998.
- Emission Factors Handbook Addendum 2: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, 1001326, February 2001.
- Estimation Methodology for Total and Elemental Mercury Emissions from Coal-fired Power Plants, 1001327, April 2001.
- Emission Factors Handbook Update: Total PAC Emission Factors, May 2001, posted on the TRI Resource Guide (EPRIWEB).
- Issues in Measurement of Dioxins and Furans, October 2001, posted on the TRI Resource Guide (EPRIWEB).
- Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI, Palo Alto, CA: 2002. 1005402

Another revision to the Emission Factors Handbook may be issued in the future incorporating the factors presented here and any additional data. There is also the possibility that alternate methods may be employed should they prove to be more representative of test data as additional data become available.

Emissions Estimation Approach

The use of emission factor estimates presumes that data obtained from tested sites are representative of other similar plants. The “similarity” among plants (i.e., the desirability of grouping sets of data) is specific to various classes of chemical substances. A well-known example would be the relationship of NO_x emissions to furnace design.

The uncertainty of a specific emission factor is dependent on three factors. As stated above, the test results used to derive the factor must be from units that are similar to those being estimated. Secondly, the absolute variation (standard deviation) of the test dataset affects the uncertainty range about any median, mean, or other calculated value. Lastly, the number of datasets available affects the confidence interval. For example, the following two datasets both have mean values of 10, with a 95% confidence interval of 5 (the true mean is between 5 and 15):

- 8, 10, 12
- 0, 4, 5, 8, 10, 12, 15, 16, 20

Obviously the first dataset has a large uncertainty because it contains only three values. The second set (which includes the first) exhibits a larger absolute variation and therefore the uncertainty about the true mean is also large. Therefore, when an emission factor has a large confidence interval, the user should use an appropriate degree of conservatism (i.e., the 75^{th} or 95^{th} percentile if a conservatively high estimate is desired).

Three types of emission estimation techniques are used in this document, based on the class of a substance. The selected techniques are based on the experience gained during the sampling and analysis effort (i.e., which streams and substances can be measured accurately) and an assessment of what information is readily available for plants that have not been tested (i.e., what terms should be independent parameters in any correlations). Inherent in all these activities is the actual measurement variability associated with trace quantities of substances (i.e., the degree of sophistication should be consistent with the measurement uncertainty).

Emission Factors for Coal-fired Units

Coal is a heterogeneous fuel, containing varying amounts of inorganic substances and combustible metamorphosed prehistoric vegetation. The degree of metamorphism determines the rank: lignite, subbituminous, bituminous, and anthracite, respectively, having increasing levels of carbon. Since plant matter is comprised almost exclusively of carbon, hydrogen, and oxygen (with low levels of nitrogen, sulfur, and phosphorus), the trace metals found in coal are due primarily to mineral forms present in the ash fraction in the coal. Consequently, with few exceptions, the chemistry of these minerals is not very dependent on the coal rank.

Modern steam-electric power plants use three major furnace types to combust coal. These types are wall-fired, tangential, and cyclone boilers/furnaces. Cyclone boilers are used extensively for coals that have low ash fusion temperatures (higher sodium levels) to avoid deposition of large amounts of ash on the furnace walls. The other boiler types, and numerous variants, are built by the different manufacturers for specific applications and customers. In all cases, coal combustion occurs at temperatures nearing 3,000°F. Consequently, once the carbon and hydrogen have been oxidized, the remaining fly ash experiences a similar environment regardless of the boiler type.

After combustion, the hot gases are cooled as high-pressure steam is generated. Prior to discharge to the atmosphere, the gas is cleaned to remove the bulk of the ash. Sulfur that is present in the coal forms sulfur dioxide during combustion, and this compound is often also removed. Electrostatic precipitators and fabric filters are commonly used to reduce particulate emissions. Wet or dry flue gas desulfurization units are currently employed on about one fourth of utility boilers (36% of the total MW capacity). A large number of units also meet SO_2 limits by burning coal with specified maximum sulfur levels. About one third of the boilers use a secondary form of NO_X reduction, either selective catalytic reduction (SCR), or non-selective catalytic reduction (SNCR). Almost all units use one or more of the primary forms of NO_x control (low NO_x burners, overfire air, etc.).

Consequently, although there are differences in the fuel and configuration of nearly all coal-fired plants, many trace substances experience similar environments as they are converted from mineral impurities in the coal to combustion byproducts. This implies that, unless fundamental differences in the combustion and treatment processes can be identified, all data should be considered equally.

Of the target substances, several logical groupings exist for presenting results. Most of the elements partition to the solid phase (at particulate control temperatures) and are effectively controlled by a conventional particulate control device. Other elements (mercury, chlorine, fluorine, and selenium) are relatively volatile at stack gas conditions. Some volatile organic substances are created during the combustion process and not generally captured by particulate or SO_2 control devices. Any uncombusted organic substances exiting the furnace are typically not effectively reduced by air pollution control devices at power plants. The above groupings are used in the following discussion.

Particulate-Phase Emissions

Nine elements, often existing in mineral forms, are found at varying levels in coal and are listed as hazardous air pollutants in Title III of the Clean Air Act Amendments (CAAA) of 1990. Most of these elements tend to partition to the solid phase. These elements are: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel. Mercury is discussed separately. During combustion, many of these elements volatilize and subsequently condense on fly ash particles. At typical stack gas temperatures of about 300°F, little, if any, of these elements pass through the filter of a gas sampling train (i.e., EPA Method 29). Thus, these elements are not generally present as vapor-phase species. Consequently, there is a strong relationship between total particulate emissions and the emissions of specific trace metals. Since the emissions of metallic elements are affected by both the fuel concentration and the total amount of particulate matter emitted, it is reasonable to correlate the emissions data with these two parameters. These two parameters are also readily available or can be estimated for most plants. Arsenic data are discussed below as an example of how the data were analyzed to develop emissions estimation procedures.

At nearly all of the sites tested, the removal of arsenic exceeded 90% of that present in the coal. Figure C-1 presents the potential uncontrolled emission (the coal concentration divided by the heating value) in equivalent units (pounds of substance per trillion Btu) against the average site emission factor for all of the datasets. The data plotted in this figure include quantified emissions from ESPs, fabric filters, and dry and wet FGD systems for all types of coals. Data from sites where arsenic was not detected, in either the coal or stack gas, are not used in the regression analysis. Ten of the data points were obtained from cyclone boilers; the rest were measured from either wall-fired or tangential-fired units. As seen in Figure C-1, the percent reduction varies considerably for a given fuel concentration. The sources of this variability include the performance of the control devices, daily fuel composition variability, and measurement uncertainty. Figure C-2 shows the relationship between total ash reduction to total arsenic reduction. Typically, the arsenic reduction is less than the particulate reduction, which indicates that arsenic is enriched in the finer ash fraction which is not as effectively removed by most control devices.

Figure C-3 presents similar information, except that the independent term (x-axis) is the product of the arsenic concentration in the coal (in ppm) divided by the ash fraction multiplied by the particulate emission rate expressed in lb/million Btu. Since both the coal composition and particulate matter emission can be obtained easily, correlating trace substance emissions with coal composition and particulate matter emission levels provides a simple method for estimating emissions that incorporates both input and performance parameters.

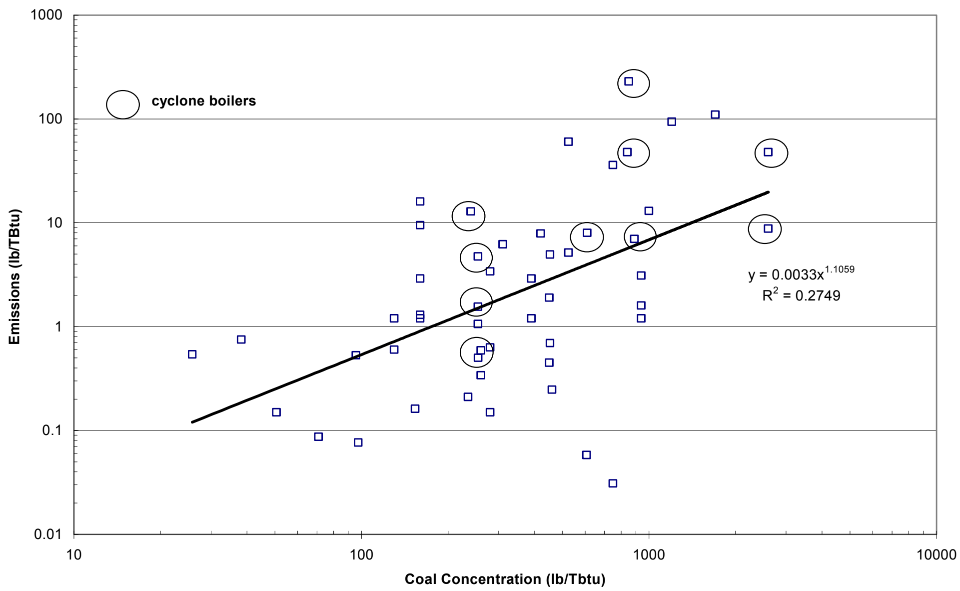


Figure C-1
Coal and Emission Levels of Arsenic

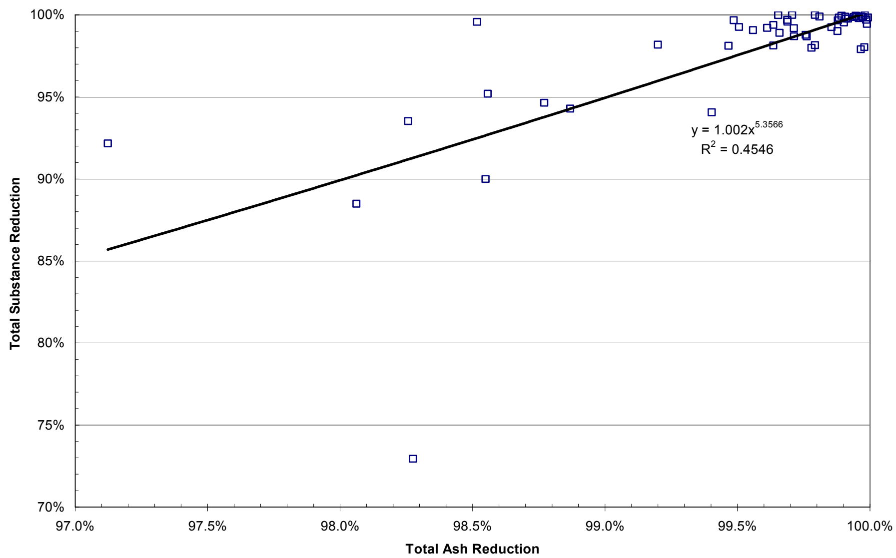


Figure C-2
Particulate Removal and Arsenic Emissions

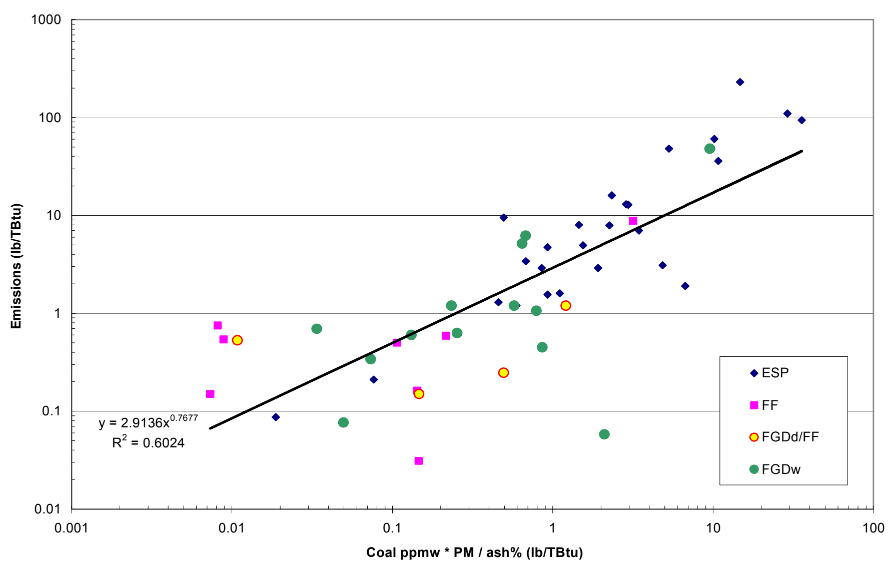


Figure C-3
Correlated Arsenic Emissions

The data in Figure C-3 are expressed in the following form:

$$E = f[(\text{coal/ash fraction}) \bullet \text{PM}]$$

where:

E	=	Emission of substance (lb/trillion Btu)
Coal	=	Trace substance concentration in coal (lb/million lb coal)
Ash fraction	=	Fraction ash in coal (lb ash/lb coal)
PM	=	Total particulate matter emission (lb ash/million Btu coal)

The data in Figure C-3 can be fit with a power relationship of the following form:

$$y = a(x)^b$$

where a and b are element-specific regression coefficients and x is the ash fraction based coal concentration times the particulate emission.

Also note that the data points do not show any marked dependence on the various types of control technologies. Although most ESP/FGD and fabric-filter sites have lower arsenic emission levels, they line up with the ESP emission data. This is true for all of the nonvolatile inorganic substances and simply indicates that the nominal composition of particulate matter exiting a control device is primarily dependent on the fuel concentration, and that any particle size/chemical composition relationships are small when data from many sites are aggregated. As more data becomes available, it may be advisable to revisit this approach and determine if further sub categorization produces better correlation coefficients. Conducting the regression analysis on the data shown in Figure C-3 yields the following:

$$E = 2.9(\text{coal/ash fraction} \bullet \text{PM})^{0.77}$$

The correlation coefficient (r^2) is 0.60. With over 50 data points, the correlation is significant at the 99.9% probability level (i.e., there is a one in one thousand probability that a set of numbers would show this relationship from chance alone). This equation predicts the median emission level of arsenic from a typical coal-fired plant for a constant coal concentration and particulate emission level (i.e., 50% of the plants with this input level would be lower or higher than this line). Actual emissions measured at specific plants may vary considerably from the predicted value. Because this approach uses data from all of the coal-fired plants for a specific substance and is based on input parameters that are readily available, it is an appropriate method for estimating the emissions from single units that have not been tested. It has an advantage over more simplistic approaches, such as average removal efficiencies or constant emission factors, since it incorporates input parameters that exhibit strong effects on emission levels.

Similar correlations and figures have been developed for the other metals of interest. The correlation statistics are presented in Table C-1. The correlation coefficients (r^2) indicate that the model relationship is statistically significant for these particulate-phase metals. Graphs showing the data are presented in Figures C-4 through C-11.

Table C-1
Summary of Emission Correlations

Element	a	b	n	r^2
Arsenic	2.91	0.77	51	0.6
Antimony	0.97	0.60	18	0.55
Beryllium	0.66	0.67	40	0.58
Cadmium	3.99	0.54	13	0.72
Chromium	3.74	0.50	51	0.53
Cobalt	1.21	0.50	47	0.39
Lead	2.77	0.66	48	0.46
Manganese	4.45	0.50	54	0.37
Nickel	3.62	0.43	44	0.40

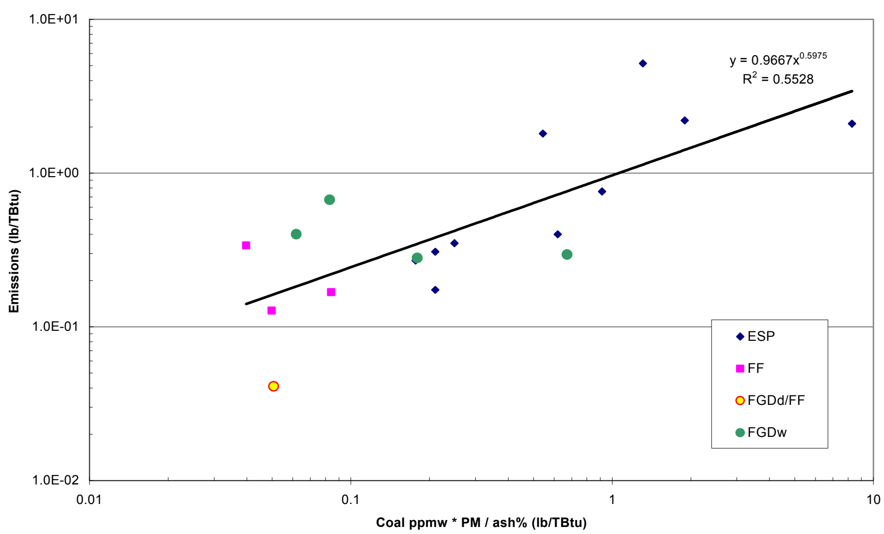


Figure C-4
Correlated Antimony Emissions

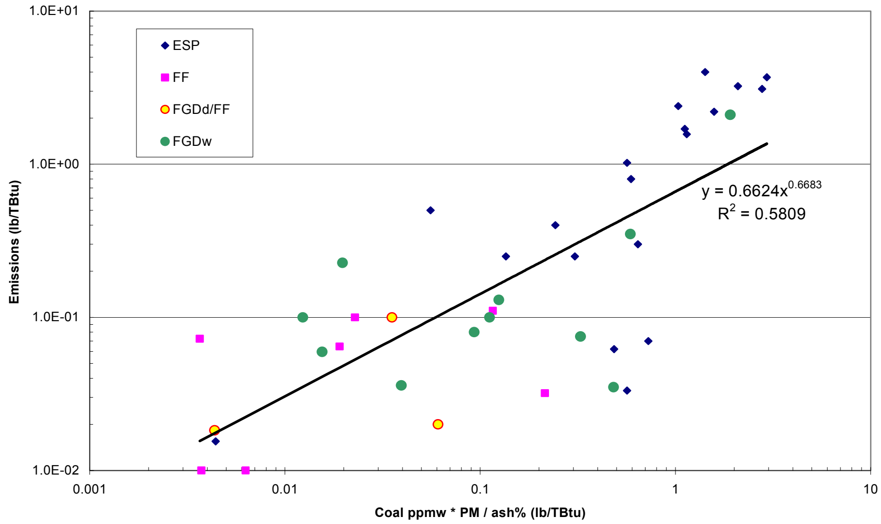


Figure C-5
Correlated Beryllium Emissions

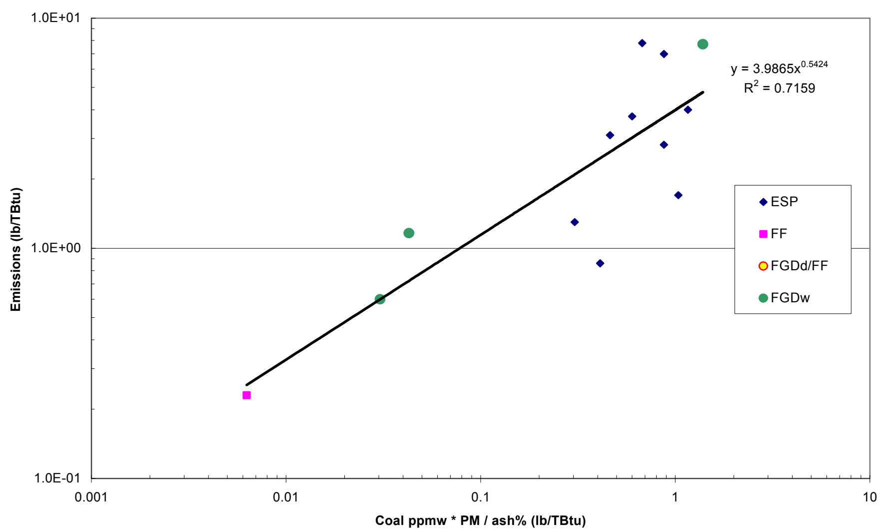


Figure C-6
Correlated Cadmium Emissions

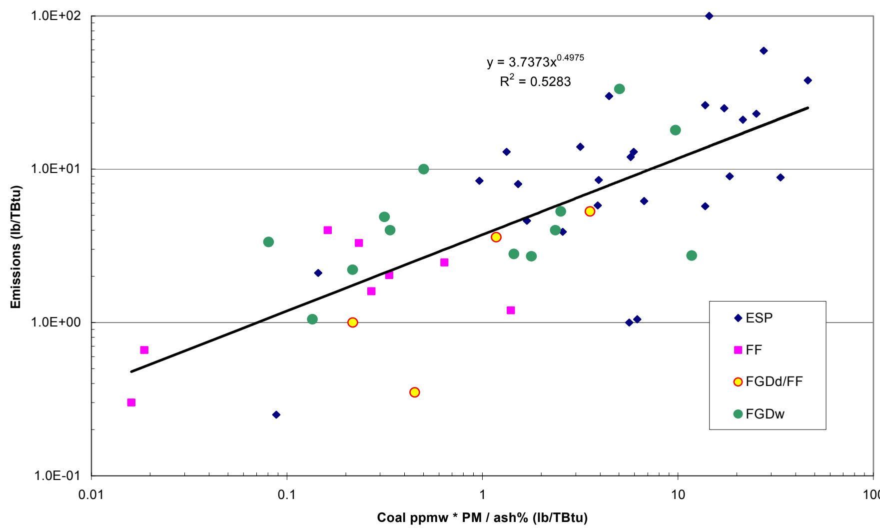


Figure C-7
Correlated Chromium Emissions

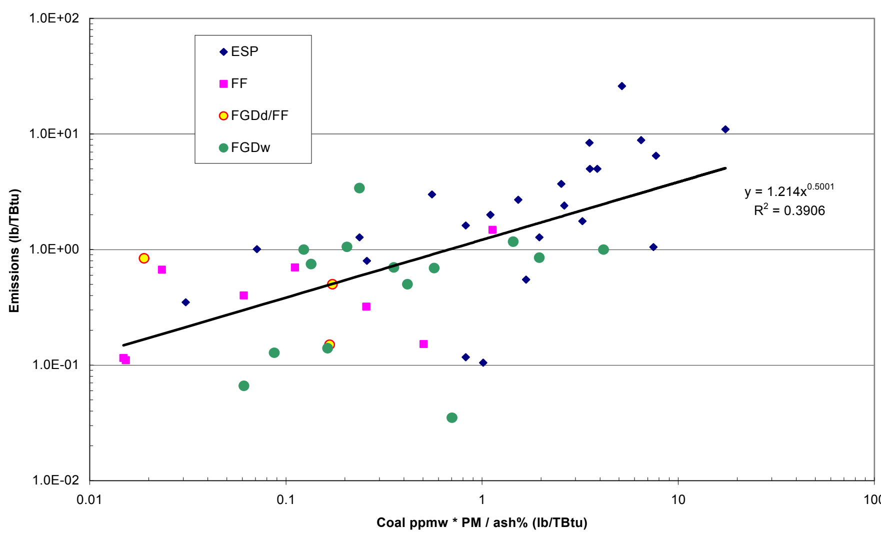


Figure C-8
Correlated Cobalt Emissions

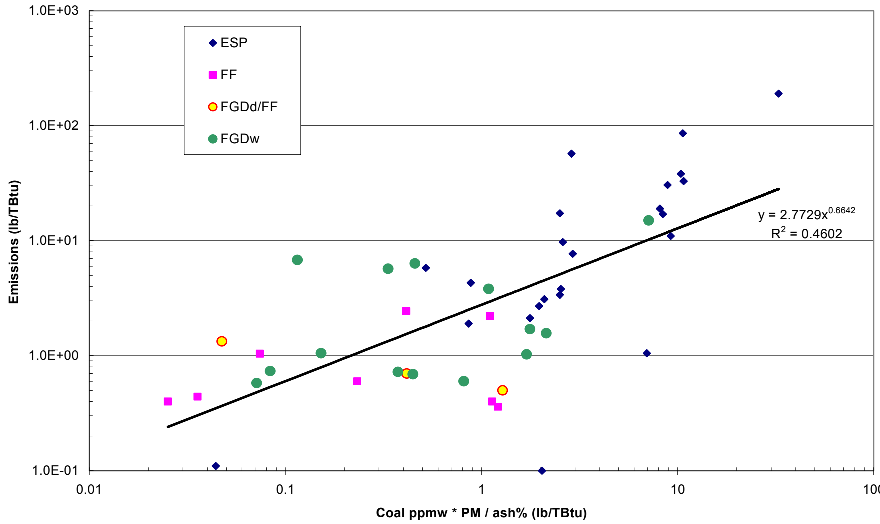


Figure C-9
Correlated Lead Emissions

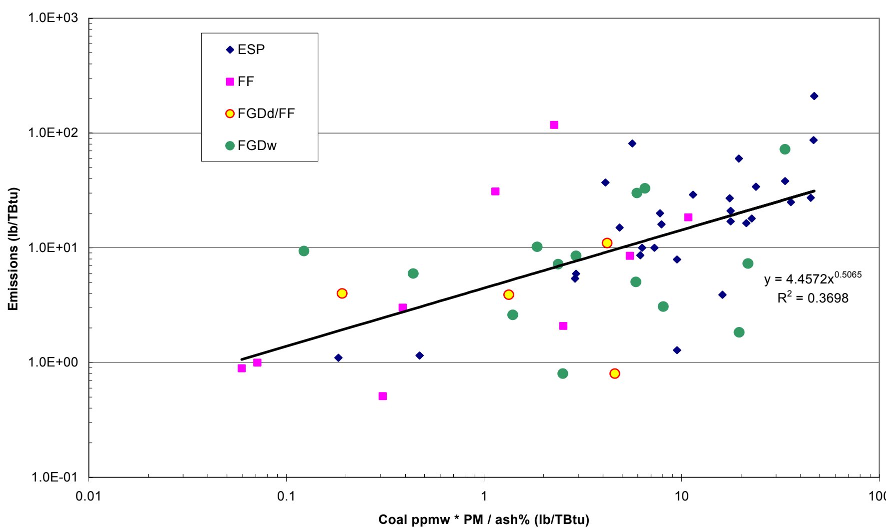


Figure C-10
Correlated Manganese Emissions

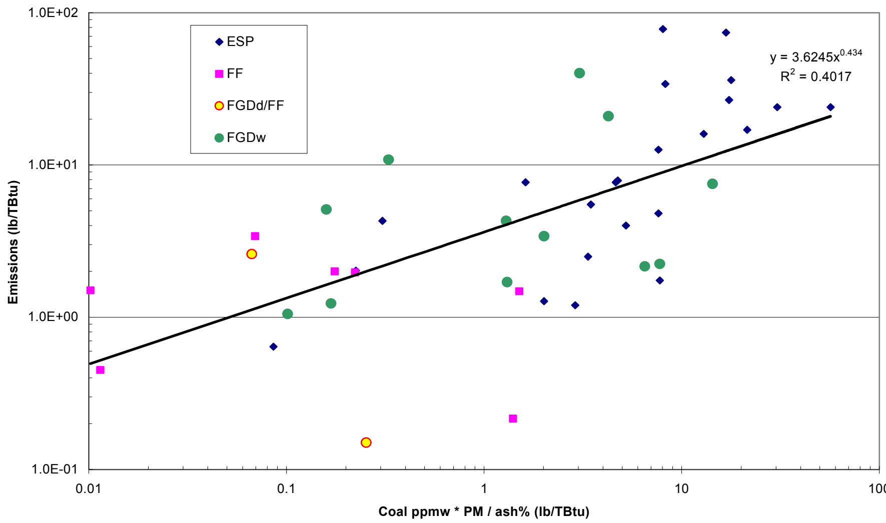


Figure C-11
Correlated Nickel Emissions

Vapor-Phase Emissions

Four inorganic substances found in coal are present primarily in the vapor phase of combustion flue gases and are not typically removed effectively by particulate control devices. Mercury, selenium, hydrochloric acid, and hydrofluoric acid measurement results and emission estimation techniques are discussed below.

Unlike the particulate-phase metals, which are typically controlled at very high efficiency, these four substances vary from essentially zero control to above 95% removal. To estimate the control efficiency, material balances were performed. The concentration of the substance in the coal, multiplied by the feed rate, was compared to the stack gas concentration and flow rate. If any of these four terms are inaccurate, the removal percentage can be significantly biased. Furthermore, since all four terms are independent of each other, it is possible to calculate a negative removal (i.e., the outlet mass can be greater than the inlet mass). Although this is a physical impossibility, it reflects the uncertainty of these measurements and such values were used in the calculation of mean values. (Gross errors were not included in the data analysis.) Therefore, some of the mean removal efficiencies have relatively large uncertainties. This reflects on the variability of the coal composition for some of these substances and/or sampling and analytical measurement bias.

Mercury

The United States Environmental Protection Agency (EPA) was required under Section 112(n)(1)(A) of the Clean Air Act (CAA) to perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units. In the Final Report to Congress(1), the EPA stated that mercury is the HAP of greatest potential concern for coal-fired power plants and that additional research and monitoring are merited. The EPA listed a number of research needs, which included obtaining additional data on the mercury content of coal burned in electric utility boilers and 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 emissions control devices, fuel type, and plant configuration affect emissions and mercury speciation).

To obtain this information, the EPA developed an information collection request (ICR) under authority of Section 114 of the Clean Air Act. Part I of the ICR requested information on fossil fuel fired boilers in the US and was used to select Part II and Part III participants. Part II of the ICR required all owner/operators of coal-fired electric utility steam generating units with a capacity greater than 25 megawatts electric [MWe] to report to EPA on a quarterly basis during 1999 the quantity of fuel shipped and the mercury content of that fuel. Part III required the owners/operators of coal-fired electric utility steam generating units selected at random from a total of 36 categories to conduct, sometime during a 1-year period, in accordance with an EPA-approved protocol, simultaneous measurement of mercury speciation in the flue gas before and after the final air pollution control device located upstream of the stack.

EPA is using the coal and stack data collected from the ICR to estimate mercury levels entering power plants as well as total and speciated mercury emissions. In parallel with EPA's evaluation of the ICR data, EPRI has also estimated mercury emissions. The data discussion and resulting calculations have been presented elsewhere(2). Since that time, many additional mercury measurements have been performed often in conjunction with mercury control technology evaluations. The baseline results of these tests have been compiled for this effort. A significant number of SCR and SNCR sites have also been tested, which has permitted more categorization of the results. The initial datasets showed a statistically valid correlation with coal chlorine levels. For many of the new categories, this relationship is not significant at the 95% level, therefore the average of the dataset is employed. Also, many of the categories of NO_x, particulate, and FGD controls do not have test data. For those cases, datasets from other similar cases have been used.

Several examples demonstrate the effect of having more data on previous valid relationships. Figure C-12 is a plot of mercury removal from plants with only cold-side ESPs. With the availability of data describing the use of flue gas conditioning, the previous correlation using the ratio of coal chlorine to sulfur becomes insignificant for both sets of data. Consequently, an average value becomes the best estimator.

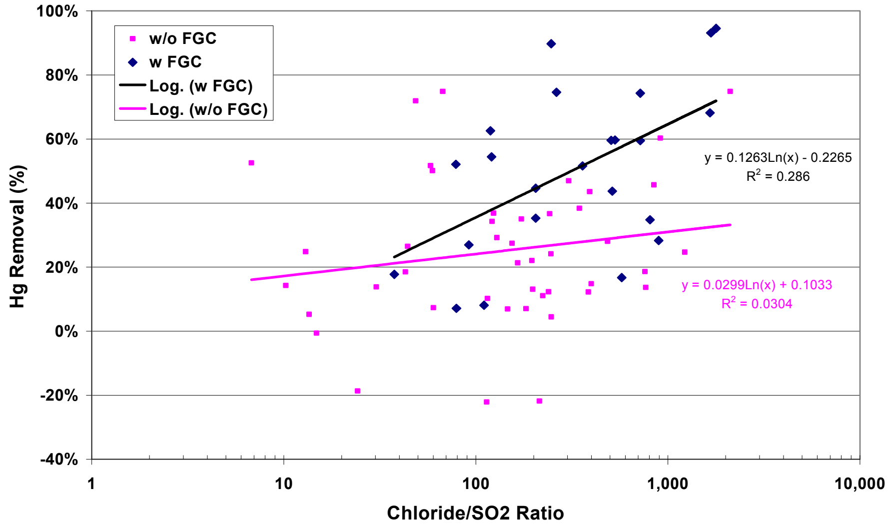


Figure C-12
ESPc Mercury Removal

In contrast, the oxidation percentage across an ESPc is still well described by the coal chlorine level, regardless of the use of flue gas conditioning as shown in Figure C-13. Therefore, a correlation is appropriate. The equations are of the form:

$$\text{Removal (or \% Elemental)} = \text{Multiplier} * \ln(\text{coal Cl, ppm}) + \text{Constant}$$

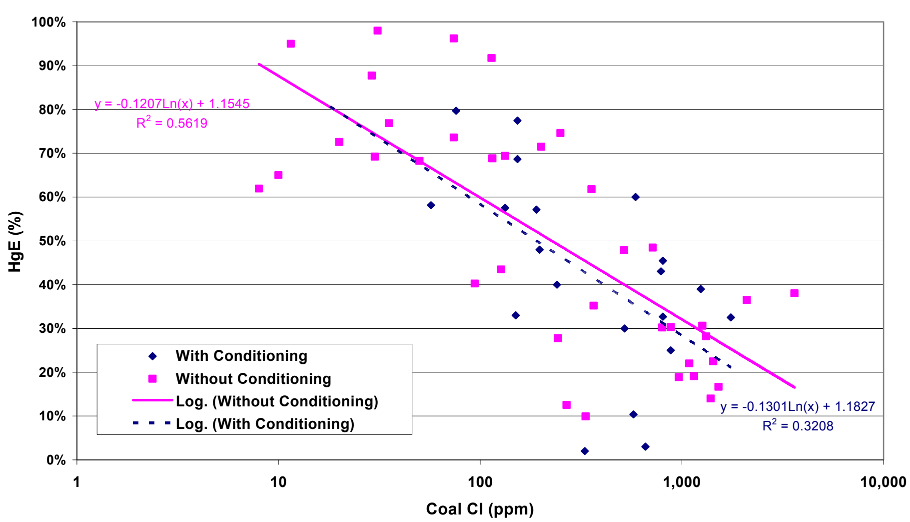


Figure C-13
Mercury Oxidation Across ESPc vs. Coal Chlorine

The data from ESPc and wet FGD systems is also of interest, as significant amounts of information have been generated over the last ten years. Figure C-14 presents the removal and oxidation values plotted against coal chlorine for ESPc and wet FGD systems. Here, the correlations are significant and are therefore used in emissions predictions. Also of interest is the effect of using a SCR system in front of the ESPc FGDw controls. Figure C-15 plots the available information and shows that the removal is higher. This is presumably due to the significant degree of mercury oxidation seen in the inlet to the FGD system, as SCRs have been shown to increase mercury oxidation. The FGD outlet gas also contains less elemental mercury, since there is significantly less entering the absorbers.

Figures C-16 and C-17 show the predicted removals across ESPc and FGDw systems with various NO_x control options. These removals are based on the data analyses performed and reflect either the average values or the correlations presented in Table 5-2 of this report for these and the other combinations of control categories present in the industry.

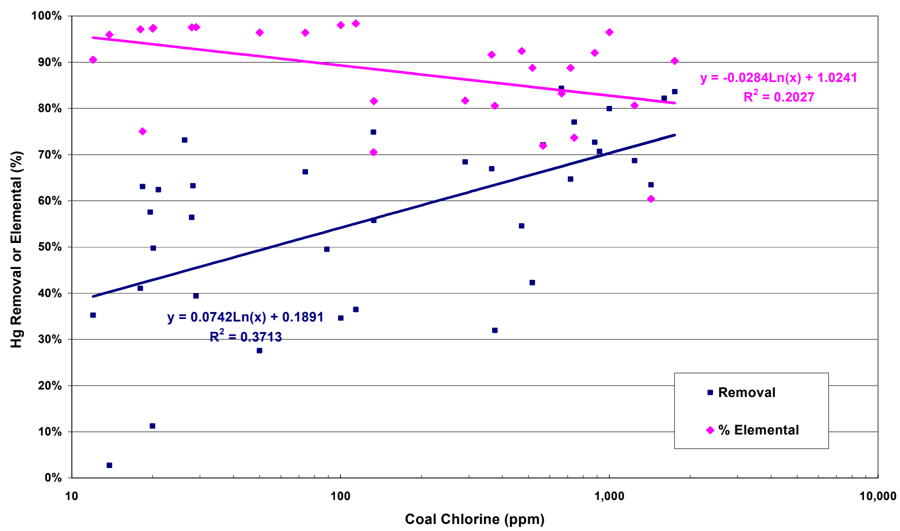


Figure C-14
Mercury Removal and Oxidation Across ESPc FGDw Systems

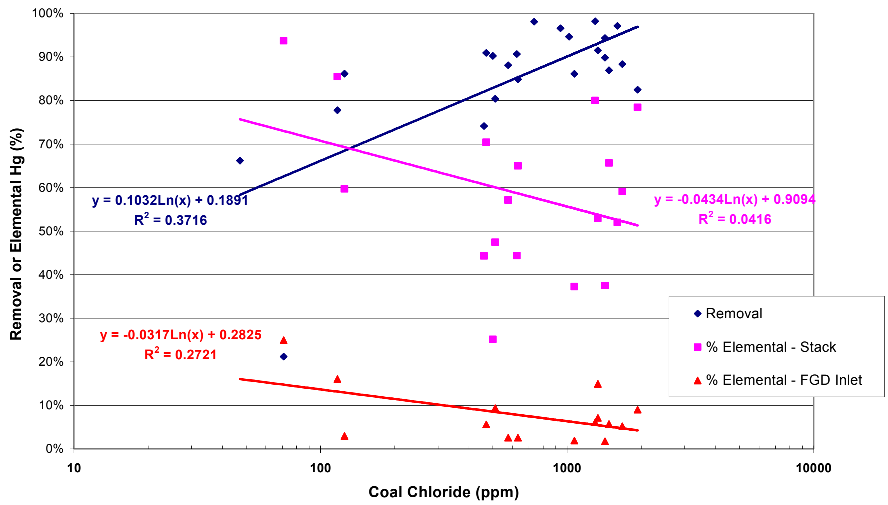


Figure C-15
Mercury Removal and Oxidation Across SCR ESPc FGDw Systems

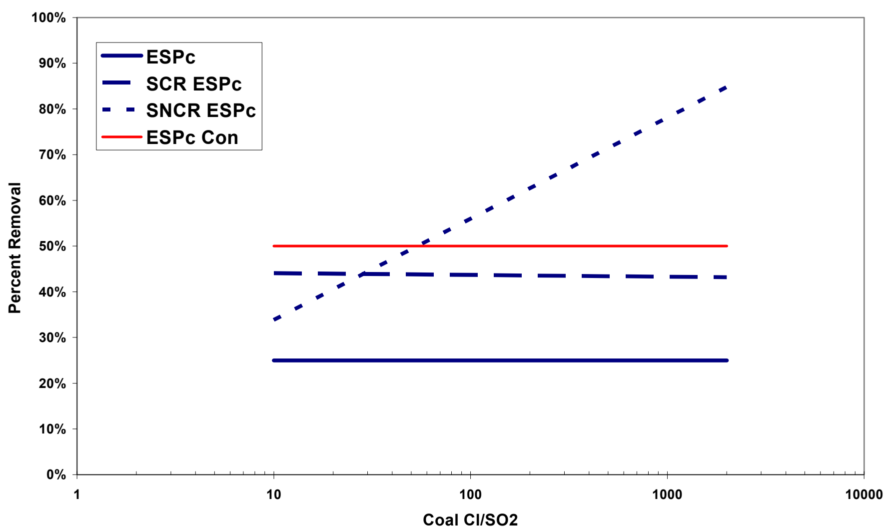


Figure C-16
Predicted Hg Removal Across Cold Side ESPs

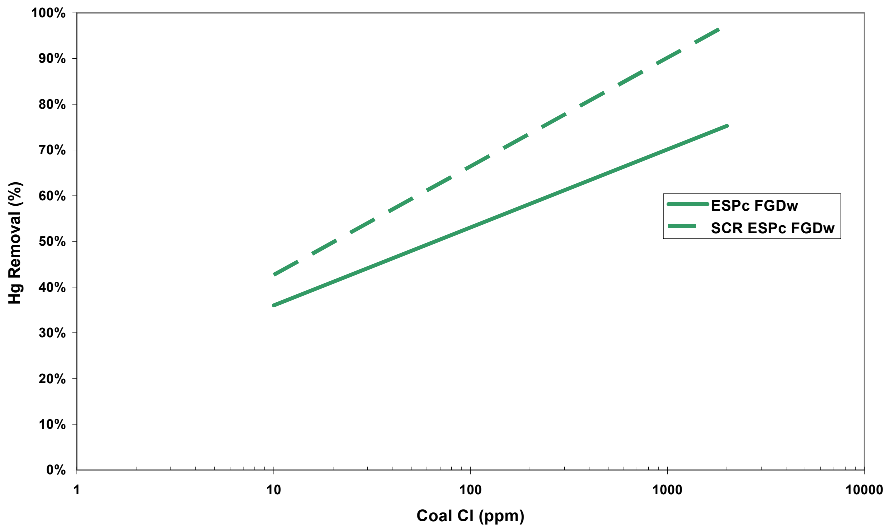


Figure C-17
Predicted Hg Removal Across ESPc and FGDw

For all of the classes of control devices, the results were averaged to develop an estimate of the amount of particulate mercury. As discussed earlier, it is not known if the mercury collected on the sample train filter is bound to particulate matter, adsorbs during sampling, or even desorbs during sampling. At all of the control device outlets, the particulate level is quite low. The relationship between the reported presence of particulate mercury, at the sampling temperature of 250°F (135°C), or the actual gas temperature when in-stack filters were used, and the actual particulate level at varying stack or atmospheric temperatures is not known.

Selenium

The behavior of selenium in power plants is somewhat similar to sulfur in that it forms an acid gas during combustion (SeO_2) and can be neutralized and absorbed by alkaline substances. SeO_2 sublimes at 650°F; therefore, as flue gas is cooled some of it will re-condense on fly ash particles. However, at stack gas temperatures the vapor pressure is still relatively high. In the absence of alkaline ash, about half of the selenium in the coal exits the stack. During this temperature transition, the relative solid/vapor ratio changes. This ratio presumably can also change in the Method 29 sampling train.

Figure 5-3 presented the matched sets of data for coal feed and associated gas emissions at various plant configurations. Here, coal-to-stack reduction is plotted as a function of coal sulfur as a surrogate for ash alkalinity (e.g., the lowest 0.9 sulfur coals are often PRB subbituminous coals with highly alkaline ash). Some particulate-controlled sites exhibit high levels of reduction (>90%); these sites predominantly are burning coals with high levels of alkaline ash (10-20% CaO). Most of the wet FGD systems show high removal also. The one wet FGD system showing slightly negative removal is designed primarily for particulate control; the mass transfer area for gas-phase species is probably very small.

Although the average reduction seen across fabric filters is higher than seen in ESPs, the difference is presumably due more to the sample population than the inherent capability of fabric filters. Most of the fabric filters tested are installed on units that burn subbituminous alkaline ash coals. The two fabric filter data points that show low reduction are from fabric filters located at bituminous coal boilers. The presence of alkaline ash in subbituminous coal or an FGD system reduces selenium emissions. Table C-2 presents the recommended emission factors for coal plants, based on control device. For fabric filters, the coal sulfur wt% is used for the multiplier in the correlation equation as follows:

$$\text{Se Reduction} = 119.26\% - 39.3\% * \text{Coal Sulfur (wt\%)}$$

Table C-2
Selenium Reduction by Control Device

Control Device	Removal/Constant	Multiplier	n	r2
ESP	58%	–	–	–
FGDw	75%	–	–	–
FF FGDd	99.5%	–	–	–
FF only	-39.3%	119.26	9	0.93

Hydrochloric Acid

Chlorides present in coals typically forms a gas-phase species, HCl, during combustion. Some test data also suggest that chlorine (Cl_2) may be formed. Of all the HAPs precursors, chloride concentrations in coal are at the highest concentrations, up to several thousand mg/kg. Gas-phase concentrations are on the order of 1 to 100 mg/Nm^3. HCl is readily absorbed in aqueous solutions and is also neutralized by alkaline substances. Table C-3 presents the removal statistics and the recommended value for emissions estimation.

Table C-3
Total Chloride Reduction by Coal Sulfur, FGD Systems

Control Device	Removal
ESP S>0.7 wt%	8%
ESP S<0.7 wt%	56%
FF	64%
FGDw	96.8%
FF FGDd	98.7%

Limited data exists for determining the split between HCl and chlorine (Cl_2) in power plant flue gas. Again, coal sulfur levels (which are a weak surrogate for coal chlorine levels) and the presence of FGD systems (which effectively remove HCl, but not Cl_2) are the basis for categorization. Table C-4 presents the average values of the datasets.

Table C-4
Chlorine as a Percentage of Total Chloride Emissions

Category	Cl_2/Total Cl
>0.7 wt % Sulfur Coal	4%
< =0.7 wt % Sulfur Coal	50%
Wet FGD	50%
Dry FGD	50%

Hydrofluoric Acid

Like chloride, fluoride present in fuel forms an acid gas during combustion. Coal concentrations are typically 10% or less. Like HCl, HF is readily absorbed in liquids or by alkaline ash. Table C-5 presents the removal statistics and the recommended value for emissions estimation.

Table C-5
HF Reduction by Coal Type, FGD Systems

Control Device	Removal
ESP/FF S>0.7 wt%	17.6%
ESP/FF S<0.7 wt%	74%
F FGDw	94%
F FF FGDd	99.4%

Organic Substance Emissions

Unlike the trace elements present in coal, the organic substance emissions were not correlated on basis of the type of control devices employed on coal rank. Data on CO levels, O_2 concentrations, etc. are not available for many of the test sites. Furthermore, the measurement variability of trace organic substances is often very large. Boilers with dry particulate controls and/or FGD systems have reported low and high values. In addition, for many substances there are few quantified results, even though numerous sites have been tested. Therefore, all of the mean site values were pooled to estimate emission factors and confidence intervals.

The FCEM and DOE programs have collected data on volatile organics, aldehydes, semivolatile organics, and dioxin/furans. Many other substances have also been analyzed in gas stream emissions. Data on all organic substance emissions is summarized below.

An attempt to assess the quality of these values requires an understanding of the procedure used to develop the statistics presented in Table C-6. The selection of data for use follows EPA protocol for performing risk assessments. The second column in Table C-6 identifies the total number of test sites where an attempt to measure the chemical substance was performed. The next column identifies how many sites had a quantified (detected) value. The number of sites used in the statistics (sample size) is based on the inclusion of one-half of any nondetect value, provided that the detection limit is no more than twice as large as the largest quantified value. For example, for four sites with results of 1, 2, <3, and <5, the mean would be 1.5 (one-half of 5 is greater than 2 and therefore excluded). High detection limits are likely indicators of low-sensitivity analytical methods.

The use of nondetected values in summary statistics introduces some uncertainty. For example, if one of ten sites has a high-level emission of a substance which was not detected at the other nine sites, the resulting mean value is very questionable. In the fifth column of Table C-6, an A through E data quality ranking is provided. “A” data have five or more quantified values and less than 50% nondetected values in the statistics. “E” data indicate a substance that was never quantified; only the detection limits are provided.

Statistics provided include the median value (based on the geometric mean) and its upper and lower 95% confidence limits. The confidence interval is the range where, with a 5% chance of being wrong, the median emission level of that substance from all coal-fired boilers is expected to lie.

Three new reports were identified which contained data for VOC compounds and aldehyde compounds not previously included in the 2002 EFH factors for coal units: Site DOE 1 (Bailey, 1994), Holcomb (DOE/EPRI program, 2002), and FCEM 25 (EPRI program, 1996). The report for DOE 1 contained data for aldehyde species, and the Holcomb and FCEM 25 reports contained data for both VOST organics and CARB 430 aldehydes. EPRI made a decision to incorporate new data from these test sites and update the emission factors for other organic compounds accordingly.

Table C-6
Coal-Fired Units – Organic Compound Emission Factors (lb/TBtu)

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
1-Chloronaphthalene	9/9	0	0	E		<0.18	<7.8
1-Naphthylamine	8/8	1	1	D	0.011		
1,2-Dibromoethane	2/2	1	2	D	2.6	0	1.3E+06
1,1-Dichloroethane	14/12	1	14	D	0.68	0.3	1.5
1,1-Dichloroethene	14/12	0	0	E		<0.3	<12
1,1,1-Trichlor-1,2,2-trifluoroethane	2/0	0	0	E		<0.26	<0.94
1,1,2-Trichloroethane	14/12	0	0	E		<0.3	<6
1,1,2,2-Tetrachloroethane	14/12	0	0	E		<0.3	<10
1,2-Dichlorobenzene	13/11	0	0	E		<0.2	<3.5
1,2-Dichloroethane	11/9	0	0	E		<0.3	<5.2
1,2-Dichloropropane	14/12	0	0	E		<0.3	<6
1,2-Diphenylhydrazine	8	0	0	E		<2.4	<33
1,2,4-Trichlorobenzene	11/9	1	11	D	1.1	0.3	4.7
1,2,4-Trimethylbenzene	2/0	0	0	E		<0.3	<0.96
1,2,4,5-Tetrachlorobenzene	8	0	0	E		<0.15	<5
1,3-Dichlorobenzene	13/11	1	13	D	0.75	0.20	2.8
1,3,5-Trimethylbenzene	2/0	1	2	D	0.95	0.00	8.6E+10
1,4-Dichlorobenzene	13/11	1	13	D	0.79	0.21	3
2-Butanone	13/11	2	13	D	2.4	1.2	4.9
2-Chloronaphthalene	9/8	2	2	C	0.0005	0	0.017
2-Chlorophenol	6/6	0	0	E		<0.2	<5
2-Hexanone	12/10	3	12	C	2.1	1	4.7
2-Methylnaphthalene	20/19	9	12	A	0.042	0.019	0.091
2-Methylphenol	8/8	0	0	E		<1.8	<7.8
2-Naphthylamine	7/7	0	0	E		<0.54	<5
2-Nitroaniline	7/7	0	0	E		<0.15	<24
2-Nitrophenol	7/7	0	0	E		<2.4	<7.8
2-Picoline	9/9	0	0	E		<0.3	<7.8
2,3,4,6-Tetrachlorophenol	9/9	0	0	E		<0.14	<16
2,4-Dichlorophenol	9/9	0	0	E		<0.14	<7.8
2,4-Dimethylphenol	9/9	0	0	E		<0.35	<7.8
2,4-Dinitrophenol	9/9	0	0	E		<1.8	<39
2,4-Dinitrotoluene	13/13	4	10	C	0.2	0.038	0.94
2,4,5-Trichlorophenol	9/9	0	0	E		<0.12	<7.8

Table C-6 (continued)
Coal-Fired Units – Organic Compound Emission Factors (lb/TBtu)

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
2,4,6-Trichlorophenol	9/9	0	0	E		<0.12	<7.8
2,5-Dimethylbenzaldehyde	2/2	2	2	C	14	9.1	23
2,6-Dichlorophenol	9/9	0	0	E		<0.19	<7.8
2,6-Dinitrotoluene	13/13	2	8	D	0.11	0.0095	1.3
3-Chloropropylene	4/2	2	4	C	2.9	0.12	73
3-Methylcholanthrene	10/10	0	0	E		<0.005	<7.8
3-Nitroaniline	9/9	0	0	E		<0.14	<39
3,3'-Dichlorobenzidine	9/9	0	0	E		<0.13	<16
4-Aminobiphenyl	10/10	0	0	E		<0.27	<7.8
4-Bromophenyl phenyl ether	9/9	0	0	E		<0.14	<7.8
4-Chloro-3-methylphenol	9/9	0	0	E		<0.19	<7.8
4-Chlorophenyl phenyl ether	9/9	0	0	E		<0.14	<7.8
4-Ethyl toluene	2/2	2	2	C	2.8	0.0001	1.30E+05
4-Methyl-2-pentanone	9/7	2	8	D	1.4	0.5	3.8
4-Methylphenol	11/8	4	8	C	1.1	0.9	1.5
4-Nitroaniline	9/9	0	0	E		<3.5	<39
4-Nitrophenol	9/9	0	0	E		<0.23	<39
4,6-Dinitro-o-cresol	9/9	0	0	E		<0.2	<39
5-Methylchrysene	3/3	1	3	D	0.0006	0.0001	0.0054
7H-Dibenzo(c,g)carbazole	3/3	0	0	E		<0.001	<0.016
7,12-Dimethylbenzo(a)anthracene	10	0	0	E		<0.005	<19
Acenaphthene	25/24	11	16	A	0.021	0.010	0.045
Acenaphthylene	25/24	12	14	A	0.0073	0.0043	0.012
Acetaldehyde	21/19	12	21	A	2.6	1	6.8
Acetone	15/11	5	15	B	1.0	0.44	2.4
Acetophenone	15	8	14	A	1.2	0.74	1.9
Acrolein	12	5	12	B	1.9	0.51	7.2
Acrylonitrile	2/0	0	0	E		<0.3	<12
Aniline	9/9	0	0	E		<0.24	<7.8
Anthracene	25/24	11	16	A	0.011	0.0048	0.026
Benzaldehyde	7/7	2	7	D	4.2	0.83	21
Benzene	28/25	24	28	A	3.5	1.8	6.8
Benzidine	10/10	0	0	E		<2.4	<7.8
Benzoic acid	11/11	5	11	B	22	9.5	53
Benzo(a)anthracene	28/27	11	16	A	0.0066	0.0029	0.015

Table C-6 (continued)
Coal-Fired Units – Organic Compound Emission Factors (lb/TBtu)

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
Benzo(a)phenanthrene (Chrysene)	27/26	9	13	A	0.0049	0.0025	0.0096
Benzo(a)pyrene	28/27	7	14	A	0.0019	0.0009	0.0041
Benzo(b,j&k)fluoranthene	25/26	10	14	A	0.0083	0.0034	0.02
Benzo(e)pyrene	8/7	4	8	B	0.0031	0.0012	0.0079
Benzo(g,h,i)perylene	27/26	6	13	B	0.0016	0.00079	0.0031
Benzyl alcohol	9/9	2	9	D	2	1.4	2.9
Benzylchloride	6/6	4	6	C	0.28	0.0042	19
Biphenyl	9/9	6	9	B	0.16	0.022	1.2
bis(2-Chloroethoxy)methane	8/8	0	0	E		<0.17	<7.8
bis(2-Chloroethyl)ether	9/9	0	0	E		<0.18	<7.8
bis(2-Chloroisopropyl)ether	10/10	0	0	E		<0.22	<7.8
bis(2-Ethlyhexyl)phthalate	11/11	7	11	A	3.6	2	6.2
Bromodichloromethane	10/10	0	0	E		<0.26	<6
Bromoform	10/10	0	0	E		<0.26	<10
Bromomethane	15/13	4	15	C	1.1	0.51	2.3
Butylbenzylphthalate	9/9	2	2	C	0.3	0.24	0.38
Carbon disulfide	16/14	8	15	A	1.0	0.4	2.4
Carbon tetrachloride	14/14	0	0	E		<0.29	<6
Chlorobenzene	17/15	1	3	D	0.14	0.11	0.19
Chloroethane	15/13	1	13	D	0.43	0.22	0.84
Chloroform	16/14	2	16	D	0.64	0.32	1.3
Chloromethane	12/10	5	12	B	1.8	0.41	5.1
cis-1,2-Dichloroethene	8/6	0	0	E		<0.26	<3.1
cis-1,3-Dichloropropene	16/14	1	16	D	0.59	0.31	1.1
Crotonaldehyde	4/4	0	0	E		<0.1	<7.1
Cumene	2/0	1	2	D	0.21	0.0016	28
Dibenzofuran	13/14	4	13	C	0.61	0.19	1.9
Dibenzo(a,e)pyrene	3/3	0	0	E		<0.0003	<0.003
Dibenzo(a,h)acridine	3/3	0	0	E		<0.001	<0.002
Dibenzo(a,h)anthracene	27/26	3	13	C	0.00098	0.00039	0.0025
Dibenzo(a,i)pyrene	3/3	0	0	E		<0.001	<0.004
Dibenzo(a,j)acridine	12/12	1	1	D	0.001		
Dibromochloromethane	14/12	0	0	E		<0.26	<6
Dibutylphthalate	9/9	1	2	D	0.11	0.0005	28

Table C-6 (continued)
Coal-Fired Units – Organic Compound Emission Factors (lb/TBtu)

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
Dichlorobromomethane	2/2	0	0	E		<0.42	<0.45
Dichloromethane	2/2	0	0	E		<1.6	<2
Diethylphthalate	10/10	2	2	C	0.2	0.02	2
Dimethylphenethylamine	9/9	0	0	E		<2.4	<40
Dimethylphthalate	9/9	1	2	D	0.09	0	1.00E+03
Di-n-butylphthalate	3/3	0	0	E		<1.9	<3
Di-n-octylphthalate	9/9	0	0	E		<0.21	<7.8
Diphenylamine	9/9	0	0	E		<0.13	<7.8
Ethyl methanesulfonate	9/9	0	0	E		<0.17	<7.8
Ethylbenzene	18/16	4	18	C	0.65	0.3	1.4
Ethylene dibromide	3/0	1	1	D	0.07		
Fluoranthene	25/24	14	23	A	0.13	0.052	0.34
Fluorene	25/24	11	24	B	0.13	0.045	0.36
Formaldehyde	30/26	13	30	B	2.4	1.4	4.8
Hexachlorobenzene	14/14	0	0	E		<0.001	<7.8
Hexachlorobutadiene	17/15	0	0	E		<0.001	<7.8
Hexachlorocyclopentadiene	13/13	0	0	E		<0.001	<7.8
Hexachloroethane	13/13	0	0	E		<0.001	<7.8
Hexaldehyde	2/2	1	2	D	5.7	0.0036	9.20E+03
Indeno(1,2,3-c,d)pyrene	26/26	7	13	A	0.0018	0.0008	0.0037
Iodomethane	3/2	2	3	C	2	0	2.30E+09
Isophorone	10/10	1	10	D	1.2	0.32	4.3
Methyl chloroform (1,1,1-Trichloroethane)	10/8	3	9	C	0.44	0.19	1.0
Methyl methacrylate	2/2	1	1	D	1.1		
Methyl methanesulfonate	9/9	0	0	E		<1.2	<17
Methylene chloride	11/7	6	11	A	3.1	1.0	9.0
m/p-Tolualdehyde	2/2	2	2	C	3.2	0.0012	8.40E+03
m/p-Xylene	15/13	8	15	A	0.7	0.28	1.8
Naphthalene	25/23	13	25	A	0.9	0.51	1.6
n-Butyraldehyde	2/2	1	2	D	8.3	0.0001	5.90E+05
n-Hexane	3/2	2	3	C	0.48	0	8.0
Nitrobenzene	9/9	0	0	E		<0.19	<7.8
N-Nitrosodibutylamine	6/6	0	0	E		<2.4	<7.8
N-Nitrosodimethylamine	10/10	0	0	E		<0.34	<7.8

Table C-6 (continued)
Coal-Fired Units – Organic Compound Emission Factors (lb/TBtu)

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
N-Nitroso-di-n-butylamine	3/3	0	0	E		<0.32	<5
N-Nitrosodiphenylamine	9/9	0	0	E		<0.14	<7.8
N-Nitrosodipropylamine	9/9	0	0	E		<0.21	<7.8
N-Nitrosopiperidine	9/9	0	0	E		<0.24	<7.8
o-Tolualdehyde	2/2	1	2	D	2.9	0	6.00E+06
o-Xylene	14/12	3	14	C	0.37	0.22	0.63
p-Chloroaniline	9/9	0	0	E		<0.18	<7.8
p-Dimethylaminoazobenzene	9/9	0	0	E		<0.17	<7.8
Pentachlorobenzene	9/9	0	0	E		<0.12	<7.8
Pentachloronitrobenzene	9/9	0	0	E		<0.54	<7.8
Pentachlorophenol	13/13	0	0	E		<0.001	<39
Perylene	3/2	1	3	D	0.0033	0	8.5
Phenacetin	9/9	0	0	E		<0.014	<7.8
Phenanthrene	25/24	14	25	A	0.40	0.19	0.84
Phenol	13/13	7	13	B	3.3	1.5	7.1
Pronamide	9/9	0	0	E		<0.17	<7.8
Propionaldehyde	8/8	5	8	B	1.9	0.3	13
Pyrene	25/24	10	22	B	0.055	0.018	0.16
Pyridine	9/9	0	0	E		<0.28	<7.8
Quinoline	3/3	0	0	E		<0.009	<5.6
Styrene	18/16	4	18	C	0.59	0.31	1.1
Tetrachloroethylene	17/15	3	12	C	0.35	0.20	0.60
Toluene	26/23	18	26	A	1.7	0.94	3.1
trans-1,2-Dichloroethene	12/12	0	0	E		<0.26	<6
trans-1,3-Dichloropropene	14/14	0	0	E		<0.26	<6.9
Trichloroethylene	14/14	0	0	E		<0.26	<6
Trichlorofluoromethane	14/12	5	14	B	0.72	0.31	1.7
Valeraldehyde	2/2	2	2	C	7.6	0.049	1200
Vinyl acetate	14/13	1	4	D	0.25	0.11	0.56
Vinyl chloride	14/12	1	14	D	0.58	0.26	1.3

[a.] Number of sites tested.
New/old = total number of sites in new dataset/number in previous 2002 Emission Factors handbook dataset.

[b] Data quality:

A = Five or more detected values, no more than 50% nondetects in statistics.
B = Four or more detected values, no more than 67% nondetects in statistics.
C = Two or more detected values, no more than 75% nondetects in statistics.

Chemical Substance	Sites Tested [a] (new/old)	Sites Detected	Sample Size	DQ[b]	Log-Normal		
					Mean	LCI	UCI
D = One or more detected values, no limit on nondetects in statistics.							
E = Substance has not been detected.							

B(a)P Equivalents

The California EPA potency equivalency factors (PEF) were selected for use in updating the calculation of B(a)P equivalents (3). B(a)P equivalents were recalculated for coal-fired units using these PEF values and EPRI selected the arithmetic average of the site B(a)P equivalent values as the emission factor to use in the emission estimates. Sites where none of the polycyclic aromatic compounds (PAH) were detected were counted as "zero" in the average calculation, analogous to the methodology used for dioxin/furan compounds.

Comparison of the 1995 and 2002 EFH datasets for PACs shows that one additional site (Milliken, Site M) was used in development of an emission factor for total PACs in the 2002 EFH. For Site M, only one of the 21 PAC compounds was detected (fluoranthene @ 0.008 lb/TBtu). Fluoranthene, however, is not included in the list of compounds used to calculate B(a)P equivalents, so the B(a)P equivalents factor becomes zero for this site in the updated B(a)P equivalents calculation.

Final emission factor values to be used in emission estimates are summarized in Table C-7 for coal-fired units.

Table C-7
Coal-Fired Units – B(a)P Equivalents

Site	B(a)P Equivalents Emission Factor (lb/TBtu)
DOE1	0
DOE3	0
DOE4	0
DOE 5	0
DOE7	0
Milliken	0
Site 115	0
DOE8	0.00092
DOE6	0.001013
DOE2	0.00118
Site 16	0.001868
Site 111	0.0021
Site 22	0.002417
Site 21	0.004309
Site 116	0.03662
Arithmetic Average	**0.00336**

Dioxins and Furans

Currently accepted weighting factors (4) were applied to the existing set of dioxin/furan data from the 15 measurement sites documented in the 2002 EFH. No new dioxin/furan measurement data were identified. EPRI made the decision to use the arithmetic average of the site TCDD equivalent values rather than the geometric mean to establish the final emission factors used in the emission estimates for coal-fired units.

Final emission factor values to be used in emission estimates are summarized in Table C-8 for coal- fired units.

Table C-8
Coal-Fired Units – TCDD Equivalents

Site	2,3,7,8-TCDD Equivalents (lb/TBtu)
DOE 7	0.00E+00
Site 1/2	2.62E-09
Site 102 New	1.81E-07
Site 122	1.45E-06
Site PI	1.10E-07
DOE M	2.85E-06
DOE 4	5.63E-07
DOE 3	1.25E-06
DOE 5	1.25E-07
Site 3	1.22E-08
DOE 8	4.60E-06
Site 22	1.78E-08
Site 116	4.01E-06
DOE 6	1.58E-06
DOE 2	4.39E-06
Arithmetic Average	**1.41E-06**

References

. . *Study of Hazardous Air Pollutant Emissions from electric Utility Steam Generating Units – Final Report to Congress,* US EPA, OAQPS, Research Triangle Park, North Carolina, EPA-453/R-98-004, February 1998.

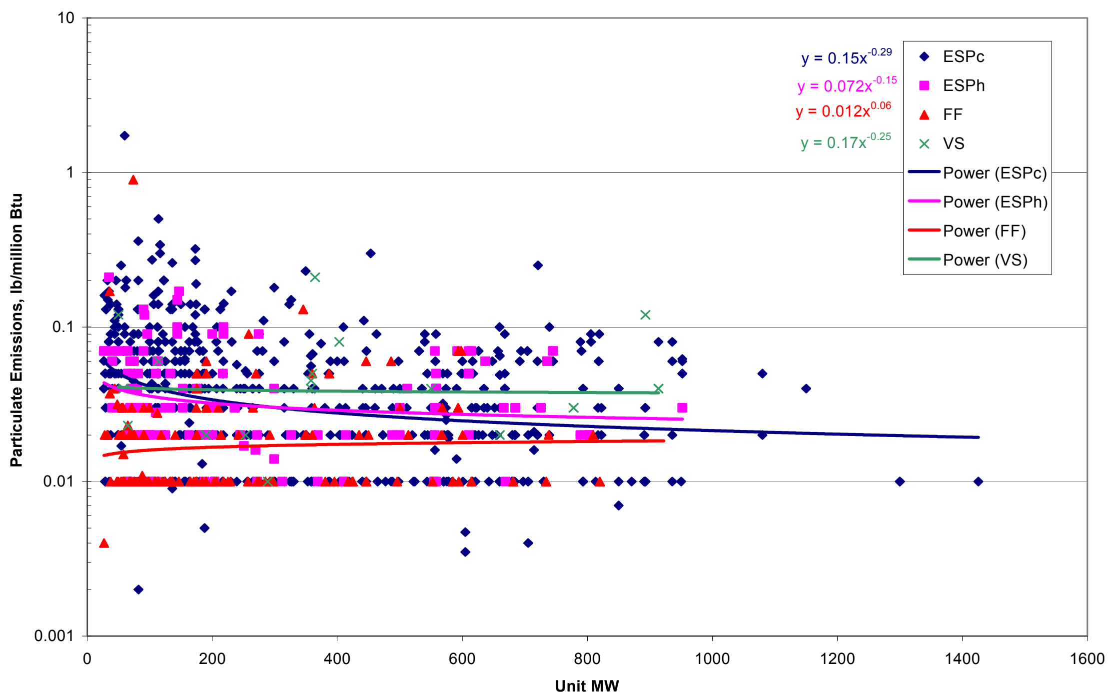
/ + An Assessment of Mercury Emissions from US Coal-fired Power Plants, EPRI, Palo Alto, CA, TR-1000608, September 2000.

0. California Environmental Protection Agency, (April 1999a; June 1999b) Air Toxics Hot Spots Program Risk Assessment Guidelines, Part II Technical Support Document for Describing Available Cancer Potency Factors, Office of Environmental Health Hazard Assessment, http://www.oehha.org/air/cancer_guide/hsca2.html (Accessed: January 2001).

1. World Health Organization, 1995.

D
PARTICULATE EMISSION CORRELATIONS

For units which did not have reported actual particulate emission rates from 2004 or 2005 on EIA Form 767 in the plant characteristics database, the data and correlation equations shown in the figure below were used to estimate particulate emission rates used as inputs to the emission estimate correlations for particulate-phase metals. These correlations were developed from the 2005 Form 767 dataset for all units based on the type of particulate control system (i.e., ESPc, ESPh, FF, or VS).



E

SAMPLE EMISSION CALCULATIONS

This section details sample calculations for the emissions of mercury, arsenic, selenium, HCl, Cl_2, and benzene. These substances were selected to illustrate the types of calculations used for various groups of compounds. For each compound the general emissions calculations equations are presented, followed by specific calculations for one site, Clay Boswell. Tables E-1 and E-2 summarize the input values used for these calculations. The trace element compositions listed in Table E-1 represent the “blended” fuel values calculated for this station as described in Appendix A.

Table E-1
Coal and Site Specific Input Data for Clay Boswell

Unit	HHV (Btu/lb)	2007 Annual Heat Input (TBtu/yr)	Coal Hg (ppmw)	Coal As (ppmw)	Coal Se (ppmw)	Coal Cl (ppmw)	Coal Ash (wt%)	Coal Sulfur (wt%)	Particulate Emissions (lb/Million Btu)
1	9,026	4.83	0.048	3.67	0.76	64	6.7	0.497	0.02
2	9,026	4.69	0.048	3.67	0.76	64	6.7	0.497	0.02
3	9,026	22.68	0.048	3.67	0.76	64	6.7	0.497	0.21
4	9,026	41.09	0.048	3.67	0.76	64	6.7	0.497	0.05

Table E-2
Mercury Correlation Constants for Clay Boswell

Unit	Configuration	Total Removal Constants (%)		Elemental Percentage Constants (%)		Particulate Percentage Constants (%)
		R_f	R_c	E_f	E_c	P_c
1	FF	23.23%	-70.26%	0%	23%	0.76%
2	FF	23.23%	-70.26%	0%	23%	0.76%
3	VS FGDw	0%	22%	0%	94%	1.0%
4	ESPh FGDw	24.66%	-109.7%	0%	91%	2.6%

Mercury

Correlations were used to calculate four values: total mercury emissions, elemental mercury emissions, oxidized mercury emissions, and particulate mercury emissions associated with each coal-fired unit. Mercury emissions correlations were developed for 35 categories based on plant configuration as described in Appendix D. Sample calculations for one coal-fired station having multiple units equipped with different types of controls are provided in the example below. The example also illustrates how total emissions were calculated for units sharing common stack emission points. For the remaining plant configurations, the constants used were different, but the methodology was identical.

Total Mercury Emissions

For total mercury emissions first a total mercury removal was calculated, represented in the general equation below:

$$\%R = R_C + R_f * \ln(Coal_{Cl})$$

where %R is the percent removal, R_c is the removal constant based on plant configuration, R_f is the removal factor based on plant configuration, and $Coal_{Cl}$ is the coal chloride content in ppmw. An example calculation is shown below for Clay Boswell Station, a station with the following configurations and stack emission points:

- Units 1&2 FF,
- Unit 3 VS FGDw, and
- Unit 4 ESPh FGDw.

The values in the equation below represent those for Unit 1, with the results for the remaining units summarized in Table E-3:

$$\%R = -70.26\% + 23.23\% * \ln(64) = 26.4\%$$

Table E-3
Mercury Removal Percentages for Clay Boswell

Unit	Total Hg Removal (%)
1	26.4
2	26.4
3	22.0
4	0*
* Adjusted to 0% because the correlation equation yielded a negative value	

As shown for Clay Boswell Unit 4, if a removal equation yielded a negative value, that value was set to the defined lower limit of the correlation equation, 0% in this case. Also for some control classes an upper limit removal value was assigned, and if the correlation equation yielded a value greater than the upper limit, percent removal was set to the defined upper limit of the particulate correlation equation. These values are listed in Table E-4 and are based on the actual measured values used to develop the correlation.

Table E-4
Lower and Upper Limits of the Mercury Percent Removal Correlations by Control Class

Configuration	Lower Limit	Upper Limit
ESPc FGDw	3	84
ESPh FGDw	0	74
FF	0	99
FF FGDd	5	99
SCR ESPc FGDw	21	98
SCR FF FGDd	4	99
SNCR ESPc FGDw	21	98
SNCR FF	0	99
SNCR FF FGDd	5	99

Next coal mercury content in lbs/yr was calculated using the equation below.

$$Hg_T = \frac{Hg_{coal} * 10^6 * BTU_{Consumed}}{Coal_{BTU}}$$

Where Hg_T is the total mass of Hg input to the unit with the fuel in 2007, Hg_{coal} is the "blended" coal mercury concentration, $Coal_{BTU}$ is the "blended" BTU/lb value for the coal, $BTU_{Consumed}$ is the total energy input in trillion BTU per year, and 10^6 is a conversion factor.

For Unit 1 this equation becomes:

$$Hg_T = \frac{0.048 * 10^6 * 4.83}{9026} = 25.67 \frac{lbsHg}{Yr}$$

The results for the remaining units at Clay Boswell are in Table E-5.

Table E-5
Total Mercury Combusted at Clay Boswell per Year

Unit	Hg_T (lb/yr)
1	25.7
2	24.9
3	121
4	218

The equation shown below was used to calculate the total Hg emissions by combining removal and coal Hg input values:

$$Hg_{Emit} = Hg_T * (100\% - \%R)$$

Where Hg_{Emit} is the lbs of mercury emitted per year. For Clay Boswell Unit 1 this equation becomes:

$$Hg_{emit} = 25.67 * (100\% - 26.4\%) = 18.9 \frac{lbsHg}{Yr}$$

The results for the remaining units at Clay Boswell are in Table E-6.

Table E-6
Annual Mercury Emissions by Unit at Clay Boswell

Unit	Hg_{Emit} (lbs/yr)
1	18.9
2	18.3
3	94.0
4	218

From information in the unit characteristics database, it was determined that Units 1 through 3 shared a common stack, and Unit 4 had its own unique stack. To generate the emissions for each stack emission point, the individual emissions estimates for each unit that shared a common stack were summed. Table E-7 below shows the results for Clay Boswell.

Table E-7
Annual Mercury Emissions by Stack at Clay Boswell

Stack Emission Point	Hg_{emit} (lbs/yr)
1	131
2	218

Elemental Mercury Emissions

For elemental mercury emissions first an emitted elemental mercury percentage was calculated using the appropriate correlation, represented in the general equation below:

$$\%E = E_C + E_f * \ln(Cl)$$

Where %E = emitted elemental mercury percentage.

An example calculation is shown below for Unit 1, with results for the other units provided in Table E-8:

$$\%E = 23\% + 0 * \ln(64) = 23\%$$

Table E-8
Elemental Mercury Emission Percentage at Clay Boswell by Unit

Unit	Elemental Emission Percentage (%)
1	23
2	23
3	94
4	91

For results where the calculated elemental percentage was negative, the elemental percentage was set to the defined lower limit of the correlation. Also for some control classes a maximum elemental percentage value was assigned, and if the correlation equation yielded a value higher than this, elemental percentage was set to the defined upper limit of the correlation. These values are listed in Table E-9.

Table E-9
Lower and Upper Limits of the Elemental Mercury Emission Percentage by Control Class

Configuration	Lower Limit	Upper Limit
ESPc	2	98
ESPc CON	2	98
ESPc FGDw	60	98
ESPh	5	92
FF FGDd	41	99
SCR ESPc	1	73
SNCR FF FGDd	41	99

This percentage elemental emissions value was then combined with the total emissions in the equation below to calculate an elemental emission rate, Hg_E:

$$Hg_E = Hg_{Emit} * \%E$$

For Unit 1 this becomes:

$$Hg_E = 18.89 * 23\% = 4.34 \frac{lbgHg_E}{yr}$$

For the remaining units at Clay Boswell the results are shown in Table E-10.

Table E-10
Emitted Elemental Mercury at Clay Boswell by Unit

Unit	Hg_E (lbs/yr)
1	4.34
2	4.22
3	88.3
4	199

Particulate Mercury Emissions

For particulate mercury emissions a average percentage was assigned to each control class. This percentage was then multiplied times the total mercury emissions to generate a mass rate of particulate bound mercury emissions shown in the equation below:

$$Hg_P = Hg_{Emit} * \%P_c$$

For Clay Boswell Unit 1 this becomes:

$$Hg_P = 18.89 * 0.76\% = 0.14 \frac{lbsHg_P}{yr}$$

Values for the remaining units at Clay Boswell are shown in Table E-11.

Table E-11
Particulate Mercury Emissions at Clay Boswell, by Unit

Unit	Hg_P (lbs/yr)
1	0.14
2	0.14
3	0.94
4	5.67

Oxidized Mercury Emissions

For all plant configurations oxidized mercury emissions were calculated as the difference between total emissions and particulate plus elemental emissions, as shown in the equation below:

$$Hg_{Ox} = Hg_{Emit} - Hg_E - Hg_P$$

A sample calculation is show for Boswell Unit 1:

$$Hg_{Ox} = 18.89 - 4.34 - 0.14 = 14.40 \frac{lbsHg_{Ox}}{yr}$$

Values for the remaining units at Clay Boswell are shown in Table E-12.

Table E-12
Oxidized Mercury Emissions at Clay Boswell, by Unit

Unit	Hg_{Ox} (lbs Hg_{Ox}/yr)
1	14.4
2	14.0
3	4.7
4	14.0

For sites where this equation yielded a negative value for Hg_{Ox}, emissions were set to zero.

Selenium

Selenium emission rates were estimated by calculating an annual mass of selenium input with the fuel, and then multiplying by a removal percentage.

The annual selenium input was calculated using a method analogous to that shown above for mercury. The equation used is shown below:

$$Se_T = \frac{Se_{coal} * 10^6 * BTU_{Consumed}}{Coal_{BTU}}$$

The equation below shows this calculation for Clay Boswell Unit 1:

$$Se_T = \frac{0.76 * 10^6 * 4.8}{9026} = 404.17 \frac{lbsSe}{yr}$$

Values for the other units at Clay Boswell are shown in Table E-13.

Table E-13
Annual Fuel Selenium Input at Clay Boswell by Unit

Unit	Annual Se Input (lbs/yr)
1	404.2
2	395.8
3	1911
4	3461

Based on plant configuration one of four correlations was used to calculate selenium removal. Three of four configuration classes, along with their removal constants are shown in Table E-14 below:

Table E-14
Removal Percentage for Selenium by Plant Configuration

Configuration	Removal Constant
ESP	58%
FGDw	75%
FF FGDd	99.5%

For the fourth configuration, FF, the following correlation equation was used to calculate removal:

$$Se_{\mathrm{Rem}} = 119.26\% - 39.325 * Sulfur_{Coal}$$

Where, Se_{Rem} = selenium removal percentage and $\mathrm{Sulfur}_{\mathrm{Coal}}$ = weight percent sulfur in the coal.

A sample calculation is shown for Clay Boswell Unit 1:

$$Se_{\mathrm{Rem}} = 119.26\% - 39.325 * 0.497\% = 99.72\%$$

Table E-15 shows the calculated selenium removals for all units at Clay Boswell.

Table E-15
Selenium Removal for Clay Boswell, by Unit

Unit	Se Removal (%)
1	99.72
2	99.72
3	75
4	75

These removal numbers were then combined with total selenium fuel input values to calculate annual selenium emissions using the equation below:

$$Se_{Emit} = Se_T * (100 - Se_{\mathrm{Rem}})$$

Detailed calculations are shown for Clay Boswell Unit 1 below:

$$Se_{Emit} = 404.17 * (100 - 99.72\%) = 1.1 \frac{lbsSe}{yr}$$

Results for the remaining units at Clay Boswell are shown in Table E-16.

Table E-16
Selenium Emissions at Clay Boswell, by Unit

Unit	Se Emissions (lbs/yr)
1	1.1
2	1.1
3	478
4	865

Arsenic

A single correlation was used to calculate the total emissions for Arsenic for all units modeled in this report. The general equations for this correlation are shown below, with specific calculations demonstrated for Clay Boswell.

To calculate the annual emissions for arsenic, first an emission factor was generated using the equation below:

$$EF_{As} = A_{As} * (\frac{As_{Coal}}{Ash_{Coal}} * Part_{Emit})^{B_{AS}}$$

Where EF_{As} is the emission factor for arsenic, A_{As} is a correlation coefficient for arsenic, As_{Coal} is the concentration of arsenic in the coal (ppmw), Ash_{Coal} is the weight fraction ash in the coal, $Part_{Emit}$ is the particulate emission rate in lb/Million Btu, and B_{As} is a correlation coefficient for arsenic.

For Clay Boswell unit 1 this equation becomes:

$$EF_{As} = 2.91 * (\frac{3.67}{0.067} * 0.02)^{0.77} = 3.13 \frac{lbAs}{TBtu}$$

Emission factors for the other units at Clay Boswell are shown in Table E-17.

Table E-17
Arsenic Emission Factors for Clay Boswell, by Unit

Unit	As Emission Factor (lb/TBtu)
1	3.13
2	3.13
3	19.1
4	6.33

This emission factor was then entered into the following equation to calculate the emission rate for arsenic:

$$As_{Emit} = EF_{As} * BTU_{Consumed}$$

For Clay Boswell Unit 1 this becomes:

$$As_{Emit} = 3.15 * 4.8 = 15.11 \frac{lbsAs}{yr}$$

Values for the remaining units at Clay Boswell are listed in Table E-18.

Table E-18
Annual Emission Rate for Arsenic at Clay Boswell, by Unit

Unit	As Emission Rate (lbs/yr)
1	15.1
2	14.7
3	434
4	260

The correlation methodology for all other metals, except selenium and mercury, are the same as that used above for arsenic. Table E-19 shows the correlation constants for all non-mercury trace elements considered in this report.

Table E-19
Correlation Coefficients for non-Mercury Trace Elements

Element	A	B
As	2.91	0.77
Be	0.66	0.67
Cd	3.99	0.54
Co	1.21	0.5
Cr	3.74	0.5
Mn	4.45	0.5
Ni	3.62	0.43
Pb	2.77	0.66
Sb	0.97	0.6

Hydrochloric Acid/ Chlorine Gas (Cl_2)

To calculate HCl/Cl_2 emissions first the total annual chloride input with the fuel was calculated for each unit, using the equation below.

$$Cl_T = \frac{Cl_{Coal} * 10^6 * BTU_{Consumed}}{Coal_{BTU}}$$

Where Cl_T is the total chloride input to the boiler with the fuel in lbs/yr and Cl_{Coal} is the coal chloride content in ppmw, For Clay Boswell Unit 1 this becomes:

$$Cl_T = \frac{64*10^6 * 4.83}{9026} = 34{,}332 \frac{lbsCl}{yr}$$

The results for the remaining units at Clay Boswell are shown in Table E-20.

Table E-20
Chloride Consumption at Clay Boswell, by Unit

Unit	Cl Consumption Rate (lbs/yr)
1	34,332
2	33,339
3	161,176
4	291,909

Once the consumption rate was calculated, a removal percentage was applied based on plant configuration. These percentages are listed in Table E-21. For the second ESP/FF entry the S <0.7 indicates those sites that burn coal with less than 0.7 wt% sulfur.

Table E-21
Chloride Removal Percentage by Plant Configuration and Coal Sulfur Content

Configuration	Removal Constant
ESP	8%
ESP S<0.7 wt%	56%
FF	64%
FGDw	96.8%
FF FGDd	98.7%

The equation below was used to calculate the total chloride, as HCl, emitted:

$$HCl = Cl_T * (100 - \% \mathrm{Re}\, m) * 36/35$$

For Clay Boswell Unit 1 this becomes:

$$HCl = 34{,}332 * (100 - 64\%) * 36/35 = 12{,}713 lbsHCl$$

Results for the remaining units at Clay Boswell are shown in Table E-22.

Table E-22
Total Chloride Emissions at Clay Boswell, by Unit

Unit	Total Cl (as HCl) Rate (lbs/yr)
1	12,713
2	12,345
3	5,305
4	9,608

From this total Cl rate, the individual rates of HCl and Cl_2 were determined by using a split percentage based on configuration and coal sulfur content. Table E-23 details the split coefficients.

Table E-23
Chlorine Gas Percentage by Plant Configuration and Coal Sulfur Content

Configuration or Coal Sulfur Content	% of Total Chloride as Cl_2
> 0.7 wt% S	4%
<= 0.7 wt% S	50%
FGDw	50%
FGDd	50%

Cl_2 and HCl emissions were then determined using the equations below:

$$Cl_{2Emit} = HCl * Split$$

$$HCl_{Emit} = HCl - Cl_{2Emit}$$

Where Cl_{2Emit} is the emitted Cl_2 in lbs/yr, HCl is the total chloride as HCL in lbs/yr, HCl_{Emit} is the HCL emitted in lbs/yr, and Split is the percentage of chloride in the form of Cl_2.

For Clay Boswell Unit 1 this becomes

$$Cl_{2Emit} = 12{,}713 * 50\% = 6{,}357 \frac{lbsCl_2}{yr}$$

$$HCl_{Emit} = 12{,}713 - 6357 = 6{,}357 \frac{lbsHCl}{yr}$$

Results for the remaining units at Clay Boswell are shown in Table E-24.

Table E-24
Chloride Emissions by Type from Clay Boswell

Unit	Cl_2 Emissions (lbs/yr)	HCl Emissions (lbs/yr)
1	6,357	6,357
2	6,173	6,173
3	2,652	2,652
4	4,804	4,804

Benzene

A single geometric mean emission factor was used to calculate the emission of benzene. Emission of other organic compounds and hydrogen cyanide were calculated the same way, using substance specific emission factors. Table E-25 shows the emission factor used for selected organic compounds or groups of compounds. Appendix C provides a complete listing of emission factors. Sample calculations for Clay Boswell are shown below.

Table E-25
Emission Factors for Organic Compounds

Chemical	Emission Factor (lb/TBtu)
Benzene	3.5
Toluene	1.7
Formaldehyde	2.4
B(a)P Equivalents	0.00336
2,3,7,8-TCDD Equivalents	1.41E-06
Hydrogen cyanide	13.3

To calculate the emission rate of benzene, the emission factor and annual coal energy input are combined using the equation below:

$$Benzene_{Emit} = EF_{Benz} * BTU_{Consumed}$$

Where $Benzene_{Emit}$ is the amount of benzene emitted in lbs/yr and EF_{Benz} is the emission factor for benzene in lb/TBtu input.

For Clay Boswell Unit 1 this becomes:

$$Benzene_{Emit} = 3.5 * 4.83 = 16.91 \frac{lbsBenzene}{yr}$$

Results for the remaining units at Clay Boswell are shown in Table E-26.

Table E-26
Benzene Emissions from Clay Boswell, by Unit

Unit	Benzene Emission Rate (lbs/yr)
1	16.9
2	16.4
3	79.4
4	144

Again, unit emissions for individual non-mercury HAPs compounds were summed for units with common stacks as described above for mercury to obtain the final stack emission point estimates for each compound.

F

STATION LEVEL EMISSION ESTIMATE RESULTS AND STACK PARAMETER VALUES

Table F-1 contains station level annual emission estimate results, presented in lbs/year, for all of the inorganic HAPs species evaluated. Results are sorted by state and station name. Annual emission values for organic species are not shown, but can be easily be derived for each station by simply multiplying the substance specific lb/trillion Btu emission factors shown in Table 5-4 by the annual trillion Btu heat input for the station shown in Table F-1. Information presented in Table F-1 is defined as follows:

OPERATOR – Operating utility name

PLANT – Station name

STATE – State location

ORISPL - ORISPL number unique to each station

TBtu/2007 - Total trillion Btu heat input in 2007

As lb/yr - Arsenic

Be lb/yr - Beryllium

Cd lb/yr - Cadmium

HCl lb/yr – Hydrogen chloride

Cl2 lb/yr - Chlorine

Co lb/yr - Cobalt

Cr lb/yr - Chromium

HF lb/yr – Hydrogen fluoride

Coal Hg lb/yr – Total mercury input to boiler with coal

Hg lb/yr – Mercury (emissions)

HgOx lb/yr – Oxidized mercury (emissions)

HgE lb/yr – Elemental mercury (emissions)

HgPM lb/yr – Particulate mercury (emissions)

Mn lb/yr - Manganese

Ni lb/yr - Nickel

Pb lb/yr - Lead

Sb lb/yr - Antimony

Se lb/yr - Selenium

Table F-2 provides a listing of the stack emission points for all coal-fired units and the associated stack parameter values as defined below:

EMISSION POINT – Stack emission point ID

STATE - State

ORISPL – ORISPL number unique to each station

LATC- latitude

LONC - longitude

TEMP degC – stack gas temperature (degrees C)

HGT meters – Stack height (meters)

DIAM meters – Stack diameter (meters)

VEL m/s – Stack gas velocity (meters per second)

FLOW cu m/s - Stack gas flow rate (cubic meters per second, actual)

TBtu/2007 – Total trillion Btu heat input in 2007

Table F-1

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
GOLDEN VALLEY	Healy	AK	6288	2.14	13	0.8	1	45187	922	2	13	10187	19
SOUTHERN	Barry	AL	3	102.56	554	60.5	87	659492	659492	139	888	158485	492
ALEC	Charles R. Lowman	AL	56	38.06	211	19	39.9	16348	16348	52	327	15032	278
TVA	Colbert Fossil Plant	AL	47	76.75	226	24.7	37	6572894	134141	66	439	325335	657
SOUTHERN	Gadsden	AL	7	7.45	45	2.8	2.6	138845	2834	10	62	54189	73
SOUTHERN	Gaston	AL	26	109.98	503	32.1	31.4	1896068	38695	126	751	800304	972
SOUTHERN	Gorgas	AL	8	66.47	292	19.6	20.5	2308181	47106	75	444	468808	1362
SOUTHERN	Greene County	AL	10	34.62	117	11.1	16.2	1001426	20437	34	211	196962	345
SOUTHERN	Miller	AL	6002	198.6	228	20.3	64.7	499495	499495	125	698	333702	1150
TVA	Widows Creek Fossil Plant	AL	50	105.82	233	29.3	72.7	1655290	68341	83	532	278012	562
AEP	Flint Creek	AR	6138	37.84	105	8.4	23.4	91515	91515	44	242	63492	231
ENTERGY	Independence	AR	6641	121.74	404	31.6	85.2	294430	294430	157	873	204272	742
ENTERGY	White Bluff	AR	6009	105.92	103	9.4	31	253699	253699	60	334	178860	630
AZ ELEC COOP	Apache Station	AZ	160	31.09	20	4.1	9.8	4188	4188	16	72	11803	109
AZ PUB SERV	Cholla	AZ	113	83.57	48	17.5	31.1	80741	80741	46	217	70210	470
SRP	Coronado	AZ	6177	60.07	71	7.2	20.2	10594	10594	36	197	23806	348
TUCSON	Irvington	AZ	126	7.95	4	1.1	2.5	8531	8531	4	14	12683	19
SRP	Navajo	AZ	4941	179.13	91	39.3	61.7	23807	23807	142	576	130943	577
TUCSON	Springerville	AZ	8223	90.97	51	16.1	30.5	7727	7727	47	230	3906	526
Trona Operating Partners	ACE Cogeneration Plant	CA	10002	9.65	5	1	3.1	993	993	5	34	284	36
Hanford Ltd Partnership	Hanford	CA	10373	2.76	1	0.2	0.5	6407	6407	1	5	4969	15
POLARIS POWER GROUP	Mt. Poso Cogeneration Plant	CA	54626	4.76	4	0.7	2	13219	13219	4	23	6948	20
Mt Poso Cogeneration Co	Port of Stockton District Energy Facility (POSDEF)	CA	54238	3.78	2			10442	10442	2	14	5689	16
Constellation Oper Services	Rio Bravo Jasmin	CA	10768	3.39	4			57549	1174	2	8	12467	86
Constellation Oper Services	Rio Bravo Poso	CA	10769	3.38	4			57410	1172	2	8	12437	86
ArcLight Capital Partners	Stockton Cogen Company	CA	10640	5.63	4			604	604	4	19	245	25
XCEL	Arapahoe	CO	465	13.52	33	2.7	7.6	966	966	14	80	524	82
XCEL	Cameo	CO	468	3.27	3	0.8	1.4	11638	11638	2	11	7319	12
XCEL	Cherokee	CO	469	49.34	17	5	10.8	8538	8538	18	86	2550	169
XCEL	Comanche	CO	470	47.33	55	5	16	93646	93646	31	173	79409	289
TRI-STATE G&T	Craig	CO	6021	102.62	50	13.4	32.2	7102	7102	49	167	27158	210
XCEL	Hayden	CO	525	39.02	13	3.9	8.3	7868	7868	14	67	2017	141
COL SPRINGS	Martin Drake	CO	492	21.35	11	2.5	5.6	98888	98888	10	47	44716	84
TRI-STATE G&T	Nucla	CO	527	8.37	2	0.6	1.3	9516	9516	2	11	18750	44
XCEL	Pawnee	CO	6248	39.83	45	4.1	13.2	78822	78822	26	143	66838	243
PLATTE RIVER	Rawhide	CO	6761	22.95	24	2.2	7.2	1989	1989	14	78	889	108
COL SPRINGS	Ray D. Nixon	CO	8219	15.68	18	1.7	5.3	32041	32041	10	57	26469	95
XCEL	Valmont	CO	477	12.7	5	1.5	3.1	2556	2556	5	24	656	43
AES THAMES	AES Thames, Inc.	CT	10675	6.21	12	2.1	2.7	5480	5480	7	31	141	22
PSE&G	Bridgeport Harbor	CT	568	24.34	451	26.9	49.2	52352	52352	72	399	45961	72
PEPCO HOLDINGS	Edge Moor	DE	593	17.4	131	13.2	10.8	439112	439112	35	165	26950	136
NRG Indian River Ops Inc	Indian River	DE	594	42.2	485	34.4	34.7	670590	670590	94	443	63846	254
TECO	Big Bend	FL	645	93.28	522	55	95.8	21342	21342	282	1195	43197	504
NEGT	Cedar Bay Generating Co., L.P.	FL	10672	18.13	36	4.6	5.1	584396	11926	16	75	79705	125
Delta Power Co	Central Power and Lime, Inc.	FL	10333	6.5	8	1.4	1.9	3421	3421	5	24	159	48
SOUTHERN	Crist	FL	641	68.13	153	20.4	61.8	1409706	28770	55	376	308659	315
PROGRESS ENERGY	Crystal River	FL	628	149.74	972	97.9	81	13422721	273933	262	1231	730998	1541

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
GOLDEN VALLEY	Healy	AK	6288	2.14	3.4	2.6	0.8	0	20	11	6	0.6	559
SOUTHERN	Barry	AL	3	102.56	354.3	244.2	99.3	10.8	1843	702	464	41.9	7204
ALEC	Charles R. Lowman	AL	56	38.06	134.3	8.6	122.2	3.5	557	248	155	17.7	1367
TVA	Colbert Fossil Plant	AL	47	76.75	445.9	333.6	100.4	11.9	801	350	208	17	5358
SOUTHERN	Gadsden	AL	7	7.45	54.8	26.5	26.4	1.9	82	45	22	3.7	354
SOUTHERN	Gaston	AL	26	109.98	882.1	533.9	324.1	24.1	984	556	254	43	5225
SOUTHERN	Gorgas	AL	8	66.47	934.7	503.5	400.6	30.6	591	333	153	25.3	3250
SOUTHERN	Greene County	AL	10	34.62	334.8	149.7	176.8	8.4	380	169	86	10.3	2170
SOUTHERN	Miller	AL	6002	198.6	611.5	267.7	328.9	14.9	1758	596	321	27	7225
TVA	Widows Creek Fossil Plant	AL	50	105.82	296.5	150.1	138.8	7.7	1017	429	300	22.6	4586
AEP	Flint Creek	AR	6138	37.84	223.8	43.5	174.7	5.6	609	191	133	10.4	1374
ENTERGY	Independence	AR	6641	121.74	556.7	207.6	329.7	19.5	2196	678	496	38.5	4420
ENTERGY	White Bluff	AR	6009	105.92	472.5	170.5	285.5	16.5	847	292	147	12.8	3881
AZ ELEC COOP	Apache Station	AZ	160	31.09	108.6	6.9	98.8	2.8	209	66	68	4.3	840
AZ PUB SERV	Cholla	AZ	113	83.57	378.6	47.4	322.7	8.6	611	195	258	17.5	5089
SRP	Coronado	AZ	6177	60.07	338.7	21.7	308.2	8.8	527	175	107	9.3	1394
TUCSON	Irvington	AZ	126	7.95	14.3	10.9	3.3	0.1	47	13	19	1.1	0
SRP	Navajo	AZ	4941	179.13	573.3	36.7	521.7	14.9	1179	667	363	34.7	3611
TUCSON	Springerville	AZ	8223	90.97	430.7	114.3	307.4	9	631	207	240	16.6	81
Trona Operating Partners	ACE Cogeneration Plant	CA	10002	9.65	5.1	2.1	2.9	0.1	42	24	15	1.1	8
Hanford Ltd Partnership	Hanford	CA	10373	2.76	9.3	7.1	2.1	0.1	14	5	2	0.2	0
POLARIS POWER GROUP	Mt. Poso Cogeneration Plant	CA	54626	4.76	9.7	7.4	2.2	0.1	26	37	11	1	24
Mt Poso Cogeneration Co	Port of Stockton District Energy Facility (POSDEF)	CA	54238	3.78	8	6.1	1.8	0.1	16	26	6	0.6	14
Constellation Oper Services	Rio Bravo Jasmin	CA	10768	3.39	28.1	21.4	6.5	0.2	11	7	2	0.3	618
Constellation Oper Services	Rio Bravo Poso	CA	10769	3.38	28	21.4	6.4	0.2	11	7	2	0.3	617
ArcLight Capital Partners	Stockton Cogen Company	CA	10640	5.63	3.5	1.5	2	0.1	26	46	11	1.1	2
XCEL	Arapahoe	CO	465	13.52	73.2	0.9	70.2	2	200	64	42	3.4	6
XCEL	Cameo	CO	468	3.27	5.6	4.3	1.3	0	24	10	12	0.6	2
XCEL	Cherokee	CO	469	49.34	90.8	12.2	76.1	2.5	190	85	77	4.3	19
XCEL	Comanche	CO	470	47.33	188.6	143.8	43.4	1.4	434	147	79	6.6	0
TRI-STATE G&T	Craig	CO	6021	102.62	79.7	20.6	56.5	2.7	600	158	237	13.2	2001
XCEL	Hayden	CO	525	39.02	69.8	10.4	57.5	2	147	66	59	3.3	15
COL SPRINGS	Martin Drake	CO	492	21.35	34.2	26.1	7.9	0.3	111	44	39	2.3	0
TRI-STATE G&T	Nucla	CO	527	8.37	32.7	24.9	7.5	0.2	24	11	9	0.5	64
XCEL	Pawnee	CO	6248	39.83	159.3	121.4	36.6	1.2	359	122	65	5.5	0
PLATTE RIVER	Rawhide	CO	6761	22.95	89.5	3.1	84	2.5	197	68	35	3	10
COL SPRINGS	Ray D. Nixon	CO	8219	15.68	60.5	46.2	13.9	0.5	143	49	26	2.2	0
XCEL	Valmont	CO	477	12.7	21.1	3.2	17.3	0.6	54	24	22	1.2	5
AES THAMES	AES Thames, Inc.	CT	10675	6.21	3	1.3	1.7	0.1	32	28	15	1.7	8
PSE&G	Bridgeport Harbor	CT	568	24.34	54	19.3	32.8	1.9	1090	284	325	27.6	1100
PEPCO HOLDINGS	Edge Moor	DE	593	17.4	78.9	56.1	20.1	2.8	207	140	91	10.6	1923
NRG Indian River Operations Inc	Indian River	DE	594	42.2	162.9	106.4	50.9	5.7	614	358	306	27.9	3436
TECO	Big Bend	FL	645	93.28	213.9	25	187.5	1.4	1037	3325	770	124.8	1049
NEGT (to GOLDMAN SACHS IN 05)	Cedar Bay Generating Company, L.P.	FL	10672	18.13	10.1	7.7	2.3	0.1	90	71	32	4.1	757
Delta Power Co	Central Power and Lime, Inc.	FL	10333	6.5	6.8	2.8	3.8	0.1	26	23	10	1.2	8
SOUTHERN	Crist	FL	641	68.13	126.6	89.3	34.9	2.5	791	307	182	15.2	4693
PROGRESS ENERGY	Crystal River	FL	628	149.74	1092.6	742	311.8	38.9	1540	1056	671	78.7	16532

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
GAINESVILLE	Deerhaven	FL	663	14.16	35	4.6	5.6	261526	261526	16	71	15585	92
NEGT (to GOLDMAN SACHS IN 05)	Indiantown Cogeneration Facility	FL	50976	21.13	29	4.6	6	11429	11429	17	78	548	146
SOUTHERN	Lansing Smith	FL	643	24.52	77	9.8	27.3	515153	10513	24	166	111590	114
LAKELAND	McIntosh	FL	676	24.77	111	11.3	11.2	22893	22893	33	165	9579	270
JEA	Northside	FL	667	35.55	90	8.5	15.9	234555	4787	43	202	218010	192
Tampa Electric Co	Polk	FL	7242	17.22	29	3.7	6.6	13574	277	12	73	6644	85
SOUTHERN	Scholz	FL	642	5.09	18	1.9	1.7	345250	7046	6	28	26411	37
SEMINOLE	Seminole	FL	136	94.39	331	37.2	83.6	184921	184921	97	652	28461	687
JEA	St. Johns River Power Park	FL	207	94.73	200	23.7	34.9	60125	60125	74	422	35438	523
ORLANDO	Stanton Energy	FL	564	61.97	159	16.1	16.2	81814	81814	56	269	22458	458
SOUTHERN	Bowen	GA	703	220.69	1961	184.8	141	16531234	337372	472	2250	1178371	1598
SOUTHERN	Hammond	GA	708	49.33	280	22.3	19.6	4311127	87982	72	332	238324	215
SOUTHERN	Harllee Branch	GA	709	101.69	594	56.6	43.4	9002268	183720	157	754	556885	1267
SOUTHERN	Jack McDonough	GA	710	37.12	469	41	28	3122440	63723	98	469	203261	204
SOUTHERN	Kraft	GA	733	14.15	94	10	13.8	90998	90998	22	139	21868	68
SOUTHERN	McIntosh	GA	6124	7.67	42	4.6	6.6	49349	49349	10	67	11859	37
SOUTHERN	Mitchell (GA)	GA	727	5.98	28	2.8	2.3	387020	7898	8	40	32764	36
SOUTHERN	Scherer	GA	6257	262.64	411	35.4	107.9	635183	635183	206	1147	440683	1601
SOUTHERN	Wansley	GA	6052	121.36	1226	81	80.9	3593714	73341	246	1153	524749	516
SOUTHERN	Yates	GA	728	79.58	943	50.9	48.5	1798016	39302	159	814	374187	407
AES HAWAII	AES Hawaii, Inc.	HI	10673	5.29	12	0.9	2.5	8247	8247	4	22	10108	15
AMES	Ames	IA	1122	6.96	14	1.2	3.4	16825	16825	6	36	11673	42
ALLIANT	Burlington	IA	1104	13.34	90	6.4	15.3	32268	32268	27	151	22387	81
MIDAMER(BERK HATH)	Council Bluffs	IA	1082	179.05	401	32.9	94.4	393657	393657	177	985	300427	1092
ALLIANT	Dubuque	IA	1046	4.26	13	1.3	3.1	11923	11923	5	30	7231	23
CORN BELT	Earl F. Wisdom	IA	1217	1.02	4	0.5	0.7	12779	261	1	7	4147	8
CEN IA PWR COOP	Fair Station	IA	1218	2.67	14	2	7.5	76916	1570	4	31	10902	15
MIDAMER(BERK HATH)	George Neal North	IA	1091	65.06	404	28.4	67	157333	157333	119	661	109156	397
MIDAMER(BERK HATH)	George Neal South	IA	7343	47.71	113	9.3	26.4	115386	115386	49	275	80054	291
ALLIANT	Lansing	IA	1047	18.68	101	8.2	19.1	50098	50098	33	187	31837	108
MIDAMER(BERK HATH)	Louisa	IA	6664	39.04	72	6.1	18.2	2790	2790	34	192	1512	238
ALLIANT	Milton L. Kapp	IA	1048	12.23	105	7.3	16.7	29586	29586	29	163	20527	75
MUSCATINE	Muscatine	IA	1167	19.51	31	2.7	8.2	18568	18568	16	87	16265	119
ALLIANT	Ottumwa	IA	6254	44.66	115	9.3	26.2	107998	107998	49	271	74928	272
PELLA	PELLA 6	IA	1175	1.41	4	0.3	0.9	3413	3413	2	9	2368	9
ALLIANT	Prairie Creek	IA	1073	9.96	42	3.6	8.7	26405	26405	15	84	17039	57
MIDAMER(BERK HATH)	Riverside	IA	1081	7.81	29	2.2	5.9	18876	18876	11	60	13096	48
ALLIANT	SIXTH STREET (IA) 8	IA	1058	2.52	3	0.2	0.8	6097	6097	2	8	4230	15
CEDAR FALLS	Streeter Station	IA	1131	1.23	13	1.8	5.4	53762	1097	3	22	6416	5
ALLIANT	Sutherland	IA	1077	13.41	45	3.5	9.4	33141	33141	18	97	22820	81
DYNEGY MIDWEST	Baldwin	IL	889	136.99	398	31.7	87.3	331300	331300	162	900	229853	835
AMEREN ENERGY GEN	Coffeen	IL	861	60.28	282	28.7	100.5	357302	357302	94	583	95110	336
MIDWEST GEN	Crawford	IL	867	28.76	123	9.3	24.1	69555	69555	44	244	48257	175
SPRING-IL	Dallman	IL	963	20.36	92	13	49.5	44791	44791	28	208	6048	115
AMEREN ENERGY RESOURCES GENERATING CO	Duck Creek	IL	6016	5.21	16	2.4	9.8	6478	6478	6	42	1549	28
AMEREN ENERGY RESOURCES GENERATING CO	E. D. Edwards	IL	856	45.35	217	16.1	40.6	111078	111078	73	407	76092	273
MIDWEST GEN	Fisk	IL	886	16.97	93	6.8	16.9	41037	41037	30	168	28471	103

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
GAINESVILLE	Deerhaven	FL	663	14.16	89.4	57.7	29.4	2.2	82	64	34	4	1414
NEGT (to GOLDMAN SACHS IN 05)	Indiantown Cogeneration Facility	FL	50976	21.13	21.6	14.9	6.5	0.2	85	74	33	4.1	26
SOUTHERN	Lansing Smith	FL	643	24.52	85.3	42.2	40.1	3	349	132	86	7	1691
LAKELAND	McIntosh	FL	676	24.77	87.4	13.6	73.2	0.6	253	145	79	9.4	1514
JEA	Northside	FL	667	35.55	81.5	62.1	18.7	0.6	262	536	98	15.3	2825
Tampa Electric Co	Polk	FL	7242	17.22	82	2.9	78.8	0.4	144	109	31	3.5	576
SOUTHERN	Scholz	FL	642	5.09	27.5	17.7	8.9	1	36	26	13	1.6	568
SEMINOLE	Seminole	FL	136	94.39	185.2	32.7	151.3	1.2	1232	585	324	26.4	3883
JEA	St. Johns River Power Park	FL	207	94.73	186.7	26.7	158.8	1.2	787	422	178	19.7	4597
ORLANDO	Stanton Energy	FL	564	61.97	91.3	20.3	70.4	0.6	342	255	116	14.6	4030
SOUTHERN	Bowen	GA	703	220.69	799.2	517.6	249.7	32	2920	1897	1280	147.8	24022
SOUTHERN	Hammond	GA	708	49.33	129.7	85.3	39.5	4.9	461	291	166	20.1	4864
SOUTHERN	Harllee Branch	GA	709	101.69	950.2	643.5	273.5	33.3	984	662	384	47.1	11479
SOUTHERN	Jack McDonough	GA	710	37.12	101.8	36.5	61.3	4.1	611	385	276	32.1	4190
SOUTHERN	Kraft	GA	733	14.15	50.9	26.9	22.3	1.8	289	108	76	6.8	994
SOUTHERN	McIntosh	GA	6124	7.67	27.6	14.3	12.3	1	139	53	35	3.2	539
SOUTHERN	Mitchell (GA)	GA	727	5.98	26.9	17.3	8.7	0.9	52	36	19	2.4	675
SOUTHERN	Scherer	GA	6257	262.64	1000.5	472.2	491.2	37	2888	954	560	46	9535
SOUTHERN	Wansley	GA	6052	121.36	258	138.9	108.8	10.3	1786	937	649	71.5	10501
SOUTHERN	Yates	GA	728	79.58	257.5	125.3	123.2	9	1170	606	416	52.4	5584
AES HAWAII	AES Hawaii, Inc.	HI	10673	5.29	9.8	7.4	2.2	0.1	61	19	12	1.2	0
AMES	Ames	IA	1122	6.96	38.2	9.2	27.9	1.1	91	29	18	1.5	253
ALLIANT	Burlington	IA	1104	13.34	40.7	14.4	24.6	1.6	381	110	100	7.3	484
MIDAMER(BERK HATH)	Council Bluffs	IA	1082	179.05	369.9	139.7	218.5	11.7	2480	793	518	41.4	3250
ALLIANT	Dubuque	IA	1046	4.26	17.2	6.7	9.9	0.6	71	23	19	1.4	169
CORN BELT	Earl F. Wisdom	IA	1217	1.02	5.8	2.6	3	0.2	11	6	3	0.4	69
CEN IA PWR COOP	Fair Station	IA	1218	2.67	11	5.8	4.8	0.4	67	22	21	1.3	180
MIDAMER(BERK HATH)	George Neal North	IA	1091	65.06	282.3	92.5	180.3	9.6	1663	482	440	32.1	2362
MIDAMER(BERK HATH)	George Neal South	IA	7343	47.71	145.4	58.1	81.6	5.8	693	221	146	11.6	1732
ALLIANT	Lansing	IA	1047	18.68	102.4	23.4	76.4	2.6	459	138	126	8.9	696
MIDAMER(BERK HATH)	Louisa	IA	6664	39.04	213.7	2	205.7	6	483	157	97	7.8	17
ALLIANT	Milton L. Kapp	IA	1048	12.23	37.3	13.3	22.6	1.5	410	116	113	8.1	444
MUSCATINE	Muscatine	IA	1167	19.51	67.9	14.7	51.9	1.3	220	73	43	3.5	521
ALLIANT	Ottumwa	IA	6254	44.66	264.1	50.2	207.3	6.6	683	216	146	11.6	1621
PELLA	PELLA 6	IA	1175	1.41	6.5	2.3	3.9	0.2	23	7	5	0.4	51
ALLIANT	Prairie Creek	IA	1073	9.96	32.2	12	19	1.2	212	64	57	4	365
MIDAMER(BERK HATH)	Riverside	IA	1081	7.81	35.7	13	21.5	1.2	151	46	35	2.7	283
ALLIANT	SIXTH STREET (IA) 8	IA	1058	2.52	11.5	4.2	7	0.4	21	7	4	0.3	92
CEDAR FALLS	Streeter Station	IA	1131	1.23	4.4	2.3	2	0.1	48	15	21	1.2	67
ALLIANT	Sutherland	IA	1077	13.41	60.8	22.6	36.1	2.1	237	110	55	4.7	470
DYNEGY MIDWEST	Baldwin	IL	889	136.99	417.6	150.7	250.2	16.7	2265	708	498	39	4973
AMEREN ENERGY GEN	Coffeen	IL	861	60.28	190.3	123.7	64.8	1.8	1374	428	366	25.9	2667
MIDWEST GEN	Crawford	IL	867	28.76	131.5	47.9	79	4.6	613	185	146	11.1	1044
SPRING-IL	Dallman	IL	963	20.36	7.3	2.9	4.3	0.1	445	148	137	8.9	815
AMEREN ENERGY RESOURCES GENERATING CO	Duck Creek	IL	6016	5.21	3.3	1.3	2	0	90	31	25	1.7	209
AMEREN ENERGY RESOURCES GENERATING CO	E. D. Edwards	IL	856	45.35	136.4	49.4	81.5	5.5	1024	306	251	18.9	1646
MIDWEST GEN	Fisk	IL	886	16.97	77.6	28.3	46.6	2.7	424	125	106	7.9	616

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
DYNEGY MIDWEST	Havana	IL	891	34.29	71	5.9	17.3	82935	82935	33	181	57540	209
DYNEGY MIDWEST	Hennepin	IL	892	21.27	116	8.5	21	51450	51450	38	210	35695	130
AMEREN ENERGY GEN	Hutsonville	IL	863	9.5	40	3.1	7.9	22966	22966	14	80	15934	58
MIDWEST GEN	Joliet 29	IL	384	57.13	246	18.6	48	138169	138169	87	485	95860	348
MIDWEST GEN	Joliet 6	IL	874	17.23	85	6.3	15.9	41679	41679	29	160	28916	105
EEI	Joppa Steam	IL	887	84.05	228	18.3	50.9	203172	203172	94	525	141210	512
KINCAID(DOM RES)	Kincaid Generation	IL	876	67.17	75	6.8	21.9	162437	162437	43	238	112697	410
SPRING-IL	Lakeside	IL	964	3.42	7	1.1	4.8	423836	8650	3	21	13948	19
AMEREN ENERGY GEN	Meredosia	IL	864	21.1	59	6.5	24.9	134927	134927	23	144	33036	114
AMEREN ENERGY GEN	Newton	IL	6017	89.83	339	26.1	68.8	218079	218079	126	700	150720	545
MIDWEST GEN	Powerton	IL	879	89.51	172	14.3	41.9	216477	216477	79	441	150189	546
SO IL PWR COOP	Southern Illinois Power Coop	IL	976	20.19	30	4.5	19	404171	25318	13	93	44661	129
DYNEGY MIDWEST	Vermilion	IL	897	9.56	27	2.1	5.7	22880	22880	11	59	16048	56
MIDWEST GEN	Waukegan	IL	883	51.57	149	11.8	32.4	124710	124710	60	334	86523	314
MIDWEST GEN	Will County	IL	884	58.41	170	13.4	36.4	141261	141261	67	374	98006	356
DYNEGY MIDWEST	Wood River	IL	898	30.34	48	4.1	12.3	73387	73387	23	130	50915	185
VECTREN(SIGE)	A. B. Brown	IN	6137	36.32	104	13.4	27	20760	20760	34	206	10761	247
NIPSCO(NISOURCE)	Bailly	IN	995	26.16	200	14.8	31.2	26004	26004	43	237	7326	152
DUKE ENERGY INDIANA	Cayuga (IN)	IN	1001	67.9	622	72.1	158.7	5986083	122165	141	900	276499	467
OVEC	Clifty Creek	IN	983	86.36	650	31.7	48.7	2935317	59904	119	634	418048	564
AES (IPALCO)	E. W. Stout	IN	990	39.52	324	36	43.7	1235565	25216	73	425	160693	218
DUKE ENERGY INDIANA	Edwardsport	IN	1004	3.46	26	2.9	3.6	97965	1999	6	35	14062	17
VECTREN(SIGE)	F. B. Culley	IN	1012	28.18	248	26.4	30.8	34549	6467	51	297	16798	205
HOOSIER	Frank E. Ratts	IN	1043	17.55	494	46.9	46.5	313370	6395	73	424	71379	136
DUKE ENERGY INDIANA	Gibson Generating Station	IN	6113	234.52	1924	182.7	252.9	137091	137091	385	2273	73220	1758
AES (IPALCO)	H.T. Pritchard	IN	991	16.76	162	17.6	20.9	396540	8093	35	201	68160	120
HOOSIER	Merom	IN	6213	69.93	235	29.4	41.7	34001	34001	73	424	20705	362
NIPSCO(NISOURCE)	Michigan City	IN	997	27.7	364	17.3	29.4	155361	155361	61	334	44434	173
AES (IPALCO)	Petersburg	IN	994	127.13	677	79.7	104.3	44282	44282	178	1037	37641	931
DUKE ENERGY INDIANA	R. Gallagher Station	IN	1008	33.03	219	29.7	106.2	814672	16626	60	443	134740	158
NIPSCO(NISOURCE)	R.M. Schahfer	IN	6085	112.39	482	45.9	169	1789937	67361	134	881	281812	682
AEP	Rockport	IN	6166	155.97	274	28.4	70.6	534210	534210	138	738	264937	899
DOMINION	State Line	IN	981	30.73	117	8.1	19.3	58052	58052	24	138	56633	148
AEP	Tanners Creek	IN	988	54.35	230	21.3	30.2	654707	654707	73	351	74349	346
DUKE ENERGY INDIANA	Wabash River Station	IN	1010	42.81	354	37.7	46.3	1451078	29614	78	453	176785	278
DUKE ENERGY INDIANA	Wabash River Station IGCC	IN	1010	10.08	24	3	4.6	11882	242	8	48	3031	65
ALCOA (VECTRON)	Warrick Power Plant	IN	6705	19.62	208	22.2	55.4	1413451	28846	45	297	79084	147
ALCOA	Warrick Power Plant	IN	6705	28.27	251	27.4	70.3	2037390	41579	57	380	113993	212
RICHMOND	Whitewater Valley	IN	1040	5.03	142	10.4	10.6	48417	3117	18	104	6850	33
SUNFLOWER	Holcomb	KS	108	29.49	53	4.5	13.5	2107	2107	26	142	1142	180
WESTSTAR ENERGY	Jeffrey Energy Center	KS	6068	164.25	489	38.6	105.3	28889	28889	195	1082	63599	1001
KCP&L(GREAT PLAINS ENERGY)	La Cygne	KS	1241	105.41	412	34.6	104.4	227390	227390	142	818	116776	676
WESTSTAR ENERGY	Lawrence	KS	1250	39.03	191	14.2	35.8	16470	16470	64	359	20641	238
KCBPU	Nearman Creek	KS	6064	17.93	32	2.7	8.1	43362	43362	15	86	30084	109
KCBPU	Quindaro	KS	1295	12.71	17	1.5	4.7	30730	30730	9	50	21320	77
EMPIRE DISTRICT	Riverton	KS	1239	7.09	60	4.5	9.6	76789	1567	19	98	39985	42
WESTSTAR ENERGY	Tecumseh	KS	1252	16.35	75	5.6	14.3	39548	39548	26	143	27438	100
AEP	Big Sandy	KY	1353	72.88	266	31.6	31.2	8725321	178068	97	452	324270	580
LGE ENERGY (POWER GEN)	Cane Run	KY	1363	37.58	226	24.9	32.3	26687	26687	55	338	11079	248

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
DYNEGY MIDWEST	Havana	IL	891	34.29	202.8	157.2	40.6	5.1	456	147	93	7.5	1245
DYNEGY MIDWEST	Hennepin	IL	892	21.27	64.9	23.4	38.9	2.6	528	156	132	9.9	772
AMEREN ENERGY GEN	Hutsonville	IL	863	9.5	43.4	15.9	26	1.5	201	61	48	3.6	345
MIDWEST GEN	Joliet 29	IL	384	57.13	261.2	95.2	156.9	9.1	1220	368	291	22.1	2074
MIDWEST GEN	Joliet 6	IL	874	17.23	78.8	28.7	47.3	2.8	402	120	98	7.4	626
EEI	Joppa Steam	IL	887	84.05	255.9	91.8	153.9	10.2	1322	415	288	22.6	3051
KINCAID(DOM RES)	Kincaid Generation	IL	876	67.17	231.8	116.7	112.9	2.2	598	204	108	9.1	2438
SPRING-IL	Lakeside	IL	964	3.42	14.5	10.2	3.9	0.5	46	16	12	0.8	230
AMEREN ENERGY GEN	Meredosia	IL	864	21.1	85.6	42.1	40.5	3	337	110	82	6	954
AMEREN ENERGY GEN	Newton	IL	6017	89.83	272.7	98.3	163.5	10.9	1761	537	408	31.4	3261
MIDWEST GEN	Powerton	IL	879	89.51	409.3	149	246	14.3	1110	360	226	18.2	3250
SO IL PWR COOP	Southern Illinois Power Cooperative	IL	976	20.19	12.6	7.3	5.2	0.1	194	75	46	3.4	1844
DYNEGY MIDWEST	Vermilion	IL	897	9.56	5.6	3.3	2.1	0.2	147	46	33	2.6	347
MIDWEST GEN	Waukegan	IL	883	51.57	265.4	74.7	182.8	8	840	262	186	14.5	1872
MIDWEST GEN	Will County	IL	884	58.41	288.2	89.4	189.7	9.2	941	293	210	16.3	2121
DYNEGY MIDWEST	Wood River	IL	898	30.34	138.8	50.8	83.1	4.9	327	108	64	5.2	1102
VECTREN(SIGE)	A. B. Brown	IN	6137	36.32	41.5	13.4	27.1	1.1	364	181	98	10.6	1459
NIPSCO(NISOURCE)	Bailly	IN	995	26.16	29.4	7.8	21.4	0.2	401	183	126	11.2	1493
DUKE ENERGY INDIANA	Cayuga (IN)	IN	1001	67.9	350.3	232	106	12.3	1701	683	577	50.4	4577
OVEC	Clifty Creek	IN	983	86.36	326.4	166.2	148.5	11.7	1189	509	349	30	5488
AES (IPALCO)	E. W. Stout	IN	990	39.52	100.6	73.4	25.7	1.5	708	352	239	26.2	2670
DUKE ENERGY INDIANA	Edwardsport	IN	1004	3.46	13.1	6.9	5.7	0.5	59	29	19	2.1	234
VECTREN(SIGE)	F. B. Culley	IN	1012	28.18	74.6	23.9	49.8	0.9	495	243	174	18.8	1194
HOOSIER	Frank E. Ratts	IN	1043	17.55	101.7	47.7	50.5	3.6	707	315	307	30.7	1186
DUKE ENERGY INDIANA	Gibson Generating Station	IN	6113	234.52	339.7	136.5	200.4	2.7	3888	1894	1244	132.3	9952
AES (IPALCO)	H.T. Pritchard	IN	991	16.76	90.1	45.1	41.9	3.2	336	165	117	12.7	1133
HOOSIER	Merom	IN	6213	69.93	77.2	31	45.6	0.6	708	382	197	23.3	2812
NIPSCO(NISOURCE)	Michigan City	IN	997	27.7	97.8	63.2	33.7	0.9	711	249	217	16.9	1364
AES (IPALCO)	Petersburg	IN	994	127.13	296	71.2	222.7	2.1	1729	895	532	60.5	5113
DUKE ENERGY INDIANA	R. Gallagher Station	IN	1008	33.03	118.6	61.2	53.3	4.2	946	307	309	19.8	2222
NIPSCO(NISOURCE)	R.M. Schahfer	IN	6085	112.39	310.6	128.6	176.8	5.2	1936	664	530	37.7	4810
AEP	Rockport	IN	6166	155.97	674.5	278.5	372.4	23.6	1770	617	398	31.9	6215
DOMINION	State Line	IN	981	30.73	105.1	55.7	47	2.4	477	133	101	10.9	589
AEP	Tanners Creek	IN	988	54.35	259.2	152.4	97.6	9.1	562	299	195	18.6	3948
DUKE ENERGY INDIANA	Wabash River Station	IN	1010	42.81	199.7	108.4	84.2	7.1	757	377	251	27.6	2938
DUKE ENERGY INDIANA	Wabash River Station IGCC	IN	1010	10.08	62.8	2.2	60.2	0.3	80	44	20	2.5	412
ALCOA (VECTRON)	Warrick Power Plant	IN	6705	19.62	83.1	69.8	12.5	0.8	611	210	214	17.2	1313
ALCOA	Warrick Power Plant	IN	6705	28.27	205.3	122.4	77.8	5.1	783	273	265	21.5	1893
RICHMOND	Whitewater Valley	IN	1040	5.03	29.6	5	24.3	0.3	168	78	73	7.1	252
SUNFLOWER	Holcomb	KS	108	29.49	160.7	1.7	154.4	4.5	358	117	71	5.8	13
WESTSTAR ENERGY	Jeffrey Energy Center	KS	6068	164.25	476.7	46.4	427.2	3.1	2724	848	605	47.2	3549
KCP&L(GREAT PLAINS ENERGY)	La Cygne	KS	1241	105.41	423	176.9	234.6	11.5	2013	619	497	36.9	3369
WESTSTAR ENERGY	Lawrence	KS	1250	39.03	184.8	15.4	167.1	2.3	903	269	222	16.7	906
KCBPU	Nearman Creek	KS	6064	17.93	54.7	19.1	33.4	2.2	216	71	43	3.5	651
KCBPU	Quindaro	KS	1295	12.71	58.1	21.3	34.8	2	126	42	24	2	461
EMPIRE DISTRICT	Riverton	KS	1239	7.09	31.3	12.3	17.9	1.1	215	163	68	6.7	220
WESTSTAR ENERGY	Tecumseh	KS	1252	16.35	74.8	27.3	44.8	2.6	361	108	87	6.6	594
AEP	Big Sandy	KY	1353	72.88	289.8	205.3	73	11.6	545	405	220	26.6	7915
LGE ENERGY (POWER GEN)	Cane Run	KY	1363	37.58	87.1	12.6	73.9	0.6	585	276	177	17.9	1556

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
WEST KY ENG (to BIG RIVERS in 2007)	Coleman	KY	1381	33.08	611	50.7	32.5	44751	44751	111	533	13192	237
EAST KY PWR COOP	Cooper	KY	1384	20.31	441	28.3	20.8	1340942	27366	65	312	99489	224
WEST KY ENG (to BIG RIVERS in 2007)	D. B. Wilson	KY	6823	35.53	89	9.7	11.2	25185	25185	39	179	15480	219
EAST KY PWR COOP	Dale	KY	1385	12.08	165	14.3	9.6	1066341	21762	33	160	66164	169
LGE ENERGY (POWER GEN)	E. W. Brown	KY	1355	40.68	248	23.1	17.5	3259617	66523	63	302	222793	479
DUKE ENERGY OHIO (to UNION LIGHT HEAT & POWER)	East Bend	KY	6018	40.15	73	8.3	14.3	45709	45709	26	168	11992	316
OWENSBORO	Elmer Smith	KY	1374	24.22	215	20.3	25.3	8677	8677	43	288	7088	271
LGE ENERGY (POWER GEN)	Ghent	KY	1356	126.9	783	75.6	87.3	3722317	147936	209	1071	249508	999
LGE ENERGY (POWER GEN)	Green River	KY	1357	11.64	130	12.6	23	367484	7500	25	170	46948	75
EAST KY PWR COOP	H.L. Spurlock	KY	6041	80.26	526	50.7	54.4	1717161	86610	137	662	122445	629
HENDERSON	Henderson One	KY	1372	0.08	2	0.2	0.2	2947	60	0.13	2	320	1
WEST KY ENG (to BIG RIVERS in 2007)	Henderson Two	KY	1382	17.23	195	17.3	12	23306	23306	42	202	6870	124
LGE ENERGY (POWER GEN)	Mill Creek	KY	1364	111.39	639	62.8	92.5	156918	156918	150	989	32556	922
TVA	Paradise Fossil Plant	KY	1378	121.82	958	91.7	116.6	172947	172947	200	1337	35653	974
WEST KY ENG (to BIG RIVERS in 2007)	R. D. Green	KY	6639	38.82	190	18.8	17.2	37320	37320	60	281	16349	255
WEST KY ENG (to BIG RIVERS in 2007)	Robert Reid	KY	1383	2.97	24	2.2	1.6	226389	4620	6	28	16264	21
TVA	Shawnee Fossil Plant	KY	1379	95.88	184	31	55.5	177307	177307	92	480	182367	401
LGE ENERGY (POWER GEN)	Trimble County	KY	6071	37.09	231	15.5	23.4	36455	36455	48	268	11045	351
LGE ENERGY (POWER GEN)	Tyrone	KY	1361	5.02	31	2.9	2.3	441929	9019	8	39	27485	24
LA GEN(NRG)	Big Cajun 2	LA	6055	127.15	247	20.7	61.2	307503	307503	116	644	213343	775
CLECO	Dolet Hills Power Station	LA	51	42.54	93	12.8	23.1	10379	10379	42	246	17722	378
Entergy Gulf States Inc	R.S. Nelson	LA	1393	61.43	371	29.2	65	662352	13517	133	673	349857	350
CLECO	Rodemacher Power Station Unit #2	LA	6190	38.55	41	3.7	12.2	93222	93222	24	132	64676	235
DOMINION	Brayton Point	MA	1619	78.58	241	29.3	45.9	334918	334918	76	472	133455	521
NU (Sell to Energy Capital Partners end of 2006)	Mount Tom	MA	1606	11.37	150	14.6	18.1	48255	48255	28	176	17575	81
DOMINION	Salem Harbor	MA	1626	19.7	87	9.5	13.9	77714	77714	22	142	30612	145
NRG Somerset Power LLC	Somerset	MA	1613	8.08	46	4.5	7.2	38471	38471	11	70	13578	33
AES WARRIOR	AES Warrior Run	MD	10678	15.13	29	1.8	3	145146	2962	10	57	74842	164
CONSTELLATION PWR SOURCE	Brandon Shores	MD	602	85.92	230	37.7	45	6739520	137541	119	527	273702	664
CONSTELLATION PWR SOURCE	C.P. Crane	MD	1552	21.15	290	12.5	13.3	634610	12951	40	208	86533	165
MIRANT-MID-ATLANTIC	Chalk Point	MD	1571	41.4	267	16.5	19.6	3366660	68707	56	276	153003	397
MIRANT-MID-ATLANTIC	Dickerson	MD	1572	30.85	168	11.6	13.5	3202481	65357	42	203	109944	316
CONSTELLATION PWR SOURCE	H.A. Wagner	MD	1554	29.84	44	6.4	8.7	2765304	56435	24	111	102216	225
MIRANT-MID-ATLANTIC	Morgantown	MD	1573	65.6	1317	61.1	67	1746967	35652	208	1133	323201	583

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
WEST KY ENG (to BIG RIVERS in 2007)	Coleman	KY	1381	33.08	72	11.8	59.8	0.5	695	423	340	38.4	2223
EAST KY PWR COOP	Cooper	KY	1384	20.31	167.7	107	54.8	5.9	407	247	196	22.5	2169
WEST KY ENG (to BIG RIVERS in 2007)	D. B. Wilson	KY	6823	35.53	34.9	14	20.6	0.3	209	379	81	12.2	1249
EAST KY PWR COOP	Dale	KY	1385	12.08	136.3	92	39.9	4.4	209	131	96	11.1	1364
LGE ENERGY (POWER GEN)	E. W. Brown	KY	1355	40.68	337.4	223.8	101.5	12	394	264	157	19.1	4592
DUKE ENERGY OHIO (to UNION LIGHT HEAT & POWER)	East Bend	KY	6018	40.15	88.2	5.6	80.3	2.3	305	142	68	6.1	1783
OWENSBORO	Elmer Smith	KY	1374	24.22	67.2	27	39.6	0.5	526	208	163	12.7	1049
LGE ENERGY (POWER GEN)	Ghent	KY	1356	126.9	560.4	331.7	215.2	13.5	1586	866	568	56.9	9599
LGE ENERGY (POWER GEN)	Green River	KY	1357	11.64	64.5	32.6	29.9	1.9	322	119	107	7.7	834
EAST KY PWR COOP	H.L. Spurlock	KY	6041	80.26	231.5	108.7	118.7	4.1	881	566	353	38.9	5214
HENDERSON	Henderson One	KY	1372	0.08	0.5	0.3	0.2	0.01	4	1	1	0.04	6
WEST KY ENG (to BIG RIVERS in 2007)	Henderson Two	KY	1382	17.23	12.5	5	7.4	0.1	264	168	116	13.7	1158
LGE ENERGY (POWER GEN)	Mill Creek	KY	1364	111.39	166.1	40.4	124.6	1.2	1805	747	511	41.3	4917
TVA	Paradise Fossil Plant	KY	1378	121.82	94.8	38.1	55.9	0.8	2442	978	737	57.8	5279
WEST KY ENG (to BIG RIVERS in 2007)	R. D. Green	KY	6639	38.82	82.5	12.8	69.1	0.5	348	448	141	19	1852
WEST KY ENG (to BIG RIVERS in 2007)	Robert Reid	KY	1383	2.97	16	10.3	5.1	0.6	37	24	15	1.8	335
TVA	Shawnee Fossil Plant	KY	1379	95.88	221.2	167	52.4	1.7	1079	401	442	24.9	510
LGE ENERGY (POWER GEN)	Trimble County	KY	6071	37.09	46.8	18.8	27.6	0.4	447	215	127	11.4	2159
LGE ENERGY (POWER GEN)	Tyrone	KY	1361	5.02	18.2	12.3	5.2	0.6	52	35	20	2.5	567
LA GEN(NRG)	Big Cajun 2	LA	6055	127.15	581.4	211.1	349.9	20.3	1621	525	327	26.5	4616
CLECO	Dolet Hills Power Station	LA	51	42.54	176.1	17.8	157.2	1.1	958	180	118	14.2	7638
Entergy Gulf States Inc	R.S. Nelson	LA	1393	61.43	313.2	88.7	215.8	8.7	1480	1174	433	45.1	1919
CLECO	Rodemacher Power Station Unit #2	LA	6190	38.55	228	45.2	177.1	5.7	332	114	59	5	1399
DOMINION	Brayton Point	MA	1619	78.58	277.9	154.5	116.8	6.6	978	393	248	21.4	4929
NU (Sell to Energy Capital Partners end of 2006)	Mount Tom	MA	1606	11.37	45.7	29	16.3	0.4	366	129	110	9.3	799
DOMINION	Salem Harbor	MA	1626	19.7	40.6	31.1	8.1	1.4	295	114	74	6.6	1374
NRG Somerset Power LLC	Somerset	MA	1613	8.08	9.2	7	1.8	0.3	158	55	39	3.5	488
AES WARRIOR	AES Warrior Run	MD	10678	15.13	61.7	47.1	14.2	0.5	43	46	18	1.8	1323
CONSTELLATION PWR SOURCE	Brandon Shores	MD	602	85.92	644	499.1	128.8	16.1	549	466	271	30.5	8880
CONSTELLATION PWR SOURCE	C.P. Crane	MD	1552	21.15	13	9.9	3	0.1	294	165	116	10.4	2885
MIRANT-M ID-ATLANTIC	Chalk Point	MD	1571	41.4	297.7	200.2	87.1	10.4	353	236	142	14.1	4193
MIRANT-M ID-ATLANTIC	Dickerson	MD	1572	30.85	237.1	166.6	62.2	8.3	283	166	94	9.5	3493
CONSTELLATION PWR SOURCE	H.A. Wagner	MD	1554	29.84	123.4	104.4	16.9	2.1	136	104	47	5.5	3083
MIRANT-M ID-ATLANTIC	Morgantown	MD	1573	65.6	291.7	154.5	125.5	11.7	867	739	576	47.5	5439

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
ALLEGHENY	RP Smith	MD	1570	7.35	142	4.8	5.2	393191	8024	16	84	33938	94
Rumford Cogeneration Co	Rumford Cogeneration	ME	10495	5.02	16	1.8	2.9	32281	32281	5	31	7758	24
CMS	B.C. Cobb	MI	1695	22.26	193	13.6	22.8	135704	135704	37	198	38431	132
DTE ENERGY	Belle River Power Plant	MI	6034	65	172	12.5	31.9	134513	134513	41	232	119790	351
CMS	Dan E. Karn	MI	1702	36.99	81	6.6	18.8	90531	90531	35	196	62073	223
LANSING	Eckert Station	MI	1831	20.43	85	6.4	16.5	49406	49406	30	167	34278	125
MI SO CEN	Endicott	MI	4259	5.79	28	1.4	2.1	7292	7292	4	26	2480	118
LANSING	Erikcson	MI	1832	13.15	14	1.3	4.2	31796	31796	8	45	22060	80
DTE ENERGY	Harbor Beach Power Plant	MI	1731	0.89	7	1	1	77319	1578	2	11	2772	6
CMS	J.C. Weadock	MI	1720	18.05	102	10.4	12.9	246183	246183	30	145	26733	97
CMS	J.H. Campbell	MI	1710	79.81	103	11.4	25.2	477686	477686	56	292	128355	479
CMS	J.R. Whiting	MI	1723	26.26	290	22.6	34.4	158571	158571	71	368	42106	161
HOLLAND	James De Young	MI	1830	1.69	11	0.8	0.9	23940	23940	3	13	2181	10
GRAND HAVEN	JB Sims	MI	1825	4.95	60	2.1	2.6	7718	7718	7	40	1675	98
DTE ENERGY	Monroe Power Plant	MI	1733	167.55	680	67.1	80.2	2788903	2788903	222	1102	279467	1495
WE ENERGIES	Presque Isle	MI	1769	40.94	73	7.8	16.9	128179	128179	29	151	78907	185
DTE ENERGY	River Rouge Power Plant	MI	1740	28.77	36	5.1	9.3	292673	292673	22	108	40648	192
MARQUETTE	Shiras	MI	1843	4.13	31	2	4.2	252	252	5	29	176	20
DTE ENERGY	St Clair Power Plant	MI	1743	67.56	422	22.5	44.4	312651	312651	67	374	120329	352
TES Filer City Station LP	TES Filer City Station	MI	50835	6.29	20	1.5	1.9	2224	2224	6	26	234	47
DTE ENERGY	Trenton Channel Power Plant	MI	1745	33.76	227	17.8	21.1	356186	356186	56	284	56869	349
WYANDOTTE	WYANDOTTE 7&8	MI	1866	4.12	31	2.2	2.5	322817	6588	7	32	15756	26
XCEL	Allen S. King	MN	1915	7.78	37	2.7	7	15391	15391	13	70	13051	47
XCEL	Black Dog	MN	1904	15.86	55	4.3	11.5	38348	38348	21	117	26605	97
ALLETE(MIN PWR)	Clay Boswell	MN	1893	73.3	724	43.5	87.1	19986	19986	104	590	44652	389
XCEL	High Bridge	MN	1912	8.14	33	2.5	6.5	19693	19693	12	66	13663	50
OTTER TAIL	Hoot Lake	MN	1943	10.73	92	5.8	12	22112	22112	15	82	19774	52
ALLETE(MIN PWR)	Laskin Energy Center	MN	1891	8.59	69	4.3	9.2	1287	1287	11	63	3653	41
AUSTIN-MN	NE Station	MN	1961	1.08	5	0.4	0.9	2616	2616	2	9	1815	7
XCEL	Riverside Generating Plant	MN	1927	23.8	62	5	13.7	34882	34882	26	144	23914	144
XCEL	Sherburne County Plant	MN	6090	164.52	355	27.1	73.3	21178	21178	109	611	47569	872
ROCHESTER	Silver Lake	MN	2008	2.51	57	5.5	12.3	146295	2986	10	60	11311	34
ALLETE(MIN PWR)	Taconite Harbor	MN	10075	17.83	119	7.7	16.7	36742	36742	20	116	32858	86
EMPIRE DISTRICT	Asbury	MO	2076	11	82	7.6	24.4	370812	7568	23	142	55369	69
INDEPENDENCE	Blue Valley	MO	2132	1.85	6	0.9	3.6	104934	2142	2	16	7534	13
CEN ELEC PWR COOP	Chamois	MO	2169	4.29	29	2.8	9.1	47911	978	8	52	21433	24
KCP&L(GREAT PLAINS ENERGY)	Hawthorn	MO	2079	38.21	41	3.7	12.2	2730	2730	24	132	1479	233
KCP&L(GREAT PLAINS ENERGY)	Iatan	MO	6065	42.06	104	8.5	24	101721	101721	45	250	70573	256
SPRING-MO	James River Power Station	MO	2161	17.81	99	7.2	17.9	50871	50871	32	178	29883	88
AMEREN-UE	Labadie	MO	2103	189.31	470	38.1	107.7	465453	465453	201	1119	317652	1134
AQUILA(GREAT PLAINS ENERGY)	Lake Road Plant	MO	2098	8.3	17	1.6	4.6	26211	26211	8	47	13089	38
AMEREN-UE	Meramec	MO	2104	63.68	99	8.5	26	154793	154793	50	276	106853	386
KCP&L(GREAT PLAINS ENERGY)	Montrose	MO	2080	33.41	257	18.1	42.2	80799	80799	74	414	56058	204
ASSOCIATED	New Madrid	MO	2167	76.61	342	25.8	66.1	185277	185277	120	666	128543	467
AMEREN-UE	Rush Island	MO	6155	71.24	105	9.1	28.1	172292	172292	54	300	119534	434
AQUILA(GREAT PLAINS ENERGY)	Sibley	MO	2094	32.6	43	4.2	12.7	98206	98206	23	135	52084	163
SIKESTON	Sikeston	MO	6768	21.89	40	3.3	10	3850	3850	19	106	8477	133

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
ALLEGHENY	RP Smith	MD	1570	7.35	70.2	43	24.8	2.5	102	65	50	4.2	631
Rumford Cogeneration Co	Rumford Cogeneration	ME	10495	5.02	23.4	10.7	12.1	0.6	63	25	14	1.3	353
CMS	B.C. Cobb	MI	1695	22.26	65.8	31.8	31.3	2.6	526	167	143	14.3	1129
DTE ENERGY	Belle River Power Plant	MI	6034	65	263.6	93.6	160.7	9.2	803	232	158	17.5	2299
CMS	Dan E. Karn	MI	1702	36.99	111.4	40.3	66.6	4.5	494	158	104	8.3	1343
LANSING	Eckert Station	MI	1831	20.43	93.4	34.2	55.9	3.3	420	127	100	7.6	742
MI SO CEN	Endicott	MI	4259	5.79	35.9	5.9	29.8	0.2	46	28	10	1	321
LANSING	Erikcson	MI	1832	13.15	60.1	22	36	2.1	114	39	20	1.7	477
DTE ENERGY	Harbor Beach Power Plant	MI	1731	0.89	3	2	0.9	0.1	11	9	7	0.7	91
CMS	J.C. Weadock	MI	1720	18.05	48.3	29	17.4	1.9	262	124	86	9.2	1440
CMS	J.H. Campbell	MI	1710	79.81	265.3	127.6	127.5	10.2	644	260	130	12.6	3951
CMS	J.R. Whiting	MI	1723	26.26	80.3	38.7	38.4	3.2	797	270	249	20.5	1357
HOLLAND	James De Young	MI	1830	1.69	7.5	4.6	2.6	0.3	18	10	7	0.6	170
GRAND HAVEN	JB Sims	MI	1825	4.95	28.4	4.8	23.4	0.2	58	34	23	2	237
DTE ENERGY	Monroe Power Plant	MI	1733	167.55	747.5	463.3	254.3	29.9	1936	954	557	61	12721
WE ENERGIES	Presque Isle	MI	1769	40.94	56.4	34.3	20.8	1.3	399	139	104	8.6	446
DTE ENERGY	River Rouge Power Plant	MI	1740	28.77	117.4	65.4	47.6	4.4	200	98	48	5	1863
MARQUETTE	Shiras	MI	1843	4.13	18.3	0	17.7	0.5	101	27	25	2.5	2
DTE ENERGY	St Clair Power Plant	MI	1743	67.56	264	121.2	133.5	9.2	1071	341	267	27.1	2949
TES Filer City Station LP	TES Filer City Station	MI	50835	6.29	14.6	3.1	11.1	0.4	41	37	12	1.5	6
DTE ENERGY	Trenton Channel Power Plant	MI	1745	33.76	174.6	98.2	69.4	7	513	236	157	16	2407
WYANDOTTE	WYANDOTTE 7&8	MI	1866	4.12	25.6	16.4	8.5	0.6	39	27	19	1.8	386
XCEL	Allen S. King	MN	1915	7.78	31.1	21.5	9.3	0.2	176	53	43	3.2	0
XCEL	Black Dog	MN	1904	15.86	72.5	26.5	43.5	2.5	296	91	67	5.2	576
ALLETE(MIN PWR)	Clay Boswell	MN	1893	73.3	349.4	47.1	295.5	6.9	2038	520	537	53.3	1345
XCEL	High Bridge	MN	1912	8.14	37.2	13.6	22.3	1.3	166	50	39	3	296
OTTER TAIL	Hoot Lake	MN	1943	10.73	38.6	13.6	23.7	1.4	285	74	71	7.2	380
ALLETE(MIN PWR)	Laskin Energy Center	MN	1891	8.59	32.2	1.6	30.2	0.3	218	57	54	5.5	181
AUSTIN-MN	NE Station	MN	1961	1.08	4.9	2	2.8	0.2	24	7	6	0.4	39
XCEL	Riverside Generating Plant	MN	1927	23.8	115.4	24.2	87.5	3.7	352	165	79	6.7	489
XCEL	Sherburne County Plant	MN	6090	164.52	720.9	23.1	685.8	12	1884	571	363	37.7	2373
ROCHESTER	Silver Lake	MN	2008	2.51	25.3	15.6	8.8	0.9	115	41	48	3.7	204
ALLETE(MIN PWR)	Taconite Harbor	MN	10075	17.83	83	15.2	65.8	2.1	401	106	95	9.9	631
EMPIRE DISTRICT	Asbury	MO	2076	11	51.5	27	22.8	1.8	337	101	98	6.8	477
INDEPENDENCE	Blue Valley	MO	2132	1.85	9.9	6.1	3.5	0.3	33	11	9	0.6	124
CEN ELEC PWR COOP	Chamois	MO	2169	4.29	18.4	7.1	10.6	0.6	123	37	35	2.4	191
KCP&L(GREAT PLAINS ENG)	Hawthorn	MO	2079	38.21	208.9	144.7	62.7	1.6	333	114	59	5	17
KCP&L(GREAT PLAINS ENERGY)	Iatan	MO	6065	42.06	192.3	69.7	115.9	6.7	629	199	134	10.6	1527
SPRING-MO	James River Power Station	MO	2161	17.81	65.8	25.5	38.1	2.3	449	132	113	8.4	647
AMEREN-UE	Labadie	MO	2103	189.31	567	204.6	339.8	22.7	2817	893	600	47.6	6873
AQUILA(GREAT PLAINS ENERGY)	Lake Road Plant	MO	2098	8.3	28.6	11.7	15.9	1	107	36	26	2	358
AMEREN-UE	Meramec	MO	2104	63.68	289.6	105.6	173.9	10.1	695	229	135	11.1	2312
KCP&L(GREAT PLAINS ENERGY)	Montrose	MO	2080	33.41	101.8	36.5	61.3	4.1	1042	298	280	20.4	1213
ASSOCIATED	New Madrid	MO	2167	76.61	264.4	132.7	129.2	2.5	1677	504	403	30.5	2781
AMEREN-UE	Rush Island	MO	6155	71.24	217.2	77.3	131.2	8.7	754	250	144	11.9	2586
AQUILA(GREAT PLAINS ENERGY)	Sibley	MO	2094	32.6	122.4	49.1	69	4.3	308	109	67	5.2	1378
SIKESTON	Sikeston	MO	6768	21.89	63.1	6.2	56.4	0.4	266	87	53	4.3	473

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
AMEREN-UE	Sioux	MO	2107	66.27	119	13.4	49.7	1765637	36033	53	329	328636	406
SPRING-MO	Southwest Power Station	MO	6195	14.62	46	3.6	9.8	2633	2633	18	101	5659	87
ASSOCIATED	Thomas Hill	MO	2168	72.7	192	15.5	43.3	175816	175816	81	449	121979	443
SOUTHERN	Jack Watson	MS	2049	48.31	293	31.6	44.6	310655	310655	71	453	74655	232
SO MISS ELEC PWR	R. D. Morrow, Sr. Generating plant	MS	6061	28.35	132	12	10.2	43887	43887	38	178	10646	189
Choctaw Generating LP	Red Hills	MS	55076	34.68	64	4.6	5.3	414559	414559	22	134	79632	253
SOUTHERN	Victor J. Daniel	MS	6073	70.81	174	23.9	39.2	392559	392559	64	380	135267	305
PPL GLOBAL	Colstrip	MT	6076	170.61	601	42.1	102.2	13753	13753	129	732	72564	998
Rosebud Operating Services Inc	Colstrip Energy Limited Partnership	MT	10784	4.21	1	0.1	0.5	14552	297	1	4	24607	48
ROCKY MOUNTAIN POWER	HARDIN GENERATING	MT	55749	9.29	18	1.4	3.7	566	566	5	27	395	45
PPL GLOBAL	J.E. Corette	MT	2187	12.66	188	12.1	25.4	30630	30630	43	241	21251	77
MDU	Lewis & Clark	MT	6089	4.61	37	2.3	4.9	1411	1411	6	34	1960	42
PROGRESS ENERGY	Asheville	NC	2706	24.29	110	9.8	8.4	42535	42535	30	144	9177	183
DUKE ENERGY CAROLINAS	Belews Creek	NC	8042	136.29	544	64.4	71.4	5716089	215144	198	893	262870	959
DUKE ENERGY CAROLINAS	Buck	NC	2720	19	49	6.9	8.2	397551	397551	22	102	22256	105
PROGRESS ENERGY	Cape Fear	NC	2708	22.01	176	19.6	17.5	2331988	47592	51	233	93111	169
DUKE ENERGY CAROLINAS	Cliffside	NC	2721	41.27	158	18.2	17.5	3474093	70900	55	257	187692	269
Goldman Sachs	Cogentrix Roxboro	NC	10379	2.45	10	0.6	0.7	7029	143	3	12	10219	8
Goldman Sachs	Cogentrix Southport	NC	10378	4.98	19	1.9	1.6	179483	3663	6	29	27258	56
DUKE ENERGY CAROLINAS	Dan River	NC	2723	11.93	111	10.7	8.3	1276553	26052	27	126	59210	84
Goldman Sachs	Dwayne Collier Battle Cogeneration	NC	10384	11.5	33	5.5	6.5	6331	6331	17	75	262	78
NORTH CAROLINA POWER HOLDINGS	Elizabethtown	NC	10380	0.24	1	0.1	0.1	687	14	0.14	1	999	1
DUKE ENERGY CAROLINAS	G.G. Allen	NC	2718	69.35	229	22.7	25	93829	93829	78	360	21174	477
PROGRESS ENERGY	L V Sutton	NC	2713	33.8	336	33.1	31.9	2280641	46544	78	400	165025	267
PROGRESS ENERGY	Lee	NC	2709	24.14	97	15.3	17.1	1781042	36348	44	195	75537	242
NORTH CAROLINA POWER HOLDINGS	Lumberton	NC	10382	0.29	1	0.1	0.1	829	17	0.17	2	1205	1
DUKE ENERGY CAROLINAS	Marshall	NC	2727	138.99	757	59.1	64.6	166985	166985	201	956	38578	1198
PROGRESS ENERGY	Mayo	NC	6250	48.49	327	32.9	35.2	929266	929266	97	442	51727	330
DUKE ENERGY CAROLINAS	Riverbend	NC	2732	23.73	73	10.3	11.4	2065322	42149	32	145	87162	160
PROGRESS ENERGY	Roxboro	NC	2712	158.06	288	124.6	122.7	259579	259579	338	1532	42985	1208
PROGRESS ENERGY	W H Weatherspoon	NC	2716	11.49	111	10	7.2	1066281	21761	25	122	62931	165
LG&E Power Services	Westmoreland LG&E Partners Roanoke Valley 1	NC	54035	10.73	12	1.4	1.5	5990	5990	6	28	428	68
LG&E Power Services	Westmoreland-LG&E Partners Roanoke Valley II	NC	54755	3.4	8	0.8	0.8	1889	1889	3	14	136	21
BASIN ELECTRIC	Antelope Valley Station	ND	6469	68.53	228	10.1	27.7	5239	5239	35	218	1434	488
GREAT RIVER ENG	Coal Creek	ND	6030	95.74	87	4.5	15.5	18159	18159	21	131	20030	945
MDU	Coyote	ND	8222	34.54	138	6	15.9	3411	3411	20	124	723	332
BASIN ELECTRIC	Leland Olds Station	ND	2817	51.37	120	5.6	16.4	541849	11058	21	134	157874	362

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
AMEREN-UE	Sioux	MO	2107	66.27	203	99.9	95	8.1	760	266	165	12.8	3020
SPRING-MO	Southwest Power Station	MO	6195	14.62	40.9	4.1	36.5	0.3	254	79	57	4.4	316
ASSOCIATED	Thomas Hill	MO	2168	72.7	332.4	121.6	199.2	11.6	1129	356	243	19.2	2639
SOUTHERN	Jack Watson	MS	2049	48.31	140	73.2	61.6	5.2	940	355	242	21.7	3393
SO MISS ELEC PWR	R. D. Morrow, Sr. Generating plant	MS	6061	28.35	66.9	4.3	60.9	1.7	239	160	85	10.6	1786
Choctaw Generating LP	Red Hills	MS	55076	34.68	90.2	68.8	20.8	0.7	175	108	37	6.8	0
SOUTHERN	Victor J. Daniel	MS	6073	70.81	152.4	72.6	73.7	6.1	804	321	243	17.8	3517
PPL GLOBAL	Colstrip	MT	6076	170.61	778.7	38.9	731.9	7.8	2532	712	528	57.4	3593
Rosebud Operating Services Inc	Colstrip Energy Limited Partnership	MT	10784	4.21	30.2	23	6.9	0.2	14	5	2	0.2	203
ROCKY MOUNTAIN POWER	HARDIN GENERATING	MT	55749	9.29	42	29.1	12.6	0.3	94	28	17	2	4
PPL GLOBAL	J.E. Corette	MT	2187	12.66	38.6	13.7	23.4	1.5	605	163	187	12.9	460
MDU	Lewis & Clark	MT	6089	4.61	32.4	1.6	30.5	0.3	117	31	29	2.9	97
PROGRESS ENERGY	Asheville	NC	2706	24.29	12.6	5.1	7.4	0.1	191	130	68	8.5	1582
DUKE ENERGY CAROLINAS	Belews Creek	NC	8042	136.29	479.3	317.9	142.2	19.2	1010	783	462	53.2	11218
DUKE ENERGY CAROLINAS	Buck	NC	2720	19	102.2	75.4	24.2	2.6	126	92	49	5.7	1940
PROGRESS ENERGY	Cape Fear	NC	2708	22.01	47.4	36.3	9.5	1.7	275	193	136	15.2	2370
DUKE ENERGY CAROLINAS	Cliffside	NC	2721	41.27	170.2	141.9	26	2.3	313	230	126	15.2	4499
Goldman Sachs	Cogentrix Roxboro	NC	10379	2.45	4.8	3.6	1.1	0	18	10	5	0.7	52
Goldman Sachs	Cogentrix Southport	NC	10378	4.98	1.7	1.3	0.4	0	38	26	13	1.7	171
DUKE ENERGY CAROLINAS	Dan River	NC	2723	11.93	74.2	52.2	20	2.1	159	105	73	8.4	1322
Goldman Sachs	Dwayne Collier Battle Cogeneration	NC	10384	11.5	9.8	2.7	6.9	0.3	78	66	40	4.4	14
NORTH CAROLINA POWER HOLDINGS	Elizabethtown	NC	10380	0.24	0.5	0.4	0.1	0	2	1	1	0.1	5
DUKE ENERGY CAROLINAS	G.G. Allen	NC	2718	69.35	84	21.3	62.1	0.6	465	327	167	20.4	6953
PROGRESS ENERGY	L V Sutton	NC	2713	33.8	133.8	90.4	39.6	3.9	632	320	234	24.7	3315
PROGRESS ENERGY	Lee	NC	2709	24.14	141.2	91.1	45.1	5	201	165	110	11.9	2489
NORTH CAROLINA POWER HOLDINGS	Lumberton	NC	10382	0.29	0.6	0.4	0.1	0	2	1	1	0.1	6
DUKE ENERGY CAROLINAS	Marshall	NC	2727	138.99	125.9	50.6	74.3	1	1294	795	458	48.3	9288
PROGRESS ENERGY	Mayo	NC	6250	48.49	320.2	248.1	64	8	534	360	245	25.6	5159
DUKE ENERGY CAROLINAS	Riverbend	NC	2732	23.73	154.8	120	31	3.9	161	129	73	8.5	2501
PROGRESS ENERGY	Roxboro	NC	2712	158.06	140.9	30.6	107.8	2.5	1755	1274	883	96.5	15119
PROGRESS ENERGY	W H Weatherspoon	NC	2716	11.49	123.6	84.5	34.7	4.3	159	102	68	8	1297
LG&E Power Services	Westmoreland LG&E Partners Roanoke Valley 1	NC	54035	10.73	9.5	4	5.3	0.2	36	28	10	1.4	14
LG&E Power Services	Westmoreland-LG&E Partners Roanoke Valley II	NC	54755	3.4	3	1.3	1.7	0.1	18	13	6	0.8	5
BASIN ELECTRIC	Antelope Valley Station	ND	6469	68.53	468.2	0	455.1	13.1	1063	168	136	12.9	36
GREAT RIVER ENG	Coal Creek	ND	6030	95.74	466.2	42.3	420.9	3	636	113	62	6.5	2495
MDU	Coyote	ND	8222	34.54	287	5.9	273.1	8	604	94	80	7.5	18
BASIN ELECTRIC	Leland Olds Station	ND	2817	51.37	271.2	92.5	169.3	9.5	636	107	77	7.4	2218

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
MINNKOTA	Milton R. Young	ND	2823	51.14	117	5.4	15.9	312358	15446	20	128	60761	591
MDU	R.M. Heskett Station	ND	2790	6.27	18	0.8	2.3	19598	19598	3	18	5941	57
GREAT RIVER ENG	Stanton Station	ND	2824	15.24	50	3.5	8.7	22266	22266	11	62	19857	73
NPPD	Gerald Gentlemen Station	NE	6077	92.48	101	9.2	29.8	182994	182994	58	323	155172	564
FREEMONT	Lon Wright	NE	2240	6.71	50	3.5	8.2	16238	16238	15	81	11266	41
OPPD	Nebraska City	NE	6096	43.3	104	8.5	24.1	104709	104709	45	251	72646	264
OPPD	North Omaha	NE	2291	37.1	91	7.4	21	89717	89717	39	218	62244	226
GRAND ISLAND	Platte	NE	59	6.77	14	1.2	3.4	16380	16380	6	36	11364	41
NPPD	Sheldon	NE	2277	17.42	21	1.9	6	34473	34473	12	65	29232	106
HASTINGS	Whelan Energy Center	NE	60	6.24	7	0.6	2	15099	15099	4	22	10476	38
NU	Merrimack	NH	2364	35.99	184	12	82.7	1702766	34750	58	318	159926	232
NU	Schiller	NH	2367	13.29	120	12.3	16.2	85448	85448	25	161	20534	64
PEPCO HOLDINGS (to RC Cape May Holdings - 1 Q-2007)	B L England	NJ	2378	15.78	160	8.6	10	441693	20118	28	144	29642	150
NEGT (to GOLDMAN SACHS IN 05)	Carneys Point Generating Plant	NJ	10566	21.47	170	6.3	7.8	11513	11513	23	129	706	190
PEPCO HOLDINGS	Deepwater	NJ	2384	5.02	11	1.5	1.8	159001	3245	5	24	19546	36
PSE&G	Hudson	NJ	2403	22.11	243	31.3	31.8	536879	536879	72	333	24228	73
NEGT (to GOLDMAN SACHS IN 05)	Logan Generating Plant	NJ	10043	15.11	34	5.8	7.2	13337	13337	19	84	344	53
PSE&G	Mercer	NJ	2408	31.02	307	37.3	36.4	769821	769821	85	391	33166	109
TRI-STATE G&T	Escalante	NM	87	20.44	8	3.1	5.8	4501	4501	9	41	9065	116
AZ PUB SERV	Four Corners	NM	2442	148.87	75	29.1	52.4	19056	19056	78	368	66024	1269
PSNM	San Juan	NM	2451	125.5	50	19.9	37.2	16065	16065	56	264	55660	1070
SIERRA RES	North Valmy Generating Station	NV	8224	35.88	44	4.1	14.9	41989	41989	22	157	21308	145
SIERRA RES	Reid Gardner	NV	2324	38.38	35	7.1	18.3	5661	5661	27	186	12852	132
AES-CAYUGA	AES Cayuga (NY)	NY	2535	23.02	258	9.4	11.1	27109	27109	32	175	7684	313
AES GREENIDGE	AES Greenidge	NY	2527	5.21	2	0.1	0.3	3057	3057	1	5	168	54
AES SOMERSET	AES Sommerset (NY)	NY	6082	53.96	398	22.5	25.3	54307	54307	82	404	14593	413
AES-WESTOVER	AES Westover	NY	2526	6	115	4	4.1	500132	10207	12	65	27607	73
NRG Huntley Operations Inc	C. R. Huntley	NY	2549	26.99	228	12.9	27.2	99760	99760	51	284	44666	167
JAMESTOWN	CARLSON 5	NY	2682	2.74	50	1.7	1.8	334010	6817	5	29	12367	65
DYNEGY NORTHEAST	Danskammer	NY	2480	26.27	131	14.5	21.1	103511	103511	34	217	40597	195
NRG Dunkirk Operations Inc	Dunkirk	NY	2554	36.91	152	11.5	29.6	89262	89262	54	299	61929	225
Black River Power LLC	Fort Drum H.T.W. Cogeneration Facility	NY	10464	4.9	48	2.7	3	95412	1947	10	47	21087	28
MIRANT-NY	Lovett	NY	2629	13.93	21	3.7	5	297775	297775	13	59	14133	96
Trigen-Syracuse Energy Corp	Trigen Syracuse	NY	50651	2.62	34	1.2	1.4	82038	1674	4	22	11828	19
WPS POWER DEV	WPS POWER Niagara	NY	50202	2.35	12	0.5	0.6	70239	1433	2	11	10606	50
FIRST ENERGY	Ashtabula	OH	2835	14.54	16	1.4	4.7	35165	35165	9	51	24397	89
RELIANT ENERGY - MIDWEST	Avon Lake	OH	2836	28.83	323	12.6	14.8	2194293	44781	42	226	126402	223
FIRST ENERGY	Bay Shore	OH	2878	40.34	197	10.9	34.8	118687	118687	55	346	57776	227
CARDINAL(AEP)	Cardinal	OH	2828	32.89	129	13	13.8	3055114	62349	41	194	147992	288
CARDINAL(BUCKEYE)	Cardinal	OH	2828	74.43	302	30.3	32	3812541	132703	95	450	193107	652
AEP	Conesville	OH	2840	107.36	1007	45.5	62.1	3712214	133714	121	734	350585	2068
FIRST ENERGY	Eastlake	OH	2837	80.81	528	21.5	40.5	2855008	58265	89	515	369275	650

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
MINNKOTA	Milton R. Young	ND	2823	51.14	334	81.6	245.6	6.8	623	102	74	7.2	1666
MDU	R.M. Heskett Station	ND	2790	6.27	42.6	15.8	25.3	1.5	88	14	11	1.1	272
GREAT RIVER ENG	Stanton Station	ND	2824	15.24	58.6	13.6	43	1.9	216	61	44	4.8	379
NPPD	Gerald Gentlemen Station	NE	6077	92.48	370.1	282.1	85.1	2.8	812	277	146	12.3	0
FREEMONT	Lon Wright	NE	2240	6.71	39.7	7.8	30.9	1	204	58	54	4	244
OPPD	Nebraska City	NE	6096	43.3	198	71.4	119.7	6.9	632	201	133	10.6	1572
OPPD	North Omaha	NE	2291	37.1	130.2	46.9	78.4	5	550	174	117	9.3	1347
GRAND ISLAND	Platte	NE	59	6.77	40.1	7.7	31.4	1	91	29	19	1.5	246
NPPD	Sheldon	NE	2277	17.42	69.4	52.9	16	0.5	163	55	30	2.5	0
HASTINGS	Whelan Energy Center	NE	60	6.24	28.5	10.3	17.3	1	56	19	10	0.8	227
NU	Merrimack	NH	2364	35.99	131.3	107.1	22.9	1.2	510	226	147	14.3	3140
NU	Schiller	NH	2367	13.29	17.8	13.7	3.6	0.6	335	122	94	8.1	933
PEPCO HOLDINGS (to RC Cape May Holdings - 1 Q-2007)	B L England	NJ	2378	15.78	26.6	16.8	9.1	0.7	230	112	72	6.6	1234
NEGT (to GOLDMAN SACHS IN 05)	Carneys Point Generating Plant	NJ	10566	21.47	25.3	17.5	7.6	0.2	173	114	67	6.1	22
PEPCO HOLDINGS	Deepwater	NJ	2384	5.02	2.9	2.2	0.7	0	30	22	11	1.3	180
PSE&G	Hudson	NJ	2403	22.11	36.4	24.3	10.7	1.5	443	257	228	22.4	2133
NEGT (to GOLDMAN SACHS IN 05)	Logan Generating Plant	NJ	10043	15.11	0.5	0.4	0.2	0	87	75	42	4.8	19
PSE&G	Mercer	NJ	2408	31.02	61.9	57.7	3.7	0.6	499	302	268	26.2	3047
TRI-STATE G&T	Escalante	NM	87	20.44	16.2	3.4	12	0.8	116	39	46	3.2	1068
AZ PUB SERV	Four Corners	NM	2442	148.87	425.8	41	375.6	9.2	1032	332	431	29.3	7782
PSNM	San Juan	NM	2451	125.5	1070	68.5	973.7	27.8	741	244	295	20.5	6560
SIERRA RES	North Valmy Generating Station	NV	8224	35.88	97.7	32.4	63.4	2	325	105	89	7.6	14
SIERRA RES	Reid Gardner	NV	2324	38.38	42.2	5.2	36.4	0.6	246	130	108	6.7	1357
AES-CAYUGA	AES Cayuga (NY)	NY	2535	23.02	33.4	13.4	19.7	0.3	241	149	97	8.6	1214
AES GREENIDGE	AES Greenidge	NY	2527	5.21	5.8	4	1.7	0	7	6	1	0.2	6
AES SOMERSET	AES Sommerset (NY)	NY	6082	53.96	50	20.1	29.5	0.4	587	321	192	18.3	3698
AES-WESTOVER	AES Westover	NY	2526	6	54.5	36.6	15.9	1.9	87	53	41	3.5	534
NRG Huntley Operations Inc	C. R. Huntley	NY	2549	26.99	154.7	47.2	103.3	4.1	669	213	183	13.9	1084
JAMESTOWN	CARLSON 5	NY	2682	2.74	48.6	34.8	12.1	1.7	38	23	18	1.5	237
DYNEGY NORTHEAST	Danskammer	NY	2480	26.27	146	68.8	72.1	5.1	450	173	111	10.1	1845
NRG Dunkirk Operations Inc	Dunkirk	NY	2554	36.91	218.3	43.7	169.2	5.5	752	227	179	13.6	1340
Black River Power LLC	Fort Drum H.T.W. Cogeneration Facility	NY	10464	4.9	5	3.8	1.2	0	66	58	24	2.5	1201
MIRANT-NY	Lovett	NY	2629	13.93	72.2	49.4	20.2	2.5	67	55	27	3.1	1414
Trigen-Syracuse Energy Corp	Trigen Syracuse	NY	50651	2.62	1.4	1.1	0.3	0	29	18	13	1.1	303
WPS POWER DEV	WPS POWER Niagara	NY	50202	2.35	6.4	4.9	1.5	0	14	10	5	0.5	327
FIRST ENERGY	Ashtabula	OH	2835	14.54	66.5	24.4	39.8	2.3	128	44	23	1.9	528
RELIANT ENERGY - MIDWEST	Avon Lake	OH	2836	28.83	62.4	47.7	12.5	2.2	309	191	128	11.5	2537
FIRST ENERGY	Bay Shore	OH	2878	40.34	162.4	74.8	82.7	4.9	902	228	254	21.4	1531
CARDINAL(AEP)	Cardinal	OH	2828	32.89	163	147.5	14	1.5	251	174	91	10.8	3525
CARDINAL(BUCKEYE)	Cardinal	OH	2828	74.43	366.7	275.5	82.4	8.8	583	403	214	25.1	6503
AEP	Conesville	OH	2840	107.36	888.4	415.7	448	24.6	1322	653	311	29.7	8484
FIRST ENERGY	Eastlake	OH	2837	80.81	372.2	203.3	155	13.9	1020	414	302	26.8	5126

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
AEP	Gen J. M. Gavin	OH	8102	181.45	1522	70.6	97.5	160236	160236	194	1165	76246	2765
HAMILTON	Hamilton	OH	2917	3.83	19	1.5	1.5	3959	3959	4	23	1559	27
DP&L	J. M. Stuart	OH	2850	143.34	616	73.8	73.2	11336928	231366	218	1000	601308	1346
DP&L	Killen	OH	6031	40.39	173	17.7	21	1310100	1310100	55	259	172212	646
OVEC	Kyger Creek	OH	2876	69.36	613	29.2	43.9	2783719	56811	104	557	332758	412
FIRST ENERGY	Lake Shore	OH	2838	13.83	90	5.1	11.4	55697	55697	20	118	22675	107
DUKE ENERGY OHIO	Miami Fort Station	OH	2832	71.21	579	40.6	75.5	4416136	90125	99	618	313661	504
AEP	Muskingum River	OH	2872	83.11	953	42.9	55.7	4222561	86175	110	657	476625	1259
RELIANT ENERGY - MIDWEST	Niles	OH	2861	13.41	64	2.9	4.3	17598	17598	10	59	5238	229
DP&L	O. H. Hutchings	OH	2848	7.89	24	3.8	4.3	724883	14794	12	51	25861	42
AEP	Picway	OH	2843	4.27	57	2.7	3.3	196115	4002	7	38	24080	71
FIRST ENERGY	R. E. Burger	OH	2864	18.95	187	7.6	9.7	1135833	23180	26	140	90725	153
AMP	Richard H. Gorsuch	OH	7286	17.43	67	6.2	7.7	993706	20280	20	95	72151	138
FIRST ENERGY	W. H. Sammis	OH	2866	154.65	495	43.6	64.6	1384503	1384503	160	798	230054	2439
DUKE ENERGY OHIO	W. H. Zimmer	OH	6019	81.4	297	18.5	32.9	92416	92416	60	370	27936	669
DUKE ENERGY OHIO	Walter C. Beckjord	OH	2830	66.44	356	37.3	52.5	4857770	99138	92	572	260757	474
Applied Energy Systems	AES Shady Point, Inc.	OK	10671	28.59	40	4.9	9.8	266646	5442	17	107	145278	621
GRDA	GRDA	OK	165	77.02	189	15.3	43.3	100746	100746	81	450	80009	470
WEST FARMERS	Hugo	OK	6772	32.47	37	3.3	10.8	78539	78539	21	117	54490	198
OG&E	Muskogee	OK	2952	91.51	238	19.3	54.1	234769	234769	101	561	153548	522
AEP PSO	Northeastern	OK	2963	65.61	116	9.9	29.6	158676	158676	56	313	110088	400
OG&E	Sooner	OK	6095	66.65	214	16.8	45.5	171846	171846	84	467	111839	378
PORTLAND G&E	Boardman	OR	6106	43.17	49	4.4	14.3	104396	104396	28	155	72429	263
AES Beaver Valley	AES BV Partners Beaver Valley	PA	10676	11.33	211	7.4	7.8	12722	12722	23	123	3605	155
ALLEGHENY	Armstrong	PA	3178	21.33	201	7.2	8.6	2215387	45212	25	140	96636	448
FIRST ENERGY	Bruce Mansfield	PA	6094	177.77	2015	107.9	116.5	172564	172564	336	1673	49750	1770
PPL CORP	Brunner Island	PA	3140	100.61	2041	66	69.5	9969060	203450	199	1096	454481	6367
Cambria CoGen Co	Cambria CoGen	PA	10641	11	12	0.6	1	623148	12717	3	18	49691	1114
RELIANT ENERGY - MID-ATLANTIC	Cheswick	PA	8226	29.27	875	27.7	28.6	3412786	69649	76	420	134964	1737
A C Power Colver Operations	Colver Power Project	PA	10143	9.37	20	0.9	1.4	540893	11039	4	24	42310	851
RELIANT ENERGY - MID-ATLANTIC	Conemaugh	PA	3118	123	870	40.1	48.9	84648	84648	132	710	45017	1234
EXELON GENERATION	Cromby Generating Station	PA	3159	7.76	173	6.2	6.3	9740	9740	18	98	2405	61
Power Systems Operations Inc	Ebensburg Power Company	PA	10603	6.35	6	0.3	0.5	318443	6499	2	10	28674	642
EXELON GENERATION	Eddystone	PA	3161	27.87	534	26.9	29.7	26471	26471	70	381	8741	173
RELIANT ENERGY - MID-ATLANTIC	Elrama	PA	3098	23.64	337	11.6	13	33594	33594	38	209	7744	288
El Paso Merchant Energy Co	Foster Wheeler Mt. Carmel, Incorporated	PA	10343	4.68	6	1	1.4	2463	2463	4	17	115	35
ALLEGHENY	Hatfield's Ferry	PA	3179	102.93	831	34.2	43.8	6485617	132360	127	682	458334	738
ED MISSION(GE CAPITAL)	Homer City	PA	3122	134.6	1349	50.8	59.5	10099723	305912	179	968	389605	2296
UGI	Hunlock Power Station	PA	3176	3.41	55	2.8	3.2	182514	3725	8	42	14688	21
Gilberton Power Co	John B. Rich Memorial Power Station	PA	10113	8.12	9	0.4	0.8	16553	16553	3	14	11568	222
RELIANT ENERGY - MID-ATLANTIC	Keystone	PA	3136	118.48	2906	114.3	113.3	1383477	28234	287	1542	595511	1326

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
AEP	Gen J. M. Gavin	OH	8102	181.45	388.2	156	229	3.1	2084	1044	486	46.9	10636
HAMILTON	Hamilton	OH	2917	3.83	3.7	0.8	2.8	0.2	33	21	10	1.2	248
DP&L	J. M. Stuart	OH	2850	143.34	1305.5	1011.8	261.1	32.6	1179	877	517	60.4	15408
DP&L	Killen	OH	6031	40.39	626.2	485.3	125.2	15.7	324	229	130	14.8	4236
OVEC	Kyger Creek	OH	2876	69.36	206.2	113.8	84.1	8.2	1012	452	322	27.7	4260
FIRST ENERGY	Lake Shore	OH	2838	13.83	53.4	22.8	28.4	2.1	283	89	71	5.8	644
DUKE ENERGY OHIO	Miami Fort Station	OH	2832	71.21	267.1	219.3	44.4	3.4	1108	478	353	28.1	5516
AEP	Muskingum River	OH	2872	83.11	829.7	581.2	228.5	20	1169	572	294	27.9	8206
RELIANT ENERGY - MIDWEST	Niles	OH	2861	13.41	23.2	9.3	13.7	0.2	96	55	24	2.4	754
DP&L	O. H. Hutchings	OH	2848	7.89	41	27.8	12.3	1	54	45	27	3	819
AEP	Picway	OH	2843	4.27	53	31.2	19.9	1.9	67	33	18	1.8	424
FIRST ENERGY	R. E. Burger	OH	2864	18.95	114.5	71.3	39.2	4	218	118	77	7.2	1617
AMP	Richard H. Gorsuch	OH	7286	17.43	103.4	63.4	36.4	3.6	128	86	44	4.9	1796
FIRST ENERGY	W. H. Sammis	OH	2866	154.65	848.8	596.2	228.9	23.7	1426	694	403	41.3	8079
DUKE ENERGY OHIO	W. H. Zimmer	OH	6019	81.4	78.6	31.6	46.4	0.6	644	326	154	14.2	4140
DUKE ENERGY OHIO	Walter C. Beckjord	OH	2830	66.44	304	196.6	96.2	11.2	1002	440	298	25.4	5202
Applied Energy Systems	AES Shady Point, Inc.	OK	10671	28.59	265.4	202.3	61	2	234	94	44	4.2	1749
GRDA	GRDA	OK	165	77.02	398.7	76.4	315.1	7.1	1134	359	241	19.1	2236
WEST FARMERS	Hugo	OK	6772	32.47	148.5	53.5	89.8	5.2	294	100	53	4.5	1179
OG&E	Muskogee	OK	2952	91.51	391.6	146	231.8	13.7	1411	445	303	24	3322
AEP PSO	Northeastern	OK	2963	65.61	300	109.2	180.4	10.5	789	258	156	12.7	2382
OG&E	Sooner	OK	6095	66.65	283.5	105.9	167.7	9.9	1174	364	264	20.5	2420
PORTLAND G&E	Boardman	OR	6106	43.17	197.4	71.2	119.3	6.9	389	132	70	5.9	1567
AES Beaver Valley	AES BV Partners Beaver Valley	PA	10676	11.33	47.5	7.7	39.5	0.3	167	98	75	6.4	620
ALLEGHENY	Armstrong	PA	3178	21.33	336	233.3	90.9	11.8	189	121	76	6.8	1865
FIRST ENERGY	Bruce Mansfield	PA	6094	177.77	598.6	255	337.7	5.8	2323	1331	914	85.7	11262
PPL CORP	Brunner Island	PA	3140	100.61	3302	2351.3	831.6	119	1468	882	699	58.8	8711
Cambria CoGen Co	Cambria CoGen	PA	10641	11	97.6	74.4	22.4	0.7	24	19	6	0.7	2320
RELIANT ENERGY - MID-ATLANTIC	Cheswick	PA	8226	29.27	1684.6	1305.6	336.9	42.1	599	327	293	24.2	2423
A C Power Colver Operations	Colver Power Project	PA	10143	9.37	64.5	49.2	14.8	0.5	33	24	10	1	1343
RELIANT ENERGY - MID-ATLANTIC	Conemaugh	PA	3118	123	425.1	62.8	359.5	2.8	1070	626	357	38.4	8130
EXELON GENERATION	Cromby Generating Station	PA	3159	7.76	37.5	9	28.2	0.4	134	76	62	5.2	443
Power Systems Operations Inc	Ebensburg Power Company	PA	10603	6.35	93.7	71.5	21.6	0.7	13	11	3	0.4	713
EXELON GENERATION	Eddystone	PA	3161	27.87	21.8	8.8	12.9	0.2	627	285	233	20	1547
RELIANT ENERGY - MID-ATLANTIC	Elrama	PA	3098	23.64	24.9	10	14.7	0.2	281	174	123	10.7	1228
El Paso Merchant Energy Co	Foster Wheeler Mt. Carmel, Incorporated	PA	10343	4.68	4.9	2.1	2.7	0.1	18	16	7	0.9	6
ALLEGHENY	Hatfield's Ferry	PA	3179	102.93	421.4	275.9	130.8	14.7	1009	578	353	32	8821
ED MISSION(GE CAPITAL)	Homer City	PA	3122	134.6	777.2	529.9	217.8	29.6	1316	820	525	47	10531
UGI	Hunlock Power Station	PA	3176	3.41	10.6	6.6	3.6	0.4	69	32	25	2.1	318
Gilberton Power Co	John B. Rich Memorial Power Station	PA	10113	8.12	157.2	119.9	36.2	1.2	19	15	5	0.5	0
RELIANT ENERGY - MID-ATLANTIC	Keystone	PA	3136	118.48	663.1	283	353.6	26.5	2326	1215	1000	98	13157

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
Northeastern Power Company	Kline Township Cogen Facility	PA	50039	5.63	12	0.5	0.8	76921	76921	3	15	8021	233
PPL CORP	Martins Creek	PA	3148	10.37	262	8.3	8.5	617717	12606	24	133	46841	162
ALLEGHENY	MITCHELL (PA) 3	PA	3181	9.36	112	4.7	6	6974	6974	13	75	3757	93
PPL CORP	Montour	PA	3149	88.03	2946	90.1	87.8	193803	193803	245	1351	28956	6228
RELIANT ENERGY - MID-ATLANTIC	New Castle	PA	3138	16.54	157	6.5	7.8	1082911	22100	21	113	75373	253
Northampton Generating Co LP (Goldman Sachs)	Northampton Generating Company, L.P.	PA	50888	9.11	13	0.6	1	110304	110304	3	18	12984	254
Constellation Oper Services	Panther Creek Energy Facility	PA	50776	7.93	13	0.6	1	58866	58866	3	17	11308	234
Piney Creek L P	Piney Creek Project	PA	54144	3.56	26	2.4	1.8	120355	2456	7	31	19485	26
RELIANT ENERGY - MID-ATLANTIC	Portland	PA	3113	23.36	439	17.2	17.4	1700848	34711	51	267	95372	221
Buzzard Power Corporation	Scrubgrass Generating Company, L. P.	PA	50974	8.9	30	1.3	1.8	422761	8628	6	31	40204	509
RELIANT ENERGY - MID-ATLANTIC	Seward	PA	3130	37.81	32	1.9	3.4	24485	24485	10	55	1384	1995
RELIANT ENERGY - MID-ATLANTIC	Shawville	PA	3131	36.05	592	19.8	21.7	3590102	73267	63	346	162853	1272
Schuylkill Energy Resource Inc	St. Nicholas Cogeneration Project	PA	54634	9.06	13	0.6	1	29487	29487	3	18	12921	236
SUNDBURY(WPS-PDI)	Sunbury	PA	3152	25.97	190	6.9	8.6	941519	19215	26	142	117313	405
RELIANT ENERGY - MID-ATLANTIC	Titus	PA	3115	15.1	175	9	9.8	1553061	31695	27	137	58474	529
WPS POWER DEV	Westwood	PA	50611	2.65	76	4	3.4	72556	1481	8	44	15007	38
Wheelabrator Environmental Sys	Wheelabrator Frackville Energy Company Inc	PA	50879	4.96	4	0.2	0.4	23918	23918	1	7	7065	148
SCANA	Canadys Steam	SC	3280	23.5	325	23.7	17.2	1318702	26912	56	266	119011	359
SCANA	Cogen South	SC	7737	7.96	10	0.7	1.2	79989	1632	4	23	39362	70
SCANA	Cope	SC	7210	30.35	76	7.4	7.7	15388	15388	26	125	1078	539
SANTEE	Cross Generating Station	SC	130	238.23	841	56.1	59.6	342572	342572	204	1036	87947	1431
SANTEE	Grainger Generating Station	SC	3317	9.52	192	15.9	10.1	849404	17335	34	162	51537	40
PROGRESS ENERGY	H B Robinson	SC	3251	11.89	126	11.3	7.9	1134409	23151	28	134	65136	86
SANTEE	Jefferies Generating Station	SC	3319	18.56	548	43	26	1653659	33748	85	408	100546	93
SCANA	McMeekin	SC	3287	14.66	38	4.1	3.6	391742	7995	14	66	80298	72
SCANA	Urquhart	SC	3295	7.19	252	8.5	9.2	335775	6853	23	108	25209	55
DUKE ENERGY CAROLINAS	W. S. Lee	SC	3264	16.28	136	13.6	11	1378186	28126	35	164	78238	116
SCANA	Wateree	SC	3297	42.38	227	20.9	19.4	2710540	55317	61	286	194858	443
SCANA	Williams	SC	3298	36.5	164	17.4	18.3	2433721	49668	49	252	186435	171
SANTEE	Winyah Generating Station	SC	6249	80.08	351	35.2	29.1	118500	118500	104	499	31149	825
OTTER TAIL	Big Stone	SD	6098	26.68	42	3.6	11	52790	52790	21	117	44764	163
TVA	Allen Fossil Plant	TN	3393	47.73	148	15.8	26.6	819467	819467	53	288	59827	461
TVA	Bull Run Fossil Plant	TN	3396	53.99	94	12.7	14.6	4226379	86253	46	211	229242	634
TVA	Cumberland Fossil Plant	TN	3399	153.29	293	34.8	136.7	119028	119028	105	730	45422	799
TVA	Gallatin Fossil Plant	TN	3403	67.89	102	11	22.7	2429656	49585	47	251	357158	482
TVA	John Sevier Fossil Plant	TN	3405	44.72	101	9.7	9.6	1523227	31086	37	173	223839	274
TVA	Johnsonville Fossil Plant	TN	3406	78.27	273	32.6	92.9	5602192	114330	82	570	316667	526
TVA	Kingston Fossil Plant	TN	3407	96.35	196	23.8	32.4	1332282	1332282	90	423	135792	578
AES Deepwater Inc	AES Deepwater	TX	10670	11.87	78	8.1	13.7	59900	1222	40	170	75512	64
LUMINANT (TXU)	Big Brown	TX	3497	92.28	198	24.8	49	438676	438676	90	519	161303	1562

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
Northeastern Power Company	Kline Township Cogen Facility	PA	50039	5.63	71.4	54.4	16.4	0.5	20	15	6	0.6	0
PPL CORP	Martins Creek	PA	3148	10.37	121.2	76.5	40.5	4.2	178	105	88	7.3	898
ALLEGHENY	MITCHELL (PA) 3	PA	3181	9.36	31.9	4.7	26.9	0.2	127	65	36	3.3	538
PPL CORP	Montour	PA	3149	88.03	268.8	108	158.6	2.2	1809	1041	949	77	4540
RELIANT ENERGY - MID-ATLANTIC	New Castle	PA	3138	16.54	71	54.3	14.2	2.5	159	97	61	5.6	1501
Northampton Generating Co LP (Goldman Sachs)	Northampton Generating Company, L.P.	PA	50888	9.11	71.7	54.6	16.5	0.5	24	18	7	0.7	24
Constellation Oper Services	Panther Creek Energy Facility	PA	50776	7.93	91.6	69.9	21.1	0.7	23	18	7	0.7	0
Piney Creek L P	Piney Creek Project	PA	54144	3.56	1.5	1.2	0.4	0.0	41	27	16	2	218
RELIANT ENERGY - MID-ATLANTIC	Portland	PA	3113	23.36	165.6	109.4	50.4	5.8	372	207	163	14.1	2369
Buzzard Power Corporation	Scrubgrass Generating Company, L. P.	PA	50974	8.9	53	40.4	12.2	0.4	42	29	14	1.3	1429
RELIANT ENERGY - MID-ATLANTIC	Seward	PA	3130	37.81	656.8	134.9	503.5	18.4	83	59	18	2.2	50
RELIANT ENERGY - MID-ATLANTIC	Shawville	PA	3131	36.05	356.1	272.4	71.2	12.5	464	284	210	18	3124
Schuylkill Energy Resource Inc	St. Nicholas Cogeneration Project	PA	54634	9.06	163.4	124.6	37.6	1.2	24	19	7	0.7	0
SUNDBURY(WPS-PDI)	Sunbury	PA	3152	25.97	116.5	78.1	35.2	3.2	191	125	74	6.7	1671
RELIANT ENERGY - MID-ATLANTIC	Titus	PA	3115	15.1	396.7	277.9	104.9	13.9	174	113	80	7.6	1431
WPS POWER DEV	Westwood	PA	50611	2.65	4.4	3.4	1	0	70	35	27	2.7	176
Wheelabrator Environmental Sys	Wheelabrator Frackville Energy Company Inc	PA	50879	4.96	81.5	62.1	18.7	0.6	9	7	2	0.2	0
SCANA	Canadys Steam	SC	3280	23.5	131.6	86.6	40.1	4.8	344	215	162	18.7	2117
SCANA	Cogen South	SC	7737	7.96	27.8	21.2	6.4	0.2	18	20	7	0.7	1459
SCANA	Cope	SC	7210	30.35	88.2	23.2	62.6	2.5	160	120	52	6.9	39
SANTEE	Cross Generating Station	SC	130	238.23	126.1	50.7	74.4	1	1371	969	460	52.6	14584
SANTEE	Grainger Generating Station	SC	3317	9.52	30.3	20.5	8.7	1.1	211	127	106	11.9	1072
PROGRESS ENERGY	H B Robinson	SC	3251	11.89	64.9	44.4	18.2	2.3	175	112	76	9	1343
SANTEE	Jefferies Generating Station	SC	3319	18.56	69.5	47.2	19.9	2.4	538	309	288	31	2076
SCANA	McMeekin	SC	3287	14.66	8.3	6.3	1.9	0.1	86	63	28	3.7	1046
SCANA	Urquhart	SC	3295	7.19	41	24.8	14.8	1.4	140	83	67	8.1	662
DUKE ENERGY CAROLINAS	W. S. Lee	SC	3264	16.28	112.8	74.5	35.5	2.8	203	137	93	10.7	1792
SCANA	Wateree	SC	3297	42.38	251	214.1	34.5	2.3	357	252	146	17.6	4555
SCANA	Williams	SC	3298	36.5	97	83.4	12.7	0.9	392	219	123	14.1	3668
SANTEE	Winyah Generating Station	SC	6249	80.08	71.7	28.8	42.3	0.6	645	449	241	30	5354
OTTER TAIL	Big Stone	SD	6098	26.68	106.5	81.2	24.5	0.8	295	97	57	4.7	0
TVA	Allen Fossil Plant	TN	3393	47.73	260.9	227	31.4	2.4	518	226	141	10.9	3499
TVA	Bull Run Fossil Plant	TN	3396	53.99	358.8	316.2	39.3	3.3	250	202	90	11.3	5818
TVA	Cumberland Fossil Plant	TN	3399	153.29	125	50.3	73.8	1	1469	593	350	26.9	6535
TVA	Gallatin Fossil Plant	TN	3403	67.89	361.1	205	143.5	12.6	506	227	108	11.2	4114
TVA	John Sevier Fossil Plant	TN	3405	44.72	173.6	101.2	66.3	6.1	235	165	71	9.3	4582
TVA	Johnsonville Fossil Plant	TN	3406	78.27	373.9	248.4	112.4	13.1	1124	437	299	22.6	5507
TVA	Kingston Fossil Plant	TN	3407	96.35	327.1	265.1	58.9	3	665	386	193	22	7900
AES Deepwater Inc	AES Deepwater	TX	10670	11.87	30.3	23.1	7	0.2	148	468	113	18.1	730
LUMINANT (TXU)	Big Brown	TX	3497	92.28	746.9	569.4	171.8	5.7	1886	390	254	28.1	10200

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	As lb/yr	Be lb/y	Cd lb/yr	HCl lb/yr	Cl2 lb/yr	Co lb/yr	Cr lb/yr	HF lb/yr	Coal Hg lb/yr
INTERNATIONAL POWER PLC	Coleto Creek	TX	6178	44.81	87	7.3	21.5	88667	88667	41	226	75186	273
TMPA	Gibbons Creek	TX	6136	34.63	500	32.4	68.1	6091	6091	116	645	13409	211
XCEL	Harrington Station	TX	6193	75.43	232	18.3	49.7	160509	160509	92	511	126560	460
SAPSB	J.K. Spruce	TX	7097	40.56	71	6.2	18.2	7373	7373	36	196	16038	244
SAPSB	J.T. Deely	TX	6181	56.43	230	17.5	45.6	115109	115109	83	462	94688	333
NRG ENERGY	Limestone	TX	298	137.69	102	14.7	34.7	36504	36504	67	390	57512	2242
LUMINANT (TXU)	Martin Lake	TX	6146	199.48	179	26.7	57.8	72025	72025	110	642	82007	4505
LUMINANT (TXU)	Monticello	TX	6147	171.28	486	55.3	109.6	350143	350143	198	1142	201090	2414
AEP PSO	Oklaunion	TX	127	44.44	80	6.8	20.3	7816	7816	39	214	17207	271
AEP	Pirkey	TX	7902	53.71	508	57.7	81.5	11868	11868	137	802	22373	1371
LCRA	Sam Seymour	TX	6179	167.54	397	32.5	92.6	300096	300096	173	965	220629	1021
SAN MIGUEL	San Miguel	TX	6183	33.66	79	10.8	19.3	65806	65806	35	204	14021	1110
LUMINANT (TXU)	Sandow	TX	6648	50.16	89	12.6	23.6	40679	40679	43	253	20897	1295
SEMPRA GENERATION (to PNM RESOURCES 2006)	TNP-One	TX	7030	27.54	49	7	13	137549	2807	24	140	157571	711
XCEL	Tolk Station	TX	6194	71.27	164	13.4	38.5	141023	141023	72	402	119583	435
NRG ENERGY	W A Parish	TX	3470	212.95	225	20.5	66.9	331982	331982	131	727	293313	1298
AEP	Welsh	TX	6139	110.25	382	29.7	79.5	266637	266637	146	812	184990	672
DESERT	Bonanza	UT	7790	36.53	26	7	13.5	9008	9008	22	108	18339	119
PACIFICORP(SCOTTISH PWR)	Carbon	UT	3644	14.98	20	3.5	9.3	118776	118776	13	96	19093	256
PACIFICORP(SCOTTISH PWR)	Hunter	UT	6165	103.39	55	11	34.1	17664	17664	51	368	30420	434
PACIFICORP(SCOTTISH PWR)	Huntington	UT	8069	73.13	57	10.8	30.9	25340	25340	45	327	21517	480
INTERMOUNTAIN/LADWP	Intermountain	UT	6481	137	54	11.4	37.3	27775	27775	57	410	40309	500
Sunnyside Operations Associate	Sunnyside Cogeneration Associates	UT	50951	5.2	1	0.1	0.6	35933	35933	1	7	6630	98
LG&E Power Serv Inc	Altavista Power Station	VA	10773	3.52	16	1.1	1.1	2066	2066	4	19	109	23
DOMINION VA POWER	Bremo Power Station	VA	3796	13.77	59	3.8	4.2	1015610	20727	16	70	56771	92
DOMINION VA POWER	Chesapeake Energy Center	VA	3803	35.89	113	10.5	17	289804	289804	29	185	57458	278
DOMINION VA POWER	Chesterfield Power Station	VA	3797	73.81	696	40.5	38.7	5474629	111727	139	617	306430	496
AEP	Clinch River	VA	3775	39.58	223	14.2	14.8	1620588	33073	54	242	166431	186
DOMINION VA POWER	Clover Power Station	VA	7213	58.42	145	10.2	12.2	64253	64253	47	210	17763	336
Goldman Sachs	Cogentrix Hopewell	VA	10377	10.92	32	2.2	2.6	58220	1188	10	44	45116	36
Goldman Sachs	Cogentrix of Richmond, INC.	VA	54081	20.54	51	5.8	5.6	12170	12170	20	93	751	377
Goldman Sachs	Cogentrix Portsmouth	VA	10071	10.39	43	4.8	4.5	398041	8123	14	67	48471	78
AEP	Glen Lyn	VA	3776	16.51	87	7.5	8.3	669727	13668	25	113	61521	63
LG&E Power Serv Inc	LG&E - Westmoreland Hopewell	VA	10771	3.43	4	0.3	0.5	29724	29724	2	8	12621	87
UAE Mecklenburg Cogeneration	Mecklenburg Power Station	VA	52007	7.64	19	2	1.8	9813	9813	7	33	305	34
MIRANT-MID-ATLANTIC	Potomac River	VA	3788	16.63	73	7	8.2	880656	17973	23	107	62158	80
GE/Goldman Sachs	SEI - Birchwood Power Facility	VA	54304	12.15	91	13.3	13.4	7822	7822	33	147	277	79
LG&E Power Serv Inc	Southampton Power Station	VA	10774	4.39	24	2.1	1.8	3305	3305	6	31	167	36
DOMINION VA POWER	Yorktown Power Station	VA	3809	17.09	165	14.1	10.4	1316535	26868	37	176	90018	120
TRANS ALTA	Centralia	WA	3845	92.65	243	17.7	45.2	13886	13886	58	328	39404	445
DAIRYLAND	Alma	WI	4140	7.87	38	4.1	14.1	23767	23767	12	78	11943	43
XCEL	Bay Front	WI	3982	4.92	70	4.4	8.9	11582	11582	14	77	8464	28
MG&E	Blount Street	WI	3992	2.6	31	3.3	3.8	76591	1563	6	36	10586	12
ALLIANT	Columbia	WI	8023	75.76	223	17.7	48.8	183234	183234	90	502	127126	462

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
INTERNATIONAL POWER PLC	Coleto Creek	TX	6178	44.81	177.2	135.1	40.8	1.3	569	184	115	9.3	0
TMPA	Gibbons Creek	TX	6136	34.63	100.4	9.8	90	0.7	1625	439	498	34.5	748
XCEL	Harrington Station	TX	6193	75.43	313.8	192.8	115.4	5.6	1286	399	287	22.4	930
SAPSB	J.K. Spruce	TX	7097	40.56	34.2	7.2	25.3	1.7	472	262	97	9	831
SAPSB	J.T. Deely	TX	6181	56.43	216	164.7	49.7	1.6	1163	352	274	20.9	0
NRG ENERGY	Limestone	TX	298	137.69	1025.1	107.1	911.3	6.7	1412	326	156	18.4	14816
LUMINANT (TXU)	Martin Lake	TX	6146	199.48	1970.2	220.9	1736.5	12.8	2448	514	258	32.3	29949
LUMINANT (TXU)	Monticello	TX	6147	171.28	1230.2	507.2	703	20	3964	847	599	61.9	12912
AEP PSO	Oklaunion	TX	127	44.44	129.1	12.5	115.8	0.8	540	176	107	8.7	960
AEP	Pirkey	TX	7902	53.71	654.1	63.4	586.5	4.3	3131	514	524	56	9643
LCRA	Sam Seymour	TX	6179	167.54	687.6	213.1	454.3	20.2	2429	773	511	40.7	5394
SAN MIGUEL	San Miguel	TX	6183	33.66	162.4	65.3	95.8	1.3	796	148	100	11.9	6043
LUMINANT (TXU)	Sandow	TX	6648	50.16	499.4	65.9	430.2	3.2	987	189	117	14.2	9006
SEMPRA GENERATION (to PNM RESOURCES 2006)	TNP-One	TX	7030	27.54	461.6	351.9	106.2	3.5	546	104	65	7.9	4708
XCEL	Tolk Station	TX	6194	71.27	281.8	214.8	64.8	2.1	1011	323	212	16.9	0
NRG ENERGY	W A Parish	TX	3470	212.95	695.9	461.4	227.4	7.1	1829	627	326	27.6	1071
AEP	Welsh	TX	6139	110.25	652	126.8	508.9	16.3	2045	629	466	36	4003
DESERT	Bonanza	UT	7790	36.53	16.7	3.5	12.4	0.8	225	96	106	5.7	765
PACIFICORP(SCOTTISH PWR)	Carbon	UT	3644	14.98	192.2	105.9	79.6	6.7	118	63	54	3.4	978
PACIFICORP(SCOTTISH PWR)	Hunter	UT	6165	103.39	152.4	18.1	132.4	1.9	449	263	170	11.5	4018
PACIFICORP(SCOTTISH PWR)	Huntington	UT	8069	73.13	194.3	24.2	168.8	1.3	399	225	165	10.9	2842
INTERMOUNTAIN/LADWP	Intermountain	UT	6481	137	70	14.7	51.8	3.5	501	302	176	12.3	5324
Sunnyside Operations Associate	Sunnyside Cogeneration Associates	UT	50951	5.2	43.8	33.4	10.1	0.3	8	6	2	0.2	40
LG&E Power Serv Inc	Altavista Power Station	VA	10773	3.52	2.5	0.7	1.7	0.1	28	17	9	1.1	4
DOMINION VA POWER	Bremo Power Station	VA	3796	13.77	89.7	56.7	30.8	2.2	104	61	33	3.9	1142
DOMINION VA POWER	Chesapeake Energy Center	VA	3803	35.89	175.6	115.2	56.8	3.5	375	160	80	7.7	2715
DOMINION VA POWER	Chesterfield Power Station	VA	3797	73.81	287.8	245.3	39.1	3.4	922	507	344	38.8	6166
AEP	Clinch River	VA	3775	39.58	92.9	53.8	35.3	3.7	360	208	121	14.2	3318
DOMINION VA POWER	Clover Power Station	VA	7213	58.42	47.1	9.9	34.8	2.4	312	194	88	11	2924
Goldman Sachs	Cogentrix Hopewell	VA	10377	10.92	17.3	13.2	4	0.1	65	40	19	2.4	365
Goldman Sachs	Cogentrix of Richmond, INC.	VA	54081	20.54	39.8	27.5	11.9	0.3	118	88	40	5.2	27
Goldman Sachs	Cogentrix Portsmouth	VA	10071	10.39	1.9	1.5	0.4	0	83	60	33	4	315
AEP	Glen Lyn	VA	3776	16.51	47.1	27.5	18	1.6	148	97	59	6.7	1516
LG&E Power Serv Inc	LG&E - Westmoreland Hopewell	VA	10771	3.43	28.4	21.7	6.5	0.2	12	7	3	0.3	626
UAE Mecklenburg Cogeneration	Mecklenburg Power Station	VA	52007	7.64	4.7	2	2.7	0.1	43	32	14	1.8	10
MIRANT-MID-ATLANTIC	Potomac River	VA	3788	16.63	77.2	44.8	30.4	1.9	148	91	55	6	1519
GE/Goldman Sachs	SEI - Birchwood Power Facility	VA	54304	12.15	6.8	4.7	2	0.1	152	118	94	9.7	15
LG&E Power Serv Inc	Southampton Power Station	VA	10774	4.39	1.6	0.5	1.1	0	41	27	15	1.8	6
DOMINION VA POWER	Yorktown Power Station	VA	3809	17.09	33.7	25.8	6.7	1.2	234	148	98	11.5	1850
TRANS ALTA	Centralia	WA	3845	92.65	214.2	20.4	192.4	1.4	1136	328	223	24.8	1951
DAIRYLAND	Alma	WI	4140	7.87	32.2	13.1	18	1.1	175	56	50	3.5	384
XCEL	Bay Front	WI	3982	4.92	21.4	7.8	12.8	0.7	209	65	62	5	176
MG&E	Blount Street	WI	3992	2.6	9.3	4.9	4.1	0.3	60	29	22	2.3	176
ALLIANT	Columbia	WI	8023	75.76	345.8	84.4	251.1	10.3	1264	394	279	21.8	2751

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
ALLIANT	Edgewater (WI)	WI	4050	48.5	139	11.1	30.7	117286	117286	57	316	81372	296
WPS POWER DEV	EJ STONEMAN 2	WI	4146	0.78	4	0.5	2	51300	1047	1	8	3190	3
DAIRYLAND	Genoa	WI	4143	21.93	157	13.8	29.1	57587	57587	46	287	32480	111
DAIRYLAND	J P Madgett	WI	4271	26.03	111	8.4	21.7	51500	51500	39	219	43670	159
MANITOWOC	Manitowoc	WI	4125	2.28	5	0.6	1.5	11739	240	3	17	12774	11
ALLIANT	Nelson Dewey	WI	4054	13.69	190	11.5	22.1	126113	2574	29	156	81163	67
WE ENERGIES	Pleasant Prairie	WI	6170	84.8	89	8.1	26.5	14916	14916	52	288	32836	517
WPS	Pulliam	WI	4072	27.9	126	9.4	23.8	69467	69467	43	240	46811	165
WE ENERGIES	South Oak Creek	WI	4041	57.53	94	8	24.3	141427	141427	46	258	96529	345
WE ENERGIES	Valley	WI	4042	18.94	8	2.4	4.9	44736	44736	8	38	42423	74
WPS	Weston	WI	4078	29.29	89	6.9	18.7	65530	65530	34	191	49148	168
ALLEGHENY	Albright	WV	3942	15.55	175	7.6	8.4	966531	19725	26	133	63025	139
ALLEGHENY	Fort Martin	WV	3943	67.83	869	36.3	43	3883978	79265	122	640	296651	460
Edison Mission Op & Maintenace	Grant Town Power Plant	WV	10151	9.12	12	0.8	1.3	2150	2150	5	22	244	229
ALLEGHENY	Harrison	WV	3944	138.22	630	37.2	46.1	116021	116021	148	737	38573	1090
AEP	John E Amos	WV	3935	179.73	346	60.3	76.4	15166113	309513	205	901	562575	1259
AEP	Kammer	WV	3947	40.42	678	24.8	27.4	2526850	51568	77	418	188252	378
AEP	Kanawha River	WV	3936	21.67	62	10.3	12.2	1768854	36099	32	141	67825	155
AEP	Mitchell (WV)	WV	3948	82.04	496	29.6	34.1	48967	48967	112	550	21987	766
Dominion Energy Services Co	Morgantown Energy Facility	WV	10743	6.22	5	0.4	0.6	105608	2155	2	12	22878	158
AEP	Mountaineer	WV	6264	91.7	556	33.3	43.6	87976	87976	104	549	31844	830
DOMINION VA POWER	Mt. Storm Power Station	WV	3954	90.93	272	14.7	22.1	61397	61397	75	408	31916	786
DOMINION VA POWER	North Branch Power Station	WV	7537	7.48	13	0.9	1.4	75122	1533	5	27	36967	66
AEP	Philip Sporn	WV	3938	61.3	161	26.6	32	4399735	89791	85	373	192562	457
ALLEGHENY	Pleasants	WV	6004	80.36	728	33.1	45.4	51809	51809	89	538	34270	760
ALLEGHENY	Rivesville	WV	3945	3.41	29	1.2	1.4	268548	5481	4	23	14609	33
ALLEGHENY	Willow Island	WV	3946	8.49	65	3	5.4	284507	5806	10	54	46004	56
PACIFICORP(SCOTTISH PWR)	Dave Johnston	WY	4158	65.1	156	12.5	35.1	95246	95246	66	364	73436	397
PACIFICORP(SCOTTISH PWR)	Jim Bridger	WY	8066	159.53	182	9.8	51	22820	22820	77	538	43003	681
BASIN ELECTRIC	Laramie River Station	WY	6204	127.18	138	12.5	40.7	22370	22370	79	442	49247	775
PACIFICORP(SCOTTISH PWR)	Naughton	WY	4162	56.58	168	8	35.4	456661	15702	51	356	122218	297
BLACK HILLS	NEIL SIMPSON 6 (II 2)	WY	7504	8.71	17	1.4	4.2	1533	1533	8	44	3374	53
BLACK HILLS	WYGEN 1	WY	55479	8.89	8	0.7	2.5	635	635	5	27	344	54
PACIFICORP(SCOTTISH PWR)	Wyodak	WY	6101	32.41	23	2.2	7.7	5701	5701	15	85	12551	198

OPERATOR	PLANT	STATE	ORISPL	TBtu/2007	Hg lb/yr	HgOx lb/yr	HgE lb/yr	HgPM lb/yr	Mn lb/yr	Ni lb/yr	Pb lb/yr	Sb lb/yr	Se lb/yr
ALLIANT	Edgewater (WI)	WI	4050	48.5	182.3	66.1	109.5	6.8	796	249	175	13.7	1761
WPS POWER DEV	EJ STONEMAN 2	WI	4146	0.78	2.5	1.6	0.9	0.1	18	6	5	0.4	53
DAIRYLAND	Genoa	WI	4143	21.93	60.2	45.9	13.8	0.5	549	192	197	13.2	119
DAIRYLAND	J P Madgett	WI	4271	26.03	90.8	69.2	20.9	0.7	552	167	131	10	0
MANITOWOC	Manitowoc	WI	4125	2.28	5.5	4.2	1.3	0	19	40	9	1.2	231
ALLIANT	Nelson Dewey	WI	4054	13.69	50	18.6	29.7	1.8	488	235	143	14.9	447
WE ENERGIES	Pleasant Prairie	WI	6170	84.8	178.9	71.9	105.6	1.4	725	249	129	10.9	1833
WPS	Pulliam	WI	4072	27.9	82.4	29.9	49.1	3.3	603	181	147	11.1	1013
WE ENERGIES	South Oak Creek	WI	4041	57.53	258.5	95.1	154.4	9	649	214	127	10.4	2089
WE ENERGIES	Valley	WI	4042	18.94	39.6	30.2	9.1	0.3	85	37	36	2	0
WPS	Weston	WI	4078	29.29	99.3	65.4	32.3	1.6	482	149	109	8.4	330
ALLEGHENY	Albright	WV	3942	15.55	86.4	54	29.1	3.2	187	108	72	6.5	1602
ALLEGHENY	Fort Martin	WV	3943	67.83	128.9	98.6	25.8	4.5	981	509	363	31.7	5918
Edison Mission Op & Maintenace	Grant Town Power Plant	WV	10151	9.12	32	13.4	17.9	0.6	32	21	7	0.8	13
ALLEGHENY	Harrison	WV	3944	138.22	158	63.5	93.2	1.3	1078	619	317	31.5	9322
AEP	John E Amos	WV	3935	179.73	712.8	634.7	71.5	6.6	931	819	436	50.1	18534
AEP	Kammer	WV	3947	40.42	283.4	179.3	94.2	9.9	601	338	256	22.2	3361
AEP	Kanawha River	WV	3936	21.67	77.3	51.1	23.1	3.1	146	124	74	8.3	2235
AEP	Mitchell (WV)	WV	3948	82.04	138.1	55.5	81.4	1.1	804	442	249	24.2	5697
Dominion Energy Services Co	Morgantown Energy Facility	WV	10743	6.22	51.5	39.3	11.9	0.4	17	11	3	0.4	1135
AEP	Mountaineer	WV	6264	91.7	109.9	44.2	64.9	0.9	872	486	240	24.7	5625
DOMINION VA POWER	Mt. Storm Power Station	WV	3954	90.93	133.1	53.5	78.5	1.1	367	331	146	14.1	4560
DOMINION VA POWER	North Branch Power Station	WV	7537	7.48	26.1	19.9	6	0.2	20	22	8	0.8	1371
AEP	Philip Sporn	WV	3938	61.3	342.7	222.4	108.3	12	387	329	192	21.5	6328
ALLEGHENY	Pleasants	WV	6004	80.36	130.1	52.3	76.7	1	969	480	226	21.7	4685
ALLEGHENY	Rivesville	WV	3945	3.41	24.9	16.5	7.5	0.9	31	19	12	1.1	316
ALLEGHENY	Willow Island	WV	3946	8.49	52.2	24.4	26.4	1.4	128	48	35	3.4	438
PACIFICORP(SCOTTISH PWR)	Dave Johnston	WY	4158	65.1	302.8	67.4	228.1	7.3	917	291	197	15.5	1956
PACIFICORP(SCOTTISH PWR)	Jim Bridger	WY	8066	159.53	329.8	31	296.7	2.1	1448	352	325	31.8	5712
BASIN ELECTRIC	Laramie River Station	WY	6204	127.18	478	37.4	438	2.6	1112	380	199	16.9	2748
PACIFICORP(SCOTTISH PWR)	Naughton	WY	4162	56.58	180.6	58.9	117.1	4.7	958	213	262	23.8	2785
BLACK HILLS	NEIL SIMPSON 6 (II 2)	WY	7504	8.71	7.4	3.1	4.2	0.1	111	36	23	1.8	188
BLACK HILLS	WYGEN 1	WY	55479	8.89	49.9	34.5	15	0.4	69	24	12	1	4
PACIFICORP(SCOTTISH PWR)	Wyodak	WY	6101	32.41	187.8	10.5	176.5	0.8	214	76	35	3.1	700

Table F-2

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Healy SK-1	AK	6288	64.8557	-146.2789	160.0	76.2	2.4	20.1	93.9	2.14
Barry SK-1	AL	3	31.006176	-88.012451	146.1	182.9	7.8	18.9	907.9	34.92
Barry SK-2	AL	3	31.006985	-88.011174	137.8	182.9	5.5	28.0	661.5	22.87
Barry SK-3	AL	3	31.007297	-88.010294	146.1	182.9	7.6	25.9	1181.5	44.77
Charles R. Lowman SK-1	AL	56	31.4875	-87.9125	140.0	76.2	2.6	15.5	82.3	6.07
Charles R. Lowman SK-2	AL	56	31.4917	-87.9167	76.7	121.6	7.4	17.7	768.9	31.98
Colbert Fossil Plant SK-1	AL	47	34.7439	-87.8486	146.1	193.2	8.0	29.6	1486.5	47.09
Colbert Fossil Plant SK-2	AL	47	34.7447	-87.8494	154.4	152.4	6.4	29.6	950.5	29.66
Gadsden SK-1	AL	7	34.012711	-85.970276	157.2	91.4	4.6	17.4	285.6	7.45
Gaston SK-1	AL	26	33.244484	-86.45678	128.3	228.6	10.1	25.6	2039.8	63.65
Gaston SK-2	AL	26	33.242851	-86.458819	143.3	228.6	10.1	22.6	1781.3	46.33
Gorgas SK-1	AL	8	33.645099	-87.19972	143.3	106.7	7.3	16.5	691.2	12.62
Gorgas SK-2	AL	8	33.644653	-87.200289	143.3	230.1	10.1	22.6	1791.2	53.85
Greene County SK-1	AL	10	32.601123	-87.78236	146.1	152.4	7.4	22.6	967.8	34.62
Miller SK-1	AL	6002	33.632022	-87.059838	132.2	228.5	10.8	23.2	2115.0	103.47
Miller SK-2	AL	6002	33.633355	-87.059352	132.2	228.5	10.8	23.2	2115.0	95.13
Widows Creek Fossil Plant SK-1	AL	50	34.8825	-85.7547	147.8	304.8	8.2	29.9	1590.1	47.51
Widows Creek Fossil Plant SK-2	AL	50	34.885	-85.7511	76.7	152.4	6.3	24.7	775.6	24.19
Widows Creek Fossil Plant SK-3	AL	50	34.8856	-85.7506	82.2	152.4	6.2	21.6	658.4	34.12
Flint Creek SK-1	AR	6138	36.2562	-94.5241	134.9	164.6	6.1	34.1	993.3	37.84
Independence SK-1	AR	6641	35.6733	-91.4083	160.6	304.8	11.0	34.7	3322.9	121.74
White Bluff SK-1	AR	6009	34.4236	-92.1392	127.8	304.8	11.1	27.4	2640.0	105.92
Apache Station SK-1	AZ	160	32.0569	-109.8875	100.0	121.9	4.9	16.5	305.9	31.09
Cholla SK-1	AZ	113	34.9392	-110.2986	47.2	76.2	3.4	19.0	175.6	9.71
Cholla SK-2	AZ	113	34.9406	-110.2992	76.9	167.6	4.5	32.8	515.5	18.59
Cholla SK-3	AZ	113	34.9406	-110.2992	146.3	167.6	5.3	27.0	603.6	22.54
Cholla SK-4	AZ	113	34.9414	-110.3003	126.1	167.6	5.8	19.5	762.2	32.74
Coronado SK-1	AZ	6177	34.5778	-109.2717	132.0	152.4	5.8	34.5	911.5	29.93
Coronado SK-2	AZ	6177	34.5778	-109.2717	132.0	152.4	5.8	32.7	865.0	30.14
Irvington SK-1	AZ	126	32.1619	-110.9289	141.7	75.6	3.1	24.1	185.7	7.95
Navajo SK-1	AZ	4941	36.9125	-111.3917	50.0	236.2	7.5	32.3	1413.2	54.35
Navajo SK-2	AZ	4941	36.9125	-111.3917	50.0	236.2	7.5	32.3	1413.2	62.57
Navajo SK-3	AZ	4941	36.9125	-111.3917	50.0	236.2	7.5	32.3	1413.2	62.21
Springerville SK-1	AZ	8223	34.3186	-109.1636	74.4	152.4	6.2	25.6	772.9	31.24
Springerville SK-2	AZ	8223	34.3186	-109.1647	74.4	152.4	6.2	25.6	772.9	27.97

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Springerville SK-3	AZ	8223	34.3186	-109.1647	74.4	152.4	6.2	25.6	772.9	31.77
ACE Cogeneration Plant SK-1	CA	10002	34.8362	-115.9697	157.2	91.4	7.0	23.5	246.6	9.65
Hanford SK-1	CA	10373	36.33235	-119.61583	154.0	60.0	1.6	16.0	34.1	2.76
Mt. Poso Cogeneration Plant SK-1	CA	54626	35.607103	-119.077053	157.2	76.2	2.4	25.3	118.1	4.76
Port of Stockton District Energy Facility SK-1	CA	54238	37.943207	-121.32978	160.0	83.8	2.4	25.3	118.1	3.78
Rio Bravo Jasmin SK-1	CA	10768	35.521917	-119.080593	138.0	55.0	1.8	16.0	42.1	3.39
Rio Bravo Poso SK-1	CA	10769	35.560278	-119.085278	147.0	55.0	1.8	15.0	39.5	3.38
Stockton Cogen Company SK-1	CA	10640	37.913056	-121.261944	148.9	45.7	2.4	26.5	123.8	5.63
Arapahoe SK-2	CO	465	39.6772	-105.0031	143.3	76.2	4.6	21.9	360.3	13.52
Cameo SK-2	CO	468	39.1333	-108.3167	160.0	76.2	2.4	20.1	93.9	3.27
Cherokee SK-1	CO	469	39.8083	-105.9664	176.7	91.4	5.2	24.4	514.2	16.23
Cherokee SK-2	CO	469	39.8086	-105.9664	143.3	91.4	5.5	18.0	425.1	9.37
Cherokee SK-3	CO	469	39.8086	-105.9664	176.7	121.9	6.7	21.3	753.5	23.73
Comanche SK-1	CO	470	38.2078	-104.5747	148.9	152.4	7.1	20.8	831.9	24.89
Comanche SK-2	CO	470	38.2078	-104.5747	132.2	152.4	7.1	20.8	831.9	22.44
Craig SK-1	CO	6021	40.4628	-107.59	73.3	182.9	7.6	22.3	1014.7	36.74
Craig SK-2	CO	6021	40.4644	-107.5903	73.3	182.9	7.6	22.3	1014.7	35.56
Craig SK-3	CO	6021	40.4644	-107.5922	75.0	182.9	7.6	22.3	1014.7	30.32
Hayden SK-1	CO	525	40.4856	-107.185	156.7	76.2	4.9	19.6	374.9	16.66
Hayden SK-2	CO	525	40.4858	-107.1853	129.4	120.4	5.2	37.5	791.5	22.37
Martin Drake SK-1	CO	492	38.8244	-104.8331	160.0	61.0	3.2	16.2	132.2	3.53
Martin Drake SK-2	CO	492	38.8244	-104.8331	160.0	61.0	3.8	16.8	193.3	6.48
Martin Drake SK-3	CO	492	38.8244	-104.8331	154.4	76.2	4.6	18.3	300.6	11.33
Nucla SK-1	CO	527	38.2386	-108.5072	117.2	65.5	3.7	22.6	236.6	8.37
Pawnee SK-1	CO	6248	40.2694	-103.6933	154.4	167.6	7.2	18.3	737.6	39.83
Rawhide SK-1	CO	6761	40.8583	-105.0269	71.1	153.9	5.3	25.3	564.0	22.95
Ray D. Nixon SK-1	CO	8219	38.6306	-104.7056	132.2	140.2	5.3	19.5	436.9	15.68
Valmont SK-1	CO	477	40.0694	-105.2022	157.2	76.5	5.5	15.4	350.6	12.70
AES Thames, Inc. SK-1	CT	10675	41.4946	-72.1276	138.0	117.0	2.6	23.0	121.2	6.21
Bridgeport Harbor SK-3	CT	568	41.1706	-73.1833	148.9	151.8	4.3	40.5	579.8	24.34
Edge Moor SK-1	DE	593	39.7379	-75.5032	148.9	67.1	3.7	11.3	118.3	6.24
Edge Moor SK-2	DE	593	39.7392	-75.5033	121.7	67.1	3.7	21.9	230.2	11.16
Indian River SK-1	DE	594	38.5883	-75.2367	137.8	70.1	4.5	21.0	339.8	9.36
Indian River SK-2	DE	594	38.5881	-75.2372	137.8	117.3	4.1	19.2	255.0	9.67
Indian River SK-3	DE	594	38.5875	-75.2361	157.2	121.9	7.3	16.2	682.4	23.16
Big Bend SK-1	FL	645	27.7944	-82.4036	148.9	149.4	7.3	28.7	1203.2	45.49
Big Bend SK-2	FL	645	27.7944	-82.4028	144.4	149.4	7.3	14.3	601.6	19.53
Big Bend SK-3	FL	645	27.7942	-82.4028	68.9	149.4	7.3	19.8	832.0	28.26

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Cedar Bay Generating Company, L.P. SK-1	FL	10672	30.4537	-81.6595	165.6	121.9	4.9	30.5	569.3	18.13
Central Power and Lime, Inc. SK-1	FL	10333	28.5639	-82.3681	162.8	91.4	3.0	26.8	195.7	6.50
Crist SK-1	FL	641	30.565901	-87.224847	142.8	137.2	5.5	16.2	381.1	14.99
Crist SK-2	FL	641	30.565984	-87.223785	131.1	137.2	7.1	29.6	1156.1	53.14
Crystal River SK-1	FL	628	28.9575	-82.6997	171.1	152.1	4.6	39.4	647.5	24.48
Crystal River SK-2	FL	628	28.9575	-82.6997	143.3	153.3	4.9	36.9	690.0	26.51
Crystal River SK-3	FL	628	28.9664	-82.6969	122.8	182.9	7.8	21.0	1000.2	48.89
Crystal River SK-4	FL	628	28.9664	-82.6969	122.8	182.9	7.8	21.0	1000.2	49.86
Deerhaven SK-1	FL	663	29.7167	-82.3833	168.9	106.7	5.6	18.9	472.4	14.16
Indiantown Cogeneration Facility SK-1	FL	50976	27.1098	-80.4832	76.7	150.9	4.9	30.2	564.0	21.13
Lansing Smith SK-1	FL	643	30.268512	-85.700057	128.3	61.0	5.5	19.8	469.4	24.52
MCINTOSH (FL) 3 SK-0	FL	676	28.0805555	-81.925	76.0	76.4	5.6	27.0	674.4	24.77
NORTHSIDE 1 SK-1	FL	667	30.3644444	-81.6222222	93.3	121.2	4.6	19.1	310.3	18.91
NORTHSIDE 2 SK-2	FL	667	30.3644444	-81.6222222	93.3	121.2	4.6	19.1	310.3	16.64
Polk SK-1	FL	7242	27.728611	-81.98972	171.0	48.0	5.8	23.0	605.6	17.22
Scholz SK-1	FL	642	30.669108	-84.887535	163.3	45.7	4.1	12.3	163.8	5.09
Seminole SK-1	FL	136	29.7336	-81.6339	51.7	211.8	11.5	19.5	2015.3	94.39
St. Johns River Power Park SK-1	FL	207	30.4308	-81.5508	60.0	195.1	9.7	27.4	2020.1	94.73
Stanton Energy SK-1	FL	564	28.4822	-81.1678	52.8	167.6	5.8	25.3	667.8	31.80
Stanton Energy SK-2	FL	564	28.4828	-81.1678	52.8	167.6	5.8	25.3	667.8	30.17
Bowen SK-1	GA	703	34.12575	-84.922493	149.4	304.8	10.7	20.7	1888.0	102.07
Bowen SK-2	GA	703	34.126034	-84.921055	161.7	304.8	10.7	27.1	2470.0	118.62
Hammond SK-1	GA	708	34.252916	-85.345691	160.0	228.6	9.0	22.9	1445.3	49.33
Harllee Branch SK-1	GA	709	33.194079	-83.300192	132.2	304.8	11.1	24.4	2344.8	101.69
Jack McDonough SK-1	GA	710	33.824673	-84.474751	155.6	254.8	7.5	22.9	998.0	37.12
Kraft SK-1	GA	733	32.149432	-81.144987	140.6	83.8	6.7	14.0	495.2	14.15
McIntosh SK-1	GA	6124	32.356759	-81.168135	152.8	121.9	3.5	24.1	232.8	7.67
Mitchell (GA) SK-1	GA	727	31.445095	-84.135098	148.9	152.4	6.4	9.8	313.6	5.98
Scherer SK-1	GA	6257	33.05959	-83.807402	136.7	304.8	11.6	23.2	2462.6	131.56
Scherer SK-2	GA	6257	33.061425	-83.806586	127.8	304.8	11.6	24.1	2559.8	131.08
Wansley SK-1	GA	6052	33.413763	-85.03327	157.2	304.8	11.9	20.4	2257.5	121.36
Yates SK-1	GA	728	33.4631	-84.9055	52.2	78.0	4.0	15.5	191.0	6.14
Yates SK-2	GA	728	33.463015	-84.90523	140.6	251.5	6.7	28.3	1005.8	29.99
Yates SK-3	GA	728	33.462308	-84.898438	137.2	243.8	7.0	28.3	1089.5	43.45
AES Hawaii, Inc. SK-1	HI	10673	21.4796	-157.9684	154.4	86.9	3.3	20.2	176.1	5.29
Ames SK-1	IA	1122	42.0247	-93.6064	198.9	61.0	2.4	17.1	79.3	2.21
Ames SK-2	IA	1122	42.0247	-93.6064	156.1	63.1	3.4	16.5	145.3	4.75
Burlington SK-1	IA	1104	40.7411	-91.1169	127.2	93.3	3.6	29.9	299.9	13.34

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Council Bluffs SK-1	IA	1082	41.18	-95.8408	160.0	76.2	3.7	12.4	129.9	5.27
Council Bluffs SK-2	IA	1082	41.18	-95.8406	143.3	76.2	3.7	12.7	133.5	9.54
Council Bluffs SK-3	IA	1082	41.1806	-95.8389	82.2	167.6	7.6	35.1	1601.8	74.72
Council Bluffs SK-4	IA	1082	41.1806	-95.8389	73.9	167.9	7.5	29.5	1309.1	89.52
Dubuque SK-1	IA	1046	42.4848	-90.804	176.7	48.2	2.7	10.4	75.6	1.81
Dubuque SK-2	IA	1046	42.4848	-90.804	154.4	48.2	2.7	14.6	86.5	2.45
Earl F. Wisdom SK-1	IA	1217	43.0827	-95.1507	176.7	45.1	2.4	18.1	84.6	1.02
Fair Station SK-2	IA	1218	41.466	-91.0763	162.8	50.0	2.4	16.8	78.3	2.67
George Neal North SK-1	IA	1091	42.3167	-96.3667	160.0	68.6	2.9	39.5	255.4	9.51
George Neal North SK-2	IA	1091	42.3167	-96.3667	143.3	91.4	4.7	31.8	540.1	18.31
George Neal North SK-3	IA	1091	42.3167	-96.3667	176.7	121.9	6.1	32.8	957.6	37.23
George Neal South SK-4	IA	7343	42.3022	-96.3622	148.9	143.0	7.6	32.3	1472.8	47.71
Lansing SK-2	IA	1047	43.3356	-91.1669	152.2	48.5	1.7	27.7	64.4	1.86
Lansing SK-3	IA	1047	43.3367	-91.1664	129.4	152.1	4.7	24.7	424.5	16.83
Louisa SK-1	IA	6664	41.3153	-91.0936	82.2	185.9	9.1	28.5	1401.7	39.04
Milton L. Kapp SK-1	IA	1048	41.8075	-90.2339	142.8	74.7	4.0	24.1	297.4	12.23
Muscatine SK-1	IA	1167	41.3903	-91.0564	170.0	67.1	2.6	27.1	143.8	6.75
Muscatine SK-2	IA	1167	41.3917	-91.0569	80.0	91.4	3.5	24.1	233.0	12.76
Ottumwa SK-1	IA	6254	41.0981	-92.5547	134.4	182.9	7.6	27.7	1264.9	44.66
PELLA 6 SK-1	IA	1175	41.3969444	-92.9055556	150.0	84.2	1.8	20.0	53.3	1.41
Prairie Creek SK-2	IA	1073	41.9442	-91.6367	156.1	54.9	3.8	7.6	85.6	2.69
Prairie Creek SK-3	IA	1073	41.9442	-91.6367	140.0	61.0	4.0	17.1	210.8	7.27
Riverside SK-2	IA	1081	41.54	-90.4478	147.2	105.6	4.1	23.8	311.3	7.81
SIXTH STREET (IA) 8 SK-0	IA	1058	41.9838888	-91.6666667	150.0	60.0	3.0	20.0	145.1	2.52
Streeter Station SK-1	IA	1131	42.4698	-92.3092	168.3	93.6	2.6	14.6	77.1	1.23
Sutherland SK-1	IA	1077	42.08	-92.8603	162.8	75.6	2.9	9.8	64.4	3.36
Sutherland SK-2	IA	1077	42.08	-92.8603	162.8	75.6	2.9	9.8	64.4	3.53
Sutherland SK-3	IA	1077	42.08	-92.8603	168.3	75.6	2.9	19.5	128.7	6.52
Baldwin SK-1	IL	889	38.205	-89.8544	148.9	184.4	6.0	29.3	818.5	36.90
Baldwin SK-2	IL	889	38.205	-89.8544	148.9	184.4	5.9	29.3	812.7	49.25
Baldwin SK-3	IL	889	38.205	-89.8544	131.1	184.4	5.9	32.6	905.8	50.83
Coffeen SK-1	IL	861	39.05838	-89.40335	166.4	152.4	8.8	23.9	1465.2	60.28
Crawford SK-1	IL	867	41.8294	-87.7228	142.8	118.3	3.1	42.7	329.0	11.64
Crawford SK-2	IL	867	41.8294	-87.7228	148.9	115.2	3.6	43.9	448.2	17.12
Dallman SK-1	IL	963	39.7547	-89.6008	160.0	137.5	3.0	22.9	166.8	4.86
Dallman SK-2	IL	963	39.7547	-89.6014	160.0	137.5	3.0	22.9	166.8	4.87
Dallman SK-3	IL	963	39.7536	-89.6019	60.0	152.4	4.6	19.8	325.3	10.63
Duck Creek SK-1	IL	6016	40.46701	-89.98498	48.2	157.0	5.8	19.5	512.6	5.21

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
E. D. Edwards SK-1	IL	856	40.59603	-89.66196	151.6	152.4	6.4	21.8	701.1	24.85
E. D. Edwards SK-2	IL	856	40.59603	-89.66196	169.4	152.4	7.6	15.9	726.0	20.50
Fisk SK-1	IL	886	41.8506	-87.6533	171.1	135.9	4.3	35.1	501.3	16.97
Havana SK-1	IL	891	40.2797	-90.08	166.1	152.4	6.1	24.7	719.9	34.29
Hennepin SK-1	IL	892	41.3028	-89.315	142.2	83.8	4.4	27.1	415.6	21.27
Hutsonville SK-1	IL	863	39.13368	-87.65986	149.4	59.7	3.7	13.0	136.3	4.95
Hutsonville SK-2	IL	863	39.13368	-87.65986	153.2	59.7	3.7	15.4	162.1	4.54
JOLIET 6 SK-6	IL	874	41.4930555	-88.1138889	148.9	136.4	4.1	39.1	516.9	17.23
Joliet SK-2	IL	384	41.495	-88.1244	143.9	167.6	5.2	36.6	808.9	27.19
Joliet SK-3	IL	384	41.495	-88.1244	143.9	167.6	5.2	36.6	808.9	29.94
Joppa Steam SK-1	IL	887	37.2083	-88.8586	160.0	167.6	5.5	26.8	632.7	28.48
Joppa Steam SK-2	IL	887	37.2092	-88.8586	160.0	167.6	5.5	26.8	632.7	28.46
Joppa Steam SK-3	IL	887	37.2106	-88.8578	160.0	167.6	5.5	26.8	632.7	27.11
Kincaid Generation, L.L.C. SK-1	IL	876	39.5942	-89.4983	157.2	186.2	9.0	36.6	2335.1	67.17
Lakeside SK-1	IL	964	39.7545	-89.602	171.1	91.4	3.7	13.4	140.9	3.42
Marion SK-1	IL	976	37.6167	-88.95	148.9	64.0	4.1	12.5	165.9	10.13
Marion SK-2	IL	976	37.6167	-88.95	53.9	121.9	4.6	19.8	325.7	10.06
Meredosia SK-1	IL	864	39.8224	-90.5674	184.7	160.3	4.3	22.2	316.9	21.10
Newton SK-1	IL	6017	38.9364	-88.2765	158.1	161.5	6.1	31.5	917.9	46.25
Newton SK-2	IL	6017	38.9364	-88.2765	176.3	161.5	7.3	23.6	990.6	43.57
Powerton SK-1	IL	879	40.545	-89.6789	148.9	152.4	10.4	33.8	2853.8	89.51
Vermilion SK-1	IL	897	40.1781	-87.7481	148.3	83.8	4.5	16.8	263.2	9.56
WAUKEGAN 6 SK-4	IL	883	42.3833333	-87.8111111	176.7	100.0	3.5	20.9	199.7	5.06
Waukegan SK-2	IL	883	42.3831	-87.8133	148.9	137.2	4.3	36.3	525.4	22.10
Waukegan SK-3	IL	883	42.3831	-87.8133	148.9	137.2	4.1	37.2	493.8	24.41
Will County SK-1	IL	884	41.6333	-88.0614	172.2	106.4	4.0	29.6	365.1	8.36
Will County SK-2	IL	884	41.6333	-88.0614	172.2	106.4	4.0	29.6	365.1	8.32
Will County SK-3	IL	884	41.6333	-88.0614	148.9	136.6	4.5	29.3	470.2	15.74
Will County SK-4	IL	884	41.6333	-88.0614	143.3	152.4	5.0	36.9	733.5	26.00
Wood River SK-1	IL	898	38.8639	-90.1347	148.9	76.2	5.2	7.3	154.3	6.07
Wood River SK-2	IL	898	38.8639	-90.1347	144.4	106.7	4.6	31.4	518.9	24.27
A. B. Brown SK-1	IN	6137	37.9053	-87.715	54.4	151.2	4.3	30.5	435.9	18.03
A. B. Brown SK-2	IN	6137	37.9053	-87.715	54.4	151.2	4.3	30.5	435.9	18.29
Bailly SK-1	IN	995	41.6431	-87.1228	143.3	121.9	4.7	39.0	662.9	26.16
Cayuga (IN) SK-1	IN	1001	39.922594	-87.427839	143.3	152.4	4.6	72.7	763.6	29.87
Cayuga (IN) SK-2	IN	1001	39.922594	-87.427839	143.3	152.4	4.6	72.7	763.6	38.03
Clifty Creek SK-1	IN	983	38.7383	-85.4192	176.7	299.6	6.9	33.5	1270.6	42.05
Clifty Creek SK-2	IN	983	38.7389	-85.4197	176.7	299.6	6.9	33.5	1270.6	44.31

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
E. W. Stout SK-1	IN	990	39.7092	-86.1967	155.6	79.9	3.7	18.8	197.4	6.92
E. W. Stout SK-2	IN	990	39.7092	-86.1967	155.6	79.9	3.7	18.8	197.4	7.54
E. W. Stout SK-3	IN	990	39.7092	-86.1967	157.2	172.2	6.1	23.5	685.0	25.06
Edwardsport SK-1	IN	1004	38.8067	-87.2472	161.1	55.8	2.6	18.0	92.9	2.14
Edwardsport SK-2	IN	1004	38.8067	-87.2472	161.1	55.8	2.6	18.0	92.9	1.32
F. B. Culley SK-1	IN	1012	37.91	-87.3267	160.6	75.9	3.0	11.0	80.1	2.24
F. B. Culley SK-2	IN	1012	37.9094	-87.3267	171.1	84.1	4.0	13.7	172.0	6.91
F. B. Culley SK-3	IN	1012	37.9092	-87.3258	53.3	152.1	6.1	18.6	544.1	19.02
Frank E. Ratts SK-1	IN	1043	38.5202	-87.2663	137.0	91.4	3.4	16.8	128.3	10.03
Frank E. Ratts SK-2	IN	1043	38.5202	-87.2663	134.0	91.4	3.4	16.6	134.2	7.52
Gibson Generating Station SK-1	IN	6113	38.3715	-87.7683	57.0	189.0	7.5	21.0	921.5	36.97
Gibson Generating Station SK-2	IN	6113	38.3715	-87.7683	57.0	189.0	7.6	21.2	965.4	43.89
Gibson Generating Station SK-3	IN	6113	38.3715	-87.7683	57.0	189.0	7.6	21.2	965.4	49.49
Gibson Generating Station SK-4	IN	6113	38.3715	-87.7683	62.8	152.4	7.2	21.4	862.3	51.45
Gibson Generating Station SK-5	IN	6113	38.3715	-87.7683	62.8	152.4	7.2	21.4	862.3	52.72
H.T. Pritchard SK-1	IN	991	39.4854	-86.418	204.4	85.6	4.6	15.5	256.2	6.89
H.T. Pritchard SK-2	IN	991	39.4854	-86.418	183.3	85.6	5.5	17.4	411.7	9.87
Merom SK-1	IN	6213	39.0694	-87.5108	80.6	214.6	8.2	31.4	1650.5	69.93
Michigan City SK-1	IN	997	41.7219	-86.9092	162.8	153.9	6.4	26.5	852.5	27.70
Petersburg SK-1	IN	994	38.5267	-87.2522	76.7	168.6	4.6	28.3	465.3	18.85
Petersburg SK-2	IN	994	38.5267	-87.2522	76.7	186.5	6.1	23.3	681.5	31.63
Petersburg SK-3	IN	994	38.5272	-87.2522	74.4	187.5	6.7	26.6	940.0	36.99
Petersburg SK-4	IN	994	38.5283	-87.2522	65.6	187.5	6.7	25.3	893.0	39.66
R. Gallagher Station SK-1	IN	1008	38.2631	-85.8378	140.6	167.6	3.7	50.0	552.2	16.70
R. Gallagher Station SK-2	IN	1008	38.2631	-85.8378	140.6	167.6	3.7	50.0	552.2	16.33
R.M. Schahfer SK-1	IN	6085	41.2167	-87.0222	152.8	152.4	6.4	28.0	901.5	27.47
R.M. Schahfer SK-2	IN	6085	41.2167	-87.0231	148.9	152.4	6.4	31.1	999.4	28.48
R.M. Schahfer SK-3	IN	6085	41.2161	-87.0242	71.1	151.2	5.5	31.7	747.7	29.49
R.M. Schahfer SK-4	IN	6085	41.2161	-87.0249	71.1	151.2	5.5	31.7	747.7	26.95
Rockport SK-1	IN	6166	37.9256	-87.0372	156.6	317.0	13.0	33.6	4429.8	155.97
State Line SK-1	IN	981	41.7072	-87.5217	165.6	121.9	5.0	15.5	309.2	14.08
State Line SK-2	IN	981	41.7072	-87.5217	148.9	137.2	4.4	29.6	452.9	16.65
Tanners Creek SK-1	IN	988	39.0809	-84.8608	143.6	121.9	7.1	16.3	653.4	31.15
Tanners Creek SK-2	IN	988	39.0833	-84.858	149.2	123.0	7.1	14.6	584.2	23.20
Wabash River IGCC Unit	IN	1010	39.5278	-87.4222	232.2	179.8	5.5	19.2	453.1	10.08
Wabash River SK-2	IN	1010	39.5278	-87.4222	137.8	137.2	7.6	34.3	1563.0	42.81
WARRICK 1 SK-1	IN	6705	37.9088888	-87.3305556	151.7	121.2	4.6	21.2	358.4	9.98
WARRICK 2 SK-1	IN	6705	37.9088888	-87.3305556	151.7	121.2	4.6	21.2	358.4	9.62

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
WARRICK 3 SK-2	IN	6705	37.9088888	-87.3305556	151.7	121.2	4.6	21.2	358.4	8.67
Warrick Power Plant SK-1	IN	6705	37.9153	-87.3336	167.2	152.4	4.4	43.0	658.4	19.62
Whitewater Valley SK-1	IN	1040	39.8028	-84.895	164.4	99.1	3.4	18.8	170.8	5.03
Holcomb SK-1	KS	108	37.9319	-100.9719	82.2	147.2	5.0	36.0	701.5	29.49
Jeffrey Energy Center SK-1	KS	6068	39.2856	-96.1083	76.7	182.9	7.8	27.7	1316.0	54.62
Jeffrey Energy Center SK-2	KS	6068	39.2856	-96.11	76.7	182.9	7.8	27.7	1316.0	59.81
Jeffrey Energy Center SK-3	KS	6068	39.2856	-96.11	76.7	182.9	7.8	27.7	1316.0	49.82
La Cygne SK-1	KS	1241	38.3481	-94.6456	79.4	212.8	7.0	27.4	1057.9	45.00
La Cygne SK-2	KS	1241	38.3481	-94.6456	148.9	213.4	7.3	30.5	1280.0	60.42
Lawrence SK-1	KS	1250	39.0075	-95.2677	132.2	42.4	2.8	14.3	87.9	4.28
Lawrence SK-2	KS	1250	39.0072	-95.2678	76.7	51.8	3.5	18.3	170.9	9.19
Lawrence SK-3	KS	1250	39.0072	-95.2678	74.4	108.2	5.5	24.4	577.3	25.56
Nearman Creek SK-1	KS	6064	39.1714	-94.6958	137.8	121.9	6.1	13.4	391.0	17.93
Quindaro SK-1	KS	1295	39.151	-94.636681	165.6	106.7	2.6	22.9	116.9	5.15
Quindaro SK-2	KS	1295	39.151	-94.636681	163.3	106.7	3.4	25.3	223.4	7.56
Riverton SK-1	KS	1239	37.0715	-94.6985	176.7	53.3	3.4	14.6	129.2	7.09
Tecumseh SK-1	KS	1252	39.0531	-95.5686	132.8	68.6	3.5	14.0	135.5	5.60
Tecumseh SK-2	KS	1252	39.0528	-95.5683	136.7	68.6	3.5	25.6	252.2	10.75
Big Sandy SK-1	KY	1353	38.1737	-82.6186	160.1	251.8	8.6	25.9	1515.6	72.88
Cane Run SK-4	KY	1363	38.1828	-85.8894	53.3	78.3	4.7	13.0	229.7	11.14
Cane Run SK-5	KY	1363	38.1831	-85.8892	53.3	78.3	4.7	14.0	245.5	11.12
Cane Run SK-6	KY	1363	38.1833	-85.8886	54.4	157.9	5.8	11.8	311.8	15.32
Coleman SK-1	KY	1381	37.9620555	-86.7927945	54.4	137.2	7.6	14.5	652.5	33.08
Cooper SK-1	KY	1384	37	-84.5917	154.4	79.2	5.5	22.6	532.0	20.31
D. B. Wilson SK-1	KY	6823	37.4496715	-87.0805373	54.4	182.9	6.7	24.4	859.9	35.53
Dale SK-1	KY	1385	37.8808	-84.262	160.0	45.7	3.4	10.7	97.8	2.97
Dale SK-2	KY	1385	37.8808	-84.262	154.4	45.7	3.7	26.9	273.5	9.11
E. W. Brown SK-1	KY	1355	37.7881444	-84.7124694	148.9	105.5	4.2	35.1	188.1	7.54
E. W. Brown SK-2	KY	1355	37.7882777	-84.7135639	148.9	172.2	5.6	26.4	929.7	33.14
East Bend Station SK-1	KY	6018	38.90417	-84.84722	65.6	198.1	7.2	34.0	1368.7	40.15
Elmer Smith SK-1	KY	1374	37.7942	-87.0608	148.9	198.1	5.7	22.5	576.6	9.79
Elmer Smith SK-2	KY	1374	37.7942	-87.0608	54.4	128.0	7.7	16.0	736.5	14.42
Ghent SK-1	KY	1356	38.7485	-85.0374	54.4	177.1	11.7	4.7	1584.2	67.45
Ghent SK-2	KY	1356	38.7493	-85.0364	154.4	201.2	9.1	16.9	891.5	27.75
Ghent SK-3	KY	1356	38.748	-85.0384	165.6	202.1	9.1	18.1	783.6	31.70
Green River SK-1	KY	1357	37.3633	-87.1217	162.8	60.7	3.7	44.5	163.8	6.14
Green River SK-2	KY	1357	37.3634	-87.1223	176.7	74.5	3.7	48.2	224.0	5.51
H.L. Spurlock SK-1	KY	6041	38.7003	-83.8164	143.9	245.4	4.6	28.7	471.0	26.24

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
H.L. Spurlock SK-2	KY	6041	38.7	-83.8175	140.6	245.4	6.7	23.5	828.8	41.79
H.L. Spurlock SK-3	KY	6041	38.7	-83.8175	60.0	198.1	4.6	18.2	298.0	12.24
HENDERSON ONE 6 SK-1	KY	1372	37.8452	-87.5912	165.0	39.7	2.9	10.7	77.8	0.08
HENDERSON TWO 1 SK-H	KY	1382	37.6472222	-87.5027778	157.2	106.1	4.8	21.5	397.1	7.82
HENDERSON TWO 2 SK-H	KY	1382	37.6472222	-87.5027778	157.2	106.1	4.8	21.5	397.1	9.41
Mill Creek SK-1	KY	1364	38.0531	-85.91	54.4	182.9	8.0	16.7	834.1	45.18
Mill Creek SK-3	KY	1364	38.0522	-85.9097	54.4	182.9	5.5	22.1	520.9	32.20
Mill Creek SK-4	KY	1364	38.0519	-85.91	54.4	182.9	5.9	23.1	642.5	34.01
Paradise Fossil Plant SK-1	KY	1378	37.2608	-86.9783	51.7	182.9	7.9	22.1	1089.6	37.51
Paradise Fossil Plant SK-2	KY	1378	37.2606	-86.9789	51.7	182.9	7.9	22.1	1089.6	42.89
Paradise Fossil Plant SK-3	KY	1378	37.2595	-86.9785	55.6	186.4	11.3	15.2	1535.7	41.42
R. D. Green SK-1	KY	6639	37.6465049	-87.5000119	54.4	106.7	4.6	26.4	433.9	20.69
R. D. Green SK-2	KY	6639	37.6465860	-87.5006238	54.4	106.7	4.6	26.4	433.9	18.13
Robert Reid SK-1	KY	1383	37.6462333	-87.5019961	151.7	76.2	3.8	18.3	208.7	2.97
Shawnee Fossil Plant SK-1	KY	1379	37.1517	-88.775	138.9	243.8	8.5	24.4	1395.9	48.65
Shawnee Fossil Plant SK-2	KY	1379	37.1533	-88.7786	138.9	243.8	8.5	24.4	1395.9	47.23
Trimble County SK-1	KY	6071	38.5846027	-85.4137306	51.7	218.2	5.5	9.4	638.1	37.09
Tyrone SK-1	KY	1361	38.0499972	-84.8467389	154.4	54.9	3.4	46.1	191.3	5.02
Big Cajun 2 SK-1	LA	6055	30.7283	-91.3686	146.7	182.9	8.1	22.9	1173.2	42.58
Big Cajun 2 SK-2	LA	6055	30.7281	-91.3694	146.7	182.9	8.1	22.9	1173.2	42.96
Big Cajun 2 SK-3	LA	6055	30.7278	-91.3703	137.8	182.9	8.1	22.9	1173.2	41.61
Dolet Hills Power Station SK-1	LA	51	32.0308	-93.5644	70.0	160.0	7.6	25.9	1181.5	42.54
R S Nelson SK-1	LA	1393	30.2861	-93.2917	136.0	59.4	3.0	30.0	217.6	21.27
R.S. Nelson 6 SK-2	LA	1393	30.2861	-93.2958	136.1	152.4	6.9	30.2	1115.6	40.16
Rodemacher Power Station SK-1	LA	6190	31.3947	-92.7169	146.7	80.8	5.5	28.7	675.8	38.55
Brayton Point SK-1	MA	1619	41.7103	-71.1931	123.9	107.3	4.4	23.8	340.0	19.04
Brayton Point SK-2	MA	1619	41.7103	-71.1931	123.9	107.3	4.4	23.8	340.0	20.21
Brayton Point SK-3	MA	1619	41.7108	-71.1947	123.9	107.3	5.9	26.5	736.5	39.34
Mount Tom SK-1	MA	1606	42.2806	-72.6056	136.7	112.8	3.1	27.4	201.4	11.37
Salem Harbor SK-1	MA	1626	42.5267	-70.8792	148.9	132.6	2.8	27.4	163.2	5.27
Salem Harbor SK-2	MA	1626	42.5267	-70.8792	148.9	132.6	2.8	27.4	163.2	5.47
Salem Harbor SK-3	MA	1626	42.5267	-70.8792	148.9	132.6	3.8	27.4	313.3	8.96
Somerset SK-2	MA	1613	41.7333	-71.1333	154.4	94.5	4.0	17.7	218.3	8.08
AES Warrior Run SK-1	MD	10678	39.6478	-78.7692	148.9	91.4	4.0	26.2	323.2	15.13
Brandon Shores SK-1	MD	602	39.18	-76.5333	131.1	211.8	6.7	23.8	839.6	39.05
Brandon Shores SK-2	MD	602	39.18	-76.5333	131.1	211.8	6.7	23.8	839.6	46.87
C.P. Crane SK-1	MD	1552	39.3233	-76.3667	154.4	77.1	3.3	29.9	260.9	9.65
C.P. Crane SK-2	MD	1552	39.3233	-76.3667	154.4	77.1	3.3	29.0	252.9	11.50

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Chalk Point SK-1	MD	1571	38.5639	-76.6806	117.8	213.4	9.6	11.0	794.9	41.40
Dickerson SK-1	MD	1572	39.2097	-77.4644	79.4	214.3	7.6	14.9	681.1	30.85
H.A. Wagner SK-1	MD	1554	39.1778	-76.5333	136.7	87.5	3.1	22.9	172.2	8.06
H.A. Wagner SK-2	MD	1554	39.1778	-76.5333	145.6	105.5	4.2	28.7	399.3	21.78
Morgantown SK-1	MD	1573	38.3611	-76.9861	121.1	213.4	5.9	24.4	677.2	31.39
Morgantown SK-2	MD	1573	38.3611	-76.9861	121.1	213.4	5.9	24.4	677.2	34.21
R. Paul Smith SK-1	MD	1570	39.594923	-77.827436	155.8	57.0	3.3	8.5	73.5	1.78
R. Paul Smith SK-2	MD	1570	39.594862	-77.826868	144.7	86.3	6.8	22.4	235.3	5.57
Rumford Cogeneration SK-CGNSTK	ME	10495	44.5524	-70.54599	170.6	125.8	5.8	33.9	882.0	5.02
B.C. Cobb SK-1	MI	1695	43.2542	-86.2402	151.7	198.1	6.3	17.0	539.6	22.26
Belle River Power Plant SK-1	MI	6034	42.775	-82.4939	143.3	202.7	7.8	27.4	1302.6	34.32
Belle River Power Plant SK-2	MI	6034	42.7756	-82.495	143.3	202.7	7.8	27.4	1302.6	30.68
Dan E. Karn SK-1	MI	1702	43.643	-83.8412	143.3	106.7	5.5	20.1	474.1	18.44
Dan E. Karn SK-2	MI	1702	43.6427	-83.8412	146.1	106.7	5.5	20.1	474.2	18.55
Eckert Station SK-1	MI	1831	42.7189	-84.5583	143.3	188.7	3.2	36.0	282.0	7.88
Eckert Station SK-2	MI	1831	42.7189	-84.5583	143.3	188.7	4.2	32.3	451.2	12.55
Endicott SK-1	MI	4259	42.031	-84.7535	71.1	76.2	2.4	20.1	93.9	5.79
Erikcson SK-1	MI	1832	42.6919	-84.6572	140.6	144.8	5.2	11.0	231.4	13.15
Harbor Beach Power Plant SK-1	MI	1731	43.8519	-82.6436	137.8	91.4	2.7	38.4	218.5	0.89
J.C. Weadock SK-1	MI	1720	43.6372	-83.8444	151.7	151.8	5.2	21.0	443.6	18.05
J.H. Campbell SK-1	MI	1710	42.9103	-86.2032	140.6	121.9	5.8	40.2	1059.8	34.01
J.H. Campbell SK-2	MI	1710	42.9121	-86.2033	160.0	195.7	8.3	27.3	1480.0	45.80
J.R. Whiting SK-1	MI	1723	41.7914	-83.4486	160.0	90.5	3.4	24.2	213.4	8.56
J.R. Whiting SK-2	MI	1723	41.7917	-83.4486	160.0	90.5	3.4	22.4	197.9	8.69
J.R. Whiting SK-3	MI	1723	41.7919	-83.4486	165.6	90.5	3.6	26.0	266.0	9.01
James De Young SK-3	MI	1830	42.96	-85.99	143.3	61.0	2.3	15.4	61.7	1.69
JB SIMS 3 SK-1	MI	1825	43.0722222	-86.2333333	77.0	109.1	5.2	21.0	437.7	4.95
Monroe Power Plant SK-1	MI	1733	41.8931	-83.3444	132.2	245.4	8.5	36.6	2092.3	78.24
Monroe Power Plant SK-2	MI	1733	41.8924	-83.3464	132.2	245.4	8.5	36.6	2092.3	89.31
Presque Isle SK-1	MI	1769	46.5789	-87.3951	148.9	121.9	5.1	22.5	462.6	20.48
Presque Isle SK-2	MI	1769	46.5789	-87.3951	160.0	125.0	5.0	25.9	512.1	20.46
River Rouge Power Plant SK-2	MI	1740	42.2739	-83.1124	147.8	117.3	3.7	45.1	492.9	15.89
River Rouge Power Plant SK-3	MI	1740	42.2742	-83.1128	160.0	129.5	3.9	48.7	585.0	12.88
Shiras SK-2	MI	1843	46.43	-87.65	73.9	106.7	2.7	15.2	90.1	4.13
St Clair Power Plant SK-1	MI	1743	42.764	-82.4722	148.9	182.6	4.1	25.6	331.0	29.85
St Clair Power Plant SK-2	MI	1743	42.766	-82.4719	148.9	129.5	4.1	47.5	613.7	16.48
St Clair Power Plant SK-3	MI	1743	42.766	-82.4711	148.9	182.9	4.9	39.9	745.8	21.22
TES Filer City Station SK-1	MI	50835	44.3413	-86.1029	71.1	76.2	2.7	19.2	111.7	6.29

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Trenton Channel Power Plant SK-1	MI	1745	42.1225	-83.1811	154.4	170.4	4.4	42.7	654.7	12.51
Trenton Channel Power Plant SK-2	MI	1745	42.1217	-83.1808	154.4	171.1	4.9	42.7	798.1	21.25
WYANDOTTE 7&8 SK-1	MI	1866	42.2083	-83.1449	150.0	62.7	3.3	20.0	174.5	4.12
Allen S. King SK-1	MN	1915	45.03	-92.7786	185.0	239.3	5.6	33.5	838.2	7.78
Black Dog SK-1	MN	1904	44.8167	-93.25	157.2	182.9	6.9	23.8	879.0	15.86
Clay Boswell SK-1	MN	1893	47.2611	-93.6572	87.8	213.4	8.8	14.6	898.4	32.21
Clay Boswell SK-2	MN	1893	47.2611	-93.6572	70.0	182.9	6.1	30.8	897.6	41.09
High Bridge SK-1	MN	1912	44.9333	-93.1083	165.6	173.7	6.6	16.2	557.4	8.14
Hoot Lake SK-2	MN	1943	46.29	-96.0428	156.7	68.6	4.1	26.5	344.8	10.73
Laskin Energy Center SK-1	MN	1891	47.53	-92.1617	57.8	91.4	3.2	29.0	233.8	8.59
NE Station SK-1	MN	1961	43.7006	-92.9617	135.0	43.3	1.9	18.4	53.8	1.08
Riverside SK-1	MN	1927	45.0203	-93.2753	149.0	74.1	3.7	15.2	159.8	9.97
Riverside SK-2	MN	1927	45.0203	-93.2753	149.0	144.8	4.9	20.1	376.0	13.83
Sherburne County SK-1	MN	6090	45.3792	-93.8958	79.4	198.1	9.9	32.0	2468.1	110.45
Sherburne County SK-2	MN	6090	45.3794	-93.8986	79.4	198.1	7.9	25.6	1260.9	54.07
Silver Lake SK-1	MN	2008	44.0281	-92.4597	176.7	54.9	3.0	15.5	113.4	2.51
TACONITE HARBOR SK-S1	MN	10075	47.5313888	-90.9111111	181.1	66.7	3.0	20.6	147.6	6.79
TACONITE HARBOR SK-S2	MN	10075	47.5313888	-90.9111111	181.1	66.7	3.0	20.6	147.6	5.70
TACONITE HARBOR SK-S3	MN	10075	47.5313888	-90.9111111	181.1	66.7	3.0	20.6	147.6	5.34
Asbury SK-1	MO	2076	37.361	-94.589	144.4	121.9	4.0	23.5	289.9	11.00
Blue Valley SK-3	MO	2132	39.0919	-94.3364	155.0	76.2	2.1	19.8	66.3	1.85
Chamois SK-2	MO	2169	38.6722	-91.7711	160.0	49.7	2.3	19.4	81.3	4.29
Hawthorn SK-1	MO	2079	39.1306	-94.4778	73.9	182.9	6.5	27.2	893.0	38.21
Iatan SK-1	MO	6065	39.4483	-94.9808	148.9	213.4	7.3	30.5	1280.0	42.06
James River Power Station SK-2	MO	2161	37.1083	-93.26	154.4	61.0	3.7	8.8	92.7	3.81
James River Power Station SK-3	MO	2161	37.1083	-93.2603	154.4	61.0	3.7	10.1	105.5	5.45
James River Power Station SK-4	MO	2161	37.1083	-93.2606	160.0	106.7	2.5	29.9	149.8	8.55
Labadie SK-1	MO	2103	38.5619	-90.8375	163.1	213.4	6.2	32.7	1001.4	47.07
Labadie SK-2	MO	2103	38.5619	-90.8375	151.1	213.4	6.2	30.3	929.7	45.68
Labadie SK-3	MO	2103	38.5619	-90.8375	140.4	213.4	6.2	32.0	979.8	48.17
Labadie SK-4	MO	2103	38.5619	-90.8375	173.8	213.4	6.3	34.8	1067.8	48.40
Lake Road Plant SK-2	MO	2098	39.725	-94.875	170.0	68.6	3.1	21.0	154.4	8.30
Meramec SK-1	MO	2104	38.402	-90.3357	135.7	76.2	3.3	29.2	255.1	10.68
Meramec SK-2	MO	2104	38.402	-90.3357	146.4	76.2	3.3	29.5	257.8	10.78
Meramec SK-3	MO	2104	38.402	-90.3357	192.7	106.7	4.3	39.7	568.2	21.46
Meramec SK-4	MO	2104	38.402	-90.3357	166.2	106.7	4.7	38.8	681.1	20.76
Montrose SK-1	MO	2080	38.3033	-93.9364	143.3	137.2	3.1	36.0	277.3	11.17
Montrose SK-2	MO	2080	38.3033	-93.9364	143.3	137.2	4.4	36.6	546.7	22.24

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m³/s	2007 TBtu
New Madrid SK-1	MO	2167	36.515	-89.5614	162.8	243.8	8.6	35.7	2068.0	76.61
Rush Island SK-1	MO	6155	38.1308	-90.2627	144.0	213.4	6.3	31.3	978.5	33.67
Rush Island SK-2	MO	6155	38.1308	-90.2627	151.7	213.4	6.3	31.0	970.3	37.57
Sibley SK-1	MO	2094	39.1775	-94.1833	148.9	213.4	4.1	37.2	493.8	32.60
Sikeston SK-1	MO	6768	36.8786	-89.6169	137.8	137.2	4.9	18.9	356.5	21.89
Sioux SK-1	MO	2107	38.915	-90.2892	145.3	182.9	5.7	28.5	730.7	28.97
Sioux SK-2	MO	2107	38.915	-90.2892	165.4	182.9	5.7	28.9	741.7	37.30
Southwest Power Station SK-1	MO	6195	37.1519	-93.3892	55.0	117.3	3.4	27.4	242.2	14.62
Thomas Hill SK-1	MO	2168	39.5481	-92.6361	171.1	125.3	4.7	18.3	317.3	11.77
Thomas Hill SK-2	MO	2168	39.5481	-92.6361	171.1	121.9	5.0	18.3	364.3	18.46
Thomas Hill SK-3	MO	2168	39.5481	-92.6361	143.3	189.0	8.8	15.2	935.8	42.47
Jack Watson SK-1	MS	2049	30.439207	-89.026294	132.2	106.7	4.9	18.9	353.0	20.09
Jack Watson SK-2	MS	2049	30.439382	-89.025854	138.9	121.9	7.0	18.3	705.3	28.22
R. D. Morrow, Sr. SK-1	MS	6061	31.2175	-89.3939	121.1	123.4	7.2	14.3	585.6	28.35
RED HILLS GENERATION FACILITY SK-C1	MS	55076	33.3761111	-89.2166667	154.4	106.1	7.9	22.1	1078.6	34.68
Victor J. Daniel SK-1	MS	6073	30.532641	-88.557186	136.7	106.7	10.4	20.4	1712.7	70.81
Colstrip Energy Limited Partnership SK-1	MT	10784	46.0186	-106.5646	162.8	76.2	2.4	20.1	93.9	4.21
Colstrip SK-1	MT	6076	45.8844	-106.6139	93.3	152.4	5.0	30.5	606.2	25.50
Colstrip SK-2	MT	6076	45.8844	-106.6131	93.3	152.4	5.0	30.5	606.2	22.82
Colstrip SK-3	MT	6076	45.8836	-106.6117	90.0	210.9	7.3	32.0	1344.0	60.34
Colstrip SK-4	MT	6076	45.8836	-106.6106	90.0	210.9	7.3	32.0	1344.0	61.96
HARDIN GENERATING SK-1	MT	55749	45.764432	-107.598993	90.0	75.8	3.4	20.0	180.0	9.29
J.E. Corette SK-1	MT	2187	45.7758	-108.48	157.2	106.7	3.5	32.6	314.9	12.66
Lewis & Clark SK-1	MT	6089	47.79	-104.56	62.8	76.2	3.5	18.9	184.3	4.61
Asheville SK-1	NC	2706	35.4714	-82.5431	48.2	99.7	4.8	14.5	264.8	12.01
Asheville SK-2	NC	2706	35.4714	-82.5425	50.5	99.7	4.8	15.4	280.3	12.28
Belews Creek SK-1	NC	8042	36.2811	-80.0603	50.6	152.4	11.0	17.4	1641.7	68.45
Belews Creek SK-2	NC	8042	36.2811	-80.0603	152.9	181.4	7.5	41.8	1830.6	67.84
Buck SK-1	NC	2720	35.7133	-80.3767	182.0	53.7	3.2	17.8	143.2	2.39
Buck SK-2	NC	2720	35.7133	-80.3767	182.0	53.7	3.2	17.8	143.2	2.39
Buck SK-3	NC	2720	35.7133	-80.3767	182.0	53.7	3.2	17.8	143.2	1.06
Buck SK-4/5	NC	2720	35.7133	-80.3767	140.0	65.7	3.5	28.1	263.2	6.59
Buck SK-6/7	NC	2720	35.7133	-80.3767	140.0	65.7	3.5	28.1	263.2	6.58
Cape Fear SK-1	NC	2708	35.5989	-79.0492	137.8	61.3	3.7	23.2	243.0	10.30
Cape Fear SK-2	NC	2708	35.5989	-79.0492	112.2	61.3	4.6	17.4	285.6	11.70
Cliffside SK-1	NC	2721	35.22	-81.7594	207.0	55.9	3.2	18.4	147.6	1.37
Cliffside SK-2	NC	2721	35.22	-81.7594	207.0	55.9	3.2	18.4	147.6	1.41
Cliffside SK-3	NC	2721	35.22	-81.7594	191.0	57.5	3.2	19.5	157.1	1.91

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Cliffside SK-4	NC	2721	35.22	-81.7594	191.0	57.5	3.2	19.5	157.1	2.12
Cliffside SK-5	NC	2721	35.2236	-81.7561	142.0	152.4	6.4	29.8	945.1	34.46
Cogentrix Roxboro SK-1	NC	10379	36.434935	-78.961964	154.4	60.0	2.6	16.4	88.7	2.45
Cogentrix Southport SK-UNIT1	NC	10378	34.01678	-78.02014	154.4	60.0	2.6	16.4	88.7	2.48
Cogentrix Southport SK-UNIT2	NC	10378	34.01678	-78.02014	154.4	60.0	2.6	17.6	95.2	2.50
Dan River SK-1	NC	2723	36.4861	-79.7209	175.0	76.2	3.2	23.1	186.0	4.01
Dan River SK-2	NC	2723	36.4861	-79.7209	175.0	76.2	3.2	23.1	186.0	3.24
Dan River SK-3/4	NC	2723	36.4861	-79.7209	166.0	78.6	3.9	24.1	284.2	4.68
Dwayne Collier Battle Cogeneration SK-1	NC	10384	35.9145	-77.5843	82.2	61.0	2.4	23.8	111.0	11.50
Elizabethtown SK-1	NC	10380	34.43	-78.6388889	150.0	54.5	2.1	20.0	69.8	0.24
G.G. Allen SK-1	NC	2718	35.1902	-81.008	51.2	111.3	9.0	16.1	1018.8	33.07
G.G. Allen SK-2	NC	2718	35.1902	-81.008	51.2	111.3	9.0	16.1	1018.8	36.27
L V Sutton SK-1	NC	2713	34.2831	-77.9867	142.0	133.8	5.5	20.8	494.2	10.86
L V Sutton SK-2	NC	2713	34.2836	-77.9797	147.0	131.8	5.0	35.7	701.0	22.95
Lee SK-1	NC	2709	35.3803	-78.0869	137.9	91.4	4.1	27.4	363.9	9.09
Lee SK-2	NC	2709	35.3778	-78.1	148.2	91.4	5.8	40.6	1069.0	15.05
Lumberton SK-1	NC	10382	34.58	-78.9944444	150.0	54.5	2.1	20.0	69.8	0.29
Marshall SK-1	NC	2727	35.5975	-80.9658	51.2	96.0	9.0	17.5	1111.4	49.77
Marshall SK-2	NC	2727	35.5975	-80.9658	50.6	96.0	9.0	15.9	1011.9	43.29
Marshall SK-3	NC	2727	35.5975	-80.9658	50.6	96.0	9.0	15.9	1011.9	45.93
Mayo SK-1	NC	6250	36.5278	-78.8919	115.6	243.8	7.3	28.3	1190.4	48.49
Riverbend SK-1/2	NC	2732	35.36	-80.9742	164.0	99.7	3.7	21.6	227.0	5.07
Riverbend SK-3/4	NC	2732	35.36	-80.9742	164.0	99.7	3.7	21.6	227.0	5.67
Riverbend SK-5/6	NC	2732	35.36	-80.9742	162.0	99.7	3.9	24.4	287.6	6.17
Riverbend SK-7/8	NC	2732	35.36	-80.9742	162.0	99.7	3.9	24.4	287.6	6.81
Roxboro SK-1	NC	2712	36.4831	-79.0711	51.1	121.9	11.1	13.7	1331.6	26.46
Roxboro SK-1	NC	2712	36.4833	-79.0719	51.1	121.9	11.1	13.7	1331.6	38.01
Roxboro SK-2	NC	2712	36.4833	-79.0731	53.1	121.9	13.2	14.3	1945.5	45.31
Roxboro SK-2	NC	2712	36.4833	-79.0747	53.1	121.9	13.2	14.3	1945.5	48.29
W H Weatherspoon SK-1	NC	2716	34.5871	-78.9749	151.9	61.0	3.8	10.4	117.9	5.77
W H Weatherspoon SK-2	NC	2716	34.5871	-78.9749	115.0	61.0	3.8	12.3	140.0	5.72
Westmoreland LG&E Partners Roanoke Valley 1 SK-1	NC	54035	36.4363888	-77.6166667	140.0	113.6	3.8	20.0	227.7	10.73
Westmoreland-LG&E Partners Roanoke Valley II SK-2	NC	54755	36.2571	-77.6284	107.2	76.2	2.4	20.1	93.9	3.40
Antelope Valley Station SK-1	ND	6469	47.37	-101.8353	85.0	182.9	7.0	20.4	788.9	30.78
Antelope Valley Station SK-2	ND	6469	47.3711	-101.8353	62.8	182.9	7.0	19.2	741.8	37.75
Coal Creek SK-1	ND	6030	47.3789	-101.1572	98.9	200.6	6.7	26.5	936.5	44.67
Coal Creek SK-2	ND	6030	47.3789	-101.1572	98.9	200.6	8.8	15.2	934.5	51.07

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Coyote SK-1	ND	8222	47.2217	-101.8139	108.3	151.8	6.4	26.5	852.5	34.54
Leland Olds Station SK-1	ND	2817	47.2811	-101.32	196.1	106.7	5.3	18.9	421.3	18.15
Leland Olds Station SK-2	ND	2817	47.2811	-101.32	187.8	152.4	6.7	26.2	925.7	33.23
Milton R. Young SK-1	ND	2823	47.0664	-101.2139	162.8	91.4	5.8	18.3	480.7	18.79
Milton R. Young SK-2	ND	2823	47.066	-101.2145	72.8	167.6	7.6	17.4	792.3	32.35
R.M. Heskett Station SK-2	ND	2790	46.8669	-100.8839	171.1	91.4	3.7	19.5	203.6	6.27
Stanton Station SK-1	ND	2824	47.2867	-101.3317	137.8	77.7	4.6	14.6	240.2	15.24
Gerald Gentlemen Station SK-1	NE	6077	41.0836	-101.1456	118.9	167.6	8.5	17.1	977.1	47.61
Gerald Gentlemen Station SK-2	NE	6077	41.0836	-101.1456	116.7	167.6	8.5	17.1	977.1	44.87
Lon Wright SK-3	NE	2240	41.45	-96.5167	148.9	59.7	3.1	12.2	89.5	6.71
Nebraska City SK-1	NE	6096	40.625	-95.7917	142.2	213.4	7.2	29.9	1221.1	43.30
North Omaha SK-1	NE	2291	41.33	-95.9467	145.0	62.2	4.4	36.6	560.3	17.61
North Omaha SK-2	NE	2291	41.33	-95.9467	135.6	62.2	2.9	36.9	246.5	8.23
North Omaha SK-3	NE	2291	41.33	-95.9467	134.4	62.2	3.5	36.6	353.6	11.26
Platte SK-1	NE	59	40.8536	-98.4022	121.1	125.6	3.7	16.5	172.7	6.77
Sheldon SK-1	NE	2277	40.5589	-96.7842	143.3	53.6	3.7	18.3	191.8	8.38
Sheldon SK-2	NE	2277	40.5592	-96.7842	161.7	53.6	3.7	21.6	227.0	9.04
Whelan Energy Center SK-1	NE	60	40.5814	-98.3169	162.8	83.8	2.7	24.1	142.3	6.24
Merrimack SK-1	NH	2364	43.1417	-71.4685	118.3	68.6	2.6	42.0	226.6	10.54
Merrimack SK-2	NH	2364	43.1417	-71.4685	148.9	96.6	4.4	36.9	566.4	25.45
Schiller SK-1	NH	2367	43.0978	-70.7853	198.9	68.9	2.4	22.6	104.8	4.38
Schiller SK-2	NH	2367	43.0978	-70.7853	204.4	68.9	2.4	22.9	106.2	4.36
Schiller SK-3	NH	2367	43.0978	-70.7853	198.9	68.9	2.4	22.9	106.2	4.55
B L England SK-1	NJ	2378	39.29	-74.6339	143.3	144.8	5.9	23.2	635.9	15.78
Carneys Point Generating Plant SK-1	NJ	10566	39.7097	-75.465	79.4	144.8	5.0	28.0	557.0	21.47
Deepwater SK-1	NJ	2384	39.6829	-75.5095	143.3	68.0	3.2	12.5	103.4	5.02
Hudson SK-2	NJ	2403	40.75	-74.075	137.2	151.8	5.3	34.7	778.2	22.11
Logan Generating Plant SK-1	NJ	10043	39.7561	-75.33307	93.3	131.1	3.7	30.1	316.3	15.11
Mercer SK-1	NJ	2408	40.175	-74.7333	131.7	99.4	5.4	27.0	611.0	16.11
Mercer SK-2	NJ	2408	40.175	-74.7333	131.7	99.1	5.4	27.0	611.0	14.91
Escalante SK-1	NM	87	35.4144	-108.0825	52.2	137.2	6.1	15.2	444.4	20.44
Four Corners SK-1	NM	2442	36.6906	-108.4822	50.0	76.2	5.6	20.4	510.0	27.43
Four Corners SK-2	NM	2442	36.69	-108.4814	54.4	76.2	4.4	24.3	360.0	18.03
Four Corners SK-3	NM	2442	36.6869	-108.4772	62.8	115.8	10.7	24.4	1730.0	103.40
San Juan SK-1	NM	2451	36.8833	-108.4833	79.4	121.9	5.5	26.8	635.5	25.33
San Juan SK-2	NM	2451	36.8833	-108.4833	79.4	121.9	5.5	27.1	642.7	24.26
San Juan SK-3	NM	2451	36.8833	-108.4833	79.4	121.9	7.6	29.3	1334.4	37.77
San Juan SK-4	NM	2451	36.8833	-108.4833	79.4	121.9	7.6	29.3	1334.4	38.14

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
North Valmy Generating Station SK-1	NV	8224	40.8833	-117.1542	131.7	152.4	5.8	16.0	420.2	16.89
North Valmy Generating Station SK-2	NV	8224	40.8833	-117.1542	130.0	138.7	5.2	19.0	400.4	18.99
Reid Gardner SK-1	NV	2324	36.6559	-114.6326	97.2	61.0	3.8	14.9	170.5	7.41
Reid Gardner SK-2	NV	2324	36.6559	-114.6326	97.2	73.2	2.9	25.9	171.0	6.48
Reid Gardner SK-3	NV	2324	36.6559	-114.6326	93.9	82.3	2.9	28.7	189.1	7.37
Reid Gardner SK-4	NV	2324	36.6559	-114.6326	67.2	152.4	5.2	23.5	494.9	17.12
AES Cayuga (NY) SK-1	NY	2535	42.6026	-76.6353	48.9	114.0	3.4	19.5	172.2	11.60
AES Cayuga (NY) SK-2	NY	2535	42.6026	-76.6353	48.9	114.0	3.4	19.5	172.2	11.42
AES Greenidge SK-4	NY	2527	42.6789	-76.9483	112.8	69.2	3.3	29.0	251.8	5.21
AES Somerset (NY) SK-1	NY	6082	43.3564	-78.5992	51.7	186.8	8.1	21.3	1108.2	53.96
AES Westover SK-1	NY	2526	42.1117	-75.9747	132.0	86.0	4.6	16.0	262.4	6.00
C. R. Huntley SK-1	NY	2549	42.9667	-78.9167	160.0	106.7	5.4	18.6	426.5	5.49
C. R. Huntley SK-2	NY	2549	42.9667	-78.9167	143.3	106.7	5.7	23.5	588.6	21.50
CARLSON 5 SK-1	NY	2682	42.0916666	-79.2416667	150.0	60.6	2.9	20.0	132.2	2.74
Danskammer SK-1	NY	2480	41.5719	-73.9664	133.3	73.2	2.9	31.9	207.7	10.24
Danskammer SK-2	NY	2480	41.5719	-73.9664	126.7	73.2	3.8	32.1	369.3	16.04
Dunkirk SK-1	NY	2554	42.4919	-79.3469	160.0	95.1	4.1	16.8	222.6	6.23
Dunkirk SK-2	NY	2554	42.5167	-79.8167	160.0	95.1	4.1	16.8	222.6	6.05
Dunkirk SK-3	NY	2554	42.4919	-79.3469	143.3	94.5	5.5	27.5	649.5	24.62
Fort Drum H.T.W. Cogeneration Facility SK-1	NY	10464	44.0357	-75.9156	157.2	76.2	2.4	25.3	118.1	4.90
Lovett SK-1	NY	2629	41.2606	-73.9792	120.6	144.8	3.4	29.1	256.6	7.24
Lovett SK-2	NY	2629	41.2606	-73.9792	140.6	144.8	3.4	31.5	277.8	6.69
Trigen Syracuse SK-1	NY	50651	43.0627777	-76.2083333	150.0	80.0	3.9	20.0	244.3	2.62
WPS POWER Niagara SK-1	NY	50202	43.0908333	-78.9638889	150.0	66.7	2.4	20.0	91.8	2.35
Ashtabula SK-1	OH	2835	41.9083	-80.7667	123.9	113.7	5.0	25.9	505.0	14.54
Avon Lake SK-1	OH	2836	41.5042	-82.05	152.8	152.4	4.0	21.3	263.1	28.83
Bay Shore SK-1	OH	2878	41.6925	-83.4375	143.9	143.9	7.0	6.5	249.4	8.54
Bay Shore SK-2	OH	2878	41.6925	-83.4375	165.6	91.4	7.0	19.8	763.3	31.80
Cardinal SK-1	OH	2828	40.2531	-80.6468	54.5	304.8	8.9	15.2	937.1	32.89
Cardinal SK-2	OH	2828	40.253	-80.6467	54.5	304.8	8.9	15.2	937.1	33.99
Cardinal SK-3	OH	2828	40.2425	-80.6567	162.8	274.3	7.3	29.2	1225.5	40.44
Conesville SK-2	OH	2840	40.1847	-81.88	143.3	137.2	5.3	10.3	230.3	8.48
Conesville SK-3	OH	2840	40.1856	-81.8798	143.3	243.8	7.9	25.3	1244.8	47.66
Conesville SK-4	OH	2840	40.1861	-81.86	51.7	243.8	7.9	23.9	1175.0	51.23
Eastlake SK-1	OH	2837	41.6708	-81.4792	153.3	164.6	8.0	23.2	1165.0	36.50
Eastlake SK-2	OH	2837	41.6708	-81.4792	151.1	182.9	7.3	21.5	903.8	44.31
Gen J. M. Gavin SK-1	OH	8102	38.9347	-82.1162	54.9	253.0	12.8	14.6	1882.2	85.49
Gen J. M. Gavin SK-2	OH	8102	38.9359	-82.1152	54.9	253.0	12.8	14.6	1882.2	95.97

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m³/s	2007 TBtu
Hamilton SK-1	OH	2917	39.4094	-84.5547	161.1	50.9	3.1	15.4	118.9	3.83
J. M. Stuart SK-1	OH	2850	38.6364	-83.6922	137.8	243.8	5.8	32.3	852.8	33.52
J. M. Stuart SK-2	OH	2850	38.6367	-83.6933	137.8	243.8	5.8	32.3	852.8	36.78
J. M. Stuart SK-3	OH	2850	38.6369	-83.6944	137.8	243.8	5.8	32.3	852.8	31.78
J. M. Stuart SK-4	OH	2850	38.6372	-83.6956	137.8	243.8	5.8	32.3	852.8	41.26
Killen SK-1	OH	6031	38.6903	-83.4803	121.1	274.3	10.0	14.2	1116.7	40.39
Kyger Creek SK-1	OH	2876	38.9161	-82.1281	148.9	304.8	8.9	33.4	2091.5	69.36
Lake Shore SK-1	OH	2838	41.5333	-81.6375	132.2	97.5	5.2	14.9	314.1	13.83
Miami Fort Station SK-1	OH	2832	39.11308	-84.80321	125.6	179.8	5.2	16.3	342.8	13.56
Miami Fort Station SK-2	OH	2832	39.11308	-84.80321	54.4	243.8	7.2	20.8	837.7	27.00
Miami Fort Station SK-3	OH	2832	39.11308	-84.80321	54.4	243.8	7.2	20.8	837.7	30.65
Muskingum River SK-1	OH	2872	39.591	-81.6795	157.2	252.4	7.6	34.4	1570.7	42.11
Muskingum River SK-2	OH	2872	39.5886	-81.6862	152.2	252.4	6.7	28.1	992.3	41.00
Niles SK-1	OH	2861	41.1667	-80.75	132.2	119.8	4.7	17.7	310.4	13.41
O. H. Hutchings SK-1	OH	2848	39.6087	-84.2925	153.3	76.2	4.2	15.9	223.7	1.85
O. H. Hutchings SK-2	OH	2848	39.6087	-84.2925	153.3	76.2	4.2	15.4	216.7	6.04
Picway SK-1	OH	2843	39.7933	-83.0101	168.2	87.5	4.2	17.6	248.1	4.27
R. E. Burger SK-1	OH	2864	39.9092	-80.7606	173.3	259.1	6.6	25.9	872.3	18.95
Richard H. Gorsuch SK-1	OH	7286	39.3672	-81.5208	148.9	110.3	5.9	20.4	567.2	9.10
Richard H. Gorsuch SK-2	OH	7286	39.3672	-81.5208	148.9	110.3	5.9	20.4	567.2	8.32
W. H. Sammis SK-1	OH	2866	40.5328	-80.6331	149.4	153.6	6.4	21.1	680.4	25.06
W. H. Sammis SK-2	OH	2866	40.5328	-80.6331	143.3	153.6	6.1	21.6	630.5	22.07
W. H. Sammis SK-3	OH	2866	40.5319	-80.6325	130.6	259.1	9.5	20.6	1456.7	57.78
W. H. Sammis SK-4	OH	2866	40.5311	-80.6322	133.3	304.8	8.2	17.8	933.4	49.74
W. H. Zimmer Station SK-1	OH	6019	38.869009	-84.228621	54.4	174.7	12.8	14.3	1840.6	81.40
Walter C. Beckjord SK-1	OH	2830	38.99111	-84.2925	138.9	91.4	3.7	16.3	171.7	5.70
Walter C. Beckjord SK-2	OH	2830	38.99111	-84.2925	153.3	91.4	3.7	16.4	172.6	5.43
Walter C. Beckjord SK-3	OH	2830	38.99111	-84.2925	153.9	114.3	3.7	20.8	219.0	7.69
Walter C. Beckjord SK-4	OH	2830	38.99111	-84.2925	137.8	114.3	3.7	26.4	277.5	10.05
Walter C. Beckjord SK-5	OH	2830	38.99111	-84.2925	148.9	137.8	5.8	39.9	1051.2	37.57
AES Shady Point, Inc. SK-1	OK	10671	34.9471	-94.7464	154.4	88.4	3.7	25.9	272.2	13.61
AES Shady Point, Inc. SK-2	OK	10671	34.9471	-94.7464	154.4	88.4	3.7	25.9	272.2	14.99
GRDA SK-1	OK	165	36.1889	-95.2892	121.1	153.6	6.1	27.4	799.8	38.88
GRDA SK-2	OK	165	36.1883	-95.2886	60.0	153.6	6.1	24.4	711.0	38.14
Hugo SK-1	OK	6772	34.0292	-95.3167	148.9	152.4	7.3	15.2	640.0	32.47
Muskogee SK-1	OK	2952	35.7653	-95.2883	128.9	106.7	7.3	14.0	588.8	34.21
Muskogee SK-2	OK	2952	35.7653	-95.2883	128.9	106.7	7.3	14.0	588.8	28.99
Muskogee SK-3	OK	2952	35.7653	-95.2883	128.9	152.4	6.6	25.1	847.7	28.31

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Northeastern SK-1	OK	2963	36.4261	-95.6989	115.6	182.9	8.2	12.2	648.0	34.73
Northeastern SK-2	OK	2963	36.4261	-95.6989	115.6	182.9	8.2	12.2	648.0	30.88
Sooner SK-1	OK	6095	36.4544	-97.05	128.9	152.4	6.1	31.1	906.5	36.61
Sooner SK-2	OK	6095	36.4544	-97.05	128.9	152.4	6.1	31.1	906.5	30.05
Boardman SK-1	OR	6106	45.4178	-119.4817	131.1	199.9	6.7	26.2	925.7	43.17
AES BV Partners Beaver Valley SK-2	PA	10676	40.657	-80.354	52.8	61.0	2.3	15.2	63.9	3.86
AES BV Partners Beaver Valley SK-3	PA	10676	40.657	-80.354	52.8	61.0	2.3	15.2	63.9	3.70
AES BV Partners Beaver Valley SK-4	PA	10676	40.657	-80.354	52.8	61.0	2.3	15.2	63.9	3.77
Armstrong SK-1	PA	3178	40.929409	-79.467342	116.7	307.2	4.4	14.4	433.8	21.33
Bruce Mansfield SK-1	PA	6094	40.6344	-80.4148	70.7	289.6	11.7	27.0	2925.2	112.47
Bruce Mansfield SK-2	PA	6094	40.6344	-80.4148	52.0	182.9	8.2	24.2	1262.7	65.30
Brunner Island SK-1	PA	3140	40.1	-76.6833	148.3	137.2	5.9	50.0	1388.3	47.49
Brunner Island SK-2	PA	3140	40.1	-76.6833	159.4	182.9	6.1	45.7	1338.4	53.12
Cambria CoGen SK-1	PA	10641	40.474742	-78.702986	162.8	91.4	3.0	10.6	309.0	11.00
Cheswick SK-1	PA	8226	40.5375	-79.7917	126.7	228.6	6.4	29.0	930.9	29.27
Colver Power Project SK-1	PA	10143	40.5511	-78.798226	140.6	121.9	3.7	22.9	240.2	9.37
Conemaugh SK-1	PA	3118	40.3842	-79.0611	54.4	160.0	8.5	26.7	1527.5	57.73
Conemaugh SK-2	PA	3118	40.3842	-79.0611	54.4	160.0	8.5	26.7	1527.5	65.27
Cromby Generating Station SK-1	PA	3159	40.1522	-75.5406	121.1	91.4	4.3	14.3	204.9	7.76
Ebensburg Power Company SK-1	PA	10603	40.4551	-78.7465	160.0	76.8	2.7	24.1	142.3	6.35
Eddystone SK-1	PA	3161	39.8586	-75.3231	143.3	75.6	5.6	16.2	403.9	13.08
Eddystone SK-2	PA	3161	39.8583	-75.3239	132.2	75.6	5.6	16.5	411.5	14.79
Elrama SK-1	PA	3098	40.2531	-79.9175	55.0	119.5	8.3	17.5	947.5	23.64
Foster Wheeler Mt. Carmel, Incorporated SK-1	PA	10343	40.8944	-76.6653	148.9	94.5	2.7	21.0	124.3	4.68
Hatfield's Ferry SK-1	PA	3179	39.856093	-79.928196	147.2	213.3	13.7	6.3	910.1	63.67
Hatfield's Ferry SK-2	PA	3179	39.855656	-79.928624	151.1	213.3	13.7	6.5	948.4	39.26
Homer City SK-1	PA	3122	40.5142	-79.1969	138.9	243.8	7.3	22.9	960.0	35.19
Homer City SK-2	PA	3122	40.5136	-79.1967	138.9	243.8	7.3	22.9	960.0	50.31
Homer City SK-3	PA	3122	40.5125	-79.1972	48.9	160.0	8.2	17.1	907.9	49.09
Hunlock Power Station SK-1	PA	3176	41.201	-76.0719	162.8	61.9	3.4	11.3	102.5	3.41
John B. Rich Memorial Power Station SK-1	PA	10113	40.79029	-76.17139	162.8	91.4	3.0	26.8	195.7	8.12
Keystone SK-1	PA	3136	40.6522	-79.3425	132.8	243.8	8.3	31.3	1692.0	60.60
Keystone SK-2	PA	3136	40.6525	-79.3419	138.3	243.8	8.3	31.3	1692.0	57.88
Kline Township Cogen Facility SK-1	PA	50039	40.8921	-76.0024	173.9	76.2	2.3	30.8	126.4	5.63
Martins Creek SK-1	PA	3148	40.7975	-75.1045	157.2	182.9	6.9	14.6	540.9	10.37
Mitchell (PA) SK-1	PA	3181	40.220551	-79.967921	45.6	114.3	6.1	13.4	389.7	9.36
Montour SK-1	PA	3149	41.07	-76.6664	148.9	182.9	6.1	36.6	1066.5	41.23
Montour SK-2	PA	3149	41.0694	-76.6653	148.9	182.9	6.1	36.6	1066.5	46.81

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
New Castle SK-1	PA	3138	40.9383	-80.3683	150.0	228.6	6.2	22.0	656.0	16.54
Northampton Generating Company, L.P. SK-1	PA	50888	40.7525	-75.3324	163.0	84.0	3.1	23.0	168.0	9.11
Panther Creek Energy Facility SK-1	PA	50776	40.9303	-75.7363	163.0	84.0	3.1	23.0	168.0	7.93
Piney Creek Project SK-1	PA	54144	41.2025	-79.4542	162.8	76.2	2.4	20.1	93.9	3.56
Portland SK-1	PA	3113	40.755	-75.0839	129.4	130.0	3.1	33.3	257.6	8.80
Portland SK-2	PA	3113	40.755	-75.0839	126.7	132.8	3.8	36.4	408.0	14.56
Scrubgrass Generating SK-1	PA	50974	41.3981	-79.7393	157.2	110.3	3.3	25.9	218.5	8.90
Seward SK-1	PA	3130	40.4069	-79.0333	61.1	184.1	5.3	32.0	696.0	37.81
Shawville SK-1	PA	3131	41.0681	-78.3661	130.0	182.9	3.8	29.3	334.1	15.16
Shawville SK-2	PA	3131	41.0683	-78.3672	122.8	259.1	5.8	15.2	402.3	20.89
St. Nicholas Cogeneration Project SK-1	PA	54634	40.822099	-76.174747	163.0	84.0	3.1	23.0	168.0	9.06
Sunbury SK-1	PA	3152	40.838	-76.825	147.2	91.4	4.5	11.9	192.7	21.70
Sunbury SK-4	PA	3152	40.838	-76.825	138.3	91.4	4.6	24.3	399.5	4.27
Titus SK-1	PA	3115	40.3047	-75.9072	176.7	106.7	5.2	18.3	386.3	15.10
Westwood SK-1	PA	50611	40.6175	-76.4527778	150.0	97.0	2.5	20.0	95.5	2.65
Wheelabrator Frackville Energy Company Inc SK-1	PA	50879	40.3285	-75.1043	162.8	76.2	2.4	24.4	113.9	4.96
Canadys Steam SK-1	SC	3280	33.0647	-80.6228	123.9	61.0	4.9	9.8	182.2	8.06
Canadys Steam SK-2	SC	3280	33.0647	-80.6228	123.9	61.0	4.9	9.8	182.2	7.48
Canadys Steam SK-3	SC	3280	33.0647	-80.6228	125.6	61.0	4.9	14.9	279.0	7.95
Cogen South SK-1	SC	7737	32.896	-79.967	154.0	60.0	3.2	16.0	130.0	7.96
Cope SK-1	SC	7210	33.3639	-81.0303	66.1	160.0	7.0	14.0	540.7	30.35
CROSS 3 SK-3	SC	130	33.3706	-80.1135	46.1	148.0	7.6	21.2	1199.9	119.12
Cross Generating Station SK-1	SC	130	33.3694	-80.1119	65.6	182.9	6.7	28.1	994.1	66.27
Cross Generating Station SK-2	SC	130	33.3694	-80.1119	60.0	182.9	6.7	21.3	753.5	52.84
Grainger Generating Station SK-1	SC	3317	33.8253	-79.0528	148.9	91.4	3.1	18.0	132.0	4.82
Grainger Generating Station SK-2	SC	3317	33.8253	-79.0525	148.9	91.4	3.1	18.0	132.0	4.70
H B Robinson SK-1	SC	3251	34.4	-80.1667	123.9	76.2	4.6	19.4	318.9	11.89
Jefferies Generating Station SK-3	SC	3319	33.2422	-79.9875	148.9	91.4	4.0	21.3	263.2	8.78
Jefferies Generating Station SK-4	SC	3319	33.2419	-79.9872	148.9	91.4	4.0	21.3	263.2	9.78
McMeekin SK-1	SC	3287	34.0556	-81.2172	123.9	125.0	4.0	19.8	242.8	7.15
McMeekin SK-2	SC	3287	34.0556	-81.2172	123.9	125.0	4.0	19.8	242.8	7.51
Urquhart SK-3	SC	3295	33.4339	-81.9114	125.0	61.0	4.7	8.5	149.0	7.19
W. S. Lee SK-1/2	SC	3264	34.6022	-82.435	140.0	64.8	3.5	12.2	113.8	4.32
W. S. Lee SK-3/4	SC	3264	34.6022	-82.435	140.0	64.8	3.5	12.2	113.8	3.63
W. S. Lee SK-5/6	SC	3264	34.6022	-82.435	139.0	64.8	3.9	17.5	206.5	8.32
Wateree SK-1	SC	3297	33.8264	-80.6228	121.1	91.4	5.8	18.9	498.8	20.97
Wateree SK-2	SC	3297	33.8264	-80.6228	121.1	91.4	5.8	18.9	498.8	21.40
Williams SK-1	SC	3298	33.0158	-79.9297	156.7	121.9	8.5	17.7	1009.9	36.50

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Winyah Generating Station SK-1	SC	6249	33.3299	-79.3579	82.2	121.9	5.2	18.3	388.2	19.81
Winyah Generating Station SK-2	SC	6249	33.3299	-79.3579	82.2	121.9	5.0	18.3	352.9	19.59
Winyah Generating Station SK-3	SC	6249	33.3299	-79.3579	71.1	121.9	4.9	22.9	427.0	20.38
Winyah Generating Station SK-4	SC	6249	33.3299	-79.3579	71.1	121.9	4.9	22.9	432.7	20.29
Big Stone SK-1	SD	6098	45.3047	-96.5083	142.2	151.8	7.4	22.9	974.4	26.68
Allen Fossil Plant SK-1	TN	3393	35.0742	-90.1492	142.8	121.9	3.9	37.5	446.1	15.95
Allen Fossil Plant SK-2	TN	3393	35.0742	-90.1486	142.8	121.9	3.9	37.5	446.1	15.45
Allen Fossil Plant SK-3	TN	3393	35.0742	-90.1481	142.8	121.9	3.9	37.5	446.1	16.34
Bull Run Fossil Plant SK-1	TN	3396	36.0211	-84.1567	117.8	243.8	8.5	21.9	1256.3	53.99
Cumberland Fossil Plant SK-1	TN	3399	36.3942	-87.6539	54.4	193.5	9.1	28.0	1841.5	76.54
Cumberland Fossil Plant SK-2	TN	3399	36.3936	-87.6544	54.4	193.5	9.1	29.0	1901.5	76.75
Gallatin Fossil Plant SK-1	TN	3403	36.3156	-86.4006	133.3	152.7	7.6	17.1	778.4	31.71
Gallatin Fossil Plant SK-2	TN	3403	36.3152	-86.401	122.2	153.0	7.6	18.9	861.8	36.18
John Sevier Fossil Plant SK-1	TN	3405	36.3767	-82.9639	145.0	106.7	7.2	14.9	602.3	22.59
John Sevier Fossil Plant SK-2	TN	3405	36.3772	-82.9639	145.0	106.7	7.2	14.9	602.3	22.13
Johnsonville Fossil Plant SK-1	TN	3406	36.0278	-87.9861	145.6	182.9	9.9	35.1	2703.1	78.27
Kingston Fossil Plant SK-1	TN	3407	35.8992	-84.5194	151.7	304.8	7.9	28.2	1388.9	48.33
Kingston Fossil Plant SK-2	TN	3407	35.8992	-84.5194	151.7	304.8	7.9	26.6	1313.2	48.02
AES Deepwater SK-1	TX	10670	29.7192	-95.2278	150.0	100.0	6.6	20.0	680.0	11.87
Big Brown SK-1	TX	3497	31.822	-96.0549	168.3	121.9	6.6	37.1	1250.7	49.01
Big Brown SK-2	TX	3497	31.8227	-96.0553	168.3	121.9	6.6	37.1	1250.7	43.27
Coleto Creek SK-1	TX	6178	28.7128	-97.2142	136.7	124.7	6.1	35.7	1039.8	44.81
Fayette (Seymour) SK-1	TX	6179	29.9172	-96.7506	150.0	182.9	8.5	29.0	1657.6	59.65
Fayette (Seymour) SK-2	TX	6179	29.9161	-96.7506	150.0	182.9	8.5	29.0	1657.6	61.02
Fayette (Seymour) SK-3	TX	6179	29.9153	-96.7503	65.6	162.5	7.9	26.8	1298.7	46.86
Gibbons Creek SK-1	TX	6136	30.6167	-96.0778	93.3	141.7	6.1	26.2	764.3	34.63
Harrington Station SK-1	TX	6193	35.2989	-101.7475	163.3	76.2	5.8	26.8	702.8	25.60
Harrington Station SK-2	TX	6193	35.2994	-101.7467	156.1	91.4	5.8	29.6	780.4	22.80
Harrington Station SK-3	TX	6193	35.2997	-101.7461	148.9	91.4	5.8	29.6	780.4	27.03
J.K. Spruce SK-1	TX	7097	29.3064	-98.3203	72.8	160.0	7.8	19.8	943.6	40.56
J.T. Deely SK-1	TX	6181	29.3072	-98.3228	132.2	213.4	11.2	16.8	1661.1	56.43
Limestone SK-1	TX	298	31.4231	-96.2533	71.1	171.6	8.2	23.4	1245.5	67.47
Limestone SK-2	TX	298	31.4239	-96.2533	71.1	171.6	8.2	23.4	1245.5	70.22
Martin Lake SK-1	TX	6146	32.2623	-94.5709	121.1	137.8	7.0	36.7	1415.8	67.94
Martin Lake SK-2	TX	6146	32.2615	-94.5705	121.1	137.8	7.0	36.7	1415.9	67.40
Martin Lake SK-3	TX	6146	32.2607	-94.57	121.1	137.8	7.0	36.7	1415.8	64.14
Monticello SK-1	TX	6147	33.0924	-95.0376	168.3	121.9	6.6	37.1	1250.7	49.06
Monticello SK-2	TX	6147	33.0931	-95.038	168.3	121.9	6.6	37.1	1250.7	50.83

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Monticello SK-3	TX	6147	33.0941	-95.0379	121.1	140.2	7.8	29.9	1415.8	71.39
Oklaunion SK-1	TX	127	34.1278	-99.1913	71.7	137.9	7.0	20.8	801.6	44.44
Pirkey SK-1	TX	7902	32.4607	-94.4852	65.0	160.1	7.6	25.9	1181.5	53.71
San Miguel SK-1	TX	6183	28.7089	-98.4722	79.4	137.2	7.6	20.4	931.3	33.66
Sandow SK-1	TX	6648	30.5642	-97.0639	82.2	121.9	6.6	29.8	1005.3	50.16
TNP-One SK-1	TX	7030	31.0928	-96.6933	160.0	103.6	3.8	24.4	278.4	14.76
TNP-One SK-2	TX	7030	31.0931	-96.6956	160.0	103.6	3.8	24.4	278.4	12.78
Tolk Station SK-1	TX	6194	34.1847	-102.5686	132.2	121.9	6.9	32.0	1183.2	40.77
Tolk Station SK-2	TX	6194	34.1853	-102.5694	132.2	121.9	6.9	32.0	1183.2	30.50
W A Parish SK-1	TX	3470	29.4781	-95.6356	130.6	182.9	7.3	25.6	1075.2	53.62
W A Parish SK-2	TX	3470	29.4775	-95.635	130.6	182.9	7.3	25.6	1075.2	60.37
W A Parish SK-3	TX	3470	29.4769	-95.6344	137.2	152.4	6.7	27.1	958.0	49.39
W A Parish SK-4	TX	3470	29.4764	-95.6339	54.4	152.4	6.7	27.1	958.0	49.58
Welsh SK-1	TX	6139	33.0546	-94.84	157.2	91.4	5.1	47.2	971.4	39.59
Welsh SK-2	TX	6139	33.0542	-94.84	141.9	91.4	5.1	43.9	904.1	30.08
Welsh SK-3	TX	6139	33.0538	-94.84	122.1	91.4	5.1	40.8	839.4	40.58
Bonanza SK-1	UT	7790	40.0833	-109.2833	48.9	182.9	7.9	15.2	751.7	36.53
Carbon SK-1	UT	3644	39.7264	-110.8639	162.8	61.0	3.1	29.3	214.8	5.60
Carbon SK-2	UT	3644	39.7264	-110.8639	162.8	52.4	3.8	23.5	268.0	9.38
Hunter SK-1	UT	6165	39.1667	-111.0261	58.9	182.9	7.3	19.6	822.5	32.86
Hunter SK-2	UT	6165	39.1667	-111.0261	58.9	182.9	7.3	19.6	822.5	35.79
Hunter SK-3	UT	6165	39.1667	-111.0261	48.9	182.9	7.3	20.0	839.0	34.73
Huntington SK-1	UT	8069	39.3792	-111.075	58.9	182.9	7.3	16.8	705.0	35.77
Huntington SK-2	UT	8069	39.3792	-111.075	127.8	182.9	7.3	19.6	822.5	37.36
Intermountain SK-1	UT	6481	39.5108	-112.5792	57.2	217.6	12.1	26.2	2982.6	137.00
Sunnyside Cogeneration SK-1	UT	50951	39.6407	-110.5648	162.8	83.8	2.7	24.1	142.3	5.20
Altavista Power Station SK-1	VA	10773	37.1184	-79.2764	97.1	67.1	2.4	24.0	111.0	3.52
Birchwood Power Facility SK-1	VA	54304	38.2631	-77.1649	65.6	122.5	4.8	17.7	323.0	12.15
Bremo Power Station SK-1	VA	3796	37.7089	-78.2878	179.4	61.0	3.7	12.5	131.1	4.19
Bremo Power Station SK-2	VA	3796	37.7089	-78.2878	131.1	61.0	4.5	13.7	225.5	9.59
Chesapeake Energy Center SK-1	VA	3803	36.7711	-76.3019	157.2	53.3	4.0	17.4	214.6	6.26
Chesapeake Energy Center SK-2	VA	3803	36.7711	-76.3019	156.1	53.3	4.0	17.4	214.6	6.48
Chesapeake Energy Center SK-3	VA	3803	36.7711	-76.3019	133.9	61.0	4.0	18.0	222.1	9.91
Chesapeake Energy Center SK-4	VA	3803	36.7711	-76.3019	153.9	61.0	4.3	21.3	305.1	13.24
Chesterfield Power Station SK-1	VA	3797	37.3822	-77.3833	162.8	61.0	4.0	14.0	173.2	5.84
Chesterfield Power Station SK-2	VA	3797	37.3822	-77.3833	146.1	61.0	4.0	22.3	274.8	10.15
Chesterfield Power Station SK-3	VA	3797	37.3822	-77.3833	145.0	61.0	5.2	21.6	456.3	17.67
Chesterfield Power Station SK-4	VA	3797	37.3822	-77.3667	145.0	127.7	6.1	30.5	888.7	40.15

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Clinch River SK-1	VA	3775	36.9333	-82.1994	137.5	137.2	4.8	36.7	594.6	26.81
Clinch River SK-2	VA	3775	36.9335	-82.1989	131.7	137.2	3.8	28.0	299.3	12.77
Clover Power Station SK-1	VA	7213	36.8685	-78.7039	82.2	135.3	6.8	18.3	661.2	30.31
Clover Power Station SK-2	VA	7213	36.8685	-78.7039	82.2	135.3	6.8	18.3	661.2	28.11
Cogentrix Hopewell SK-UNIT1	VA	10377	37.2971	-77.2827	143.3	60.0	2.6	15.8	85.4	5.42
Cogentrix Hopewell SK-UNIT2	VA	10377	37.2971	-77.2827	137.8	60.0	2.6	15.8	85.4	5.50
Cogentrix of Richmond, INC. SK-1	VA	54081	37.5115	-77.5105	82.2	76.2	2.4	23.8	111.0	5.24
Cogentrix of Richmond, INC. SK-2	VA	54081	37.5115	-77.5105	82.2	76.2	2.4	23.8	111.0	5.24
Cogentrix of Richmond, INC. SK-3	VA	54081	37.5115	-77.5105	82.2	76.2	2.4	23.8	111.0	5.07
Cogentrix of Richmond, INC. SK-4	VA	54081	37.5115	-77.5105	82.2	76.2	2.4	23.8	111.0	4.98
Cogentrix Portsmouth SK-UNIT1	VA	10071	36.87024	-76.352207	137.8	60.0	2.6	16.1	87.0	5.09
Cogentrix Portsmouth SK-UNIT2	VA	10071	36.87024	-76.352207	137.8	60.0	2.6	16.7	90.3	5.30
Glen Lyn SK-1	VA	3776	37.3707	-80.8642	151.1	66.6	5.2	11.0	276.4	4.14
Glen Lyn SK-2	VA	3776	37.3696	-80.8632	137.3	132.6	3.5	35.9	345.7	12.37
LG&E - Westmoreland Hopewell SK-1	VA	10771	37.2971	-77.2827	82.0	61.0	2.4	24.0	111.0	3.43
Mecklenburg Power Station SK-1	VA	52007	36.6009	-78.53	93.4	83.8	3.8	18.1	206.8	7.64
Potomac River SK-1	VA	3788	38.8078	-77.0372	165.6	50.3	2.6	27.9	147.3	3.98
Potomac River SK-2	VA	3788	38.8078	-77.0372	165.6	50.3	2.6	27.9	147.3	3.02
Potomac River SK-3	VA	3788	38.8078	-77.0372	122.2	50.3	2.4	49.7	230.8	3.29
Potomac River SK-4	VA	3788	38.8078	-77.0372	122.2	50.3	2.4	49.7	230.8	3.04
Potomac River SK-5	VA	3788	38.8078	-77.0372	122.2	50.3	2.4	49.7	230.8	3.30
Southampton Power Station SK-1	VA	10774	36.6506	-76.9967	82.3	67.1	2.4	24.0	111.0	4.39
Yorktown Power Station SK-1	VA	3809	37.2144	-76.4611	144.2	98.8	4.9	22.6	475.6	17.09
Centralia SK-1	WA	3845	46.7625	-122.8567	148.9	143.3	7.3	25.3	1062.4	44.47
Centralia SK-2	WA	3845	46.7625	-122.8567	148.9	143.3	7.3	25.3	1062.4	48.17
Alma SK-1	WI	4140	44.3078	-91.905	185.6	213.4	5.2	23.2	488.5	7.87
BAY FRONT 6 SK-1	WI	3982	46.58694444	-90.9	157.0	59.1	2.1	21.6	75.4	4.92
Blount Street SK-2	WI	3992	43.0792	-89.3739	176.7	76.2	3.7	9.4	98.7	1.16
Blount Street SK-3	WI	3992	43.0792	-89.3739	171.1	76.2	3.2	10.5	84.6	1.45
Columbia SK-1	WI	8023	43.4859	-89.4206	142.2	152.4	6.4	36.6	1175.8	40.08
Columbia SK-2	WI	8023	43.4859	-89.4206	145.0	198.1	6.4	36.6	1175.8	35.68
Edgewater (WI) SK-1	WI	4050	43.7156	-87.705	179.4	167.6	5.2	33.8	713.4	25.86
Edgewater (WI) SK-2	WI	4050	43.7181	-87.7092	172.2	167.6	5.3	30.5	665.6	22.63
EJ STONEMAN 2 SK-1	WI	4146	42.70833333	-90.9833333	150.0	60.3	2.7	20.0	115.7	0.78
Genoa SK-1	WI	4143	43.5592	-91.2333	168.3	152.4	4.7	33.5	569.7	21.93
J P Madgett SK-1	WI	4271	44.3022	-91.9142	175.0	213.4	5.3	33.5	747.5	26.03
MANITOWOC 6 SK-S20	WI	4125	44.08194444	-87.6555556	176.7	75.8	1.3	16.1	20.6	2.10
MANITOWOC 9 SK-S10	WI	4125	44.08194444	-87.6555556	176.7	75.8	3.6	15.2	157.2	0.18

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Nelson Dewey SK-1	WI	4054	42.7228	-90.0078	155.6	107.9	4.0	32.3	399.0	13.69
Pleasant Prairie SK-1	WI	6170	42.5381	-87.9033	54.4	137.2	11.5	17.8	1831.4	84.80
Pulliam SK-1	WI	4072	44.5394	-88.0042	176.7	114.9	6.1	19.8	584.2	27.90
South Oak Creek SK-1	WI	4041	42.844	-87.8284	137.8	138.4	5.8	30.9	821.3	26.16
South Oak Creek SK-2	WI	4041	42.844	-87.8284	148.9	169.8	5.3	41.6	911.0	31.37
Valley SK-1	WI	4042	43.0303	-87.925	148.9	121.9	3.4	24.1	212.4	4.87
Valley SK-2	WI	4042	43.0303	-87.9217	148.9	121.9	3.4	25.9	228.9	14.07
Weston SK-1	WI	4078	44.8617	-89.655	170.0	73.8	3.8	12.5	142.7	3.98
Weston SK-2	WI	4078	44.8617	-89.655	169.4	73.8	3.8	14.6	167.1	5.12
Weston SK-3	WI	4078	44.8644	-89.6542	167.2	151.2	4.9	38.4	717.4	20.19
Albright SK-1	WV	3942	39.488427	-79.637628	153.3	51.1	6.3	20.6	119.5	3.61
Albright SK-2	WV	3942	39.488351	-79.6367316	140.0	51.1	5.8	19.1	110.6	3.87
Albright SK-3	WV	3942	39.48821	-79.637085	132.8	68.7	7.6	24.8	205.3	8.07
Fort Martin SK-1	WV	3943	39.7103	-79.927341	140.0	168.9	6.5	21.4	844.2	38.47
Fort Martin SK-2	WV	3943	39.709983	-79.927824	133.9	168.9	5.9	19.4	765.6	29.36
Grant Town Power Plant SK-1	WV	10151	39.5116	-80.2168	162.8	91.4	3.0	26.8	195.7	9.12
Harrison SK-1	WV	3944	39.385506	-80.333577	55.6	304.8	13.7	17.7	2574.5	138.22
John E Amos SK-1	WV	3935	38.4731	-81.8233	155.0	274.3	10.1	32.6	2589.9	90.89
John E Amos SK-2	WV	3935	38.4747	-81.825	163.3	274.3	9.2	32.6	2179.0	88.85
Kammer SK-1	WV	3947	39.8455	-80.8171	129.4	274.3	7.0	28.2	1088.0	40.42
Kanawha River SK-1	WV	3936	38.2044	-81.8344	152.2	99.1	5.8	20.2	542.8	21.67
Mitchell (WV) SK-1	WV	3948	39.8309	-80.8168	53.4	304.8	10.3	14.9	1239.1	47.43
Mitchell (WV) SK-2	WV	3948	39.831	-80.8168	53.4	304.8	10.3	14.9	1239.1	34.61
Morgantown Energy Facility SK-1	WV	10743	39.6397	-79.9606	162.8	102.7	2.4	28.0	165.7	6.22
Mountaineer SK-1	WV	6264	38.9794	-81.9344	53.9	304.8	13.0	15.2	2004.7	91.70
Mt. Storm Power Station SK-1	WV	3954	39.2014	-79.2667	51.7	225.9	8.7	29.3	1784.1	58.52
Mt. Storm Power Station SK-2	WV	3954	39.2008	-79.2636	51.7	181.7	6.4	22.3	730.7	32.40
North Branch Power Station SK-1	WV	7537	39.2633	-79.3308	163.0	109.1	4.0	25.0	182.7	7.48
Philip Sporn SK-1	WV	3938	38.9669	-81.9231	126.7	182.9	6.6	33.5	1130.9	35.14
Philip Sporn SK-2	WV	3938	38.9683	-81.9236	126.7	183.3	4.6	41.4	687.2	26.16
Pleasants SK-1	WV	6004	39.367565	-81.296166	54.4	195.1	12.5	16.1	1974.0	80.36
Rivesville SK-1	WV	3945	39.531142	-80.11322	192.6	46.2	2.5	14.1	109.8	0.09
Rivesville SK-2	WV	3945	39.531186	-80.113068	178.7	46.2	2.7	21.7	192.0	3.32
Willow Island SK-1	WV	3946	39.367014	-81.300227	160.6	48.6	2.6	18.6	93.8	1.68
Willow Island SK-2	WV	3946	39.366861	-81.299913	124.4	65.7	4.5	14.8	237.8	6.81
Dave Johnston SK-1	WY	4158	42.8333	-105.7667	143.3	152.4	3.4	28.3	250.3	9.84
Dave Johnston SK-2	WY	4158	42.8333	-105.7667	143.3	152.4	3.4	28.3	250.3	9.66
Dave Johnston SK-3	WY	4158	42.8333	-105.7667	131.1	152.4	4.6	37.8	621.3	17.87

EMISSION POINT	STATE	ORISPL	LATC	LONC	TEMP °C	HGT meters	DIAM m	VEL m/s	FLOW m^3/s	2007 TBtu
Dave Johnston SK-4	WY	4158	42.8333	-105.7667	54.4	76.2	7.0	15.2	587.7	27.74
Jim Bridger SK-1	WY	8066	41.75	-108.8	60.0	152.4	7.3	25.0	1049.6	42.02
Jim Bridger SK-2	WY	8066	41.75	-108.8	60.0	152.4	7.3	25.0	1049.6	35.08
Jim Bridger SK-3	WY	8066	41.75	-108.8	60.0	152.4	7.3	25.0	1049.6	42.37
Jim Bridger SK-4	WY	8066	41.75	-108.8	52.2	152.4	9.4	15.3	1074.4	40.06
Laramie River Station SK-1	WY	6204	42.1086	-104.8711	57.2	184.1	8.7	15.2	908.9	43.44
Laramie River Station SK-2	WY	6204	42.1092	-104.8711	57.2	184.1	8.7	15.2	908.9	46.28
Laramie River Station SK-3	WY	6204	42.11	-104.8711	82.2	184.1	8.7	19.8	1181.6	37.47
Naughton SK-1	WY	4162	41.7572	-110.5986	148.9	61.0	4.1	26.5	379.2	13.69
Naughton SK-2	WY	4162	41.7572	-110.5986	148.9	68.8	4.7	29.6	519.0	17.47
Naughton SK-3	WY	4162	41.7572	-110.5986	48.9	144.8	8.4	12.8	706.4	25.42
NEIL SIMPSON 6 (II 2) SK-1	WY	7504	44.28694444	-105.385	140.0	89.4	2.8	20.0	123.0	8.71
WYGEN 1 SK-1	WY	55479	44.28694444	-105.384	90.0	89.4	2.8	20.0	123.0	8.89
Wyodak SK-1	WY	6101	44.2833	-105.385	65.6	121.9	6.1	31.1	906.5	32.41

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