ELECTRIC POWER
RESEARCH INSTITUTE

2018 TECHNICAL REPORT

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

2017 Base Year Post-MATS Evaluation

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

2017 Base Year Post-MATS Evaluation

3002013577

Final Report, June 2018

EPRI Project Managers
P. Chu
E. Knipping

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

AECOM

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

AECOM
9400 Amberglen Blvd
Austin, TX 78729

Principal Investigators
D. Orr
G. Behrens

AECOM
250 Apollo Drive
Chelmsford, MA 01824

Principal Investigator
D. Heinold
S. Carcieri

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Hazardous Air Pollutants (HAPs) Emission Estimates and Inhalation Human Health Risk Assessment for U.S. Coal-Fired Electric Generating Units: 2017 Base Year Post-MATS Evaluation. EPRI, Palo Alto, CA: 2018. 3002013577.

ABSTRACT

The emissions of Hazardous Air Pollutants (HAPs)-classified chemicals from coal-fired electric generating units have not been reassessed since promulgation of the Mercury and Air Toxics Standards (MATS) rule for fossil-fuel fired electric generation units (EGUs) in 2012. The Electric Power Research Institute's (EPRI's) last assessment of HAPs emissions, and risks associated with those emissions for coal-fired EGUs was conducted prior to the MATS rule and results were published in EPRI's 2009 report entitled *Updated Hazardous Air Pollutant (HAPs) Emissions Estimates and Inhalation Risks for U.S. Coal-Fired Electric Generating Units* (1017980). The information presented here provides an evaluation of projected HAPs emissions and associated risks from coal-fired power plants for a 2017 base case year, using available current data concerning coals burned, controls installed, and new emission measurements taken as part of the 2010 MATS Information Collection Request (ICR). This study was primarily conducted in 2016; therefore, fuel and plant configuration information available at the time of the study was used to project forward for the 2017 base case.

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. 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 consequent human health risks by inhalation for all U.S. coal-fired electric generation units projected to be in operation for the 2017 base year. Inhalation risks from coal-fired EGU HAP emissions for each plant were found to be below the health threshold of interest: for carcinogenicity, all risk values were below 1 in a million; both chronic (long-term exposure) and acute (shorter exposure) non-cancer risks were all below a hazard index of 1. These results demonstrate that the inhalation health risks from coal-fired EGUs for each chemical individually, and all emitted chemicals combined, were well within EPA's established acceptable risk thresholds.

Keywords

Air pollution controls
Hazardous air pollutants (HAPs)
Emission estimates
Human health risk assessment
Coal-fired power plants
Mercury and Air Toxics Standard (MATS)

ELECTRIC POWER RESEARCH INSTITUTE

Deliverable Number: 3002013577

Product Type: Technical Report

Product Title: Hazardous Air Pollutants (HAPs) Emission Estimates and Inhalation Human Health Risk Assessment for U.S. Coal-Fired Electric Generating Units: 2017 Base Year Post-MATS Evaluation

PRIMARY AUDIENCE: Power plant environmental managers, Environmental Protection Agency (EPA), and regulatory agencies

KEY RESEARCH QUESTION

There has been no comprehensive evaluation of the emissions and risks due to hazardous air pollutants (HAPs) from coal-fired electric utilities after promulgation and implementation of the Mercury and Air Toxics (MATS) Rule for fossil fuel-fired electric generating units (EGUs). The Electric Power Research Institute's (EPRI's) last assessment of such risk was in 2009 prior to industy-wide installation of and modifications to air pollution control sytems to reduce emissions of mercury and other HAPs. A large number of EGUs have also been retired since the last assessment was conducted.

RESEARCH OVERVIEW

EPRI re-evaluated HAPs emissions from coal-fired power plants based on updated emission correlations and factors applied to a post-MATS 2017 base year industry profile scenario to assess the potential human health risks by inhalation.

To estimate emissions for coal-fired power plants projected to be in operation for the 2017 base year, 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 anticipated to be representative of the 2017 base year; and
- Use current EPRI correlations and factors for specific HAPs to estimate emissions by stack and by facility.

Annual emission estimates for each power plant unit were developed using the 2017 base year plant configuration database, "blended" coal composition data, and current EPRI emission correlations. Data were compiled for units discharging to common stacks. Emission estimates (mass per time) were compiled based on the 2015 fuel firing rate for each unit and each stack, by HAP species.

Emission estimates were prepared for coal- and petroleum-coke fired units regulated by the MATS rule. These 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 estimate inhalation health risks.

EXECUTIVE SUMMARY

KEY FINDINGS

- Inhalation risks for all power plants were found to be below EPA's acceptable risk thresholds:
  - For carcinogenic health effects by inhalation, all risks were below 1 in a 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.

WHY THIS MATTERS

The overall effort provides the projected post-MATS operation and control configuration of all coal-fired power plant EGUs generating more than 25 MW of electricity, and of their emissions of detected air toxics at each such plant. The study uses 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 EPA's acceptable risk thresholds.

HOW TO APPLY RESULTS

This project is designed to serve both as support for regulatory reviews by public agencies and as guidance for additional EPRI research. The database of HAPs emission rates by U.S. power plants 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 human health inhalation risk.

LEARNING AND ENGAGEMENT OPPORTUNITIES

This research complements other EPRI research on HAPs emissions and risks. Some of those results are published in the following:

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

This report will be useful for communicating estimated emission rates and resulting human health risk from coal-fired power plants to public agencies and other stakeholders.

EPRI CONTACTS: Paul Chu, pchu@epri.com; Eladio Knipping, eknipping@epri.com

PROGRAM: Program 59: Power Plant Multimedia Characterization; Program 91: Air Pollutants and Toxics: Assessments and Models

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

ACRONYMS AND ABBREVIATIONS

AERMOD	AMS/EPA regulatory model
ACI	Activated carbon injection
APC	Air pollution control
AMPD	Air markets program data
AMS	American Meteorological Society
Btu	British thermal unit
°C	Degrees Celsius
CAA	Clean Air Act
CEM	Continuous emissions monitoring
CDS	Circulating dry scrubber
CFD	Cumulative frequency distribution
CFR	Code of Federal Regulations
COHPAC	Compact hybrid particulate collector
DOE	Department of Energy
DSI(HCl)	Dry sorbent injection for acid gas (HCl) control
DSI(SO_3)	Dry sorbent injection for SO_3 control
EEMS	Emission-Economic Modeling System
EFH	Emission factors handbook
EGU	Electricity generation unit
EIA	Energy Information Agency
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
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
FGDadd	FGD additives for mercury re-emissions control

FGDd	Dry flue gas desulfurization
FGDdsi	Dry sorbent injection for SO_2 control
FGDw	Wet flue gas desulfurization
FPM	Filterable particulate matter
FuelBr	Fuel bromine addition
HAP	Hazardous air pollutant
HACI	Halogenated activated carbon injection
HEM	Human exposure model
HI	Hazard Index
HQ	Hazard Quotient
HCl	Hydrogen chloride
HF	Hydrogen fluoride
HgT	Mercury (total)
HgE	Elemental mercury
HgOx	Oxidized mercury
HgP	Particulate mercury
ICR	Information collection request
IGCC	Integrated gasification combined cycle
kg	kilogram
KM	Kaplan-Meier
lb	Pound
L/G	Liquid-to-gas ratio
ln	Natural logarithm
LOI	Loss on ignition
MACT	Maximum achievable control technology
MMBtu	Million British thermal units
MWe	Megawatt of electricity
NCSI	Non-carbon sorbent injection for mercury control
OAQPS	Office of Air Quality Planning and Standards
OFA	Overfire air
PCD	Particulate control device
PPTMD	Power Plant Toxics Measurements Database
PRB	Powder River Basin
RRF	Risk Reduction Factor
SCA	Specific collection area
SCR	Selective catalytic reduction
SD	Spray dryer
SNCR	Selective non-catalytic reduction

TDF	Tire-derived fuel
TBtu	Trillion British thermal units
TEQ	Toxicity equivalents
URE	Unit Risk estimate
USGS	United States Geological Survey
VS	Venturi scrubber

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
BACKGROUND AND INTRODUCTION

This report presents an assessment of hazardous air pollutant (HAP) emissions and the consequent human health risks by inhalation for United States coal-fired electric generation units (EGUs) that were projected to be in operation for a 2017 base year scenario following implementation of air pollution controls in response to the Mercury and Air Toxics Standards (MATS) regulations (i.e. post-MATS).

The last major compilation and evaluation of emissions data for HAPs (e.g., trace elements, acid gases such as HCl, HF, Cl_2, and selected organic compounds) was conducted by EPRI in 2009 [1]. Prior to the 2009 evaluation, EPRI conducted a similar evaluation in mid-1990s as part of the 1994 Synthesis Report [2] and subsequent data analyses and development of emission factor correlations, now incorporated into AP-42. In addition, EPRI performed an analysis of the mercury 1999 Information Collection Request (ICR) data set to examine mercury emissions in more detail and develop a set of updated mercury emission factors for various plant configurations [3]. Since the 2009 study, additional full-scale emissions test information has been generated as part of EPA's ICR in support of the MATS rulemaking effort. This information provides a significant amount of new data to supplement the information analyzed in previous EPRI efforts. EPRI initiated a project to evaluate and compile these new sources of data and subsequently use these data to supplement and update work previously conducted by EPRI. The updated emission correlations and factors were developed as part of a separate EPRI project in 2013/2014 and documented in EPRI's 2014 Emission Factors Handbook [4]. As a result of this effort, many of the factors and equations previously published have changed slightly.

One objective of this current EPRI program was to prepare revised emission estimates for the current fleet of coal-fired electric generating units for the 2017 base year. These revised emission estimates were then used in a separate subsequent EPRI-sponsored project to conduct stack air dispersion modeling and develop inhalation health risk estimates for the fleet of coal-fired EGUs expected to be in operation in 2017. This work was conducted in 2016, therefore plant information and data prior to 2017 were used to project the profile and characteristics of units expected to be in operation as of 2017. This report provides details regarding the methodology used to develop these revised emission estimates and a summary of the revised emission estimates for coal- and 100% petroleum coke-fired units, as well as the results of the inhalation health risk assessment.

Emission Estimation Methodology Overview

To estimate emissions for all individual coal-fired power plants, a number of data sources were required. 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. Since the study was primarily conducted in 2016, it was necessary to use information regarding plant configurations and stack parameters from 2-3 years prior to the 2017 base scenario, supplemented with industry knowledge on future plant modifications and unit retirements. This approach was used to obtain a reasonable representation of coal-fired power plant industry for projecting 2017 base year emissions and inhalation health risk.

The general approach for emission estimation included the following steps:

1. Obtain a coal composition data set for HAPs that is categorized by coal source at the county/state/coal region level.
2. Obtain fuel consumption data to develop a) "blended" coal compositions specific to each station and b) actual unit consumption rates.
3. Obtain appropriate power plant characteristics projected to be representative of the 2017 base year operations (e.g., control technology configuration, stack particulate emission rate, and stack parameters necessary for dispersion modeling).
4. Apply the current set of updated EPRI 2014 correlations and factors for specific HAPs to estimate emissions.

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

Coal Composition Data Set

In EPRI's 1994 Synthesis Report, the USGS Coal Quality database [5] which was previously screened by EPRI was used to provide HAPs coal concentrations for 22 major coal regions by state. Since that time, USGS has not updated the data set. 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 data set, calculated on a lb/trillion Btu (lb/TBtu) basis.

For coal mercury and chloride, the 1999 EPA mercury Information Collection Request (ICR) dataset was used, as it contains 40,000 as-fired concentrations. It is organized by state/county and can be grouped into coal regions as well. Given the large number of data points available in the 1999 ICR data set, county average chloride values by coal rank were used for this effort as opposed to geometric mean values by state/region that were used for other HAPs. Note that coal mercury data were not used in this evaluation to estimate mercury stack emissions as has been done in past EPRI emission estimation evaluations. For this current effort, measured total mercury values from EPA's Air Markets Program Data (AMPD) were used. However, 1999 ICR coal mercury data were used to estimate total mass of mercury input for each unit when evaluating total reduction in mercury for the industry.

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 data source or foundation of these databases is the *Emission-Economic Modeling System* (*EEMS*) Database. The primary information sources used to maintain the database are Energy Information Administration (EIA) Forms 860 and 923, published reports, and individual discussions with electric generators.

EIA 923 records from 2015 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 forms were incorporated to calculate "blended" coal compositions for individual stations based on the percentage of coal fired and applied to the future 2017 base year. The 22 USGS data sets account for over 90% of the coal consumed. For the other sources, estimates were derived using appropriate combinations of the 22 USGS data sets.

Power Plant Characteristics

The projected characteristics of each power plant unit (e.g., air pollution control device, particulate emissions) necessary to estimate emissions were defined using information from the plant database supplied by James Marchetti, Inc. as referenced above. These 2017 base-year unit characteristics databases for coal units provided the anticipated plant configuration information and other key input parameter values necessary to apply the updated emission correlations and estimate HAPs emissions for each unit. Control configuration classes assigned to each unit were unique to each HAP or HAP group being modeled (e.g., mercury, selenium, acid gases). The plant database also provided information regarding fuel usage as of 2015 necessary to estimate annual emissions. (i.e., trillion Btu fired at the unit and station level and assumed to apply to the future 2017 base year). All U.S. units expected to be in operation as of January 1, 2017 were included in the plant database and subsequent emissions estimate and risk evaluation.

Emission Correlations

Emission correlations and emission factors for both mercury and non-mercury HAPs have been developed previously for both coal- and oil-fired units as part of the EPRI 2014 Emission Factors Handbook [4]. The two groups are described below.

Mercury - EPRI factors and correlations for total mercury were not used in this evaluation since these factors were developed from historical test data prior to wide-spread implementation of mercury emission controls in response to the MATS Rule. Instead, actual reported mercury emissions data from EPA's Air Markets Database for the period from September 2015 through March 2016 were used calculate an average total mercury emission value for each of the units with reporting data (approximately 240 units). In the absence of such data, a default average emission value derived from the units with AMPD data was used. For speciated mercury emission estimates, correlations and factors from the 2014 Emission Factors Handbook were used. In some cases, slight modifications to these correlations and factors were made to account for the potential impact of new MATS control technologies on speciation of mercury at the stack emission point.

Non-Mercury HAPs - New sources of non-mercury HAPs emissions test data from the 2010 MATS ICR were incorporated to previous versions of EPRI correlations and factors as documented in EPRI's 2014 Emissions Factors Handbook and described in this current report. In some cases, slight modifications to these correlations and factors were made to account for the potential impact of new MATS control technologies on emission of other HAPs such as selenium and HCl.

Emission factors for organic compound HAPs for coal-fired units were also updated using new information from the 2010 MATS ICR as documented in the 2014 Emission Factors Handbook. In the 2014 Handbook, EPRI used the Kaplan-Meier (KM) statistical analysis technique to develop emission factors for organic compounds. The KM technique provides an improved method for analysis of data sets containing large amounts of censored values (i.e., values reported as being below the limit of detection).

Estimate Emissions

Annual emission estimates for each power plant unit were developed using the projected 2017 base-year plant configuration database parameters (control device configuration, total heat input, stack particulate emission rate), “blended” coal composition data, and the current EPRI emission correlations. In cases where units are 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 reported 2015 fuel firing rate for each unit (e.g., trillion Btu fired in 2015). In the case of 100% petroleum coke-fired units, emission estimates were based on a set of KM-based emission factors (lb/trillion Btu input) for each individual HAPs species derived from data collected as part of the 2010 MATS ICR. These emission estimates for each stack emission point were subsequently used as inputs to perform air dispersion modeling and inhalation health risk estimates for each power plant.

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

Development of the Final Inhalation Risk Estimates

Emission estimates were prepared for all coal- and petroleum-coke fired units regulated under the MATS rule 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 points.

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. Development of emission correlations and factors, as well as the sources of emissions test data used, are presented in Section 4. Section 5 provides a summary of the final emission estimates, including a discussion of uncertainties associated with these estimates. Inhalation human health risk assessment methodology and results are provided in Sections 6 and 7, respectively.

References

1. 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.
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
3. An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants, EPRI, Palo Alto, CA: September 2000. TR-1000608
4. Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants. EPRI, Palo Alto, CA: 2014. 3002003848.
5. USGS COALQUAL Database. http://energy.er.usgs.gov/products/databases/CoalQual/index.htm

2 PLANT DESIGN AND OPERATIONAL CHARACTERISTICS

Details regarding the development of the unit characteristic database for coal- and 100% petroleum coke (pet coke)-fired units are provided in this section. Oil-fired units were not evaluated by EPRI as part of this project.

The database for coal-fired units was developed for the purposes of modeling both mercury and non-mercury hazardous air pollutant emissions. The primary data source or foundation of this database 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 perform specific emission and economic analyses of environmental policies and regulations impacting the electric utility industry.

The EEMS database is a proprietary description tool that accounts for all major fossil generating units in the U.S. that have been or are currently operating. The EEMS database was initially derived from Energy Information Agency (EIA) data of generating units, but unlike EIA, the EEMS is updated weekly and has been over the last 15 years.

EEMS describes the entire suite of flue gas control technologies for coal-based generating assets. These include the presence of wet or dry FGD for SO_2; low NOx burners (LNB), overfire air (OFA), selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) for NOx; and dry sorbent injection for SO_2, sulfur trioxide (SO_3), and hydrogen chloride (HCl). The type of particulate collector (fabric filters or ESP) is imbedded in the database. In addition, special-purpose steps to comply with the MATS rule are defined, including: 1) the use of halogenated vs. conventional activated carbon injection; 2) special-purpose SCR catalysts or halogen addition to either the fuel or flue gas to prompt the oxidation of Hg; and 3) additives to minimize Hg re-emission from wet FGD process. Sources of data used to develop the database and the projected emission control profile for the 2017 base case modeling year are discussed in the following sections.

Coal Plant Database Development

The initial task was to develop a database for all coal- and 100% pet coke-fired units that were expected to be operating in 2017 with a focus upon 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 has a nameplate capacity greater than 25 MWe and sells electricity to the grid. The plant database therefore only included units which met these criteria, which totaled 710 boilers. Emission estimates were developed at the boiler level since individual boilers can have different types of emission controls in some instances, and fuel use/heat input data are available at the boiler level. Table 2-1 illustrates those categories and data fields that composed the database for the year 2017. As noted in Table 2-1, information reported by EIA and other sources prior to 2017 were used to compile the initial plant database. This information was supplemented with information from various industry contacts to account for expected future change through 2017 (e.g., the anticipated addition of a wet FGD scrubber in 2016 or 2017).

Table 2-1
Design and Operational Data for Coal Generating Boiler/Unit Database 2017

Categories	Data Fields	Primary Data Sources
Plant Identification	Plant Name, Plant ID, Operator, State, Prime Mover, Generator & Boiler ID, Nameplate Capacity, In-service Date, Boiler & Bottom Type	Form EIA-860
2015 Coal Type/Quality	Coal Type/Rank, Coal Quality – heat content, sulfur & ash content by rank, Total & Coal Heat Input by Rank at the boiler level	Form EIA-923 [a]
Projected 2017 NOX Controls	Existing Combustion and Post-combustion NOX Controls, SCR & SNCR In-Service Dates	EEMS Data Base, Form EIA-860 Contact with Individual Generators
Projected 2017 Particulate Controls	Collector ID, Existing Particulate Controls by Type, ESP Upgrades, In-Service Dates	EEMS Data Base, Form EIA-860, Contact with Individual Generators
2014 Particulate Emission Rate	Stack Particulate Emission Rate (lbs/MMBtu)	Form EIA-860
Projected 2017 FGD and Other SO_2 Control Systems	FGD ID, Existing FGD Systems by Type, Sorbent and Oxidation Mode, DSI, FGD Upgrades, In-Service Date	EEMS Data Base, Form EIA-860 Contact with Individual Generators
Projected 2017 MATS Controls	Technology Type (e.g., ACI, DSI, Chemical Additives) for Hg, HCl & SO_3	EEMS Data Base, Form EIA-860, Contact with Individual Generators
Mercury Emissions	Hg Emissions, Heat Input and Emission Rates (lbs/TBtu)	EPA's Air Markets Program Data (AMPD) file; Data from September 2015 through March 2016 [b]
2014 Stack Information	Stack ID, Stack Height, Stack Area at the Top, In-Service Date, Flues, Stack Exit Temperatures, Stack Exit Velocities	Form EIA-860
2015 EPA Part 75 Data	Monitor ID, Stack Height, Areas at the Top, Load Units, Load Values, High Flow	EPA Clean Air Markets Division
Geography	County, Latitude, Longitude, Zip Code	Form EIA-860, EPA AMPD

[a] If annual heat input data were not reported in EIA Form 923, the 2015 data from EPA's Air Markets Program Data (AMPD) were used to estimated total annual heat input for the unit.

[b] Seven months of hourly data from EPA's Air Markets Program Data (AMPD) files were utilized (September 2015 through March 2016), for those units reporting. The variables extracted from the AMPD file were the boiler identification fields, the operating date and hour, gross load, heat input, and mercury (Hg) mass emissions. It should be noted those lines of hourly data which did not report either heat or emissions data were omitted. Each unit emission rate was calculated by dividing the total Hg mass emissions by the total heat for the seven-month period.

Once this initial database was completed, it was reviewed by EPRI advisory committee members for accuracy and completeness. Details in the final plant database were used to define the following key unit-level operational parameters necessary for development of the final emission estimates for the 2017 base-year:

- Unit-level control technology class;
- Unit-level stack particulate emission rate (lb/MMBtu);
- Unit-level total heat input (TBtu/yr);
- Mapping of units to common stack emission points;
- Stack latitude and longitude; and
- Stack height, diameter, flue gas velocity, and flue gas flow rate.

2017 Industry Profile

Table 2-2 provides a summary of the air pollution control device profile for the coal-fired utility industry developed for use in this project based on the information available in the final boiler/unit characteristics database. Since emissions were developed at the boiler level, counts in Table 2-2 represent the number of boilers within each control class category (710 total boilers were modeled representing 675 unique units). Details regarding the rationale for selection of the various control class categories are provided in Section 4 – Emission Correlations and Factors. Table 2-2 shows approximately 44% of the total projected 2017 MW capacity (278 of the 710 total boilers) was associated with units having either SNCR or SCR NO_X control systems. Units having either dry or wet FGD systems for SO_2 control comprise approximately 80% of the total projected MW capacity. The combination of SCR with a wet FGD scrubber, an important MATS control class configuration with respect to mercury oxidation and potential for mercury removal in downstream control systems, accounts for approximately 30% of the total MW capacity. Approximately 26% of the total projected MW capacity (132 boilers) reported boilers equipped with some form of SO_3 control (ammonia, hydrated lime, limestone, sodium bisulfite, or wet electrostatic precipitators) or were anticipated to have such systems in place by 2017.

In addition, available information regarding plant add-on mercury controls was compiled from EIA, EPA and various industry contacts. Based on this information, the anticipated profile of add-on mercury controls was developed and is summarized in Table 2-3. Of the total capacity by MW, 45% report using some form of activated carbon injection for mercury control; either halogenated or non-halogenated carbon, or activated carbon injection in combination with fuel bromine addition and/or FGD system additives. Approximately 28% of the total MW generating capacity (251 boilers) reported use of “existing air pollution control systems” as their mercury/MATS control.

Table 2-2
Projected Control Class Profile for Coal-Fired Boilers (Units >25 MW to grid) – 2017 Base Year

Control Class	Total MWe	Number of Boilers
Boilers without NO_X Controls		
ESPc	25,892	76
ESPc CDS	80	1
ESPc FBC	75	1
ESPc FGDd	1,280	3
ESPc FGDdsi	5,147	7
ESPc FGDw	33,751	74
ESPc FGDw SO_3 Control	17,079	32
ESPh	35	1
ESPh FBC	103	2
ESPh FGDdsi	326	1
ESPh FGDw	4,132	11
ESPh FGDw SO_3 Control	809	2
FBC	3,603	23
FF	12,224	38
FF FBC	708	14
FF FGDd	25,486	76
FF FGDdsi	2,062	16
FF FGDw	14,687	31
FF FGDw SO_3 Control	7,407	14
VS FGDw	2,322	5
VS FGDw WetESP	1,320	2
Boilers with SCR or SNCR NO_X Controls		
SCR ESPc	3,477	8
SCR ESPc CDS	1,320	2
SCR ESPc FGDd	643	1
SCR ESPc FGDdsi	1,319	2
SCR ESPc FGDw	27,845	50
SCR ESPc FGDw SO_3 Control	34,624	58
SCR ESPh FGDw	411	1
SCR ESPh FGDw SO_3 Control	3,467	7

Table 2-2 (continued)
Projected Control Class Profile for Coal-Fired Boilers (Units >25 MW to grid) – 2017 Base Year

Control Class	Total MWe	Number of Boilers
SCR FF	1,061	2
SCR FF FGDd	10,164	37
SCR FF FGDw	9,438	13
SCR FF FGDw SO_3Control	7,985	12
SCR VS FGDw SO_3Control	1,827	2
SNCR ESPc	1,665	8
SNCR ESPc FGDdsi	1,786	4
SNCR ESPc FGDdsi SO_3Control	84	2
SNCR ESPc FGDw	7,797	16
SNCR ESPc FGDw SO_3Control	334	1
SNCR ESPh FGDw	400	2
SNCR ESPh/ESPc FGDw SO_3Control	187	2
SNCR FBC	3,052	23
SNCR FF	1,770	7
SNCR FF FGDd	1,626	5
SNCR FF FGDdsi	68	2
SNCR FF FGDw	3,287	11
IGCC	618	2
Total All Boilers	283,782	710
Total without SCR or SNCR NO_X Controls	158,529 (56%)	430 (61%)
Total with SCR	102,580 (36%)	195 (27%)
Total with SNCR	22,056 (8%)	83 (12%)
Total with SO_3 Control	73,803 (26%)	132 (19%)
IGCC	618	2

Key:

ESPc = cold-side electrostatic precipitator
SCR= selective catalytic reduction
ESPh = hot-side electrostatic precipitator
SNCR= selective non-catalytic reduction
FGDdsi = dry sorbent injection for SO_2 control
IGCC = integrated gasification combined cycle
CDS = circulating dry scrubber
FGDw = wet flue gas desulfurization
VS = venturi scrubber
FF = fabric filter
FBC = fluidized bed combustion
SO_3Control = SO_3 control using ammonia, lime, limestone, hydrated lime, SBS, Trona, or wet ESP
FGDd = spray dryer flue gas desulfurization

Table 2-3
Projected Control Class Profile for Mercury and HCl at Coal-Fired Boilers (>25 MW to grid) – 2017 Base Year

Mercury Control Class	Total MWe	Number of Boilers
ACI	75,792	164
ACI DSI(HCl)	11,762	39
ACI FGDadd	2,562	4
DSI(HCl)	4,037	20
Existing APC	80,347	251
FGDadd	11,895	19
FGDadd DSI(HCl)	363	1
FuelBr	8,847	20
FuelBr ACI	24,836	55
FuelBr ACI DSI(HCl)	231	2
FuelBr ACI FGDadd	5,821	11
FuelBr FGDadd	13,790	28
FuelBr HACI	720	1
FuelIodide DSI(HCl)	990	3
GORE	2,362	6
HACI	35,024	72
HACI DSI(HCl)	3,920	6
HBr FGDadd	265	1
NCSI	168	2
NCSI DSI(HCl)	500	4
ReACT	351	1
Total All Boilers	283,782	710

Key:

ACI = activated carbon injection

DSI(HCl) = dry sorbent injection for HCl

FGDadd = FGD system additives

FuelBr = fuel bromine addition

FuelIodide = fuel iodide addition

HBr = hydrogen bromide addition

GORE = GORE membrane

HACI = halogenated activated carbon

NCSI = non-carbon sorbent injection

ReACT = ReACT multi-pollutant control

Existing APC = existing air pollution control system

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). 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.

1. Obtain/generate a database of coal composition data by major coal region.
2. Obtain information regarding the type and quantity of fuel consumed by each coal-fired power plant using EIA Form 923 data from 2015. This was the latest set of available data at the time the emission modeling estimates were conducted.
3. Link and 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). The assumption was made that the fuel consumption data from 2015 were representative of the coal fired at each unit for the 2017 base year.

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 analyzed to provide HAPs coal concentrations and heating values for 22 major coal producing regions by state. From an initial 3,300 coal samples, a final count of about 2,700 samples were produced. The screening excluded thin and deep (non-economic) beds. Data for several specific coal types were then processed using coal cleaning algorithms to produce the final screened USGS coal data set. The details of the methodology EPRI used to develop the screened USGS database is described in EPRI's 1994 Synthesis Report. Table 3-1 below 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 grouped by state, region, and coal rank. This database of geometric mean composition values was then used as the basis for calculating mass-weighted "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 chloride, the 1999 ICR data was used for the emission estimates, as it contains 40,000 as-fired concentrations. It is organized by state/county and was 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.

Unlike previous EPRI emission estimates, coal mercury data were not used to estimate mercury emissions in this current project.

For non-coal fuels [e.g., tired-derived fuel (TDF), petcoke] the trace element and heating value information was retrieved from the EPRI PPTMD database (version 2008a) and an average value for each of these fuel types was generated and used in the calculation of "blended" fuel compositions in cases where 2015 fuel purchase records indicated coal was co-fired with these fuels. Composition data for these fuel types are provided in Appendix A. If a unit fired 100% pet coke, then the stack emission modeling approach did not use the pet coke composition. Instead, as described in Section 4, stack emission factors developed based on measured emissions data from 100% pet coke fired units were used to estimate annual stack emissions.

Fuel Purchased Information (2015 EIA 923)

Fuel purchase information was taken from EIA Form 923 data for the year 2015 [3]. This database contains the monthly fuel purchase records for all US power plants at the station level. These monthly records were combined into a yearly total. After screening out all oil and natural gas fired units, approximately 450 unique station entries remained in the database, including some industrial and non-power generating stations. 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 station.

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 EIA database was mapped to one of the 22 USGS categories listed in Table 3-1. The 22 major seams accounted for 91% of the 2015 coal tonnage for all plants. An additional 58 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. For 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 EPRI's PPTMD database (v2008a). Imported coal was assigned as Eastern bituminous, or Powder River subbituminous, depending on the reported rank as these represents the two largest sources of coal by rank.

Once a fuel source was applied to each plant's fuel purchases, the two databases were combined, to obtain a composition input value for inorganic species at 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 individual unit level.

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. An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants, EPRI, Palo Alto, CA: September 2000. TR-1000608
3. 2015 EIA Coal Purchase Records: https://www.eia.gov/electricity/data/eia923/http://www.eia.doe.gov/cneaf/electricity/page/eia423.html

4
EMISSION CORRELATIONS AND FACTORS

Current EPRI emission factors for coal- and 100% petroleum coke-fired units are discussed in this section. Information regarding the data sources used to develop these factors as well as the associated test programs that generated these data are described first, followed by an overview of the emission estimation approach used for various HAPs groups (particulate-phase metals, volatile inorganic species, and organic compounds). Finally, a more detailed discussion of emission correlations and factors for both coal- and 100% petroleum coke-fired units is presented.

Data Sources

The compilation of data used in the development of emission correlations and emission factors for this study were generally collected during three distinct time periods: the 1990s (including the 1999 EPA mercury ICR), post 2000 EPRI- and Department of Energy (DOE)-sponsored field studies, and the 2010 Mercury and Air Toxics Standards (MATS) Rule Information Collection Request (ICR). These three periods are described below.

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 DOE had two initiatives which collected similar data during the same timeframe. The Clean Coal Technology program, in which advanced technologies are demonstrated, incorporated the measurement of emissions as project objectives 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 sources formed the basis of the early- to mid-1990s data set and were used to develop the emission correlations and emission estimates presented in EPRI's 1994 Electric Utility Trace Substances Synthesis Report [1]. 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 mercury 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 [2].

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 programs included collection of mercury speciation and emissions data during baseline conditions, and in some cases, also included measurement of other HAPs species. Some utilities also 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.

Finally, a significant amount of HAPs emissions data for fossil fuel-fired EGUs were collected by EPA as part of the 2010 ICR in support of the MATS rule development process. These data were reviewed by EPRI and subsequently incorporated into existing data sets for emission factor and correlation development. A more detailed discussion of EPRI methodology for review and incorporation of the 2010 ICR data to emission factors and correlations is provided in Appendix B. EPRI also provided comments to EPA during the MATS rulemaking process regarding potential issues regarding data quality for selected data sets, in particular evidence of metals contamination in the source sampling equipment at selected sites which resulted in elevated levels of metals such as chromium and nickel in the stack emission sample train components [3]. A number of these suspect sites were retested in 2012 and emission levels for selected metals were significantly lower as discussed in EPRI comments to EPA. 2010 ICR data with suspected data quality issues (e.g., data from sites with suspected metals contamination) were not included in the overall data set used to develop the current EPRI emission factors. Instead, data from emission retests conducted in 2012 at selected sites were used.

Test Program Overview

Table 4-1 compares the number of units tested for HAP emissions as part of various data gathering efforts that have been incorporated into EPRI emission factors over the past 30 years. The total number of test 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 data sets generated to illustrate that some test sites were used to generate data for multiple control class groups. Over 150 sites were sampled for mercury and other HAPs since EPRI's previous 1994 Synthesis Report and 2000 mercury emissions assessment efforts. Of these post-2000 group of 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 being from miscellaneous literature or utility sources. Finally, an additional 371 coal-fired sites were tested as part of the 2010 MATS ICR for one or more groups of HAPs species (e.g., metals, acid gases, organic compounds).

A summary of all available data for non-mercury HAPs (non-mercury trace elements, hydrogen chloride, chlorine gas, hydrogen fluoride, organic compounds, and dioxin/furan compounds) emission correlations and emission factors are summarized in Table 4-2. Approximately 70-80% of the total available data for any given analyte was generated as part of the 2010 MATS ICR, with the remainder from historical sources as described previously.

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

Period	Test Campaign	Number of Test Sites [a]	Number of Control Class Data Sets [b]
1990s	1990-1995 EPRI FCEM and DOE Air Toxics	28	38
	1999 EPA Mercury ICR	84	109
Post-2000	DOE and EPRI Sources [c]	153	153
2010	EPA 2010 MATS ICR [d]	371	371

[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 data sets for more than one control class configuration (e.g., ESPc FGDw sites can provide data for both ESPc and ESPc FGDw control class groups if the flue gas was sampled upstream of the scrubber and at the stack).

[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.

[d] Count of coal-fired units from EPA's 2010 MATS Information Collection Request MS Access® database (original MS Access® ICR Database file entitled "EGU ICR Part III" and dated 12/16/11) for which data submittal_id values were reported.

Table 4-2
Summary of Available Coal-Fired Plant Data Points for Emission Correlations or Factors – Non-Mercury HAPs

Analyte	Historical Data	2010 ICR Data [a]	Total Current 2014 EFH Correlations
Antimony	44	168	212
Arsenic	60	203	263
Beryllium	57	207	264
Cadmium	58	203	261
Chromium	57	201	258
Cobalt	50	188	238
Lead	57	208	265
Manganese	59	188	247
Nickel	58	198	256
Selenium	53	197	250
Hydrogen Chloride	80	200	280
Chlorine (Cl_2)	27	16	43
Hydrogen Fluoride	54	185	239
Organic Compounds [b]	1 - 28	1 - 96	1 - 122
Dioxin/Furan Compounds	15	48	63

[a] Includes units retested in 2012 for trace element HAP emissions.
[b] Range of stack data counts for individual organic compounds.

In the 2014 EFH, EPRI also presented total mercury correlations that were updated using 2010 ICR data; however, for the purposes of estimating post-MATS Hg emissions and risk for the 2017 base year, these correlations were not used since they represent control configurations prior to implementation of the MATS rule. As described later in the report, total mercury emissions were estimated using available MATS compliance measurement data reported by EPA for the period from September 2015 through March 2016 in their Air Markets Program Data [4]. EPRI's mercury speciation correlations were used to estimate the speciation of total mercury between elemental, oxidized and particulate forms of mercury. These speciation correlations and factors have remained unchanged since their development using the comprehensive set of data obtained as part of the 1999 Mercury ICR.

Emission Estimation Approach Overview

This section presents the techniques used for estimating trace substance emissions from coal- and 100% petroleum coke-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). More recent data collected by the Environmental Protection Agency (EPA), DOE, and individually sponsored utilities have also been incorporated, as well as data generated as part of EPA's 2010 ICR. The methodology presented here was first used by EPRI in the Electric Utility Trace Substances Synthesis Report [1]. It is presented here to document recent inclusion of more data. EPRI emission factors for coal- and pet coke-fired units published in the 2009 emission modeling and inhalation risk report [5] have since been updated using additional data from the 2010 ICR and other sources. These final emission factors are compiled in EPRI's 2014 Emission Factors Handbook (EFH) and described further in this section [6].

The following caveats are important to reiterate when using this information:

- Actual measurements of HAPs emissions can vary from estimated levels by several orders of magnitude. 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). Emission estimates developed from such data distributions may differ significantly from measured values.
- 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.
- Site-specific factors at any given plant may be so different from the sample population used to produce these equations that the predictive value may be compromised. For example, co-firing waste tires or natural gas with coal was not examined at any test site. The coal-fired unit emission factors may not be good estimators for such plants for substances contained in waste tires.

This section presents emission estimation techniques for the following trace substances used in the inhalation risk assessment:

- Antimony, arsenic, beryllium, cadmium, chromium, cobalt, manganese, mercury, lead, nickel, and selenium;
- Hydrogen chloride (HCl);
- Chlorine (Cl_2);
- Hydrogen fluoride (HF); and
- Organic substances that have been detected in emissions from coal-fired plants (note that only a subset of organic substances were selected for the inhalation risk assessment).

Background

The measurement programs described previously 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, EPA and others provided results for various HAPs for a subset of operating units. These tests encompass plants with each major fuel type and boiler configuration as well as SO_2, NO_X, and particulate control technologies. The resulting database represents a data set obtained by consistent sampling and analytical protocols to estimate emissions from steam-electric power plants; however, emissions varied significantly among similar plants.
- The measured emission results have been quite variable, with measurements of some individual specific HAPs ranging across several orders of magnitude. For some HAPs, the emissions data are not normally distributed; many of the data sets have been shown to be log-normal. Some results were subdivided into smaller subsets to account for variables such as fuel type and SO_2 and particulate control technologies.
- The correlations or emission factors presented in this section are based on specific groups of data and calculational approaches. Alternate 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. Therefore, the emission factors suggested in this section may over or under estimate the actual emissions of a particular unit.

The approaches used for estimating emissions from coal-fired units are summarized at a high level below for these groups. Additional details for both coal- and 100% pet coke-fired units are provided later in this section. Appendix B provides more background information regarding development of emission factors and correlations.

Particulate-Phase Trace Elements

This group includes the following: antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), manganese (Mn), lead (Pb), and nickel (Ni). The estimation approach used for each particulate-phase trace element emission is a correlation that incorporates the inlet concentration in the coal and the filterable particulate matter (FPM) emission factor on a lb/MMBtu basis. These regressions are not dependent upon specific control technology devices or coal types. However, the correlation indirectly incorporates the particulate control efficiency. Figure 4-1 is an example of this type of correlation for arsenic. The independent parameter is the coal concentration, divided by the ash in the coal, and multiplied by the FPM emission level. A power function is used to fit this parameter to the measured emission. Both values are expressed on a common basis, the pounds of the substance per trillion Btus heat input. New constants are generated when additional site results are added to the database.

The control device designations used in Figure 4-1 are based on the final FPM control device present in the air pollution control system before the flue gas exits the stack: FF = fabric filter, ESP = electrostatic precipitator, and FGDw = wet flue gas desulfurization. Therefore, units equipped with a spray dryer for SO_2 control followed by a fabric filter for PM control are designated as FF for this plot, as are units with only a fabric filter control system and no SO_2 controls. Figure 4-2 shows the same arsenic correlation data set with historical data and 2010 ICR data set identified separately. Historical and 2010 ICR data sets cover a similar range of values on both the X- and Y-axis of the plots. Of the total 263 data points used in the arsenic correlation, 77% (203) are from the 2010 ICR.

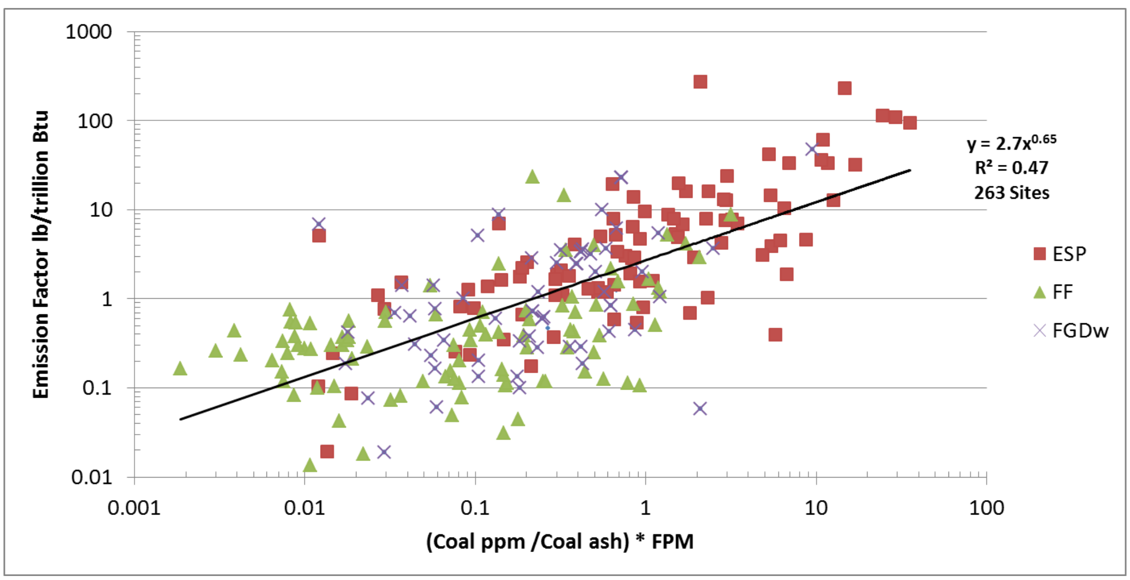


Figure 4-1
Arsenic Emission Correlation – By Control Device

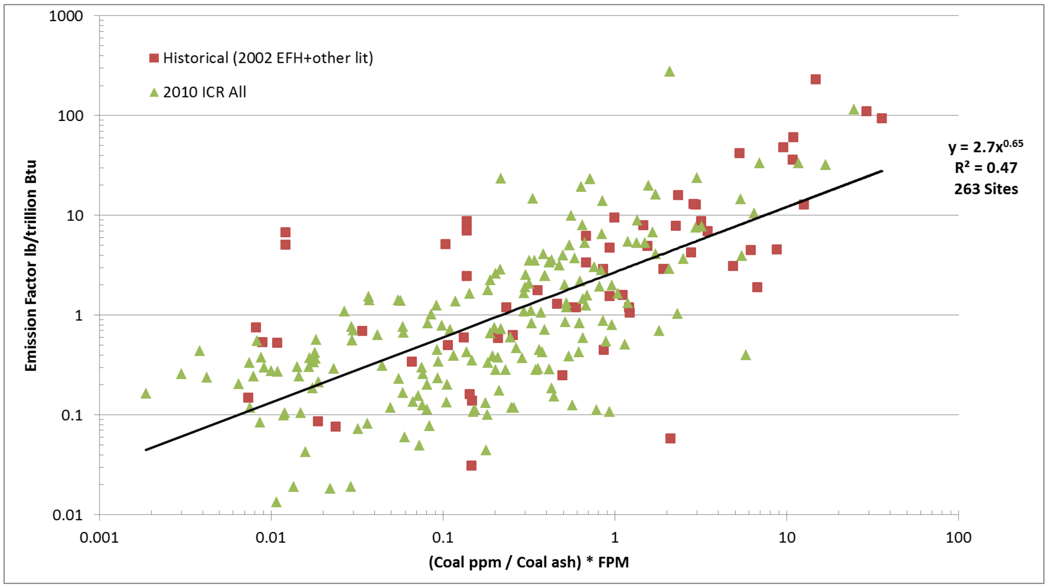


Figure 4-2
Arsenic Emission Correlation – By Data Source

Volatile Inorganic Substances

This group includes the following: hydrogen chloride (HCl), hydrogen fluoride (HF), chlorine (Cl_2), mercury (Hg), and selenium (Se). Inorganic substances in the fuel such as chlorine, fluorine, mercury, and, in some cases, selenium exist primarily in the vapor phase after combustion and, thus, are not consistently captured by a particulate control device. The average removal efficiencies for HCl and HF, based on the type of air pollution control device(s) present, are used to estimate these emissions. Emission factors are expressed as percent of coal chloride and fluoride emitted as HCl and HF, respectively.

In the case of selenium, two types of emission factors were developed. For units with fabric filter controls, ESP controls, or wet FGD controls, the data supported development of separate emission correlations to predict the percent of coal selenium emitted as a function of the coal sulfur content. For all other control device categories, the average "percent of coal selenium emitted" (i.e., 100 minus percent removal) for each device category was used to estimate emissions.

Total mercury emission estimates were developed using AMPD MATS compliance test data reported to EPA from September 2015 through March of 2016 for each unit based on sorbent trap or mercury CEM-based data. At the time of this study, such data was available for approximately 240 units in the list of units modeled for the 2017 base year. When such measurement data were not available, an average value of 0.5 lb/TBtu, derived from the approximately 240 units with actual measured values, was used to estimate emissions. For speciated forms of mercury (elemental, oxidized, and particulate), EPRI correlations and average factors for various control device categories were used to estimate emissions of elemental and particulate mercury; oxidized mercury was estimated by difference using the total mercury, elemental mercury, and particulate mercury values. EPRI correlations and average factors for speciated forms of mercury are expressed as percent of total mercury present in elemental or particulate forms, and are based primarily on comprehensive speciated mercury stack measurement data collected as part of the EPA mercury ICR conducted in 1999. Where speciated mercury correlations could be developed, they were based on the chlorine content of the coal and the type of control device present; otherwise average factors were developed based on control device.

Organic Compounds

EPRI did not attempt to develop correlations for organic substance emissions from coal-fired power plants or divide the data into categories based on control devices or coal rank. Consequently, EPRI pooled all of the mean site values and used the Kaplan-Meier (KM) non-parametric method to estimate emission factors, to reduce the impact of the large number of non-detect values [7]. Refer to Appendix B for additional details. Compounds that have been noted in the scientific literature as potential artifacts of the organic sampling and analytical methods are identified, but test results were not corrected for potential contamination.

Emission Factors and Correlation Results for Coal-Fired Sites

Emission factor development for each HAPs group are discussed below.

Particulate-Phase Trace Elements

This group includes the following: antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), manganese (Mn), lead (Pb), and nickel (Ni). The relationship function (f) in Figure 4-1 is expressed in the following form:

$$E = f[(\text{coal/ash fraction}) \times \text{FPM} \qquad \textbf{Eq. 4-1}$$

where:

E	=	Emission of substance (lb/trillion Btu)
coal	=	Trace substance concentration in coal (lb/million lbs coal or ppmw)
ash fraction	=	Fraction of ash in coal (lb ash/lb coal)
FPM	=	FPM emission rate (lb ash/million Btu coal)

An examination of Figure 4-1 suggests that a power relationship of the following form will fit the data.

$$y = a(x)^b \qquad \textbf{Eq. 4-2}$$

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

Also note that the data points plotted in this way do not show any marked dependence on the various types of control technologies. Although most ESP/FGD and fabric-filter units have lower absolute arsenic emissions, they line up with the ESP emission data. This is true for all of the nonvolatile inorganic substances, which simply indicates that the nominal trace element composition of particulate matter exiting a control device is primarily dependent on the fuel concentration. Also, any particle size/chemical composition relationships have an inconsequential impact when data from many sites are aggregated. A regression analysis on the arsenic data in Figure 4-1 produces the following equation:

$$E = 2.7x\,(\text{coal ppm/ash fraction} \times \text{FPM})^{0.65} \qquad \textbf{Eq. 4-3}$$

Because EPRI's 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 plots were made and correlations were calculated for the other particulate-phase elements of interest.

Table 4-3 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 rate. Also shown in the table are the number of data pairs for each element, the coefficient of determination (r^2), and the split of data points between the 2010 ICR and historical data sources.

Table 4-3
Particulate Metal Correlation Coefficients

Element	a	b	N pairs	r^2	P value	N - 2010 ICR	N - Historical
Antimony	0.64	0.17	212	0.05	7E-04	168	44
Arsenic	2.7	0.65	263	0.48	2E-38	203	60
Beryllium	0.42	0.53	264	0.35	1E-26	207	57
Cadmium	0.72	0.31	261	0.23	2E-16	203	58
Chromium	3.0	0.51	258	0.45	2E-35	201	57
Cobalt	0.96	0.41	238	0.28	3E-18	188	50
Lead	2.5	0.55	265	0.36	2E-27	208	57
Manganese	2.6	0.58	247	0.47	2E-35	188	59
Nickel	3.3	0.42	256	0.32	3E-23	198	58

The r^2 value indicates the modeled degree of relationship between the independent term and the emission. A value of 1.0 indicates a perfect predictive relationship. The validity of the correlation is expressed by the P statistic, which shows the probability that the correlation exists due to chance alone. A p-value of 0.05 or lower (1 in 20) was used as an indicator for statistical significance of the observed correlation. With the number of data sets available, all of the correlations shown in the table are highly significant.

Mercury

As described previously, EPRI estimated total mercury emissions using actual stack measurement data expressed on a lb/TBtu basis where available from September 2015 through March 2016 from the EPA Air Markets Database [4], or used an average emission factor based on these actual measurements in cases where actual data were not available. The selection of final average total mercury emission values used for emission modeling at each unit are documented in Appendix C. EPRI has also developed a set of mercury emission correlations and factors based on historical pre-MATS data, including the 2010 MATS ICR data. As such these historical total mercury emission factor and correlations are not applicable for estimation of total mercury emissions in the current post-MATS 2017 base year scenario; however, these correlations and factors are available in EPRI's 2014 EFH. The MATS Rule specifies that existing coal-fired units larger than 25 megawatts electric (MWe) were required to measure and report mercury emissions starting in 2015. Therefore, for most coal-fired power plants, the total mercury emission factors presented in the 2014 EFH have been superseded by actual measurement data collected by each facility.

Mercury can occur in flue gas as an ionic species, as elemental mercury, and as particulate-bound mercury. EPRI's correlations and factors discussed below for speciated forms of mercury were used in the current emission modeling estimates to estimate the split of total mercury emissions at the stack between these various form. EPRI is not aware that any additional substantial amount of speciated stack mercury data has been collected since these speciated mercury correlations were developed using the 1999 mercury ICR data set; therefore, these values are considered the best available set of factors for estimating speciated forms of mercury.

Speciation Correlation Parameters

It is evident that many factors may affect the speciation and removal of mercury in a power station; however, insufficient data are available to develop complex models. Table 4-4 lists parameters that are generally readily available for all of the mercury data sets and parameters that are suspected of having an effect on mercury emissions but for which measurements are not readily available for most data sets.

The data were grouped according to the type of control devices used. After examining several approaches, it became evident that fuel chlorine is the dominant predictor of mercury removal performance and speciation. Fuel chlorine content varies by two orders of magnitude over the data set. Fuel sulfur levels vary by one order of magnitude, while heating value and ash content change at most by a factor of 2 to 3, respectively.

Table 4-4
Candidate Model Parameters

Parameter Class	Available	Not Readily Available for Majority of the Data Set
Fuel	Mercury concentration, heating value, chlorine, sulfur, ash, tons fired by rank	Trace metal concentrations in coal and ash
Furnace	Boiler design (tangential, cyclone, etc.)	Excess air, CO, NO_x, LOI in ash
Control devices	General type (cold-side ESP, wet FGD, NO_x reduction, etc.)	Design and operating parameters (SCA, L/G, etc.)
Operational conditions	SO_2 concentration	Temperature, pH

CO – carbon monoxide; NO_x – nitrogen oxides; LOI – loss on ignition; SCA – Specific Collection Area for ESP; L/G – Liquid to Gas ratio in the FGD absorber

Each control device category selected by EPRI represents a group of pollution control configurations that operate under similar temperature and mercury reaction conditions. After combustion of the fuel, the heat is removed to produce steam, which starts the flue gas cooling process. The control devices in each configuration operate at different conditions, which affect the degree of mercury oxidation and mercury removal. For example, ESPs are classified as either "hot-side" or "cold-side", depending on the temperatures experienced by the flue gas. These two types of ESPs are distinctly different in mercury removal, and are therefore separated into different categories. If the unit is equipped with a FGD (scrubber), the flue gas can either be water-saturated (wet) or just partially cooled (dry); these devices have different mercury removal efficiencies. EPRI's first-level categorization of plants is based on the type of particulate control device. Wet FGD systems located downstream of particulate controls are classified as a separate group. NO_x removal systems are classified in two groups: catalytic (operating at ~700°F) and non-catalytic (operating at much higher temperatures).

Elemental mercury is the thermodynamically preferred form of mercury in the combustion zone. As the flue gas cools down, elemental mercury will react with chlorine or other halogens to form mercuric chloride (oxidized mercury), which is more readily captured on fly ash. For this reason, the least efficient mercury removal devices are venturi scrubbers and hot-side ESPs, which do not provide sufficient cooling or residence time to convert mercury to oxidized form. In venturi scrubbers, elemental mercury does not have time to oxidize before the gas temperature is quenched, the ash removed, and the chlorine species are removed. In cold-side ESPs, the gas is moving co-currently with the fly ash for 4-10 seconds at ~300 ºF. At higher chlorine levels, the mercury oxidation and removal becomes significant. Across fabric filters, the flue gas has to pass through inches of fly ash, where mercury adsorption and reaction may occur. Fluidized bed units with fabric filter controls often provide even higher mercury removal, as the level of unburned carbon in the ash is typically higher than for a pulverized coal boiler, creating excellent adsorption conditions.

Mercury removal across wet FGD systems is relatively consistent. At nearly all test sites, oxidized mercury is effectively removed, while elemental mercury is not removed. Three separate categories are required for wet FGDs, because the type of particulate control device that precedes the FGD system affects both the amount and form of mercury entering the wet FGD system. For hot-side ESPs, the gas entering the FGD system is primarily elemental mercury. In units with fabric filters, total emissions are typically very low; this makes the split between species subject to increased analytical uncertainty.

Many power plants have installed post-combustion NO_x reduction systems – either selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) units. In both technologies, ammonia is injected to react with NO_x, forming molecular nitrogen (N_2) and water. SNCRs operate at higher temperatures (~1400°F), which limits the reactivity of mercury. SCRs provide several seconds of contact time at 600-700°F and oxidation catalyst; they have been observed to significantly increase the mercury oxidation reaction. Consequently mercury speciation categories were assigned to reflect differential mercury removal from these two devices.

With each additional technology for which measurement data are now available, the number of possible combinations of control devices increases, complicating the data analysis and application of these mercury factors. To minimize complexity, EPRI has pooled data from different control device configurations where justified by mercury chemistry and supported by available data.

Tables 4-5 and 4-6 present averages or correlation values that were used to estimate the relative amounts of elemental mercury present in stack gas for the current 2017 base year modeling scenario. Also shown are the numbers of data sets and either the average and 95% confidence interval, or the regression constants, the coefficient of determination (r^2), and the P-value ($P_{0.05}$ = 95% certainty that the observed correlation is not due to chance).

When valid, a correlation using the coal chloride concentration provides good estimates. If not, an average is provided. Since the dependent term can vary from only 0 to 100% (species must add up to the total), a logarithmic correlation provided the best fit.

The equations in Table 4-6 are of the form:

$$\% \text{ Elemental Hg} = \{[\text{Multiplier} \times \ln(\text{coal Cl, ppmw})] + \text{Constant}\} \times 100\% \qquad \text{Eq. 4-4}$$

The 1999 ICR and other tests measured speciation data; however, the 2010 ICR tests did not. Therefore, there are fewer data sets and fewer categories available for evaluation compared to particulate phase metals or other HAPs groups. For categories without speciated mercury measurements, values from similar categories were used.

Table 4-5
Average Mercury Speciation for Various Control Device Classes

Control Class	Data Sets	Average % Elemental	95% CI [a]
all NOx ESP FGDw	22	58%	11%
all NOx FF FGDw	1	66%	-
ESPc FGDd	6	94%	4%
ESPh FGDw	8	91%	8%
FBC coal	5	56%	41%
FF	12	23%	10%
FF COHPAC	1	8%	-
FF FGDw	3	74%	59%
SNCR ESPc	9	20%	8%
VS FGDw	15	94%	13%

[a] 95 percent confidence interval about the average (e.g., 58% ± 11%, or 47% to 69% to total mercury as elemental).

Table 4-6
Mercury Speciation Correlation Coefficients for Various Control Classes

Control Class	Data Sets	Multiplier	Constant	r^2	P Value
all FF FGDd	14	-0.162	1.7	0.60	1.1E-03
SCR ESPc	14	-0.1572	1.202	0.74	8.5E-05
ESPc	57	-0.123	1.158	0.51	4.7E-10
ESPc con	57	-0.123	1.158	0.51	4.7E-10
ESPc FGDw	28	-0.0284	1.024	0.20	1.7E-02
ESPh	19	-0.1856	1.62	0.48	1.0E-03

For particulate phase mercury the previous average values per control device category, expressed as % of total mercury present in particulate form, were not used in the current modeling effort. It was not known whether these historical factors developed based on pre-MATS stack measurement data from the 1999 EPA mercury ICR were representative of well controlled, post-MATS units. Therefore, for all units it was assumed that 1% of the total mercury was present in particulate form. One percent was considered a typical value based on past historical data for control categories similar to the majority of post-MATS control configurations (e.g., ESPc FGDw, FF, or SCR ESPc FGDw). At all of the control device outlets, the particulate fraction is quite low; therefore, selection of a single representative value for post-MATS modeling was considered a reasonable approach given the lack of current measurement data.

Adjustments to Speciated Mercury Correlations for Impacts of MATS Control

The one change in speciated mercury emission factors is for units that use wet FGD scrubbers for SO_2 control. As shown previously in Table 4-5 and 4-6, the current average emission factors or emission correlations for wet FGD configurations are based on coal Cl levels (expressed as % of total stack mercury as elemental). These factors, while valid for a pre-MATS scenario, may not be valid for a post-MATS scenario. The historical data used to develop these factors was based primarily on speciated mercury data collected as part of the 1999 Hg ICR and likely included plants with varying amounts of flue gas bypass of the scrubber which will impact the mercury speciation profile at the stack. In addition, the historical data may have included plants with significant re-emission of mercury (as elemental mercury) which will also impact the speciation profile. Current wet FGD scrubbers have been optimized for compliance with MATS, i.e., they no longer have bypass, and reemission of mercury is controlled with FGD additives or other FGD operational changes for scrubbers where this issue has been found. The optimized MATS scrubbers are highly effective at removing oxidized mercury; therefore, while total mercury emissions will be at or below the MATS limit, nearly all the mercury exiting the stack will be present in the elemental form. The consensus of the AECOM and EPRI MATS control practitioners was that a value of 95% elemental mercury at the stack for all units with wet scrubbers was an appropriate value to use for post-MATS emission estimates. A complete discussion of other possible impacts considered are provided in Appendix D.

Selenium

EPRI determined that the available selenium data were best grouped according to control technology. A significant relationship between emissions percentage and coal sulfur content was found for three control categories: units with fabric filters, units with only ESPs, and units with wet FGD systems. The other control categories are best described by average emission percentages expressed as % of coal selenium emitted. The correlation is a linear relationship using the coal sulfur level as the independent parameter and then adding the constant to obtain the "percentage of coal Se emitted" factor, as shown below.

$$\% \text{ Coal Se Emitted} = \{[\text{Multiplier} \times (\text{coal S, wt\%})] + \text{Constant}\} \times 100\% \qquad \textbf{Eq. 4-5}$$

The selenium data are plotted in Figure 4-3 for the three correlated categories. Table 4-7 presents the correlation statistics. The categories with average factors expressed as a percent of coal selenium emitted are presented in Table 4-8. As shown in Figure 4-4, most units in the FBC and FF FGDd average factors categories emitted less than 1% of coal selenium (> 99% coal-to-stack reduction).

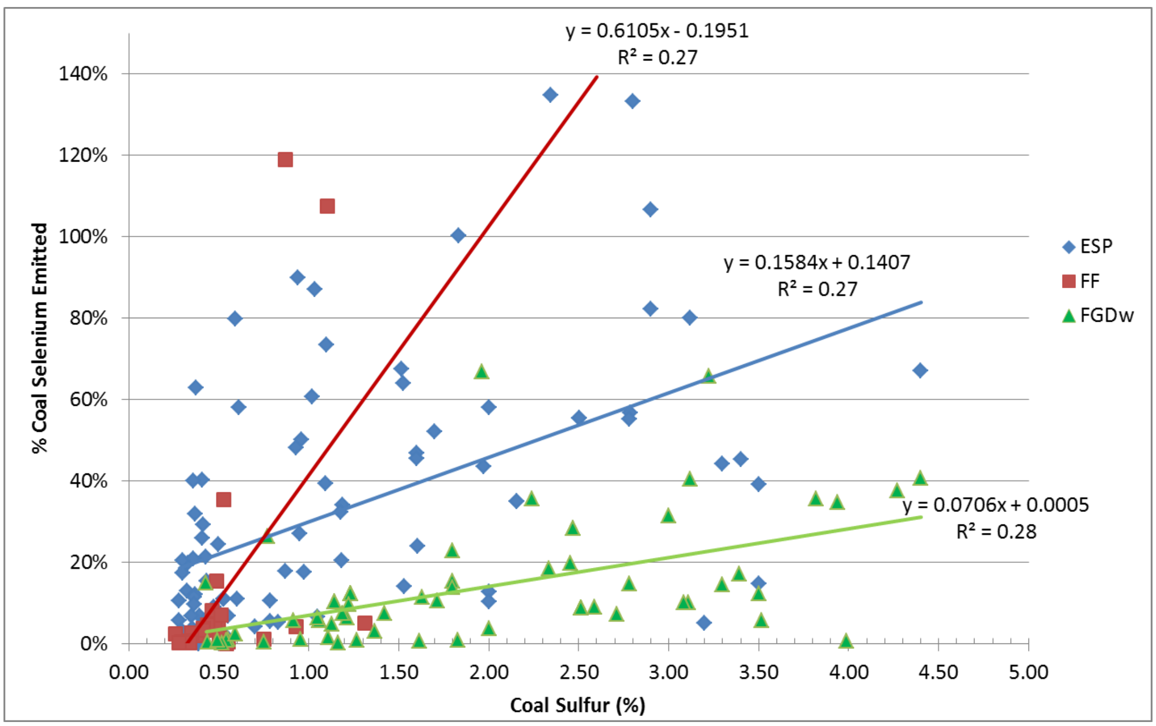


Figure 4-3
Selenium Emissions vs. Coal Sulfur

Table 4-7
Selenium Correlation Coefficients (vs. Coal %S)

Category	Constant	%S multiplier	Data sets	r^2	P value
ESP	0.141	0.158	87	0.27	2.1E-07
FF	-0.195	0.611	28	0.27	4.2E-03
all FGDw	0.0005	0.0706	66	0.28	6.1E-06

Table 4-8
Average Selenium Emission Values by Control Category

Category	% of Coal Se emitted	95% CI [a]	Data sets
ESP FGDdsi	6.2%	19%	2
FBC	0.39%	0.39%	32
FF FGDd	0.5%	0.3%	29

[a] 95 percent confidence interval about the average (e.g., 6.2% ± 19%, or 0% to 25% of coal Se emitted).

Only two sites with ESP in combination with dry sorbent duct injection for SO_2 gas control (FGDdsi) have been tested.

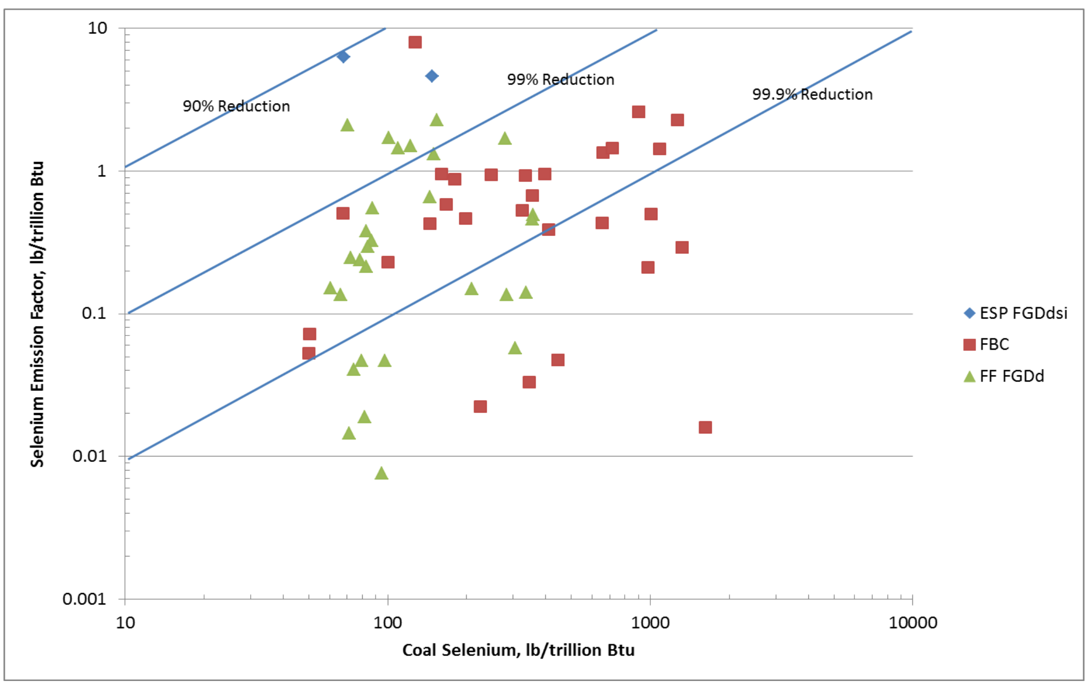


Figure 4-4
Selenium Emissions vs. Coal Selenium

Adjustments to Selenium Correlations for Impact of MATS Control

MATS controls evaluated for potential impacts on selenium emissions included the following: activated carbon injection (ACI), halogenated activated carbon injection (HACI), fuel bromine addition (FuelBr), wet flue gas desulfurization mercury reemissions additives (FGDadd), and dry sorbent injection for HCl control [DSI(HCl)]. EPRI identified and reviewed various documents containing information assessing the possible impact these types of MATS control have on selenium emissions. Details of this evaluation and recommended modifications and additions to existing selenium emission factors are provided in Appendix D. A summary is provided below.

ACI/HACI –The overall conclusion based on review of information from these sources is that there is no consistent trend with regard to the ability of ACI and HACI to impact selenium emissions. Therefore, no modifications to existing selenium correlations or factors are warranted at this time for MATS categories involving activated carbon injection (ACI) or halogenated activated carbon injection (HACI).

FuelBr –The conclusion based on review of this information is that fuel bromine addition may increase emissions of selenium for control configurations using only electrostatic precipitators (ESPs) or fabric filters (FFs) for PM control, or any PM control in combination with wet flue gas desulfurization (FGD). The dosing rate of bromine may be important, but there is only limited data available to make any assessment in that regard. Appendix D provides further details and summarizes the adjustments to existing selenium emission factors and correlations for control combinations using FuelBr that were used in this study based on this current body of information.

FGDadd – FGD additives used to control mercury re-emissions can be organic or inorganic based molecules that contain reduced sulfur groups, or PAC-based reagents, and have been shown to change the solid/liquid partitioning of selenium and the speciation of selenium in the FGD absorber liquor. However, the impact on overall selenium removal in the scrubber and selenium stack emissions are unknown. EPRI is not aware of any studies which document the impact of various FGD additives on stack emission of selenium from units with wet FGD scrubbers. In the absence of such data, the current recommendation is no change to the existing FGDw selenium correlation shown previously in Figure 4-2 and Table 4-8.

DSI(HCl) – Injection of alkaline reagents is expected to reduce the concentration of selenium in the flue gas and enhance capture with the ash collected in the ESP or FF particulate control device. Refer to Appendix D for details.

Additional New Control Types – Table 4-9 provides a summary of the selenium emission factor approach for new categories of control not considered in the previous 2014 EFH. Many only apply to a small number of coal-fired units.

Table 4-9
Summary of Additional New Control Configuration Not Represented in the Current 2014 EFH - Selenium

2014 EFH Category + MATS Combinations	Se EF, % of Coal Se Emitted	Notes
All FGDw with DSI for SO_3 control	Use 1/2 of the current FGDw correlation predicted values If DSI for SO_3 used in combination with FuelBr addition, no change.	For example, injection of SBS, HL, or trona. DSI(SO_3) is only reported in the plant database for units using FGDw. Reduce the current FGDw correlation predicted % emitted values by 50%. If DSI(SO_3) used in combination with FuelBr addition, the ½ correction negates the potential increase cited above for FuelBr + FGDw, so no net change in Se emissions. Alkaline DSI material will remove vapor phase Se. SBS data shows 60-90% Se removal possible in the ash during injection at various molar ratios and flue gas temperatures. If FGD inlet selenium concentrations are reduced by 50% due to DSI(SO_3), then corresponding FGD outlet stack emission will be reduced by 50%, assuming selenium removal across the scrubber remains constant.
ReACT	Use existing FF-coal sulfur correlation	Multipollutant control technology using a FF. Activated coke adsorption with regeneration. Dry scrubber with moving activated coke bed. Use existing FF-coal sulfur correlation. EPRI test data for selenium not available in M29 test data set from a pilot unit.
FF CDS	0.5	SO_2/PM control. Assume same as existing FF FGDd factor. No data identified to date.
ESPc CDS	6.2	SO_2/PM control. Assume same as existing ESPc FGDdsi factor. No data identified to date.
ESP or FF with FGDw + Wet ESP	0.05	Significant reduction of Se by wet ESPs are expected. ICR data for units with FGDw + Wet ESP show some of the lowest selenium emissions for units tested in the 2010 ICR. Assume 99.95% overall reduction (0.05% of coal emitted)

CDS = circulating dry scrubber; FBC = fluidized bed combustor; ESP = electrostatic precipitator; FF = fabric filter, DSI(SO_3) = dry sorbent injection for SO_3 control; DSI(SO_2) = dry sorbent injection for SO_2 control; FGDd = spray dryer; ESPc = cold-side electrostatic precipitator

Hydrochloric and Hydrofluoric Acid

Chlorides present in coals typically form an acid gas species, HCl, during combustion. Of all the HAPs precursors, chloride concentrations in coal occur in the highest concentrations, up to several thousand mg/kg. HCl is readily absorbed by aqueous solutions and is also neutralized by alkaline substances; thus, it is readily removed from flue gas by alkaline ash or in a FGD system. Table 4-10 presents the average emissions of HCl as a percentage of the coal chlorine concentration. No correlations with readily available parameters were identified in the 2014 EFH data analysis; thus, emission factors are given average factors expressed as % of coal chloride emitted as HCl. If the predicted emission value using these factors was less than the MATS limit, the predicted value was used. If the value is greater than the limit, and the plant database indicated the presence of MATs controls for acid gases, the emissions were set to the MATS limit of 0.002 lb/MMBtu. In some cases, units firing high chloride coals did not indicate the use of acid gas controls and predicted emissions exceeded the MATS HCl limit. Often, these were units that were expected to be retired sometime in 2017 or 2018 and thus no additional MATS controls were planned; therefore, predicted emissions were allowed to exceed the MATS limit resulting in conservative emission estimates.

Table 4-10
Average HCl Emission Values by Control Category

Category	% of Coal Cl Emitted as HCl	95% CI [a]	Data Sets
ESP Bit/Lig	88%	18%	56
ESP Sub	40%	16%	22
all FGDw	2.7%	3%	102
FBC	39%	18%	41
FF Bit/Lig	75%	42%	5
FF Sub	21%	17%	9
FF FGDd Sub/Bw	13%	5%	22
FF FGDd Bit	0.7%	1%	20
all FGDdsi	23%	19%	3

[a] 95 percent confidence interval about the average (e.g., 88% + 18%, or 70% to 100% of coal Cl emitted).

Like chloride, fluoride forms an acid gas during combustion. Coal fluoride concentrations are typically 10% or less of the chloride concentrations. Like HCl, HF is readily absorbed in aqueous solutions or by alkaline ash or flue gas additives. The additional data from the 2010 ICR permits many additional categories to be examined. Table 4-11 presents the average coal-based percentage of emission for different unit configurations. No correlation was seen with coal sulfur levels.

Table 4-11
Average HF Emission Values by Control Technology

Category	% of Coal F Emitted as HF	95% CI [a]	Data Sets
ESP Bit/Lig	85%	21%	44
ESP Sub	19%	9%	17
all FGDw	3.4%	4%	88
FBC	6.4%	7%	26
FF	65%	29%	10
FF FGDd	2.3%	1%	43
all FGDdsi	9.7%	1%	4

[a] 95 percent confidence interval about the average (e.g., 85% ± 21%, or 64% to 100% of coal F emitted).

Adjustments to HCl and HF Correlations for Impact of MATS Control

Adjustment of 2014 EFH emission factors was related to the use of DSI for control of HCl [DSI(HCl)] in combination with other controls. For units using DSI for HCl control, our assumption is that the DSI system will be optimized at each site to meet the MATS limit for HCl (or SO_2 surrogate limit), or some fraction of the MATS limit to ensure compliance with a 30-day rolling average. Therefore, for purpose of estimating HCl emissions, HCl emissions were estimated using the adjusted factors for selected control category combinations as documented in Appendix D. Where adjustments were made, the 2014 EFH emission factor described previously for the "all FGDdsi – DSI for SO_2 control" category (23% emitted, refer to Table 4-10) was substituted as representative of DSI(HCl). The resulting emission estimates were then compared to the MATS limit. If the predicted emission value was less than the limit, the predicted value was used. If the value is greater than the limit, the emissions were set to the MATS limit of 0.002 lb/MMBtu. This assumes that such units will be in compliance with the MATS HCl limit.

For HF, a MATS limit does not exist; therefore, the approach used was to calculate the percent coal emitted value using the adjusted emission factor values as documented in Appendix D. Where adjustments were made, the 2014 EFH value shown previously in Table 4-11 for the "all FGDdsi" category (9.7% emitted) was substituted.

Table 4-12 summarizes assignment of HCl and HF emission factors for new control device categories not represented in EPRI's 2014 EFH

Table 4-12
Summary of Additional New Control Configuration Not Represented in the Current 2014 EFH – HCl/HF

2014 EFH Category + MATS Combinations	% of Coal Cl Emitted as HCl	% of Coal F Emitted as HF	Notes
ReACT	Use MATS limit or “FF Sub” (21)	Use MATS limit or “FF Sub” (65)	Multipollutant control technology. Activated coke adsorption with regeneration. Dry scrubber technology with moving activated coke bed. EPRI pilot test data from Valmy show 70% removal of HF. HCl at inlet was too low to accurately quantify removals. Limited test data, therefore use existing “FF Sub” EFH category factors (21% HCl, 65% HF).
FF CDS	Use MATS limit or factors below, whichever is lowest 13 (sub/bitw) 0.7 (bit)	2.3	PM/SO_2 control. Assume same as FF FGDd by coal type. Use MATS limit or FF FGDd factors whichever is lowest. No data identified to date.
ESPc CDS	Use MATS limit or 9.4	3.9	PM/SO_2 control. Assume ESP performance not as good as FF CDS, so used 9.4% for HCl and 3.9% for HF. No data identified.
ESPc FGDd	Use MATS limit or 9.4	3.9	PM/SO_2 control. Assume ESP performance not as good as FF FGDd, so used 9.4% for HCl and 3.9% for HF. No data identified.
All configs with DSI for SO_3 control (only used with FGDw)	No change. Use existing “all FGDw” (2.7)	No change. Use existing “all FGDw” (3.4)	DSI(SO_3) only reported in combination with FGDw based on plant database information. For example, injection of SBS, HL, or Trona. SBS data show 40-70% HCl removal with the ash across the ESP at varying SBS injection rates. Only one data point and the ability of DSI(SO_3) to capture HCl will depend on site specific SO_3/HCl ratios and amount of excess DSI reagent injected; therefore, no change to existing FGDw emission factors were implemented.
ESP or FF with FGDw + Wet ESP	1.0	3.4	Assume wet ESP will remove HCl/HF on the back end of a wet scrubber (already low HCl/HF at ~95% reduction anyway). Assume wet ESP will reduce any HCl left at the scrubber outlet to 1% emitted levels compared to current factor of 2.7% for the All FGDw category. Use All FGDw value of 3.4% for HF. No data for Wet ESPs identified.

ESP = electrostatic precipitator, FF = fabric filter, FGDdsi = sorbent injection for SO_2 control; ESPc = cold-side electrostatic precipitator; CDS = circulating dry scrubber, FBC = fluidized bed combustor, ESP = electrostatic precipitator, FF = fabric filter, DSI(SO_3) = dry sorbent injection for SO_3 control, DSI(SO_2) = dry sorbent injection for SO_2 control; FGDd = spray dryer; ESPc = cold-side electrostatic precipitator, sub = subbituminous; bit = bituminous; bitw = western bituminous; lig = lignite

Chlorine (Cl_2)

The presence of molecular chlorine in flue gas is subject to great uncertainty, due to known and suspected biases in the standard test methods, which have been reported to bias results for chlorine both high and low, according to different researchers. A limited number of tests for chlorine were conducted at coal-fired plants during the 2010 ICR, and there are also some pre-2010 measurements available from various sources. EPRI determined that some of these measurements suffered from serious data quality issues (e.g., reporting HCl as chlorine); however, when those were omitted, there were some data available for evaluation. This evaluation as well as preliminary emission factors and correlations based on coal chloride concentration are presented in Appendix B. These preliminary factors were used to estimate emissions for use in the current inhalation risk assessment; however, results based on these factors are subject to a considerable amount of uncertainty and should be used with caution.

Organic Compounds

Emission estimates were prepared for a selected subset of organic compounds based on the data needs for the inhalation health risk assessment. Emission factors for these selected compounds are provided in Table 4-13. EPRI did not attempt to develop correlations for organic substance emissions from coal-fired power plants or to divide the data into categories based on control devices or coal rank. There are several reasons that EPRI chose to group all organic data together. First, the scientific literature indicates that many of the organic substances detected in power plant flue gas are products of incomplete combustion, formed in the boiler when oxygen levels and combustion time are not adequate to convert all coal carbon to CO_2. Parameters that could be used as surrogates for incomplete combustion (CO, O_2, etc.) are not available for many of the data sets. Second, it is common to observe large run-to-run fluctuations in the amounts of trace organic substances emitted from a single unit, indicating that independent parameters would be poor predictors of emissions. Lastly, a large percentage of the available measurements are non-detects, which greatly reduces the ability to evaluate the impact of various control devices on emissions.

Consequently, EPRI pooled all of the mean site values and used the Kaplan-Meier (KM) non-parametric method to estimate emission factors, to reduce the impact of the large number of nondetect values. Where applicable, KM median values were selected as the final emission factor. Additional details regarding the development of KM-based emission factors are provided in Appendix B. Emission factors for organic compounds were rated A to E based on the percentage of detected values in the data set used to calculate the factor and the number of sites used to develop the factor as described in Appendix B. Only factors rated as A to D were used to estimate emissions in the current 2017 base year case. An E rating was assigned for organic compounds in which no detected values were observed. Compounds that have been noted in the scientific literature as potential artifacts of the organic sampling and analytical methods are identified, but test results were not corrected for potential contamination.

Table 4-13
Organic Substance Emission Factors for Coal-Fired Boilers (lb/trillion Btu)

Parameter	CAS	Sites Tested	Sites Detected	Sites Used	Emission Factor	Emission Factor Method	Emission Factor Rating [a]
1,1-Dichloroethane	74-34-3	68	2	56	1.1	Median	D
1,1,1-Trichloroethane	71-54-6	85	6	47	0.25	Median	B
1,2,4-Trichlorobenzene	120-82-1	93	1	93	2.8	Median	D
1,2-Dibromoethane*	106-93-4	83	5	58	0.49	Median	C
1,4-Dichlorobenzene*	106-46-7	97	3	97	2.5	Median	D
2,3,7,8-TCDD TEQ	NA	63	54 [d]	63	1.3E-06	Average [b,c]	A
2,4-Dinitrotoluene*	121-14-2	83	5	80	2.7	Median	C
5-Methylchrysene	3697-24-3	3	1	3	0.0009	Median	D
Acetaldehyde	74-07-0	21	12	21	3.0	KM Median	B
Acrolein	107-02-8	12	5	12	3.5	Median	C
B(a)P TEQ	NA	99	39 [d]	99	0.0092	Average [c,e]	B
Benzene*	71-43-2	116	80	116	2.0	KM Median	A
Benzyl chloride	100-44-7	7	4	7	1.9	Median	C
Bis(2-ethylhexyl)phthalate*	117-81-7	88	34	86	2.4	KM Median	B
Carbon disulfide	74-14-0	97	48	96	1.7	KM Median	A
Dichloromethane*	75-09-2	90	67	90	19	KM Median	A
Formaldehyde	50-00-0	122	33	120	0.4	KM Median	B
Hexane*	110-54-3	9	5	9	2.2	Median	C
Isophorone	78-59-1	80	1	80	4.4	Median	D
m/p-Xylene	179601-23-1	15	8	15	0.020	KM Median	C
Naphthalene*	91-20-3	118	54	111	0.30	KM Median	B
Phenol*	108-95-2	93	35	93	1.9	KM Median	B
Propionaldehyde	123-38-6	8	5	8	5	Median	C
Tetrachloroethene	127-18-4	97	17	95	0.054	KM Median	B
Toluene*	108-88-3	109	70	109	1.6	KM Median	A
Trichloromethane*	67-66-3	105	29	105	0.16	KM Median	B
Vinyl acetate	108-05-4	21	1	2	0.35	Median	D

* Potential artifact based on scientific literature. Refer to Appendix B for additional details.

[a] A = ≥ 50% ADL and ≥ 50 sites used. ADL = Above limit of detection.
B = 10 to <50% ADL and ≥ 20 sites used, or ≥ 50% ADL and 20 to <50 sites used
C = 5 to <10% ADL and ≥ 5 sites used, or ≥ 10% ADL and 5 to <20 sites used
D = < 5% ADL or < 5 sites used
Refer to Appendix B for a complete discussion of rating factor criteria.

[b] Emission factors 2,3,7,8-TCDD TEQ were calculated using 2005 WHO toxicity equivalency factors [8].

[c] Arithmetic averages of individual site B(a)P TEQ and 2,3,7,8-TCDD TEQ values. Refer to Appendix B for additional details.

[d] Count of sites where one or more of the listed dioxin/furan or PAH species was detected.

[e] Emission factors B(a)P TEQ were calculated using toxicity equivalency factors referenced by the California EPA as part of their Air Toxics Hot Spots program [9].

In the case of 2,3,7,8-TCDD TEQ, dioxin/furan emissions expressed as 2,3,7,8-TCDD equivalents (TEQ) were calculated for each of the 15 historical measurement sites documented in EPRI's 2002 EFH and the 48 additional sites tested in EPA's 2010 ICR. The TEQ for each site was obtained by multiplying the site average emission of each congener by its 2005 World Health Organization (WHO) toxicity equivalence factor [8]. The TEQs for the 17 congeners were then summed to obtain a total TEQ for that site. Sites where none of the dioxin/furan species were detected were assigned a value of zero, as discussed in Appendix B. An arithmetic average TEQ was calculated from the resulting TEQ emission factors for each site. The range of TEQ emission factors for the 2010 ICR data set was comparable to that observed in the historical data set.

Similarly, for the B(a)P TEQ factor, polycyclic aromatic hydrocarbon (PAH) emissions expressed as Benzo(a)pyrene toxicity equivalents (TEQ) were calculated for each of the 99 available sites (15 historical sites and 84 sites from the 2010 ICR) using toxicity equivalence factors defined by California EPA Air Toxics Hot Spots guidance [9]. The TEQs for the 21 defined PAH compounds at each site were then summed to obtain a total TEQ for that site. Sites where none of the PAH species were detected were assigned a value of zero, as discussed in Appendix B.

Emission Factors and Correlation Results for 100% Pet Coke-Fired Sites

Petroleum coke was defined by EPA in the MATS Rule as an oil-based solid fuel and separate emission limits were established. All data used for development of emission factors was associated with the 2010 MATS ICR. Of the petroleum coke units tested in the 2010 ICR, all but one were FBC boilers. The non-FBC unit was a conventional wall fired boiler with an ESP and FGD system.

Petroleum coke is primarily carbon, obtained from petroleum refining coker units or similar processes, typically vacuum residual distillation column bottoms. In the coker, steam is used to crack and volatilize high boiling point hydrocarbons for subsequent conversion to more profitable liquids. The residue contains very low concentrations of hydrogen and can contain several percent sulfur. Since the residue comes from a liquid source material, it contains very low amounts of ash. The amount of trace metals present is highly variable. Since little ash is produced when petroleum coke is burned, the trace metals correlation approach that EPRI uses for coal is not valid. Therefore, the KM emission factor approach was used to develop factors for both trace metals and organic compounds. Table 4-14 presents emission factors for inorganic and organic substances used in the risk assessment. For chlorine (Cl_2), only a single site was tested as part of the 2010 ICR; therefore, an emission factor was not developed.

In the case of 2,3,7,8-TCDD TEQ, dioxin/furan emissions expressed as 2,3,7,8-TCDD equivalents (TEQ) were calculated for each of the 7 sites tested in EPA's 2010 ICR. The TEQ for each site was obtained by multiplying the site average emission of each congener by its 2005 World Health Organization (WHO) toxicity equivalence factor [8]. The TEQs for the 17 congeners were then summed to obtain a total TEQ for that site. An arithmetic average TEQ was calculated from the resulting TEQ emission factors for each site.

Table 4-14
Emission Factors for Petroleum Coke-Fired Boilers (lb/trillion Btu)

Parameter	CAS	Sites Tested	Sites Detected	Sites Used for KM	Emission Factor	Emission Factor Method	Emission Factor Rating [a]
Antimony	7440-36-0	7	6	7	0.077	Median	C
Arsenic	7440-38-2	7	6	7	0.22	Median	C
Beryllium	7440-41-7	7	3	7	0.052	Median	C
Cadmium	7440-43-9	7	6	7	0.19	Median	C
Chromium	7440-47-3	7	7	7	0.70	KM Median	C
Cobalt	7440-48-4	7	6	7	0.34	Median	C
Hydrogen chloride	7647-01-0	9	6	9	333	Median	C
Hydrogen fluoride	7664-39-3	9	4	9	84	Median	C
Lead	7439-92-1	7	7	7	0.66	KM Median	C
Manganese	7439-96-5	7	7	7	1.6	KM Median	C
Mercury	7439-97-6	8	7	8	0.080	KM Median	C
Nickel	7440-02-0	7	7	7	3.3	KM Median	C
Selenium	7782-49-2	7	6	7	1.0	Median	C
1,2-Dibromoethane*	106-93-4	9	1	7	0.18	Median	C
2,3,7,8-TCDD TEQ	NA	7	7 [d]	7	1.9E-07	Average [b,c]	C
Benzene*	71-43-2	8	6	7	2.9	Median	C
Bis(2-ethyl-hexyl)phthalate	117-81-7	6	4	6	12	Median	C
Carbon disulfide	75-15-0	7	5	7	8.4	Median	C
Dichloromethane*	75-09-2	8	7	8	37	KM Median	C
Hexane	110-54-3	1	1	1	0.15	Median	D
Napthalene*	91-20-3	5	2	5	0.53	Median	C

Table 4-14 (continued)
Emission Factors for Petroleum Coke-Fired Boilers (lb/trillion Btu)

Parameter	CAS	Sites Tested	Sites Detected	Sites Used for KM	Emission Factor	Emission Factor Method	Emission Factor Rating [a]
Phenol*	108-95-2	6	5	6	4.5	Median	C
Tetrachloroethene	127-18-4	8	1	6	0.13	Median	C
Tetrachloromethane	56-23-5	9	1	5	0.14	Median	C
Toluene*	108-88-3	8	7	8	2.1	KM Median	C
Trichloromethane*	67-66-3	9	3	7	0.18	Median	C

* Potential artifact based on scientific literature. Refer to Appendix B for additional details.

[a] A = $\geq$ 50% ADL and $\geq$ 30 sites used. ADL = above limit of detection.
B = 10 to <50% ADL and $\geq$ 20 sites used, or $\geq$ 50% ADL and 20 to <30 sites used
C = 5 to <10% ADL and $\geq$ 5 sites used, or $\geq$ 10% ADL and 5 to <20 sites used
D = < 5% ADL or < 5 sites used
Refer to Appendix B for a complete discussion of rating factor criteria.

[b] Emission factors 2,3,7,8-TCDD TEQ were calculated using 2005 WHO toxicity equivalency factors [8].

[c] Arithmetic average of individual site 2,3,7,8-TCDD TEQ values. Refer to Appendix B for additional details.

[d] Count of sites where one or more of the listed dioxin/furan species was detected.

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. *An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants*, EPRI, Palo Alto, CA: September 2000. TR-1000608
3. EPRI Comments Concerning Select Technical Aspects of the U.S. EPA "Mercury and Air Toxics Substances" (MATS) Rule. April 13, 2012; EPA docket document EPA-HQ-OAR-2009-0234-17621.
4. EPA Air Markets Database (AMPD). https://ampd.epa.gov/ampd/ (Data as reported from September 2015 through March 2016 at the time this study was conducted).
5. *Updated Hazardous Air Pollutants (HAPs) Emission Estimates and Inhalation Human Health Risk Assessment for U.S. Coal-Fired Electric Generating Units.* EPRI, Palo Alto, CA: 2009. 1017980.
6. *Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants.* EPRI, Palo Alto, CA: 2014. 3002003848.
7. Statistics for Censored Environmental Data Using Minitab® and R, Second Edition. Dennis R. Helsel. 2012 John Wiley & Sons, Inc.
8. World Health Organization (WHO), 2005.
9. 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).

5

EMISSION ESTIMATES

This section contains a summary of the annual mass emission rate estimates. An overview of the methodology is presented first, followed by a discussion of the annual emission estimates and uncertainties associated with these estimates.

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 described in Section 4. Final emission estimates were developed for the listed HAPs species of mercury, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, selenium, hydrogen chloride, chlorine (Cl_2), hydrogen fluoride, and selected individual organic compounds or groups of organic compounds (e.g., B(a)P TEQ or 2,3,7,8-TCDD TEQ). In addition to total mercury, estimates for the elemental, oxidized and particulate forms of mercury were also developed.

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

1. *The unit characteristics databases were used to project the operations of individual units for the 2017 post-MATS 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 2015 fuel purchase records.* For trace elements other than chloride, coal characteristics from the screened USGS COALQUAL database were used in conjunction with 2015 EIA Form 923 coal purchase records for each station to assign a blended fuel composition for each unit based on the rank and origins of the coals fired at each station. For chloride, 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 filterable particulate emission rates each coal-fired unit were defined.* Stack filterable particulate emission rates, in the form of lb/MMBtu input, were established for each unit using data from the unit characteristics database described in Section 2. The primary source of the filterable particulate matter (FPM) emission data were actual emission rates as reported on 2014 EIA Form 860. When no data was available from EIA for 2014 or a zero value was reported, available MATS related test data reported in EPA's WebFIRE database was reviewed and a representative FPM value was assigned. In the absence of any data from

these two sources, FPM values used in previous EPRI emission modeling or from sister units at the same facility were reviewed to determine if an appropriate value could be assigned. In all cases, if the EIA Form 860 value was greater than the MATS FPM limit of 0.03 lb/MMBtu, the MATS limit was used for modeling emissions. Detailed FPM data for each unit are provided in Appendix C.

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 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 total mercury, average mercury emission values on a lb/TBtu basis were derived from measurement data reported in EPA Air Markets Database for the period from September 2015 through March 2016. In the absence of such measured data, a default value of 0.5 lb/TBtu was assigned for non-lignite units and 2.5 lb/TBtu for lignite units. These default values were the average values for all coal-fired units in each fuel group that had measured data reported in the AMPD database (approximately 240 units at the time this study was conducted). Detailed mercury data for each unit are provided in Appendix C.

   EPRI correlations or factors were used to estimate emissions for the various speciated forms of mercury (oxidized, elemental, and particulate forms) as well as chlorine. For selenium, hydrogen chloride, chlorine, hydrogen fluoride, particulate phase mercury, and in some cases elemental mercury, average emission 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 emission factors (mass of substance emitted per unit heat input) were used. Section 4 provides a detailed discussion of how the various emission correlations equations and factors were derived.

   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, mass rate 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.

5. *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 by EPRI as inputs to initial Tier I and Tier II risk assessment analyses based on air dispersion modeling for each of the unique stack emission points. As discussed in Section 6 of this report, he resulting risk results were aggregated to the station level to identify those stations that had the highest inhalation cancer risk.

A summary of the emission estimate results is provided in the following sections. Detailed annual mass emission estimates for each station are provided in Appendix G.

Annual Emissions

Table 5-1 summarizes results of the emissions estimates on an annual basis for the 2017 base year aggregated at the station level for 324 stations (536 stack emission points). For each electric utility steam generating unit, the emissions of each trace substance was 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. Only organic compounds used in the risk assessment with an emission factor rating of A through C are included in Table 5-1. As noted in Table 5-1, many of these organic compounds are potential artifacts based on scientific literature as discussed in Appendix B.

Note that MATS acid gas controls were not indicated in the plant information database for eight units firing high chloride bituminous coals; therefore, estimated HCl emissions were allowed to exceed the existing unit MATS limit of 2000 lb/TBtu (0.002 lb/MMBtu). These units were often noted as being scheduled for retirement or conversion to natural gas sometime in 2017/2018, so additional MATS controls were not planned at these units. Such units were included in the emission and risk modelling study but are not expected to remain in the fleet of coal-fired units beyond 2018. These units are included in the statistics shown in Table 5-1 as reflected in the mean and maximum values. Statistical values, excluding these eight units, are shown in parentheses.

In addition, estimated HCl emissions that marginally exceeded the 2000 lb/TBtu MATS (up to approximately 2400 lb/TBtu estimated) for four other units firing low chloride subbituminous coals and having no additional controls indicated for acid gases. Estimated HCl emissions were retained for these four units rather than substituting the 2000 lb/TBtu MATS limit.

Table 5-2 summarizes estimated normalized emission rates for mercury for all units as well as averages for speciated forms of mercury. The average normalized emission rate for total mercury across all units is 0.65 lb/TBtu with an overall coal-to-stack reduction of 91.5 percent. Cumulative estimated mercury emissions for all units are estimated at approximately 4.4 tons (4.0 metric tons).

Table 5-1
Annual Emission Summary at the Station Level

	Annual Emissions at Station Level (lb/yr)			
	Median	**Mean**	**Maximum**	**Minimum[b]**
Arsenic	47	93	780	0.0053
Beryllium	4	6.6	44	0.00047
Cadmium	5.7	8.2	59	0.00036
Cobalt	19	28	180	0.002
Chromium	97	150	970	0.0096
Manganese	180	260	2,000	0.011
Nickel	94	150	1,100	0.0089
Lead	55	84	560	0.0049
Antimony	12	17	80	0.0009
Hydrochloric acid	13,000 (13,000) [c]	45,000 (37,500)[c]	2,000,000 (260,000)[c]	1.2
Chlorine (Cl_2) [d]	1,900 (1,900) [c]	8,200 (7,800) [c]	500,000 (500,000) [c]	0.12
Hydrofluoric acid	7,100 (6,900) [c]	19,000 (19,000) [c]	480,000 (480,000) [c]	0.86
Selenium	200	960	17,000	0.002
Mercury (total)	14	27	290	0.001
Mercury (elemental)	11	23	270	0.00023
Mercury (oxidized)	1.2	3.8	160	0
Mercury (particulate)	0.14	0.27	2.9	0.00001
1,2-Dibromoethane[a]	14	21	89	0.00098
2,3,7,8-TCDD TEQ	3.7E-05	5.5E-05	2.4E-04	2.6E-09
Acetaldehyde	86	130	550	0.006
Acrolein	100	150	640	0.007
B(a)P TEQ	0.26	0.39	1.7	0.000018
Benzene[a]	57	84	370	0.004
Benzylchloride	55	80	350	0.0038
bis(2-Ethlyhexyl)phthalate[a]	69	100	440	0.0048
Carbon disulfide	50	74	320	0.0035

Table 5-1 (continued)
Annual Emission Summary at the Station Level

	Annual Emissions at Station Level (lb/yr)			
	Median	Mean	Maximum	Minimum[b]
Chloroform[a]	4.7	6.9	30	0.00033
Formaldehyde	11	17	73	0.0008
m/p-Xylene	0.57	0.84	3.7	0.00004
Methyl chloroform	7.2	11	46	0.0005
Methylene chloride[a]	550	800	3,500	0.038
Naphthalene[a]	8.7	13	55	0.00061
Hexane[a]	63	92	400	0.0044
Phenol[a]	56	82	350	0.0039
Propionaldehyde	140	210	910	0.01
Tetrachloroethylene	1.5	2.3	9.8	0.00011
Toluene[a]	45	66	290	0.0032
Vinyl acetate	10	15	64	0.0007
2,4-Dinitrotoluene[a]	77	110	490	0.0054

[a] Potential artifact based on scientific literature. Refer to Appendix B discussion.

[b] Minimum values often based on stations with units having very low total annual heat input due to lack of operation in the reporting year or pending retirements.

[c] Note that MATS acid gas controls were not indicated in the plant information database for eight units firing high Cl bituminous coals; therefore, estimated HCl emissions were allowed to exceed the MATS limit of 2000 lb/TBtu (0.002 lb/MMBtu). These units were often noted as being scheduled for retirement or conversion to natural gas sometime in 2017/2018, so additional MATS controls were not planned at these units. Such units were included in the 2017 base year emission and risk modelling study but are not expected to remain in the fleet of coal-fired units beyond 2018. Statistical values, excluding these eight units, are shown in parentheses.

[d] The presence of molecular chlorine in flue gas is subject to great uncertainty, due to known and suspected biases in the standard test methods, which have been reported to bias results for chlorine both high and low, according to different researchers. Preliminary factors used to estimate emissions for use in the current inhalation risk assessment; however, results based on these factors are subject to a considerable amount of uncertainty and should be used with caution.

Table 5-2
Summary of Estimated Unit-Level Mercury Emissions

Number of Units	657 (710 boilers)
Total Heat Input (TBtu)	13,619
Total Coal Hg Input (lbs/yr)	104,911
Total Stack Hg Emissions (lbs/yr) [a]	8,887
Coal-to-Stack Reduction (%) [b]	91.5
Average Stack Mercury (lb/TBtu) [c]	0.65
Average % Elemental	79
Average % Oxidized	20
Average % Particulate	1

[a] Equivalent to 4.4 tons or 4.0 metric tons.

[b] Calculated based on the total coal mercury input (lbs/yr) and the total stack mercury emissions (lbs/yr).

[c] Calculated based on the total trillion Btu input and the total stack mercury emissions (lbs/yr).

Estimated annual emissions (lbs/yr) at the station level are also presented graphically in Figures 5-1 through 5-3 as cumulative frequency distribution (CFD) plots. Figure 5-1 presents estimated annual emissions for particulate phase metals, Figure 5-2 show estimates for acid gas species (HCl, Cl_2, HF, and Se), and Figure 5-3 shows estimates for total and speciated forms of mercury.

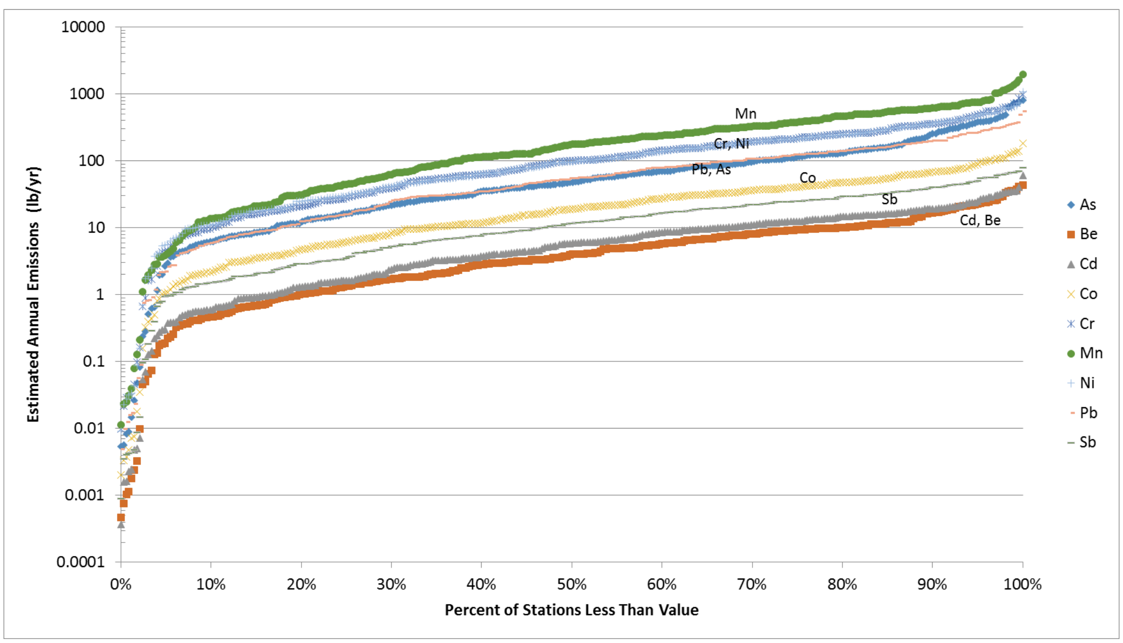


Figure 5-1
Cumulative Frequency Distribution of Station-Level Annual Emissions for Particulate Phase Metals

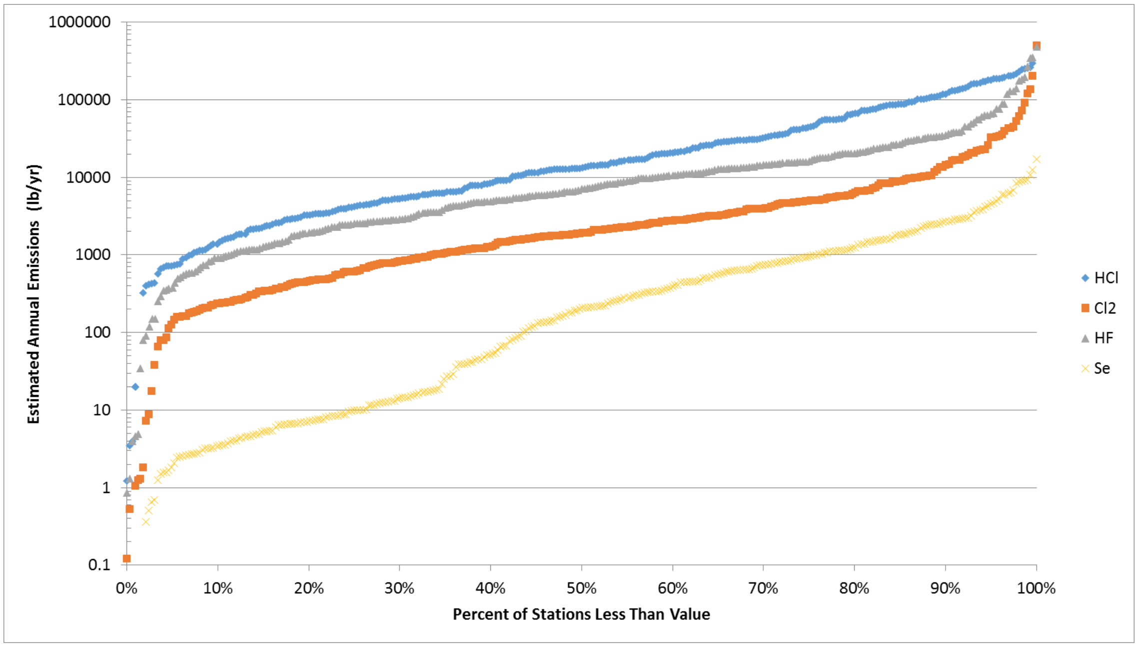


Figure 5-2
Cumulative Frequency Distribution of Station-Level Annual Emissions for Acid Gas Species

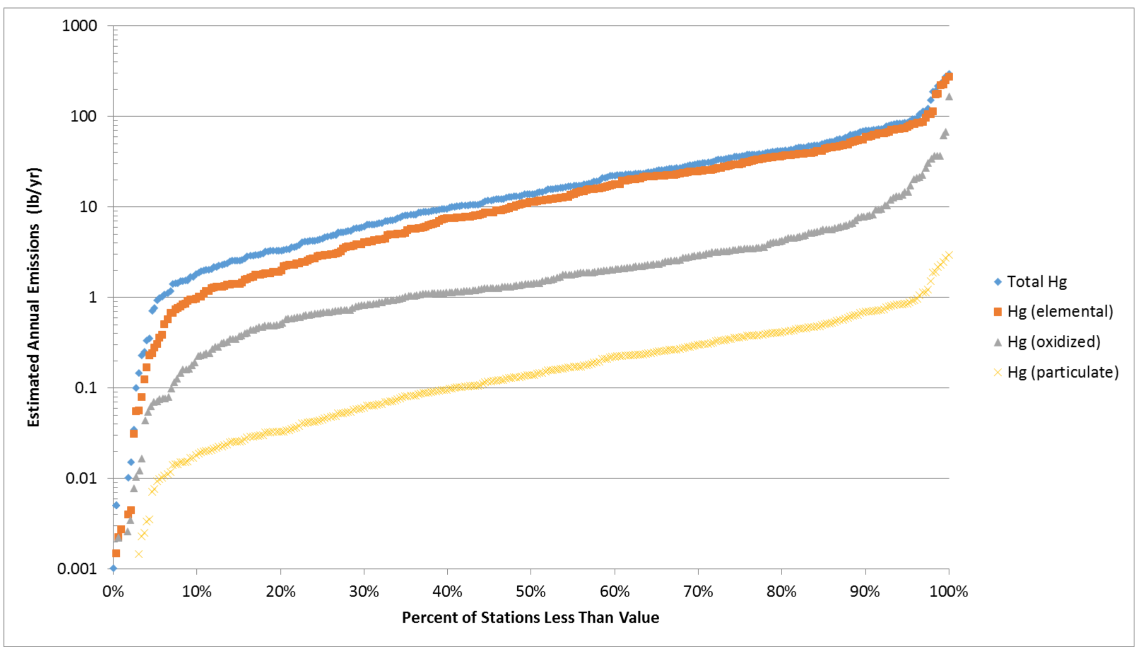


Figure 5-3
Cumulative Frequency Distribution of Station-Level Annual Emissions for Total and Speciated Mercury

Figure 5-4 presents results of the annual mercury emission calculations on an 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 710 boilers (representing 657 unique units). A line representing 90% reduction is shown on the figure as a reference point. As shown previously in Table 5-2, the average reduction for all plants is about 91.5 percent, calculated based on the estimated total annual coal mercury input (104,511 lbs/yr) and the estimated total annual mercury emissions (8,887 lbs/yr).

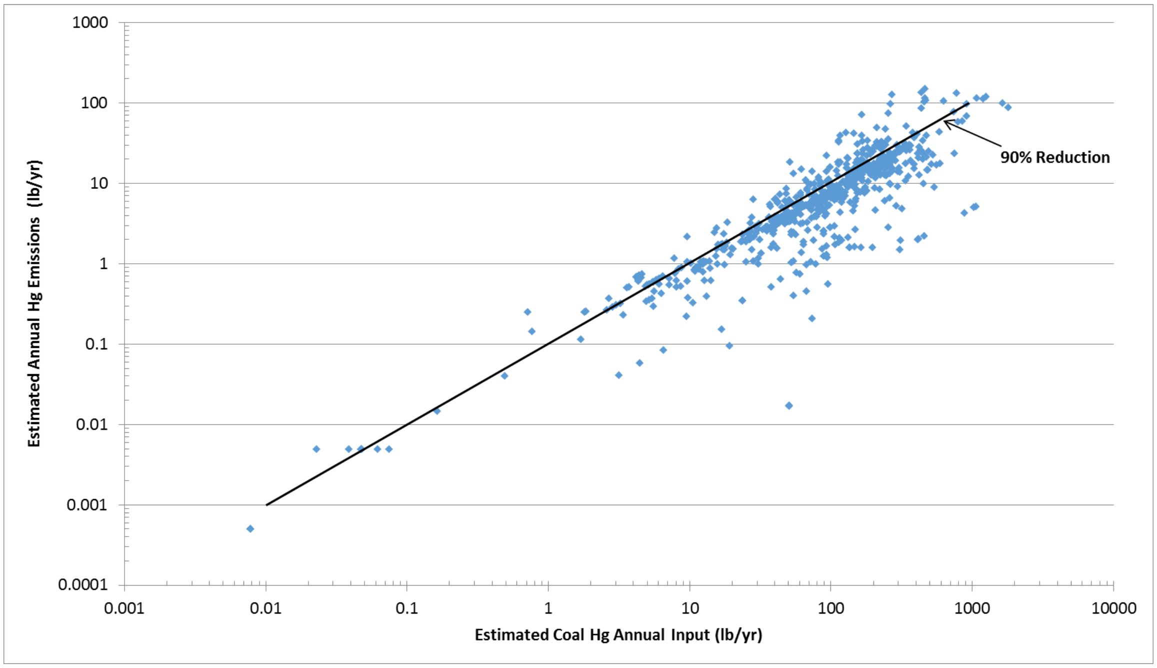


Figure 5-4
Mercury Reduction by Units

Figure 5-5 presents the cumulative frequency distribution of estimated total 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 projected annual emissions. The total amount of mercury emissions is estimated to be 4.4 tons (4.0 metric tons) for 2017. Figure 5-5 shows that 50 percent of the individual units emit less than 6.6 pounds of mercury per year for a cumulative total of 0.48 tons (0.43 metric tons). Conversely, the remaining 50 percent of the units account for approximately 3.9 of the 4.4 tons (3.5 of 4.0 metric tons) per year of mercury emissions. Approximately 80% of all units account for 39% of the estimated total annual mercury emissions (1.7 of 4.4 tons). The smallest 25% of units emit less than about 2.4 pounds each for a cumulative total of only 0.1 ton (0.09 metric ton) per year.

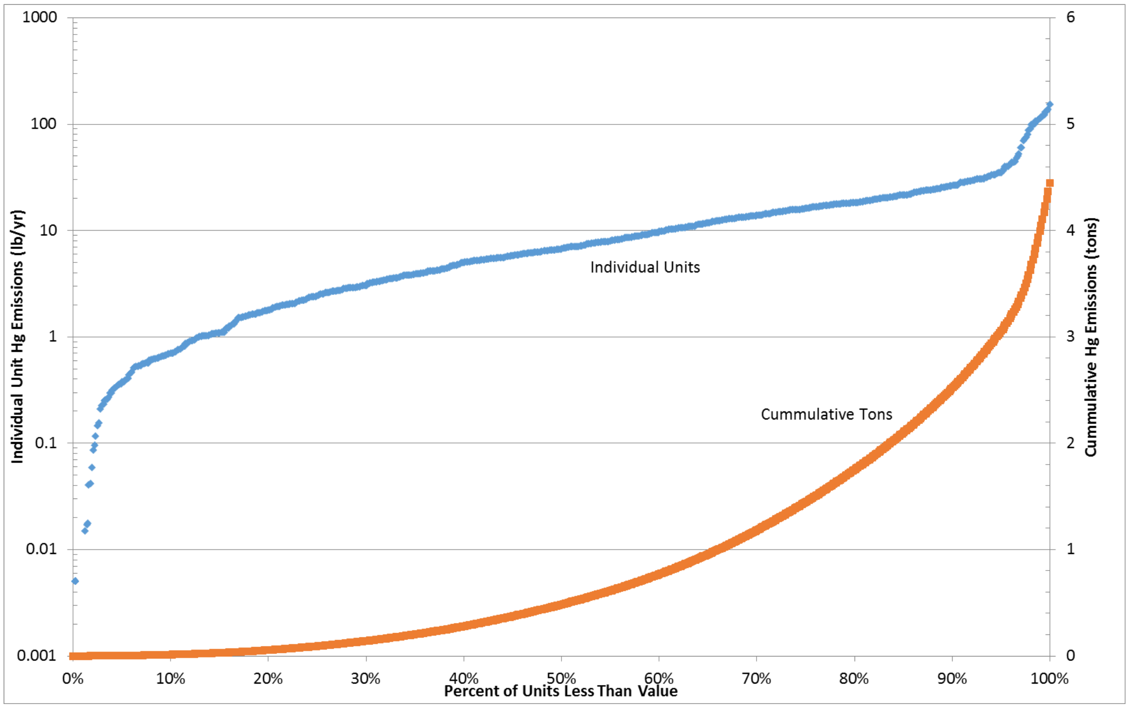


Figure 5-5
Distribution of Annual Mercury Emissions by Individual Units

Uncertainty in Emission Estimates

All of the emissions estimates calculated in this current study contain uncertainty 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. It has also been assumed that information regarding plant configurations and stack parameters from 2-3 years prior to the 2017 base scenario, supplemented with industry knowledge on future plant modifications and unit retirements, can be used to obtain a reasonable representation of coal-fired power plant industry for projecting 2017 base year emissions and inhalation health risk. Lastly, the long-term variability of input parameters and/or control device performance needs to be considered. Uncertainties in the underlying historical and 2010 MATS ICR measurement data sets used to develop EPRI's emission factors and specific data quality considerations are documented in Appendix B.

Test Sample Population

There are about 710 individual boilers (657 unique 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 HAP categories, about 100 to 300 sites have been tested in total. Over two-thirds of these sites were tested as part of the 2010 ICR. For mercury, AMPD data (sorbent trap or Hg CEMs data) were available for approximately 240 units for the period from September 2015 to March 2016.

With the exception of mercury averaged from the seven month period described above, 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, is the same as the coal is combusted, the flue gas cooled, ash removed, and finally scrubbed. Only the total mass rate varies. For this reason, long term input parameters, using correlated data sets, provide reasonable emission values for use in risk assessment analyses.

Sampling and Analytical Methods

Since the early 1990s, the procedures for collecting and analyzing most analytes in stack emissions have remained essentially the same, with the exception of mercury and 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 this 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, but for minor procedural modifications. The multi-metals and mercury speciation methods have actually been validated by EPA’s Method 301 procedure.

HAPs Metals

The impact of variations in correlation input values on the predicted emissions of HAPs trace metals are examined in this section. The predictive equation for the HAPs particulate phase elements is of the form:

$$\text{Emissions} = a \times (\text{coal ppm}/\text{coal ash fraction} \times \text{FPM})^{b} \quad \textbf{Eq. 5-1}$$

This regression has easy to obtain input parameters; the coal composition and the particulate emission level for a specific unit. As an example, the calculated emissions for arsenic are reviewed. For the arsenic data set, the a and b constants are 2.7 and 0.65 for 263 data pairs, with an r^2 of 0.48 and a P-value many orders of magnitude below the 0.05 significance level, indicating the observed level of correlation is not likely due to chance.

To illustrate the potential variability in coal trace element compositions and ash content, data from EPRI's screened USGS coal quality database was 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 5-6 is a plot of the coal ash wt% versus the coal arsenic level. As can be seen, there is no valid correlation between these two parameters. Figure 5-7 is a plot of the reported arsenic concentrations, showing the cumulative distribution frequency. The coal ash content averages 12 wt%, with a standard deviation of 4 wt percent.

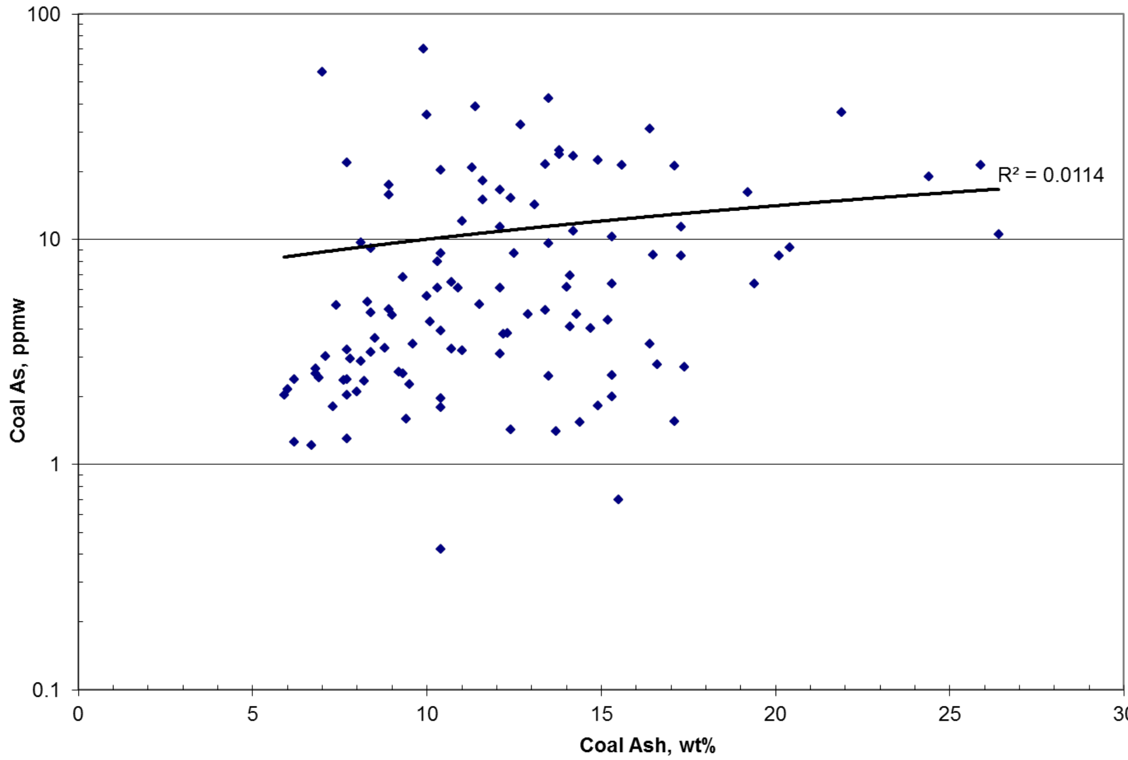


Figure 5-6
Ash vs Arsenic Concentrations for Eastern Kentucky Coal

For most sites, the reported particulate emission level is likely 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 5-3 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 be significantly different from a predicted value obtained using the correlations. Consequently, the use of larger data sets (i.e., EPRI's screened USGS coal quality database) offer a more realistic long-term input value than actual short-term test measurements.

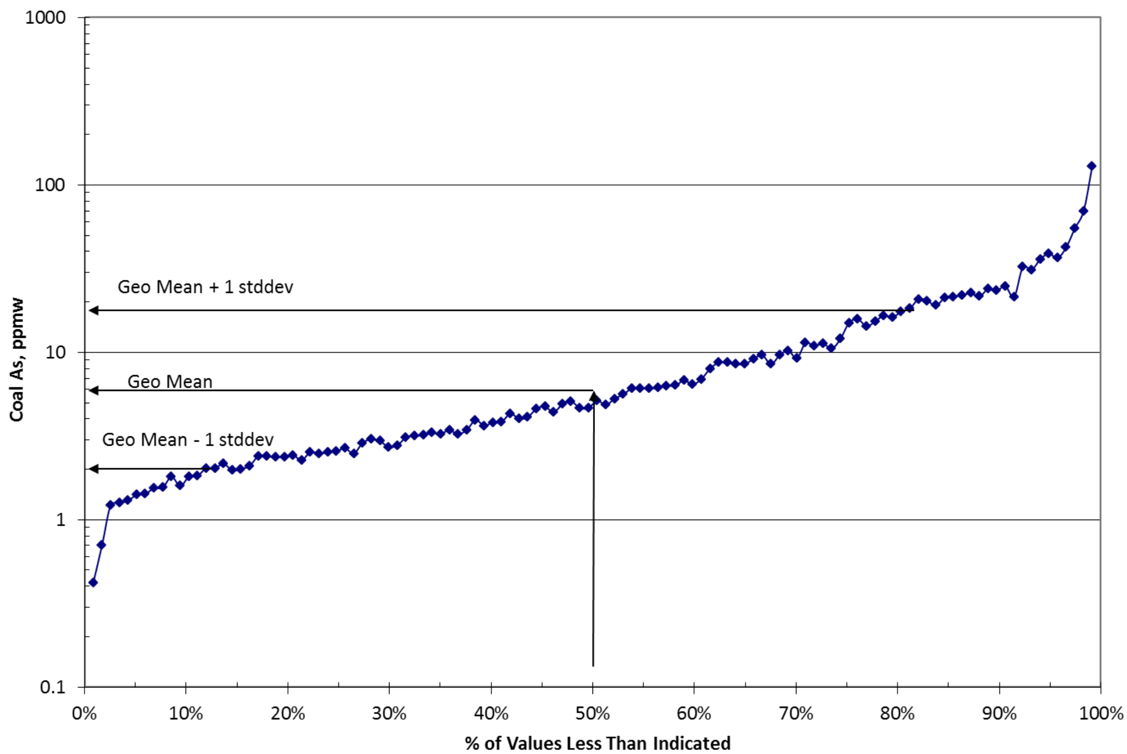


Figure 5-7
Eastern Kentucky Coal Arsenic Distribution

Table 5-3
Uncertainty in Arsenic Emission Factor Estimates

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

Table 5-4 presents the geometric mean and one upper standard deviation concentration for the HAPs elements by coal region developed from the screened USGS coal data set used in the emission estimates. Note that most upper standard deviation values are 2 to 3 times greater than the mean value, which can lead to discrepancies when comparing measured values to predicted values.

Table 5-4
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

Mercury emissions were estimated using unit-specific factors developed from 7 months of hourly data reported in EPA's AMPD database for 240 units. Variability in these data were evaluated by looking at data from 84 units with >4000 hours of operating data for the period. Figure 5-8 shows the mean and $5^{th}/95^{th}$ percentile about the mean for each of these 84 units. The X-axis shows the unit name and total operating hours for which mercury data were available. In most cases, the $5^{th}/95^{th}$ percentiles span at least an order of magnitude. Mean values for individual units are typically between 0.2 and 1 lb/TBtu. Units shown in Figure 5-8 with values greater than the MATS limit of 1.2 lb/TBtu for existing non-lignite coal-fired units are lignite fired units and were excluded from the overall average of 0.6 lb/TBtu as indicated on the figure.

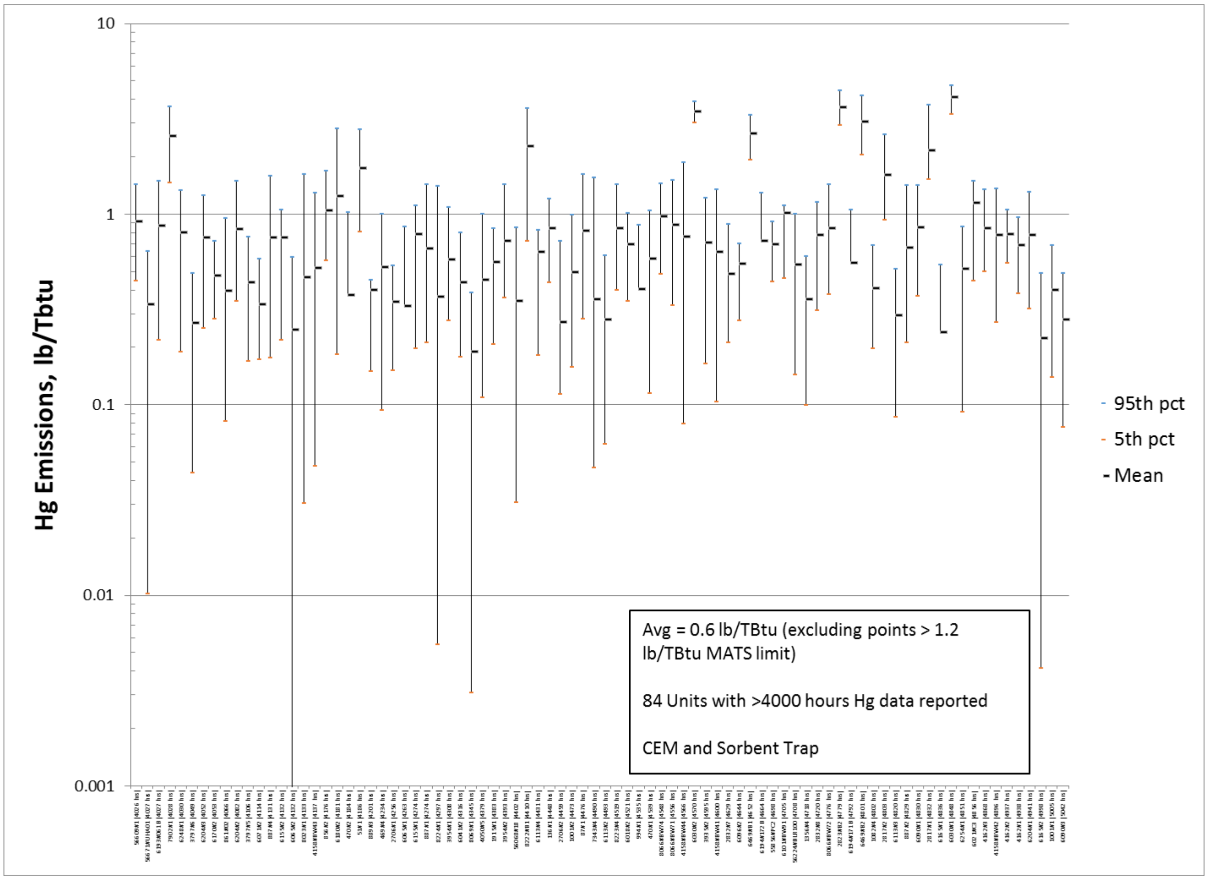


Figure 5-8
Variability in Unit Average Total Mercury Values from EPA's AMPD (September 2015 through March 2016)

Organic Compounds

For organic compounds, the KM median emission factors used to estimate emissions were calculated based on anywhere from 7 to 120 individual field measurement values for all coal-fired units and 6 to 7 values for petroleum coke-fired units. The measurement variability of trace organic substances is often very large. The distribution of individual measurements for a given substance typically varied over 2 to 5 orders of magnitude.

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

6
INHALATION HEALTH RISK ASSESSMENT

Study Approach

The tiered approach for the inhalation risk assessment of this study generally follows guidelines in Volume 2 of the EPA Air Toxics Risk Assessment Reference Library [1]. A Tier 1 screening-level inhalation risk assessment was conducted for all HAPs emitted from 324 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 cancer risk, as this type of risk was determined to be more limiting than non-cancer risks.

Source Data

As discussed in previous sections, stack parameters and annual emission estimates representing 2017 were developed for coal-fired units at each of the 324 power plants (total of 536 stacks). Annual emissions of a large number of stack-gas constituents measured in coal-fired EGU exhaust were quantified and all HAPs for which EPA ORD has established dose-response factors were evaluated [2]. The physical parameters for individual stacks used in the assessment provided in Appendix F and the HAP emission estimates for EGUs are provided in Appendix G.

Inhalation Dose-Response Data

Table 6-1 lists the HAPs and their corresponding dose-response factors (endpoints) obtained from EPA OAQPS [2]. 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 6-1 assumes per EPA guidance that 12% of the emissions are in the hexavalent form [3]. As discussed previously, 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 continuous exposure. These long-term dose response factors are based on a 70 kg body weight and 20 m^3/day inhalation rate. For the acute toxic endpoints, EPA has compiled information from a variety of sources. For this study, the hierarchy applied in EPA’s residual risk program was followed [8].

Table 6-1
Inhalation Toxic Endpoints

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	0.015	0.2	REL	0.0043
Beryllium (Be)	7440-41-7	0.02			0.0024
Cadmium (Cd)	7440-43-9	0.01	0.03	MRL	0.0018
Hydrogen Chloride (HCl)	7647-01-0	20	2100	REL	
Chlorine (Cl2)	7782-50-5	0.15	210	REL	
Cobalt (Co)	7440-48-4	0.1			
Chromium VI* (Cr)	18540-29-9	0.1			0.012
Hydrogen Fluoride (HF)	7664-39-3	14	240	REL	
Mercury (total) (Hg)	7439-97-6	0.3	0.6	REL	
Manganese (Mn)	7439-96-5	0.3			
Nickel Compounds (Ni)	7440-02-0	0.09			0.00048
Lead (Pb)	7439-92-1	0.15			
Antimony (Sb)	7440-36-0				
Selenium (Se)	7782-49-2	20			
1,1-Dichloroethane	75-34-3	500			0.0000016
1,2,4-Trichlorobenzene	120-82-1	200			
1,2-Dibromoethane	106-93-4	9			0.0006
1,4-Dichlorobenzene	106-46-7	800	12000	MRL	0.000011
2,3,7,8-TCDD equivalents	1746-01-6	0.00004			33
2,4-Dinitrotoluene	121-14-2	7			0.000089
2-Chloronaphthalene	91-58-7				
2-Methylnaphthalene	91-57-6				
3-Chloropropylene	107-05-1	1			0.000006
4-Methyl-2-pentanone	108-10-1	3000			
4-Methylphenol	106-44-5				
5-Methylchrysene	3697-24-3				0.0011
Acetaldehyde	75-07-0	9	470	REL	0.0000022
Acetophenone	98-86-2	1E+14			
Acrolein	107-02-8	0.02	6.9	REL	
B(a)P equivalents	91-57-6				0.0011
Benzene	71-43-2	30	1300	MRL	0.0000078

Table 6-1 (continued)
Inhalation Toxic Endpoints

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)$^{-1}$
Benzylchloride	100-44-7	1E+14	240	REL	0.000049
Biphenyl	92-52-4	1E+14			
bis(2-Ethlyhexyl)phthalate	117-81-7	10			0.0000024
Bromomethane	74-83-9	5	3900	REL	
Carbon Disulfide	75-15-0	700	6200	REL	
Chlorobenzene	108-90-7	1000			
Chloroethane	75-00-3	10000	40000	MRL	
Chloroform	67-66-3	98	490	REL	
Chloromethane	74-87-3	90	1000	MRL	
Cumene	98-82-8	400			
Ethylbenzene	100-41-4	1000	22000	MRL	0.0000025
Formaldehyde	50-00-0	9.8	55	REL	0.000013
Iodomethane	74-88-4				
Isophorone	78-59-1	2000			
m/p-Xylene	1330-20-7	100	22000	REL	
Methyl Chloroform	71-55-6	5000	68000	REL	
Methyl Methacrylate	80-62-6	700			
Methylene Chloride	75-09-2	600	14000	REL	0.00000001
Naphthalene	91-20-3	3			0.000034
n-Hexane	110-54-3	700			
o-Xylene	95-47-6		22000	REL	
Phenol	108-95-2	200	5800	REL	
Propionaldehyde	123-38-6	8			
Styrene	100-42-5	1000	21000	REL	
Tetrachloroethylene	127-18-4	40	20000	REL	0.00000026
Toluene	108-88-3	5000	37000	REL	
Vinyl Acetate	108-05-4	200			
Vinyl Chloride	75-01-4	100	180000	REL	0.0000088
Hydrogen Cyanide	74-90-8	0.8	340	REL	

* 12% of chromium emissions are modeled as Cr(VI).

According to EPA, the hierarchy is REL (Reference Exposure Level) [4] followed by MRL (Minimal Risk Level) [5]. If neither of these values exist, acute effects for that HAP are not evaluated because the risk resulting from acute exposure is considered minimal.

For this screening-level inhalation assessment, it is assumed that all HAP contributions to long-term risks are additive. Acute risks are evaluated by computing hazard quotients (HQ), defined as the ratio of the modeled concentrations to the corresponding toxic endpoint. For acute effects the maximum hazard quotient among all HAPs is used to assess potential for risk. For chronic effects, a hazard index (HI) is computed as the sum of the hazard quotient for each HAP. A HI or HQ of less than 1.0 is the threshold used by EPA to establish whether non-cancer health effects associated with a modeled exposure are unlikely. The lifetime incremental inhalation cancer risk associated with each carcinogenic HAP is computed by multiplying the modeled long-term average concentration by the Unit Risk Estimate. The maximum individual lifetime inhalation cancer risk (MIR)[1] is computed by summing the cancer risk among all carcinogenic HAPs. According to the residual risk provisions of the Clean Air Act, if the lifetime cancer risk to the maximum exposed individual is less than 1 in 1 million (10^{-6}), this is considered within EPA's acceptable risk thresholds.[1] In considering whether further regulation is appropriate, EPA generally presumes, on a case-by-case basis, that "if the risk to the maximum exposed individual is no higher than approximately 1 in ten thousand, that risk level is considered acceptable." [1]

Multi-Tiered 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 "actual" risk. Tier 1 screening was conducted for all 324 coal-fired power plants in the U.S. Given that Tier 1 is a highly conservative screening approach, the Tier 1 calculated risk values themselves are not suitable to quantify health risk but rather to identify power plants for which, even under very conservative assumptions, risk will remain well below EPA's acceptable risk threshold of 10^{-6}. As discussed below, Tier 1 results are used to guide the selection of power plants for which a more refined Tier 2 modeling approach may be suitable. The ratio of the Tier 2 to Tier 1 results for specific plants represents a "screening refinement factor" (SRF) indicating the degree of conservatism built into the Tier 1 methodology for acute, chronic and cancer risks. The highest SRF among all of the Tier 2 simulations is computed for each of the three types of health effect indicators (cancer risk, hazard index and acute hazard quotient). These SRFs are then applied to the Tier 1 results for the plants not modeled with Tier 2 as a way of conservatively re-estimating risks (Tier 1.5). For instance if at least 20 plants were modeled with Tier 2, the highest SRF among them could be conservatively considered a 95th percentile (1 chance in 20) upper limit.

Tier 1 Inhalation Risk Modeling

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 AERSCREEN model, which 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.

[1] EPA defines the maximum individual lifetime cancer risk (MIR) as being "the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years." (54 FR 38045)

AERSCREEN 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 has been incorporated into the Tier 1 assessment.

The assessment followed EPA's approach for inhalation risk screening assessments used in the Risk and Technology Review process [6]. It is noted that EPA's approach to assess nationwide risk for an industry sector does not include the effects of building downwash. EPA's approach to not include building downwash is due to the practical consideration that such detailed information for all sources within an industrial sector are not readily available [9]. Conservative aspects of the screening methodology (e.g., not including plume deposition or depletion), generally outweigh the contribution of downwash which is an aspect of dispersion that only affects modeled concentrations very close to the source.

In the Tier 1 analysis, the risks associated with each modeled stack at a power plant were computed so that the total computed risk is the sum of the individual computed risks for each stack. This is considered conservative, since it assumes that the location of the maximum modeled concentration for each stack is the same and occurs during the same meteorological conditions. Each stack at a power plant was modeled at a unit emission rate (i.e., 1 g/sec) resulting in a 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 AERSCREEN dispersion factor was multiplied by the annual emission rates of each HAP (g/sec) to assess chronic non-cancer risk and cancer risk.

To estimate the short-term risk, EPA guidance [1] suggests that the annual average emission rates be adjusted upward by a factor of 10 to account for variability and that this peak emission rate be used to estimate maximum 1-hour concentrations. For Tier 1 assessment the maximum 1-hour dispersion factors were estimated with AERSCREEN and EPA's default peak-to-mean emission factors are applied. As discussed below, a more refined peak-to-mean factor is used to assess acute risk for the more refined Tier 1.5 and Tier 2 assessments.

The results of the Tier 1 assessment for each power plant are provided in Appendix H. The highest Tier 1 acute HQ was 0.8, well within EPA's range of acceptable risk from short-term exposure. The highly conservative Tier 1 analysis demonstrated that 98% of the power plants were below EPA's acceptable chronic non-cancer risk HI threshold of 1 and 53% of the plants (171 plants) were below EPA's acceptable cancer risk threshold of 10^{-6}.

Appendix H provides a listing of the HAPs that contribute to most of the modeled Tier 1 risk. On average, 90% of the modeled cancer risk was associated with three HAPs: arsenic (49%), chromium VI (30%), and nickel (10%). Eighty percent of the chronic non-cancer hazard index was associated with three HAPS: chlorine (50%), acrolein (18%) and arsenic (12%). The HAPs with the highest acute HQ were arsenic and cadmium.

Tier 2 Inhalation Risk Modeling

Given that all but one of the plants with a Tier 1 HI exceeding 1 were also associated with a modeled cancer risk exceeding 10^{-6}, it was appropriate to base the selection of Tier 2 plants based only on cancer risk. Because conducting a Tier 2 analysis for all 153 power plants with a Tier 1 modeled cancer risk exceeding 10^{-6} would be a substantial undertaking, the Tier 2 assessment was limited to the top quartile (i.e., 39) of these power plants. The minimum degree to which the Tier 2 assessment for these 39 power plants demonstrated a modeled risk reduction compared to Tier 1 was then used to conservatively adjust the Tier 1 results (referred to as Tier 1.5).

For Tier 2, the Human Exposure Model (HEM-3, Version 1.4.2) with the AERMOD option 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 data set is comprised of several hundred one-year hourly wind speed and direction and atmospheric stability data sets (for 2011) at measured locations shown in Figure 6-1. 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 2010 census blocks. Receptor data also included terrain elevation. For cancer risk and chronic hazard index, HEM3 computes the risk at each receptor following the same methodology as described for Tier 1. The long-term cancer and non-cancer risk, acute toxic endpoints and unit risk estimates in the HEM3 library were applied for this assessment. These are consistent with EPA's Air Toxics guidance values listed in Table 6-1. 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, and gas exit velocity and temperature.

For the acute Tier 2 assessment, the maximum 1-hour average concentration of each HAP at any off-site location was evaluated. The acute assessment used a polar receptor grid, centered on the geometric plant center based on the stack coordinates. The radial grid generated by HEM3, does not account for the actual power plant fence line or property boundary, a conservative approach. HEM3 computes the maximum 1-hour concentrations. The peak-to-mean emissions ratio for the Tier 2 assessment was based on a utilization survey of power plants by the U.S. Energy Information Administration [7]. Based on monthly data for coal-fired power generation from 2015-2017, the minimum capacity factor was 36%. Taking the inverse of this value resulted in a more representative peak-to-mean ratio of 2.8 instead of 10 which was used in the Tier 1 assessment. This approach is similar to EPA's Tier 2 methodology, which uses a peak-to-mean ratio of 10 by default. EPA will refine the peak-to-mean ratio based on industry-specific data if EPA determines that these refinements are warranted.

The results of the Tier 2 cancer risk estimates for the 39 selected plants are provided in Table 6-2. The highest modeled risk was 4×10^{-7}, well less than the 10^{-6} EPA acceptable risk threshold.

Comparison of the Tier 2 and Tier 1 modeled risks resulted in a maximum Tier 1 to Tier 2 RRF of 0.079 for cancer, 0.083 for HI and 0.28 for acute HQ. For the plants that were not modeled in Tier 2, Tier 1 risks were multiplied by these RRF values to provide upper-bound risk estimates. To place these values in context, the corresponding average risk reduction factors were 0.036 for cancer risk, 0.038 for hazard index, and 0.1 for acute hazard quotient.

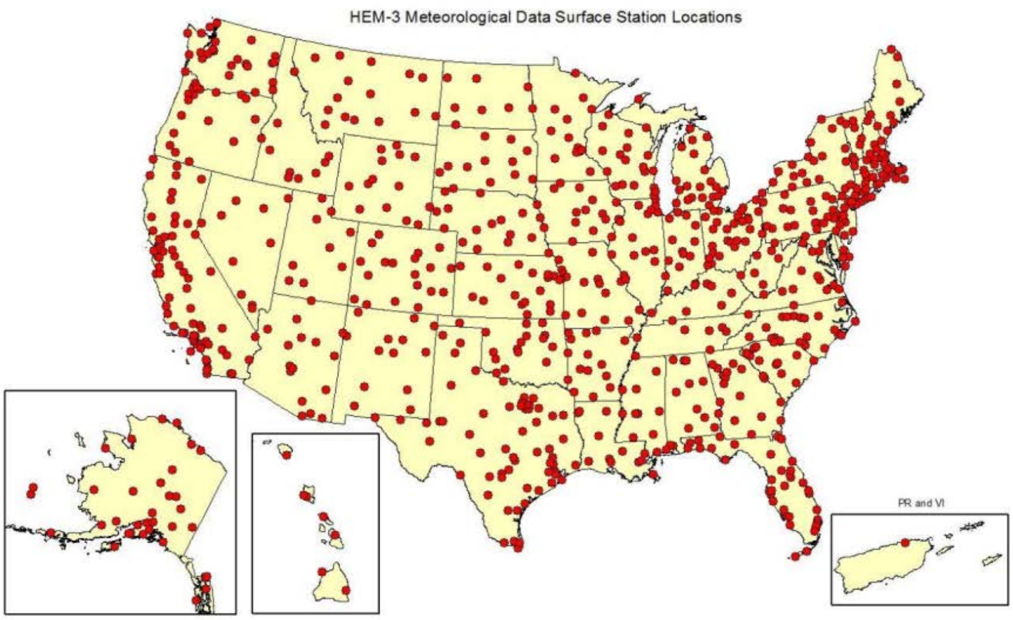


Figure 6-1
Surface Air Stations in the HEM-3 Database

Table 6-2
Tier 2 Results

Facility Name	Cancer Risk (per million)	Top Contributors			Hazard Index	Top Contributors			Acute Hazard Quotient	HAP
		As	Cr VI	Ni		Cl_2	As	Acrolein		
Amos	0.19	57%	27%	9%	0.014	61%	12%	10%	0.03	As
Belews Creek	0.17	60%	24%	8%	0.020	74%	8%	7%	0.06	As
Big Bend	0.35	58%	27%	8%	0.032	70%	10%	7%	0.03	As
Brandon Shores	0.39	70%	19%	6%	0.036	71%	12%	6%	0.02	As
Bruce Mansfield	0.17	66%	22%	7%	0.007	38%	26%	13%	0.03	As
Brunner Island	0.31	71%	20%	6%	0.014	52%	24%	7%	0.05	As
Cardinal	0.25	67%	20%	7%	0.014	52%	18%	12%	0.03	As
Colstrip	0.15	60%	23%	9%	0.008	38%	18%	19%	0.04	As
Conemaugh	0.13	60%	23%	8%	0.017	72%	7%	9%	0.08	As
Cross	0.18	58%	24%	9%	0.080	92%	2%	2%	0.02	As
Crystal River	0.07	52%	29%	10%	0.004	35%	16%	19%	0.02	As

Table 6-2 (continued)
Tier 2 Results

Facility Name	Cancer Risk (per million)	Top Contributors			Hazard Index	Top Contributors			Acute Hazard Quotient	HAP
Cumberland	0.19	47%	35%	10%	0.009	36%	16%	16%	0.03	Cd
D. B. Wilson	0.10	53%	29%	12%	0.003	13%	28%	17%	0.02	As
Elm Road	0.08	61%	24%	8%	0.003	36%	21%	18%	0.02	As
Gavin	0.23	68%	20%	7%	0.009	35%	26%	15%	0.05	As
Gibson	0.29	52%	29%	10%	0.010	17%	22%	25%	0.03	As
Green	0.13	52%	28%	14%	0.009	63%	11%	7%	0.04	As
Homer City	0.17	72%	18%	6%	0.118	97%	2%	1%	0.03	As
Jim Bridger	0.05	46%	34%	9%	0.004	47%	11%	23%	0.01	As
J.M. Stuart	0.18	53%	29%	9%	0.031	81%	5%	5%	0.03	As
Keystone	0.29	69%	20%	6%	0.020	65%	15%	6%	0.04	As
Labadie	0.08	47%	34%	10%	0.005	37%	12%	18%	0.02	As
Marshall	0.28	57%	25%	9%	0.042	76%	6%	7%	0.04	As
Martin Lake	0.19	47%	35%	10%	0.009	37%	15%	18%	0.03	As
Monroe	0.18	60%	25%	9%	0.006	29%	26%	14%	0.05	As
Montour	0.17	68%	21%	6%	0.011	61%	17%	8%	0.03	As
Morgantown	0.26	70%	19%	6%	0.022	69%	13%	6%	0.05	As
Mount Storm	0.17	59%	26%	8%	0.010	50%	15%	15%	0.02	As
Muskogee	0.09	48%	34%	10%	0.005	37%	15%	18%	0.01	As
Naughton	0.20	53%	33%	7%	0.009	38%	19%	19%	0.02	As
Paradise	0.18	54%	30%	9%	0.009	43%	18%	13%	0.04	As
Petersburg	0.09	54%	29%	10%	0.003	18%	25%	21%	0.02	As
Pleasants	0.09	68%	20%	7%	0.004	35%	27%	14%	0.02	As
Roxboro	0.34	63%	23%	8%	0.054	81%	6%	5%	0.05	As
Rush Island	0.03	46%	34%	11%	0.002	38%	12%	19%	0.01	As
Saint Clair	0.13	75%	17%	5%	0.003	19%	44%	9%	0.05	As
Thomas Hill	0.04	47%	34%	10%	0.002	37%	12%	18%	0.01	As
W.A. Parish	0.14	46%	34%	11%	0.010	35%	10%	18%	0.02	As
Wateree	0.12	68%	21%	7%	0.006	52%	20%	9%	0.02	As

Nationwide Tier 2 and Tier 1.5 Inhalation Risk Assessment Results

The conclusions drawn from this assessment were that inhalation risks from coal-fired power generation are well within EPA's acceptable risk thresholds. The highest Tier 2 risks were as follows: 0.4×10^{-6} cancer risk, 0.2 hazard index, and 0.1 hazard quotient, all of which indicate levels of risk that are well below EPA's acceptable risk thresholds. The listing of all of the Tier 2 and Tier 1.5 results are provided in Table 6-3 and the frequency plots for cancer, chronic hazard index and acute hazard quotient are provided in Figures 6-2, 6-3 and 6-4, respectively. These plots show that 90% of the power plants have a modeled cancer risk of less than 0.2×10^{-6}, hazard index of 0.02 or less, and acute hazard quotient of 0.045 or less.

Uncertainty of Inhalation Risk Assessments

The evaluation of inhalation risks are subject to uncertainties related to emission estimates, physical source parameters, dispersion modeling, exposure assumptions and dose-response factors relating modeled ambient concentrations to long and short term health effects. As discussed in previous sections, care was taken in the characterization of source emissions.

There are several factors that would lead to the conclusion that this assessment provides an upper-limit estimate of the risk posed by individual power plants:

- The Tier 1 and Tier 2 dispersion models applied have been developed by EPA to (conservatively) overestimate ground-level concentrations to a modest degree;
- The exposure assumption is that the maximum exposed individual is present at a specified receptor location for an entire 70 year lifetime;
- The dose-response data developed by EPA and applied in this assessment are intentionally derived to be health protective;
- The Tier 1.5 risk estimates represent a conservative upper limit adjustment of Tier 1 risks.

Table 6-3
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
3	SOUTHERN-ALPC	BARRY	Tier 1.5	1.45E-07	0.005	0.030
8	SOUTHERN-ALPC	GORGAS TWO	Tier 1.5	1.74E-07	0.004	0.037
26	SOUTHERN-ALPC	GASTON (AL)	Tier 1.5	9.17E-08	0.007	0.020
47	TVA	COLBERT	Tier 1.5	1.30E-11	0.000	0.000
51	CLECO	DOLET HILLS	Tier 1.5	8.58E-08	0.005	0.015
56	POWER SOUTH (ALEC)	CR LOWMAN	Tier 1.5	1.98E-07	0.011	0.042
59	GRAND ISLAND	PLATTE	Tier 1.5	4.50E-08	0.002	0.009
60	HASTINGS	WHELAN ENERGY CENTER	Tier 1.5	3.07E-08	0.003	0.006
87	TRI-STATE G&T	ESCALANTE	Tier 1.5	3.67E-08	0.004	0.010
108	SUNFLOWER	HOLCOMB	Tier 1.5	4.87E-08	0.003	0.009
113	AZ PUB SERV	CHOLLA	Tier 1.5	1.15E-07	0.011	0.030
127	AEP PSO	OKLAUNION	Tier 1.5	6.98E-08	0.003	0.014
130	SANTEE	CROSS	Tier 2	1.79E-07	0.080	0.023
136	SEMINOLE	SEMINOLE (FL)	Tier 1.5	2.38E-07	0.010	0.053
160	AZ ELEC COOP	APACHE	Tier 1.5	5.10E-08	0.005	0.013
165	GRDA	GRDA	Tier 1.5	1.34E-07	0.007	0.026
207	JEA	ST JOHNS RIVER	Tier 1.5	1.29E-07	0.004	0.025
298	NRG ENERGY	LIMESTONE	Tier 1.5	1.30E-07	0.010	0.024
469	XCEL	CHEROKEE (CO)	Tier 1.5	1.36E-08	0.001	0.004

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
470	XCEL	COMANCHE	Tier 1.5	8.00E-08	0.008	0.017
477	XCEL	VALMONT	Tier 1.5	1.99E-08	0.002	0.005
492	COL SPRINGS	DRAKE	Tier 1.5	5.88E-08	0.004	0.011
508	LAMAR	LAMAR REPOWERING PROJECT	Tier 1.5	4.08E-11	0.000	0.000
525	XCEL	HAYDEN	Tier 1.5	3.99E-08	0.003	0.011
527	TRI-STATE G&T	NUCLA	Tier 1.5	4.08E-09	0.001	0.001
564	ORLANDO	CH STANTON	Tier 1.5	2.07E-07	0.074	0.040
568	PSE&G	BRIDGEPORT HARBOR	Tier 1.5	1.78E-08	0.001	0.006
594	NRG Indian River Operations Inc	INDIAN RIVER (DE)	Tier 1.5	5.12E-08	0.004	0.015
602	TALEN ENERGY	BRANDON SHORES	Tier 2	3.89E-07	0.036	0.023
628	DUKE ENERGY FLORIDA	CRYSTAL RIVER	Tier 2	7.27E-08	0.004	0.018
641	SOUTHERN-GP	CRIST	Tier 1.5	1.11E-07	0.071	0.021
645	TECO	BIG BEND (FL)	Tier 2	3.48E-07	0.032	0.032
663	GAINESVILLE	DEERHAVEN	Tier 1.5	3.85E-08	0.007	0.008
667	JEA	NORTHSIDE	Tier 1.5	3.19E-08	0.004	0.015
676	LAKELAND	MCINTOSH (FL)	Tier 1.5	8.70E-08	0.076	0.018
703	SOUTHERN-GAPC	BOWEN	Tier 1.5	1.44E-07	0.118	0.032
708	SOUTHERN-GAPC	HAMMOND	Tier 1.5	5.02E-08	0.005	0.011
856	DYNEGY MIDWEST	ED EDWARDS	Tier 1.5	1.01E-07	0.005	0.020

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
861	DYNEGY MIDWEST (ILLINOIS POWWR HODLINGS)	COFFEEN	Tier 1.5	2.15E-08	0.005	0.006
876	DYNEGY	KINCAID	Tier 1.5	3.58E-08	0.002	0.006
879	NRG	POWERTON	Tier 1.5	5.64E-08	0.003	0.011
883	NRG	WAUKEGAN	Tier 1.5	5.60E-08	0.003	0.011
884	NRG	WILL COUNTY	Tier 1.5	6.33E-08	0.003	0.013
887	DYNEGY MIDWEST	JOPPA	Tier 1.5	1.33E-07	0.006	0.027
889	DYNEGY MIDWEST	BALDWIN	Tier 1.5	1.98E-07	0.012	0.036
891	DYNEGY MIDWEST	HAVANA	Tier 1.5	5.84E-08	0.004	0.011
892	DYNEGY MIDWEST	HENNEPIN	Tier 1.5	7.84E-08	0.004	0.021
963	SPRING-IL	DALLMAN	Tier 1.5	8.43E-08	0.042	0.025
976	SO IL PWR COOP	NEW MARION	Tier 1.5	1.70E-07	0.008	0.044
983	OVEC	CLIFTY CREEK	Tier 1.5	5.74E-08	0.008	0.011
994	AES	PETERSBURG	Tier 2	9.07E-08	0.003	0.022
995	NIPSCO	BAILLY	Tier 1.5	7.38E-08	0.003	0.015
997	NIPSCO	MICHIGAN CITY	Tier 1.5	6.66E-08	0.002	0.018
1001	DUKE ENERGY INDIANA	CAYUGA	Tier 1.5	1.39E-07	0.005	0.029
1004	DUKE ENERGY INDIANA (VECTRON)	EDWARDSPORT IGCC	Tier 1.5	3.06E-08	0.002	0.007
1008	DUKE ENERGY INDIANA	GALLAGHER	Tier 1.5	9.89E-09	0.017	0.004

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
1012	VECTREN	CULLEY	Tier 1.5	9.04E-08	0.003	0.019
1040	IMPA	WHITEWATER VALLEY	Tier 1.5	3.02E-09	0.001	0.001
1047	ALLIANT	LANSING	Tier 1.5	3.85E-08	0.002	0.008
1073	ALLIANT	PRAIRIE CREEK	Tier 1.5	1.94E-08	0.001	0.004
1082	MIDAMER	COUNCIL BLUFFS (SCOTT ENERGY CENTER)	Tier 1.5	1.68E-07	0.010	0.031
1091	MIDAMER	GEORGE NEAL	Tier 1.5	2.43E-08	0.002	0.004
1104	ALLIANT	BURLINGTON (IA)	Tier 1.5	4.66E-08	0.002	0.009
1131	CEDAR FALLS	STREETER	Tier 1.5	3.40E-10	0.001	0.000
1167	MUSCATINE	MUSCATINE	Tier 1.5	4.55E-08	0.003	0.008
1241	KCP&L	LA CYGNE	Tier 1.5	2.30E-07	0.011	0.045
1250	WESTSTAR ENERGY	LAWRENCE (KS)	Tier 1.5	2.24E-07	0.010	0.045
1252	WESTSTAR ENERGY	TECUMSEH	Tier 1.5	3.97E-08	0.002	0.008
1355	LGE-KU	EW BROWN	Tier 1.5	6.07E-08	0.003	0.012
1356	LGE-KU	GHENT	Tier 1.5	2.96E-07	0.040	0.056
1364	LGE-KU	MILL CREEK (KY)	Tier 1.5	2.25E-07	0.015	0.044
1374	OWENSBORO	ELMER SMITH	Tier 1.5	2.15E-07	0.006	0.048
1378	TVA	PARADISE	Tier 2	1.85E-07	0.009	0.039
1379	TVA	SHAWNEE (KY)	Tier 1.5	8.08E-08	0.004	0.016
1381	BIG RIVERS	COLEMAN (KY)	Tier 1.5	1.16E-07	0.018	0.024

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
1382	HMP&L	HENDERSON TWO	Tier 1.5	1.14E-07	0.020	0.024
1384	EAST KY PWR COOP	JS COOPER	Tier 1.5	2.80E-08	0.010	0.007
1393	ENTERGY	R S Nelson	Tier 1.5	6.44E-08	0.004	0.012
1552	TALEN ENERGY	CP CRANE	Tier 1.5	2.41E-08	0.001	0.005
1554	TALEN ENERGY	HA WAGNER	Tier 1.5	2.06E-08	0.203	0.048
1571	NRG	CHALK POINT	Tier 1.5	8.79E-08	0.013	0.023
1572	NRG	DICKERSON	Tier 1.5	5.26E-08	0.005	0.015
1573	NRG	MORGANTOWN	Tier 2	2.64E-07	0.022	0.051
1606	FirstLight Power Resources Services LLC	MOUNT TOM	Tier 1.5	9.25E-11	0.000	0.000
1619	DYNEGY	BRAYTON POINT	Tier 1.5	9.45E-08	0.006	0.018
1702	CMS	DE KARN	Tier 1.5	4.33E-08	0.003	0.008
1710	CMS	JH CAMPBELL	Tier 1.5	9.20E-08	0.006	0.016
1733	DTE ENERGY	MONROE (MI)	Tier 2	1.80E-07	0.006	0.053
1740	DTE ENERGY	RIVER ROUGE	Tier 1.5	2.85E-08	0.002	0.005
1743	DTE ENERGY	ST CLAIR	Tier 2	1.28E-07	0.003	0.047
1745	DTE ENERGY	TRENTON CHANNEL	Tier 1.5	6.39E-08	0.003	0.016
1769	WE ENERGIES	PRESQUE ISLE	Tier 1.5	5.82E-08	0.003	0.013
1825	GRAND HAVEN	JB SIMS	Tier 1.5	1.33E-08	0.004	0.003
1831	LANSING	ECKERT	Tier 1.5	9.42E-09	0.001	0.002

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
1832	LANSING	ERICKSON	Tier 1.5	3.16E-08	0.002	0.006
1843	MARQUETTE	SHIRAS	Tier 1.5	3.02E-08	0.002	0.006
1866	WYANDOTTE	WYANDOTTE	Tier 1.5	1.48E-09	0.000	0.000
1893	ALLETE	CLAY BOSWELL	Tier 1.5	1.55E-07	0.008	0.033
1915	XCEL	ALLEN S KING	Tier 1.5	4.07E-08	0.003	0.007
1943	OTTER TAIL	HOOT LAKE	Tier 1.5	2.58E-08	0.001	0.007
2076	EMPIRE DISTRICT	ASBURY	Tier 1.5	7.74E-08	0.003	0.015
2079	KCP&L	HAWTHORN	Tier 1.5	6.65E-08	0.004	0.012
2080	KCP&L	MONTROSE	Tier 1.5	1.86E-08	0.001	0.003
2094	KCP&L Greater Missouri Operations Co	SIBLEY (MO)	Tier 1.5	3.31E-08	0.002	0.006
2103	AMEREN-UE	LABADIE	Tier 2	8.27E-08	0.005	0.024
2104	AMEREN-UE	MERAMEC	Tier 1.5	4.32E-08	0.002	0.008
2107	AMEREN-UE	SIOUX	Tier 1.5	1.76E-07	0.011	0.039
2167	ASSOCIATED	NEW MADRID	Tier 1.5	5.99E-08	0.004	0.011
2168	ASSOCIATED	THOMAS HILL	Tier 2	4.20E-08	0.002	0.009
2240	FREEMONT	LD WRIGHT	Tier 1.5	3.73E-08	0.002	0.007
2277	NPPD	SHELDON	Tier 1.5	2.45E-08	0.004	0.023
2291	OPPD	NORTH OMAHA	Tier 1.5	6.49E-08	0.004	0.012
2324	NV ENERGY	REID GARDNER	Tier 1.5	1.52E-08	0.001	0.003

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
2364	PSNH	MERRIMACK	Tier 1.5	1.75E-07	0.009	0.050
2367	PSNH	SCHILLER	Tier 1.5	4.27E-08	0.001	0.010
2378	RC CAPE MAY HOLDINGS	BL ENGLAND	Tier 1.5	2.19E-08	0.001	0.007
2403	PSE&G	HUDSON	Tier 1.5	1.93E-08	0.001	0.005
2408	PSE&G	MERCER	Tier 1.5	1.38E-08	0.001	0.004
2442	AZ PUB SERV	FOUR CORNERS	Tier 1.5	6.56E-08	0.004	0.019
2451	PSNM	SAN JUAN (NM)	Tier 1.5	1.19E-07	0.009	0.034
2535	UPSTATE NY POWER PRODUCERS	CAYUGA (MILLIKEN)	Tier 1.5	1.86E-07	0.010	0.055
2706	DUKE ENERGY PROGRESS	ASHEVILLE	Tier 1.5	1.06E-07	0.014	0.025
2712	DUKE ENERGY PROGRESS	ROXBORO	Tier 2	3.37E-07	0.054	0.048
2718	DUKE ENERGY CAROLINAS	ALLEN	Tier 1.5	7.67E-08	0.016	0.015
2721	DUKE ENERGY CAROLINAS	CLIFFSIDE	Tier 1.5	4.91E-08	0.008	0.009
2727	DUKE ENERGY CAROLINAS	MARSHALL (NC)	Tier 2	2.77E-07	0.042	0.041
2790	MDU	HESKETT	Tier 1.5	2.04E-08	0.001	0.005
2817	BASIN ELECTRIC	LELAND OLDS	Tier 1.5	1.58E-07	0.009	0.042
2823	MINNKOTA	MR YOUNG	Tier 1.5	1.37E-07	0.008	0.036
2824	GREAT RIVER ENG	STANTON (ND)	Tier 1.5	7.21E-08	0.003	0.018
2828	CARDINAL(AEP)	CARDINAL	Tier 2	2.54E-07	0.014	0.025
2832	DYNEGY MIDWEST	MIAMI FORT	Tier 1.5	1.73E-07	0.013	0.040

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
2836	NRG	AVON LAKE	Tier 1.5	1.51E-07	0.085	0.046
2840	AEP GENERATION RESOURCES	CONESVILLE	Tier 1.5	2.79E-07	0.010	0.081
2850	AES (DP&L)-	JM STUART	Tier 2	1.83E-07	0.031	0.027
2866	FIRST ENERGY	WH SAMMIS	Tier 1.5	1.89E-07	0.017	0.046
2876	OVEC	KYGER CREEK	Tier 1.5	6.23E-08	0.003	0.016
2878	FIRST ENERGY	FirstEnergy Bay Shore	Tier 1.5	1.56E-08	0.002	0.007
2952	OG&E	MUSKOGEE	Tier 2	9.19E-08	0.005	0.010
2963	AEP PSO	NORTHEASTERN	Tier 1.5	4.86E-08	0.003	0.009
3118	NRG	CONEMAUGH	Tier 2	1.26E-07	0.017	0.077
3122	NRG ENERGY SERVICES	HOMER CITY	Tier 2	1.72E-07	0.118	0.031
3130	NRG	SEWARD	Tier 1.5	3.11E-08	0.003	0.007
3136	NRG (GENON	KEYSTONE (PA)	Tier 2	2.88E-07	0.020	0.041
3140	TALEN ENERGY	BRUNNER ISLAND	Tier 2	3.11E-07	0.014	0.052
3149	TALEN ENERGY	MONTOUR	Tier 2	1.72E-07	0.011	0.031
3297	SCANA	WATEREE (SC)	Tier 2	1.24E-07	0.006	0.025
3298	SCANA	AM WILLIAMS	Tier 1.5	1.87E-07	0.027	0.040
3393	TVA	TH ALLEN	Tier 1.5	1.20E-07	0.005	0.024
3396	TVA	BULL RUN (TN)	Tier 1.5	1.53E-07	0.007	0.036
3399	TVA	CUMBERLAND	Tier 2	1.95E-07	0.009	0.029

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
3403	TVA	GALLATIN	Tier 1.5	6.85E-08	0.005	0.012
3406	TVA	JOHNSONVILLE (TN)	Tier 1.5	2.21E-08	0.001	0.004
3407	TVA	KINGSTON	Tier 1.5	7.23E-08	0.004	0.014
3470	NRG ENERGY	WA PARISH	Tier 2	1.45E-07	0.010	0.017
3497	LUMINANT	BIG BROWN	Tier 1.5	1.33E-07	0.009	0.044
3797	DOMINION VA POWER	CHESTERFIELD	Tier 1.5	2.82E-07	0.057	0.061
3809	DOMINION VA POWER	YORKTOWN	Tier 1.5	1.70E-08	0.045	0.010
3845	TRANS ALTA	CENTRALIA	Tier 1.5	2.35E-07	0.011	0.055
3935	AEP	AMOS	Tier 2	1.89E-07	0.014	0.032
3943	FIRST ENERGY	FORT MARTIN	Tier 1.5	2.62E-07	0.022	0.065
3944	FIRST ENERGY	HARRISON	Tier 1.5	1.73E-07	0.011	0.044
3948	AEP	MITCHELL (WV)	Tier 1.5	6.06E-08	0.006	0.013
3954	DOMINION VA POWER	MOUNT STORM	Tier 2	1.71E-07	0.010	0.022
4041	WEC ENERGY GROUP	OAK CREEK (WI)	Tier 1.5	1.66E-07	0.011	0.029
4050	ALLIANT	EDGEWATER (WI)	Tier 1.5	7.70E-08	0.004	0.015
4072	WEC ENERGY GROUP	JP PULLIAM	Tier 1.5	1.69E-08	0.001	0.003
4078	WEC ENERGY GROUP	WESTON	Tier 1.5	9.67E-08	0.007	0.017
4125	MANITOWOC	MANITOWOC	Tier 1.5	1.77E-09	0.000	0.001
4143	DAIRYLAND	GENOA THREE	Tier 1.5	2.25E-08	0.001	0.004

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
4158	PACIFICORP	DAVE JOHNSTON	Tier 1.5	1.57E-07	0.011	0.027
4162	PACIFICORP	NAUGHTON	Tier 2	2.03E-07	0.009	0.017
4271	DAIRYLAND	MADGETT	Tier 1.5	2.03E-08	0.001	0.004
4941	SRP	NAVAJO	Tier 1.5	1.54E-07	0.007	0.034
6002	SOUTHERN-ALPC	MILLER	Tier 1.5	1.77E-07	0.012	0.031
6004	FIRST ENERGY	PLEASANTS	Tier 2	9.41E-08	0.004	0.024
6009	ENTERGY	WHITE BLUFF	Tier 1.5	5.89E-08	0.003	0.011
6016	DYNEGY MIDWEST	DUCK CREEK	Tier 1.5	5.60E-08	0.004	0.010
6017	DYNEGY MIDWEST	NEWTON	Tier 1.5	1.04E-07	0.005	0.019
6018	DUKE ENERGY KENTUCKY	EAST BEND	Tier 1.5	1.15E-07	0.014	0.026
6019	DYNEGY MIDWEST	ZIMMER	Tier 1.5	1.17E-07	0.007	0.028
6021	TRI-STATE G&T	CRAIG	Tier 1.5	6.34E-08	0.007	0.019
6030	GREAT RIVER ENG	COAL CREEK	Tier 1.5	7.07E-08	0.006	0.017
6031	AES (DP&L)	KILLEN	Tier 1.5	8.35E-08	0.017	0.018
6034	DTE ENERGY	BELLE RIVER	Tier 1.5	1.93E-07	0.007	0.051
6041	EAST KY PWR COOP	HL SPURLOCK	Tier 1.5	1.16E-07	0.078	0.023
6052	SOUTHERN-GAPC	WANSLEY	Tier 1.5	5.12E-08	0.019	0.013
6055	LA GEN(NRG)	BIG CAJUN TWO	Tier 1.5	1.06E-07	0.005	0.021
6061	SO MISS ELEC PWR	MORROW	Tier 1.5	2.29E-08	0.005	0.005

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
6064	KCBPU	NEARMAN CREEK	Tier 1.5	4.24E-08	0.002	0.008
6065	KCP&L(GREAT PLAINS ENERGY)	IATAN	Tier 1.5	1.15E-07	0.008	0.020
6068	WESTSTAR ENERGY	JEFFREY	Tier 1.5	2.68E-07	0.017	0.048
6071	LGE-KU(PP&L)	TRIMBLE COUNTY	Tier 1.5	1.67E-07	0.042	0.032
6073	SOUTHERN-MSPC	VJ DANIEL	Tier 1.5	3.46E-08	0.001	0.007
6076	TALEN ENERGY	COLSTRIP	Tier 2	1.52E-07	0.008	0.038
6077	NPPD	GERALD GENTLEMAN	Tier 1.5	5.73E-08	0.008	0.048
6082	UPSTATE NY POWER PRODUCERS	SOMERSET	Tier 1.5	8.38E-08	0.004	0.026
6085	NIPSCO	RM SCHAHFER	Tier 1.5	1.80E-07	0.011	0.041
6089	MDU	LEWIS & CLARK	Tier 1.5	3.46E-08	0.002	0.008
6090	XCEL	SHERBURNE COUNTY	Tier 1.5	8.61E-08	0.007	0.017
6094	FIRST ENERGY	BRUCE MANSFIELD	Tier 2	1.67E-07	0.007	0.035
6095	OG&E	SOONER	Tier 1.5	1.25E-07	0.006	0.025
6096	OPPD	NEBRASKA CITY	Tier 1.5	1.04E-07	0.006	0.019
6098	OTTER TAIL	BIG STONE	Tier 1.5	2.54E-08	0.001	0.005
6101	PACIFICORP	WYODAK	Tier 1.5	6.44E-08	0.005	0.012
6106	PORTLAND G&E	BOARDMAN (OR)	Tier 1.5	2.25E-08	0.002	0.004
6113	DUKE ENERGY INDIANA	GIBSON	Tier 2	2.88E-07	0.010	0.030

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
6124	SOUTHERN-GAPC	MCINTOSH (GA)	Tier 1.5	1.64E-09	0.000	0.000
6136	TMPA	GIBBONS CREEK	Tier 1.5	8.86E-08	0.004	0.017
6137	VECTREN(SIGE)	AB BROWN	Tier 1.5	1.69E-07	0.009	0.034
6138	AEP - SWEPCO	FLINT CREEK (AR)	Tier 1.5	7.86E-08	0.003	0.016
6139	AEP - SWEPCO	WELSH	Tier 1.5	8.15E-08	0.007	0.038
6146	LUMINANT	MARTIN LAKE	Tier 2	1.89E-07	0.009	0.026
6147	LUMINANT	MONTICELLO (TX)	Tier 1.5	1.09E-07	0.007	0.021
6155	AMEREN-UE	RUSH ISLAND	Tier 2	3.26E-08	0.002	0.010
6165	PACIFICORP	HUNTER	Tier 1.5	1.78E-07	0.008	0.040
6166	AEP	ROCKPORT	Tier 1.5	7.07E-08	0.003	0.014
6170	WEC ENERGY GROUP	PLEASANT PRAIRIE	Tier 1.5	1.82E-07	0.013	0.032
6177	SRP	CORONADO	Tier 1.5	1.62E-07	0.010	0.031
6178	INTERNATIONAL POWER PLC	COLETO CREEK	Tier 1.5	3.90E-08	0.003	0.018
6179	LCRA	FAYETTE(SEYMOR) (TX)	Tier 1.5	1.55E-07	0.010	0.028
6180	LUMINANT	OAK GROVE	Tier 1.5	2.45E-07	0.019	0.045
6181	SAPSB	JT DEELY	Tier 1.5	2.62E-08	0.002	0.013
6183	SAN MIGUEL	SAN MIGUEL	Tier 1.5	5.65E-08	0.005	0.010
6190	CLECO	Brame Energy Center	Tier 1.5	1.30E-07	0.010	0.031
6193	XCEL	HARRINGTON	Tier 1.5	1.33E-07	0.009	0.037

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
6194	XCEL	TOLK	Tier 1.5	8.25E-08	0.007	0.040
6195	SPRING-MO	SOUTHWEST (TWITTY ENERGY CENTER)	Tier 1.5	1.20E-07	0.006	0.024
6204	BASIN ELECTRIC	LARAMIE RIVER	Tier 1.5	2.42E-07	0.014	0.044
6213	HOOSIER	MEROM	Tier 1.5	5.48E-08	0.003	0.010
6248	XCEL	PAWNEE	Tier 1.5	5.50E-08	0.004	0.010
6249	SANTEE	WINYAH	Tier 1.5	2.55E-07	0.033	0.055
6250	DUKE ENERGY PROGRESS	MAYO	Tier 1.5	1.88E-07	0.028	0.048
6254	ALLIANT	OTTUMWA	Tier 1.5	7.26E-08	0.003	0.015
6257	SOUTHERN-GAPC	SCHERER	Tier 1.5	8.27E-08	0.008	0.017
6264	AEP	MOUNTAINEER	Tier 1.5	1.77E-07	0.007	0.048
6288	GOLDEN VALLEY	HEALY	Tier 1.5	2.54E-08	0.002	0.007
6469	BASIN ELECTRIC	ANTELOPE VALLEY	Tier 1.5	1.60E-07	0.009	0.042
6481	INTERMOUNTAIN/LADWP	INTERMOUNTAIN	Tier 1.5	5.93E-08	0.003	0.014
6639	BIG RIVERS	GREEN	Tier 2	1.26E-07	0.009	0.043
6641	ENTERGY	INDEPENDENCE	Tier 1.5	2.69E-08	0.002	0.005
6648	LUMINANT	SANDOW	Tier 1.5	1.05E-07	0.006	0.019
6664	MIDAMER	LOUISA	Tier 1.5	7.00E-08	0.004	0.013
6705	ALCOA	WARRICK	Tier 1.5	2.97E-07	0.021	0.057
6761	PLATTE RIVER	RAWHIDE	Tier 1.5	5.13E-08	0.003	0.009

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
6768	SIKESTON	SIKESTON	Tier 1.5	5.99E-08	0.003	0.011
6772	WESTERN FARMERS	HUGO	Tier 1.5	5.99E-08	0.003	0.012
6823	BIG RIVERS	DB WILSON	Tier 2	9.70E-08	0.003	0.021
7030	MAJOR OAK POWER	TNP ONE (TWIN OAKS)	Tier 1.5	1.09E-07	0.006	0.020
7097	SAPSB	SPRUCE	Tier 1.5	1.34E-07	0.008	0.023
7210	SCANA	COPE	Tier 1.5	9.52E-08	0.014	0.022
7213	DOMINION VA POWER	CLOVER	Tier 1.5	1.71E-07	0.055	0.033
7343	MIDAMER	GEORGE NEAL	Tier 1.5	2.43E-08	0.005	0.023
7504	BLACK HILLS	NEIL SIMPSON 6 (II 2)	Tier 1.5	3.43E-08	0.003	0.006
7737	SCANA	KAPSTONE(Cogen South)	Tier 1.5	8.84E-08	0.004	0.020
7790	DESERT	BONANZA	Tier 1.5	3.14E-08	0.003	0.010
7902	AEP - SWEPCO	PIRKEY	Tier 1.5	1.36E-07	0.007	0.026
8023	ALLIANT	COLUMBIA (WI)	Tier 1.5	3.68E-08	0.003	0.007
8042	DUKE ENERGY CAROLINAS	BELEWS CREEK	Tier 2	1.69E-07	0.020	0.057
8066	PACIFICORP	JIM BRIDGER	Tier 2	5.28E-08	0.004	0.014
8069	PACIFICORP	HUNTINGTON	Tier 1.5	9.56E-08	0.004	0.022
8102	AEP GENERATION RESOURCES	GAVIN	Tier 2	2.31E-07	0.009	0.046
8219	COL SPRINGS	RD NIXON	Tier 1.5	3.62E-08	0.002	0.007
8222	MDU	COYOTE	Tier 1.5	4.75E-08	0.002	0.013

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
8223	TUCSON	SPRINGERVILLE	Tier 1.5	1.48E-07	0.013	0.033
8224	NV ENERGY (MID-AMERICAN)	NORTH VALMY	Tier 1.5	3.56E-08	0.002	0.007
8226	NRG	CHESWICK	Tier 1.5	1.29E-07	0.010	0.034
10043	Logan Generating Co	Logan Generating Plant	Tier 1.5	3.47E-08	0.004	0.007
10075	ALLETE	TACONITE HARBOR ENERGY CENTER	Tier 1.5	1.00E-07	0.004	0.023
10113	Gilberton Power Co	John B Rich Memorial Power Station	Tier 1.5	4.53E-08	0.003	0.011
10143	A C Power Colver Operations	Colver Power Project	Tier 1.5	2.55E-08	0.002	0.006
10151	Edison Mission	Grant Town Power Plant	Tier 1.5	1.35E-08	0.001	0.003
10343	El Paso Merchant Energy Co	MT. CARMEL	Tier 1.5	2.67E-08	0.002	0.007
10377	Cogentrix -James River Cogeneration Co	James River Cogeneration	Tier 1.5	8.75E-08	0.004	0.022
10378	Primary Energy of North Carolina	Primary Energy Southport	Tier 1.5	1.42E-07	0.205	0.048
10379	Primary Energy of North Carolina LLC	Primary Energy Roxboro	Tier 1.5	4.95E-08	0.082	0.019
10380	NORTH CAROLINA POWER HOLDINGS	Elizabethtown	Tier 1.5	3.15E-11	0.000	0.000
10384	Edgecombe Operating Services LLC	Edgecombe Genco LLC	Tier 1.5	7.20E-08	0.010	0.017
10495	Rumford Cogeneration Co	Rumford Cogeneration	Tier 1.5	1.44E-08	0.001	0.003
10566	Chambers Cogeneration LP	Chambers Cogeneration LP	Tier 1.5	1.25E-07	0.012	0.034

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
10603	Power Systems Operations Inc	Ebensburg Power Co	Tier 1.5	1.45E-08	0.001	0.004
10641	Cambria CoGen Co	Cambria Cogen	Tier 1.5	2.32E-08	0.003	0.005
10671	AES SHADY POINT	AES Shady Point Inc	Tier 1.5	1.85E-08	0.001	0.003
10672	Caryle Group	Cedar Bay Generating Co LP	Tier 1.5	1.53E-08	0.006	0.003
10673	AES HAWAII	AES HAWAII	Tier 1.5	7.65E-08	0.005	0.016
10678	AES WARRIOR	AES Warrior Run Cogeneration	Tier 1.5	5.45E-08	0.006	0.012
10743	Morgantown Energy Associates	Morgantown Energy Facility	Tier 1.5	1.62E-08	0.002	0.003
10768	Contellation Oper Services	Rio Bravo Jasmin	Tier 1.5	6.68E-11	0.000	0.000
10769	Constellation Oper Services	Rio Bravo Poso	Tier 1.5	5.97E-11	0.000	0.000
10784	Rosebud Operating Services Inc	Colstrip Energy LP	Tier 1.5	1.75E-08	0.002	0.004
10849	Cleveland Cliffs Inc	SILVER BAY POWER	Tier 1.5	1.79E-10	0.000	0.000
50039	Northeastern Power Company	Kline Township Cogen Facil	Tier 1.5	1.31E-08	0.002	0.003
50202	WPS POWER DEV	WPS POWER Niagara	Tier 1.5	6.14E-09	0.004	0.002
50611	WPS POWER DEV	Westwood	Tier 1.5	1.29E-08	0.001	0.003
50776	Constellation Oper Services	Panther Creek Energy Facility	Tier 1.5	2.46E-08	0.002	0.006
50835	TES Filer City Station LP	TES Filer City	Tier 1.5	8.36E-08	0.003	0.020
50879	Wheelabrator Environmental Sys	Wheeler Frackville Energy Co Inc	Tier 1.5	1.07E-08	0.001	0.002
50888	Northampton Generating Co LP	NORTHAMPTON	Tier 1.5	1.89E-08	0.002	0.005
50931	Rosebud Operating Serv Inc	Yellowstone Energy LP	Tier 1.5	2.08E-08	0.003	0.010

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
50951	Sunnyside Operations Associate	Sunnyside Cogeneration Associates	Tier 1.5	6.02E-09	0.001	0.002
50974	Buzzard Power Corporation	SCRUBGRASS	Tier 1.5	1.81E-08	0.001	0.005
50976	US Operating Services Company	Indiantown Cogeneration Facility	Tier 1.5	2.81E-08	0.005	0.006
52007	DOMINION VA POWER	Mecklenburg Cogeneration Facility	Tier 1.5	1.89E-08	0.004	0.003
52071	LUMINANT	SANDOW	Tier 1.5	1.05E-07	0.009	0.035
54035	Westmoreland Partners	Westmoreland LG&E Partners Roanoke Valley	Tier 1.5	1.24E-08	0.005	0.002
54081	Spruance Operating Services LLC	Spruance Genco LLC	Tier 1.5	4.96E-08	0.017	0.009
54304	Birchwood Power Partners LP	Birchwood Power Facility	Tier 1.5	2.65E-08	0.005	0.005
54634	Schuylkill Energy Resource Inc	St Nicholas Cogeneration Project	Tier 1.5	2.91E-08	0.002	0.007
54755	Westmoreland Partners	Westmoreland LG&E Partners Roanoke Valley	Tier 1.5	1.24E-08	0.008	0.007
55076	Choctaw Generating LP	RED HILLS GENERATION FACILITY	Tier 1.5	4.04E-08	0.003	0.008
55479	BLACK HILLS	WYGEN	Tier 1.5	7.23E-08	0.004	0.014
55749	ROCKY MOUNTAIN POWER	HARDIN GENERATING	Tier 1.5	2.45E-08	0.002	0.005
55856	PRAIRIE STATE	PRAIRIE STATE	Tier 1.5	1.21E-07	0.075	0.030
56068	WEC ENERGY GROUP	ELM ROAD	Tier 2	7.64E-08	0.003	0.019

Table 6-3 (continued)
Tier 1.5 and Tier 2 Modeled Risks

EPA Plant No.	Operator	Plant Name	Analysis Tier	Cancer Risk	Hazard Index	Acute HQ
56224	NEWMONT MINING	TS POWER (NEWMONT/BOULDER VALLEY)	Tier 1.5	3.08E-08	0.002	0.005
56319	BLACK HILLS	WYGEN	Tier 1.5	7.23E-08	0.003	0.012
56456	Plum Point Energy Associates LLC	PLUM POINT	Tier 1.5	9.13E-08	0.006	0.016
56564	AEP - SWEPCO	J. TURK (FULTON, AK)	Tier 1.5	6.57E-08	0.003	0.013
56596	BLACK HILLS	WYGEN	Tier 1.5	7.23E-08	0.003	0.012
56609	BASIN ELECTRIC	DRY FORK	Tier 1.5	7.70E-08	0.005	0.013
56611	SANDY CREEK	SANDY CREEK ENERGY STATION	Tier 1.5	6.21E-08	0.004	0.011
56671	LONGVIEW POWER	LONGVIEW	Tier 1.5	1.20E-07	0.014	0.032
56786	GREAT RIVER ENG	SPIRITWOOD STATION	Tier 1.5	2.86E-08	0.002	0.007

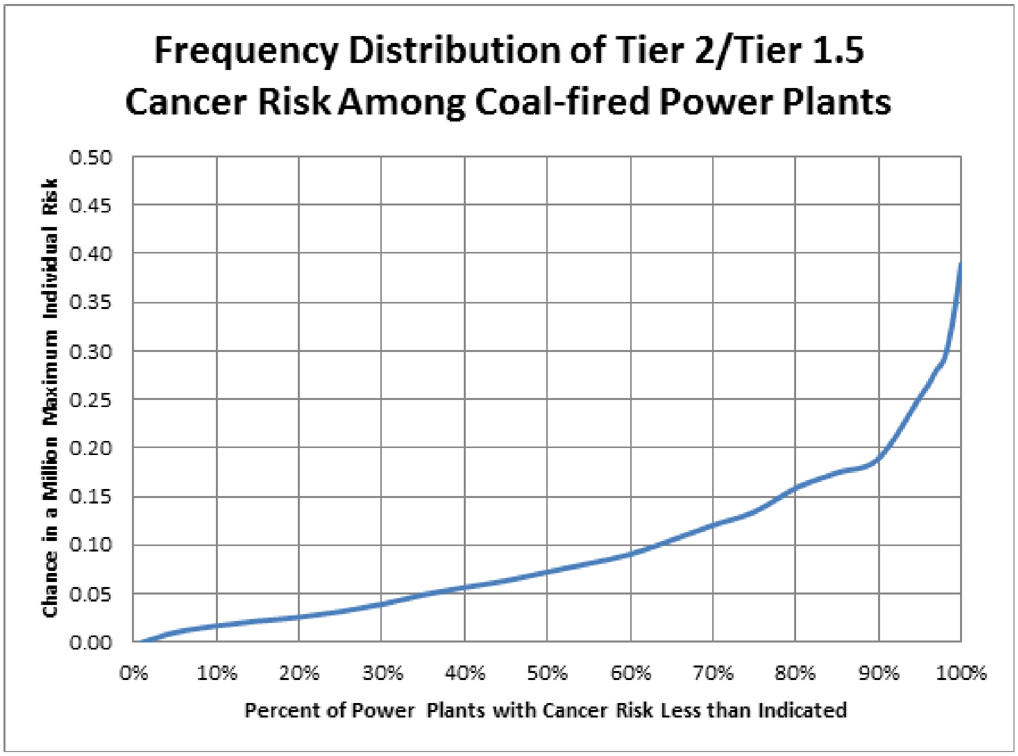


Figure 6-2
Frequency Distribution of Tier 2 and Tier 1.5 Modeled Cancer Risk

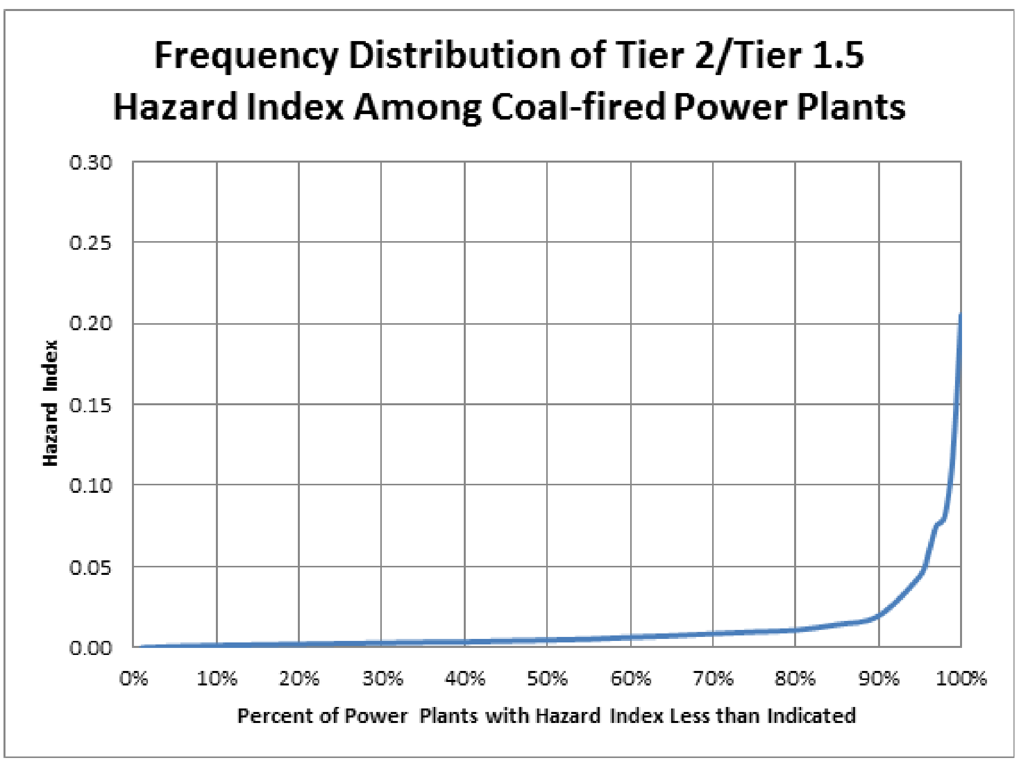


Figure 6-3
Frequency Distribution of Tier 2 and Tier 1.5 Modeled Hazard Index

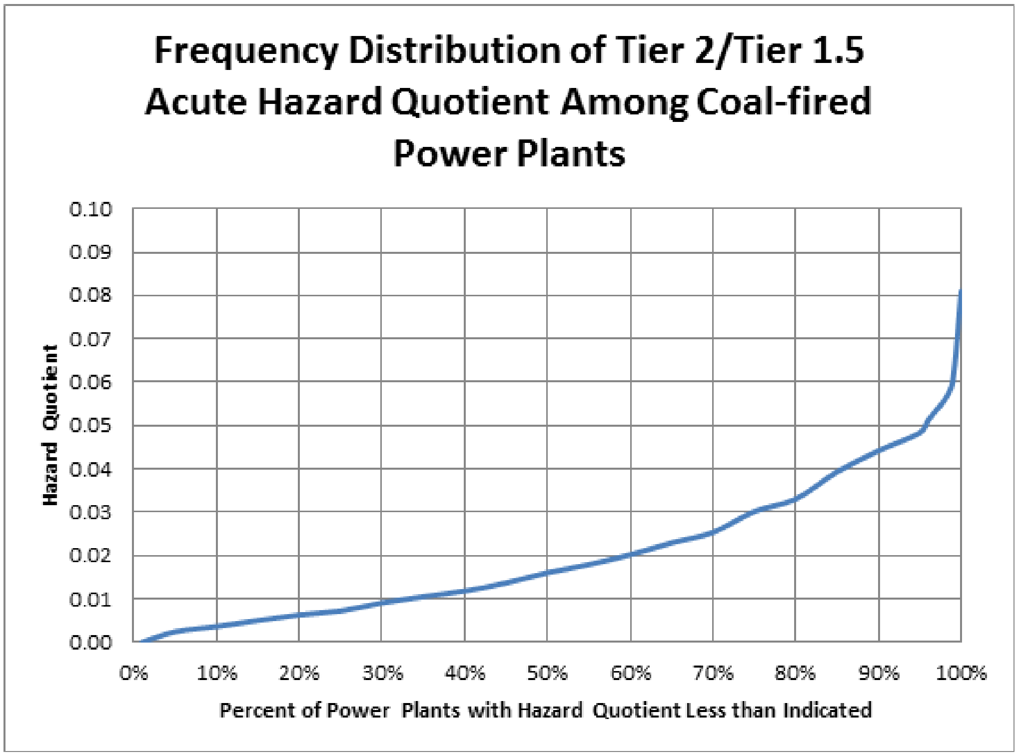


Figure 6-4
Frequency Distribution of Tier 2 and Tier 1.5 Modeled Acute Hazard Quotient

References

1. EPA, 2004. Air Toxics Risk Assessment Reference Library, Volume 2- Facility-specific Assessment, EPA-453-K-04-001B, April. https://www.epa.gov/fera/air-toxics-risk-assessment-reference-library-volumes-1-3
2. EPA, 2017a. Dose-Response Assessment for Assessing Health Risks Associated With Exposure to Hazardous Air Pollutants. https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants
3. EPA, 2011. Chromium Emissions Speciation for Selected Source Categories, March 2011, Memo TO: Ted Palma, HEID, FROM: Chuck French and Anne Pope, SPPD https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=504209
4. OEHHA, 2016. Acute, 8-hour and Chronic Reference Exposure Level (REL) Summary, Office of Environmental Health Hazard Assessment, California Environmental Protection Agency. https://oehha.ca.gov/air/general-info/oehha-acute-8-hour-and-chronic-reference-exposure-level-rel-summary
5. ASTDR, 2017. Minimal Risk Levels. Agency for Toxic Substances & Disease Registry. https://www.atsdr.cdc.gov/mrls/index.asp
6. EPA, 2017b Risk and Technology Review. https://www3.epa.gov/airtoxics/rrisk/rtrpg.html
7. USEIA, 2017, U.S. Energy Information Administration, Electric Power Monthly, Table 6.7.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, January 2013-October 2017. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a
8. EPA, 2005. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. Office of Solid Waste and Emergency Response, EPA-530-R-05-006, September 2005.
9. EPA, 2017c. Residual Risk Assessment for the Portland Cement Manufacturing Source Category in Support of the September 2017 Proposed Rule. EPA-HQ-OAR-2016-0442-0153, July 2017.

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.

Methodology

As described in Section 3, the USGS database was screened to provide approximately 2,700 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 2015 EIA database, an additional 58 unique types of fuel were identified that were not explicitly listed in 22 USGS coal-producing regions. These additional 58 types were each assigned to one of 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]. Coal mercury concentrations were not needed for stack emission estimates, since AMPD stack mercury data were used to estimate emissions. However, the coal mercury values were used to estimate the total mass of mercury entering with the fuel and coal-to-stack removal levels for all units in the 2017 plant database as noted in Section 5. Table A-3 provides the geometric mean composition data for petroleum coke and tired derived fuel (TDF) developed from data taken from the EPRI PPTMD 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		
Rank	**Coal Supply Region**	**State**	**Rank**	**Coal Supply Region**	**State**
Bituminous	-	Central Appalachian	Bituminous	Average	Central Appalachian
Bituminous	Kentucky	Central Appalachian	Bituminous	Kentucky	Central Appalachian
Bituminous	Alabama	Southern Appalachian	Bituminous	Alabama	Southern Appalachian
Bituminous	Arkansas	Southern Appalachian	Bituminous	Alabama	Southern Appalachian
Bituminous	Australia	Northern Appalachian	Bituminous	Average	Northern Appalachian
Bituminous	Arizona	San Juan River	Bituminous	New Mexico	San Juan River
Bituminous	Columbian	Eastern	Bituminous	Average	Eastern
Bituminous	Colorado	Green River	Bituminous	Colorado	Green River
Bituminous	Idaho	Eastern	Bituminous	Average	Eastern
Bituminous	Illinois	Eastern	Bituminous	Illinois	Eastern
Bituminous	Imported	Eastern	Bituminous	Average	Eastern
Bituminous	Indiana	Eastern	Bituminous	Indiana	Eastern
Bituminous	Indonesia	Eastern	Bituminous	Average	Eastern
Bituminous	Kansas	Eastern	Bituminous	Illinois	Eastern
Bituminous	Kentucky	Eastern	Bituminous	Kentucky	Eastern
Bituminous	Maryland	Northern Appalachian	Bituminous	Maryland	Northern Appalachian
Bituminous	Missouri	Eastern	Bituminous	Average	Eastern
Bituminous	Montana	Powder River	Subbituminous	Montana	Powder River
Bituminous	New Mexico	San Juan River	Bituminous	New Mexico	San Juan River
Bituminous	-	Northern Appalachian	Bituminous	Average	Northern Appalachian
Bituminous	Ohio	Northern Appalachian	Bituminous	Ohio	Northern Appalachian
Bituminous	Oklahoma	Eastern	Bituminous	Average	Eastern
Bituminous	Other	Eastern	Bituminous	Average	Eastern

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

Actual Coal Type Reported			USGS Coal Type Assigned		
Rank	**Coal Supply Region**	**State**	**Rank**	**Coal Supply Region**	**State**
Bituminous	Pennsylvania	Northern Appalachian	Bituminous	Pennsylvania	Northern Appalachian
Bituminous	Tennessee	Central Appalachian	Bituminous	Tennessee	Central Appalachian
Bituminous	Utah	Uinta	Bituminous	Utah	Uinta
Bituminous	Virginia	Central Appalachian	Bituminous	Virginia	Central Appalachian
Bituminous	Venezuelan	Eastern	Bituminous	Average	Eastern
Bituminous	West Virginia	Central Appalachian	Bituminous	West Virginia	Central Appalachian
Bituminous	West Virginia	Northern Appalachian	Bituminous	West Virginia	Northern Appalachian
Bituminous	Wyoming	Green River	Bituminous	Colorado	Green River
Bituminous	Wyoming	Powder River	Subbituminous	Wyoming	Powder River
Lignite	Alaska	Fort Union	Lignite	North Dakota	Fort Union
Lignite	Louisiana	Texas	Lignite	Texas	Texas
Lignite	Mississippi	Southern Appalachian	Bituminous	Alabama	Southern Appalachian
Lignite	Montana	Powder River	Subbituminous	Montana	Powder River
Lignite	North Dakota	Fort Union	Lignite	North Dakota	Fort Union
Lignite	Texas	Texas	Lignite	Texas	Texas
Lignite	Wyoming	Powder River	Subbituminous	Wyoming	Powder River
Synthetic Coal	Alabama	Southern Appalachian	Bituminous	Alabama	Southern Appalachian
Synthetic Coal	Illinois	Eastern	Bituminous	Illinois	Eastern
Synthetic Coal	Indiana	Eastern	Bituminous	Indiana	Eastern
Synthetic Coal	Kentucky	Central Appalachian	Bituminous	Kentucky	Central Appalachian
Synthetic Coal	Kentucky	Eastern	Bituminous	Kentucky	Eastern
Synthetic Coal	Montana	Powder River	Subbituminous	Montana	Powder River
Synthetic Coal	-	Northern Appalachian	Bituminous	Average	Northern Appalachian
Synthetic Coal	Pennsylvania	Northern Appalachian	Bituminous	Pennsylvania	Northern Appalachian

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

Actual Coal Type Reported			USGS Coal Type Assigned		
Rank	Coal Supply Region	State	Rank	Coal Supply Region	State
Synthetic Coal	Utah	Uinta	Bituminous	Utah	Uinta
Synthetic Coal	Virginia	Central Appalachian	Bituminous	Virginia	Central Appalachian
Synthetic Coal	Venezuelan	Eastern	Bituminous	Average	Eastern
Synthetic Coal	West Virginia	Central Appalachian	Bituminous	West Virginia	Central Appalachian
Subbituminous	Colorado	Green River	Subbituminous	Colorado	Green River
Subbituminous	Idaho	Powder River	Subbituminous	Average	Powder River
Subbituminous	Illinois	Eastern	Bituminous	Illinois	Eastern
Subbituminous	Imported	Powder River	Subbituminous	Average	Powder River
Subbituminous	Indiana	Powder River	Subbituminous	Average	Powder River
Subbituminous	Indonesia	Powder River	Subbituminous	Average	Powder River
Subbituminous	Montana	Powder River	Subbituminous	Montana	Powder River
Subbituminous	New Mexico	San Juan River	Subbituminous	New Mexico	San Juan River
Subbituminous	Pennsylvania	Northern Appalachian	Bituminous	Pennsylvania	Northern Appalachian
Subbituminous	-	Powder River	Subbituminous	Average	Powder River
Subbituminous	Utah	Uinta	Bituminous	Utah	Uinta
Subbituminous	Virginia	Central Appalachian	Bituminous	Virginia	Central Appalachian
Subbituminous	West Virginia	Central Appalachian	Bituminous	West Virginia	Central Appalachian
Subbituminous	Wyoming	Green River	Subbituminous	Wyoming	Green River
Subbituminous	Wyoming	Powder River	Subbituminous	Wyoming	Powder River
Waste Coal	Alaska	Fort Union	Lignite	North Dakota	Fort Union
Waste Coal	Illinois	Eastern	Bituminous	Illinois	Eastern
Waste Coal	Indiana	Eastern	Bituminous	Illinois	Eastern
Waste Coal	Kentucky	Eastern	Bituminous	Illinois	Eastern
Waste Coal	Maryland	Northern Appalachian	Bituminous	Average	Northern Appalachian
Waste Coal	Montana	Powder River	Subbituminous	Montana	Powder River

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

Actual Coal Type Reported			USGS Coal Type Assigned		
Rank	Coal Supply Region	State	Rank	Coal Supply Region	State
Waste Coal	-	Northern Appalachian	Bituminous	Average	Northern Appalachian
Waste Coal	Pennsylvania	Northern Appalachian	Bituminous	Pennsylvania	Northern Appalachian
Waste Coal	Utah	Uinta	Bituminous	Utah	Uinta
Waste Coal	Washington	Green River	Bituminous	Colorado	Green River
Waste Coal	West Virginia	Central Appalachian	Bituminous	West Virginia	Central Appalachian
Waste Coal	Wyoming	Powder River	Subbituminous	Montana	Powder River
Waste Coal	West Virginia	Northern Appalachian	Bituminous	West Virginia	Northern Appalachian

Table A-3
Petroleum Coke and Tire Derived Duel 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 PPTMD Database, version 2008a.

For each power plant the monthly fuel purchase records from the EIA coal database were retrieved and totaled. Fuels used for start-up only (oil, natural gas, etc.) were not included in this total or in this assessment.

Clay Boswell Example

Table A-4 shows the fuel purchase records for Clay Boswell (Plant ID = 1893) for 2015.

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	Bighorn	Sub	Subbituminous Montana Powder River	1,601,188	9,360	0.369	4.62
WY	Campbell	Sub	Subbituminous Wyoming Powder River	3,300,592	8,900	0.298	5.35
WY	Converse	Sub	Subbituminous Wyoming Powder River	384,937	8,850	0.238	5.51
Total				5,286,717			

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 2015. 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:

$$As_{Coal} = Conc_{As} * BTU_{Coal} * Mass_{Coal}$$

Where As_{Coal} is the total annual arsenic from coal type 1, $Conc_{As}$ is the geometric mean coal arsenic composition in lbs/TBtu for coal type 1, BTU_{Coal} is the average heat content of coal type 1 in Btu/lb as reported in the EIA fuel purchase database, and $Mass_{Coal}$ is the amount of coal type 1 purchased in 2015 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:

$$As_{Bighorn} = 408.22*9{,}357.5*1{,}601{,}188*2000/10^{12} = 12{,}233 \text{ lbsAs/yr}$$

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

	Element Mass (lbs)												
Coal Name	As	Se	Cd	Cl	Co	Cr	F	Hg	Mn	Ni	Pb	Sb	Se
Bighorn	12,233	2,202	286	65,290	3,740	12,610	201,794	144	106,590	13,365	11,314	1,638	2,524
Campbell	9,699	2,034	326	68,582	9,280	30,063	360,242	358	134,506	22,289	14,679	1,263	5,079
Converse	1,125	236	38	5,715	1,076	3,486	41,778	32	15,599	2,585	1,702	146	589
Total	**23,057**	**4,472**	**650**	**139,587**	**14,096**	**46,159**	**603,815**	**534**	**256,695**	**38,239**	**27,696**	**3,047**	**8,192**

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.

$$S_{Coal} = S_{wt\%} * Mass_{Coal}$$

$$S_{Bighorn} = Coal_S * Mass_{Coal}$$

Where, $S_{Bighorn}$ = sulfur content of coal type 1 (wt fraction), and

$Mass_{Coal}$ = amount of coal type 1 purchased in 2015 (tons).

For Clay Boswell Bighorn coal this becomes:

$$S_{Bighorn} = 0.003686*1{,}601{,}188 = 5{,}903 \text{ tons S}$$

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)
Bighorn	5,903	73,946	29,966,233
Campbell	9,176	176,692	58,759,339
Converse	917	21,207	6,814,435
Total	**15,995**	**271,844**	**95,540,007**

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:

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

Where $Blend_{As}$ = blended fuel composition in parts per million by weight (ppmw), As_{Total} = total annual arsenic input for all fuel types in lbs, and $Coal_{Total}$ = total annual fuel purchased in tons.

For Clay Boswell this becomes:

$$Blend_{As} = 23{,}057/(5{,}286{,}717*2000) * 10^6 = 2.18 \text{ ppmw}$$

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
2.2	0.4	0.06	13	1.3	4.4	57.1	0.051	24	3.6	2.6	0.29	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 these additional coal characteristics 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)**
0.30	5.14	9,036

References

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

B
EMISSION FACTOR METHODOLOGY AND DATA LIMITATIONS

Emissions Factor Methodology

The general methodology used to develop EPRI's current emission factors for coal- and pet coke-fired utility boilers, as presented in the EPRI's 2014 EFH, is discussed below. Only those species or groups of species used in the current 2017 base year risk assessment are discussed. The overall process involved updating the EFH my merging the historical data used in the 2002 Emission Factors Handbook [1] with data from newer sources, which included the following:

- HAPs data supplied by individual utilities as part of an industry survey;
- Additional EPRI and DOE-sponsored HAPs studies conducted since 2002; and
- Part III fuel and stack test data from EPA's 2010 utility ICR (original MS Access® ICR Database file entitled "EGU ICR Part III" and dated 12/16/11) obtained from the MATS rulemaking docket, with subsequent modifications made to address various data quality and formatting issues identified by EPRI.

The resulting combined and cleaned-up data set was subsequently evaluated to develop the emission factors and emission correlations presented in this current report. Table B-1 summarizes the methodologies used for various groups of compounds and types of units. Three general approaches were used:

1. Emission correlations – A correlation approach was used for particulate phase trace metals from coal-fired units, where stack emissions were correlated with fuel trace metal content, ash content, and stack FPM emission rate. A correlation approach was also used for speciated mercury emissions from some control configurations, by correlating emissions or percent oxidation with coal chloride levels. For selenium, correlations with fuel sulfur levels were used for control categories where the relationships were statistically significant.
2. Percent of Fuel Content Emitted – In cases where sufficient fuel composition data were available in combination with stack emissions data, emission factors were computed on a fuel-to-stack reduction basis, with the final emission factor expressed as percent of fuel input emitted.
3. Median or mean of stack emission measurements – For most organic compounds detected at coal-fired units, the Kaplan-Meier (KM) statistical technique, described in detail later in this section, was used to derive a median and/or mean emission factor using the set of available site average emission values available for each compound. The KM median provides an accurate estimate of emissions from an untested unit, for data sets with many nondetect values. However, in some cases the KM technique cannot calculate a median value; therefore the Kaplan-Meier mean value or the conventional median value was selected as the recommended emission factor.

Table B-1
Summary of Emission Factor Methodologies

Compound Group	Coal-Fired Boilers	100% Petroleum Coke-Fired Boilers
Particulate phase metals and metalloids	Coal-FPM/ash correlations.	Simple median since < 7 sites tested.
Selenium	Average % coal emitted by control class and/or coal rank. Correlation with coal sulfur for some control device configurations.	Simple median since < 7 sites tested.
Speciated Mercury (elemental and particulate; oxidized by difference)	Average % eliminated by control class or correlations with coal chloride levels.	Simple median since < 7 sites tested.
HCl, HF	Average % coal emitted by coal rank and control class.	Simple median since < 7 sites tested.
HCN	Emission factors not developed. Data are poor quality [2].	Emission factors not developed. Data are poor quality [2].
Chlorine (Cl_2)	Coal chloride correlations for bituminous coals. Kaplan-Meier median or mean for combined set of subbituminous, western bituminous and lignite coals, where correlations were not statistically significant.	Single 2010 ICR test site available
Dioxin/Furan TEQ and B(a)P TEQ	Arithmetic averages of all sites TEQ using zero for non-detect runs and zero for non-detect site averages.	Arithmetic average of all sites TEQ using zero for non-detect runs and zero for non-detect site averages.
Individual semi-volatile and volatile organic compounds	Kaplan-Meier median or mean. Simple median if only detected at 1 - 6 sites.	Simple median since < 7 sites tested.

Development of Site Average Values

Development of emission factors and/or correlations requires a single average emission value per compound for each site tested. Typically, most test programs conduct a minimum of three individual source measurement test runs for each sample method employed (e.g., Method 29 for metals or Method 23 for dioxin/furan compounds). The following conventions, which are consistent with conventions used for most historical test sites that preceded the 2010 ICR, were used to calculate site averages from the 2010 ICR and other recent sources.

When all individual run values were reported as above the detection or reporting limit, the site average was calculated as the arithmetic mean. For the 2010 ICR, EPA required that utilities report non-detects at the detection limit; however, in many cases, reporting limits were provided rather than detection limits. EPRI used the value as reported.

For results that included both detected and non-detected (< or BDL flag) individual runs, one-half of the reported detection limit was used to calculate the site average. For example:

Run Values	Calculation	Site Average
10, 12, <(8)	[10+12+(8/2)]/3	8.7

Where <(8) means the measurement was below the detection or reporting limit of 8.

The calculated site average was not allowed to be smaller than the largest reported detection limit value for the test series. In the example below, using one-half the detection limit value would have resulted in a site average of 2.8. This is less than the highest reported detection limit for the three runs, so the reported site average is set to the largest reported detection limit and flagged as non-detected [i.e., <(4)].

Analytical Values	Site Average
5, <(4), <(3)	<(4)

When all individual test run values for a given compound were less than the reported detection limit (all non-detects), the site average was set equal to the largest detection limit value reported.

These conventions are consistent with the methodology used in most of the major historical test programs conducted by EPRI and DOE, and used to develop the previous update of the Emission Factors Handbook in 2002. Therefore, for the most part, the same methodology for deriving site average values has been used across data sets considered in the present analyses. Exceptions to these conventions were made when developing selected emission factors as noted below:

Dioxin/Furan – For dioxin/furan, EPA Method 23 allows for substitution of zero values to calculate a total when individual congeners are not detected. Therefore, when these compounds were reported as not detected for a given individual test run, a value of zero was used in the site average calculations. If the resulting calculated site average value was smaller than the largest reported detection limit for that test series, the site average was considered a non-detect and a value of zero was used for the site in calculation of all dioxin/furan related emission factors (i.e., individual compound factors, dioxin/furan factors and dioxin/furan TEQ based factors).

Data Flag Conventions

For all data sets except the 2010 ICR, when a substance was not detected for an individual test run, the data are typically flagged as non-detect with an associated detection limit or reporting limit being reported. For the 2010 ICR, EPA requested that each test measurement be assigned one of the following flags: "BDL" (below detection limit), "DLL" (detection level limited), or "ADL" (above detection limit). The BDL flag was to be used when the compound of interest was non-detect in all fractions of a sample train; whereas the "DLL" designation was to be used when sample train fractions showed a mix of detected and non-detect values (e.g., the Method 29 filter was a quantified value and the Method 29 impinger result was a non-detect value). "ADL" was to be used when a compound was detected in all sample train fractions for a given test run. For the "BDL" designations, the final individual run emission factor value reported by respondents in EPA's 2010 ICR database was based on the sum of the detection limits for each fraction; for "DLL" it was based on the sum of detection limits (for non-detect fractions) and measured concentrations (for detected fractions).

EPRI's handling of the ICR detection flags differs from EPA's. Identical to EPA, EPRI considers individual ICR test runs flagged as "BDL" as non-detects when calculating the test site averages using conventions discussed previously. However, EPRI considered runs flagged as "DLL" as detected values in the site average calculations while EPA considers them as non-detects. The rationale for EPRI's approach is that the value of the detected fraction of a Method 29 run is generally much higher than the detection limit; it makes no sense to consider the entire sample as a non-detect. The same statements can be made for other multi-fraction methods such as those for semi-volatile organics and dioxins/furans/PCBs.

2010 ICR Data Evaluation and Cleanup

During the 2010 ICR data collection effort, EPRI conducted preliminary reviews of stack test reports that were voluntarily submitted to EPRI, comprising about half of the generating units included in the ICR. Findings of these reviews were summarized in an EPRI report published in December, 2010 [2]. A number of data quality and data reporting issues were identified that had impacts on the usability of the ICR data. EPRI provided the results of the reviews to the power plant owners, but had no authority to require that issues that were identified be corrected in their submittal to EPA. Thus, issues identified in the EPRI reviews may persist in the final EPA data compilation.

Using as a basis the final EPA ICR database (EPA MS Access® MDB files for Part I/II and Part III data dated 12/16/11), EPRI implemented data checks designed to identify and correct, to the extent possible, issues identified in the preliminary reviews conducted by EPRI in 2010. The data check included both automated checks and more detailed review of individual test reports and/or laboratory data posted in the MATS rulemaking docket or in EPA's compilation of ERT files. The general types of data checks applied to the test data from EPA's ICR database were as follows:

Missing or incorrect data flags – In many cases, ICR respondents failed to properly report data flags (BDL, DLL, ADL). If data flags were missing, an attempt was made to define the proper flag by reviewing information in the ICR database file, the test contractor report and/or original lab data where reports were available. If a missing flag could not be defined, the data were not used in emission factor development. Typographic errors in the flags were also corrected (e.g., DDL corrected to DLL).

Concentration to emission factor ratios – Many of the compounds reported to EPA in the EPA's Excel template had errors in units conversion. Proper conversion from concentration based units of measure (e.g., micrograms per dry standard cubic meter) to emission factor based units (pounds per million Btu) was checked by calculating the ratio of concentration to emission factor ratio, which should remain relatively constant for any given fuel type and across individual test runs at unit. If the calculated ratio was outside the expected range, the data were reviewed more closely to identify the problem and correct the data, where possible.

Data range checks – Data for each chemical were subject to range checks by fuel type (coal, oil, petroleum coke, etc.) to identify measurements with potential errors. Data that fell outside the expected ranges were subjected to additional review of the contractor test reports and/or laboratory data, where reports were available.

Standardization of chemical substance names – In some cases, multiple names for the same compound existed in the EPA's database. This issue was most common for organic compounds. Chemical names were standardized prior to final development of emission factors.

Missing or "zero" emission factor values – If emission values (e.g., lb/MMBtu) were missing, an attempt was made to calculate a value from the reported stack gas concentrations (e.g., µg/m3), if reported. If neither value was reported, the data were excluded from emission factor calculations. Emission factor values reported as zero were by definition excluded from emission factor calculations.

Follow-up on specific data quality comments noted in preliminary reviews – Specific data quality comments noted in the preliminary reviews conducted by EPRI in 2010 were reviewed and more detailed investigations were conducted to determine if the issue had been corrected in the final data submitted to EPA. If the issue remained, an attempt was made to correct the problem prior to using the data for emission factor development.

EPRI's more detailed review and cleanup of the ICR database for both stack emissions and fuel samples improved the quality of the information used to develop final emission factors. However, it is important to note that EPRI did not review every measurement in the ICR database but instead relied on the indicators above to identify problem values. In addition, detailed test reports and laboratory reports were not available for a substantial fraction of the ICR facilities. Thus, it is likely that many measurements incorporated into EPRI's emission factors have significant quality issues.

Data quality issues that triggered a more thorough review of selected data sets for specific compounds or classes of compounds are noted below.

Metallic contamination of Method 29 trace metals samples – EPRI performed a detailed review of potential stack gas sampling system contamination issues for selected trace metals (chromium, manganese, and nickel) and provided comments to EPA in the MATS rulemaking docket [3]. Measurements identified as having suspected contamination were excluded from the data sets used for emission factor development. In addition, seven 2010 ICR sites with suspected metallic contamination were retested in 2012 and these data were incorporated into the data set used for development of emission factors.

Acid gas stack measurements - The 2010 ICR required analysis of HCl, HF and HCN. The most significant quality issues to affect these measurements were: (1) very high detection limits for HCl and HF in some samples due to incorrect sampling and laboratory procedures, and (2) inability of testers to maintain a high pH (>12) in the HCN collection impingers due to CO_2 acidifying the alkaline impinger. A low impinger pH reduces HCN capture efficiency and causes a low bias in the results. Sites with very high detection limits for HCl and HF were excluded from emission factor calculations. Due to the high percentage of HCN tests reviewed by EPRI that suffered from issue #2, EPRI considers the overall quality of the all HCN data to be poor and therefore, an emission factor for HCN was not developed. The EPA also concluded in the final MATS rule that the HCN data were not accurate [4].

Formaldehyde stack measurements – Multiple methods were used in the ICR tests. The most significant quality issue was associated with measurements made by EPA Method 0011, the most commonly used method in the ICR tests. In the data sets reviewed by EPRI, most of the reported values were close to concentrations in the blanks. Contamination of the field blank was more common for Method 0011 than the other test methods. Therefore, associated field blank data from all of the ICR test sites, where available in the MATS rulemaking docket, were reviewed to determine how levels in the field blanks compared to reported sample results. If the field blank accounted for >50% (an arbitrary criteria) of the reported sample result, the reported values were flagged and not used in development of emission factors.

Kaplan-Meier Statistical Analysis Technique

The Kaplan-Meier (KM) technique was used to develop factors when insufficient data existed to develop % of coal emitted type factors or correlation-based factors. KM is a statistical method used for estimating median and mean values from data sets containing non-detects [i.e., below detection limit results (BDL)]. The KM procedure was developed for use in biomedical experiments (survival statistics) but has been applied to environmental measurements by many regulatory agencies (for example EPA's ProUCL software uses this approach). Traditionally, KM procedures were designed for right censored data ("greater thans"). In the case of power plant emissions, measurements result in a high proportion of left censored "less than" or non-detect values. To take advantage of the KM procedure and its ability to handle multiple detection limits, left censored data values must be converted into right censored data by subtracting all detected values from a high constant value. The new right censored detected values are then ranked from lowest to highest, and their percentiles in the distribution are computed. The percentile computation takes the non-detect censored values into account for every detected value. In general, the KM median value, where available, is expected to provide the best estimate (most probable) emission factor from an individual untested unit using data from similar, tested units.

The KM procedure is described in detail elsewhere; however the calculations can be performed using the open-source software "R" [5, 6];. A routine was developed by EPRI to analyze various combinations of the emission factors that do not exhibit correlations (e.g., organic substances, oil and gas plant emissions).

The general principle behind the KM method is that quantified values (ADL data), and results that are below detection (BDL data) are used to estimate a median or mean value for the data set. KM computes a percentile for every unique ADL value. For example, with a dataset of 5 values

(<1, <2, 5, 7, and 10), the KM median equals 5; the position of the non-detects is incorporated when computing the percentiles of the detected values. The data and percentile probabilities for the ADL data make up the Kaplan-Meier survival function. When plotted, this function looks like a step-wise curve, with ADL values on the x-axis and Kaplan-Meier percentiles ("survival probabilities") on the y-axis. The area under that curve is the KM mean, and this represents that sum of the products of the proportion of data for each value times the magnitude of that observation's value. The KM standard deviation is similarly computed using the Kaplan-Meier survival function. The KM median is intersection of the 50% probability value on the y-axis with its corresponding x-axis value.

For the KM median, if more than 50% of the data are below the lowest reporting limit, the median cannot be estimated via the Kaplan-Meier survival function (no intersection line to draw). Thus, the KM median defaults to <RL, where RL is the reporting limit. The KM algorithm in the R software script used to conduct the KM analyses leaves this value as missing ("NA"). In this case, the KM mean is the only value that can be obtained using the KM technique. Figure B-1 is an example of the survival function plot for a specific data set having more than 50% BDL values. As shown, the curve (solid line) does not cross the 50th percentile; therefore a median cannot be estimated as anything other than <RL.

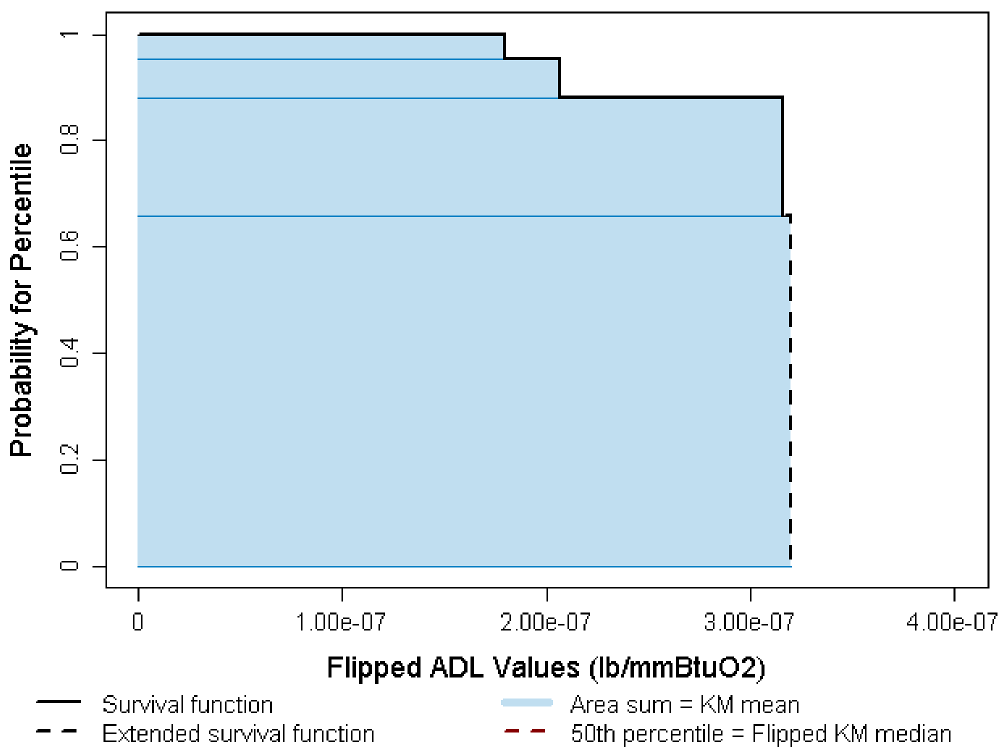


Figure B-1
Example of Kaplan-Meier Survivor Function for Data Set with >50% BDL Values Where a KM Median Cannot be Estimated

For compound data sets with only 1 to 6 detected values, the KM procedure is not applicable, regardless of the total number of site tested. In these cases, the emission factor was calculated as the conventional median of the all the site average values after the high non-detect values (e.g., BDL values greater than the highest detected value) were removed from the data set. BDL values were set equal to the detection limit in the conventional median calculation. Emission Factor Rating Criteria

Each reported emission factor value has been assigned a rating based on a combination of two indicators:

1. The percentage of detected values in the data set used to calculate the factor (% ADL); and
2. The number of sites used to develop the emission factor (sited used).

"Sites used" is defined as the number of test site averages remaining in the data set after the high non-detect values (BDL values higher than the largest detected value) have been removed.

The criteria used to rate emission factors for coal-fired units are shown in Table B-2. These criteria are depicted in Figure B-2 for emission factors that were developed using the KM or simple median approach. Each data point in the figure represents the data set for an individual chemical species. Both organic and inorganic species are included.

Table B-2
Emission Factor Rating Criteria for Coal-Fired Units

Rating	Criteria
A	> 50% ADL and > 50 sites used
B	10 to <50% ADL and > 20 sites used, or > 50% ADL and 20 to <50 sites used
C	5 to <10% ADL and > 5 sites used, or > 10% ADL and 5 to <20 sites used
D	< 5% ADL or < 5 sites used
E	No detected values

A to C rated factors were included in the body of EPRI's 2014 Emission Factors Handbook report as recommended factors. D rated factors were provided in Appendix B of the 2014 Handbook report ; however, because they are based on less than 5 sites or the chemical was detected only sporadically (defined for this report as less than 5% of the usable values above detection or reporting limits), D-rated factors are considered to be not representative of emissions from the U.S. power fleet. Users will need to evaluate the use of D rated factors on a case-by-case basis, depending on their specific application. Emission factors were not developed for E rated compounds (measured but never detected).

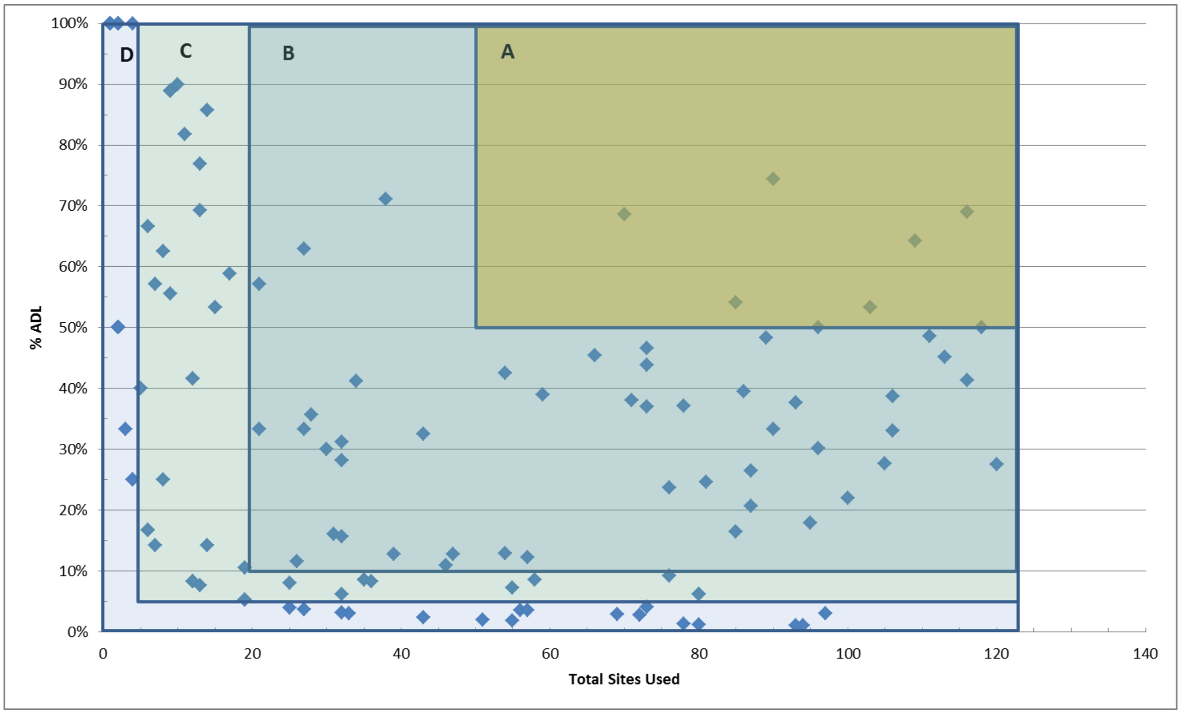


Figure B-2
Emission Factor Ratings for Coal-Fired Boilers

Data Limitations

Although EPRI attempted to improve the quality of the overall ICR data set prior to use in development of emission factors, it is important to note areas where data limitations still exist. Several of these limitations are discussed in more detail in EPRI's ICR data quality review from 2010 [2]. Highlights are provided below.

Volatile Organic Compounds (VOC) and Semi-Volatile Organic Compounds (SVOC)

EPRI's preliminary review of selected ICR data sets in 2010 indicated the following issues for VOC compounds:

Elevated field blanks – It is common for certain VOCs to be found in samples as contaminants from the sampling or analytical process. Methylene chloride is used as a recovery solvent in other stack test methods, and was frequently present in the ICR field blanks at very high levels. Toluene is used as a recovery solvent in EPA Method 23 and was also detected in several VOC field blanks. These findings are indicative of contamination of the samples at some point in the sampling, shipping, or analytical process. Not all data sets reviewed by EPRI reported field blanks; thus, the frequency of contamination could not be determined. In addition, since many contractors do not uncap field blank tubes while in the field, a negative result in the field blanks does not rule out cross-contamination from solvents used in the field. Thus, it is not always possible to determine if detection is due to contamination. All detections of these chemicals are suspect, as sample values are likely to be biased high due to contamination.

Laboratory contamination – In one case, EPRI did omit VOC data due to excessive contamination of samples. Samples tested during the 2010 ICR by one laboratory, RTP Laboratories, showed a pattern of extremely high levels of acetone, methylene chloride, dioxane, and many other solvents. The high VOCs were observed in samples collected by multiple stack testers at different types of power plants (coal, oil, IGCC). EPRI suspects laboratory contamination and accordingly discarded all VOC results from that laboratory.

Suspected artifacts – A large number of VOCs have been reported to be produced from breakdown of the Tenax® sorbent after exposure to oxidants such as ozone, NO_x and molecular halogens [7 - 12]. In addition, the EPA [13] in their 1994 data usability guidance for risk assessments identified many VOCs that are ubiquitous in laboratory environments and must be considered as potential artifacts.

Table B-3 lists chemicals that have been reported in the above-referenced sources as artifacts of VOC sampling and analysis procedures or as laboratory contaminants and that were reported one or more times in the EPRI data compilation used for this report. Chemicals that are potential artifacts are noted in the various emission factor tables of this report but have not been omitted or corrected for blank concentrations.

Table B-3
Summary of Reported VOC Artifacts

Artifact	Reference
1, 2-Dibromoethane	8
1,2-Dichloroethane	8
2-Hexanone	10
Acetone	15
Acetophenone	10,9
Benzaldehyde a	10,9
Benzene	13
Benzoic acid	9
Bromoform (Tribromomethane)	8
Bromomethane	13
Chlorobenzene	8
Chloroform (Trichloromethane)	8
Chloromethane	13
Dichlorobenzenes (1,3- and 1,4- isomers)	8
Dichloromethane (Methylene chloride)	15
Freons (Dichlorodifluoromethane and Trichlorofluoromethane)	15
Hexanes	15
Phenol	9
Toluene	15

[a] This compound was not sampled as part of the 2010 ICR. Historical data used in the development of emission factors for this compound were not obtained using Method 0031 or similar Tenax-based methods; therefore, emission factors were not flagged in the report tables as having the issue of potential Tenax® resin artifacts.

The VOC method used in the ICR, EPA Method 0031 [14], lists chemicals that are not appropriate to analyze by that method due to high volatility, reactivity or water solubility; chemicals from this list that were measured at EGUs are shown in Table B-4. Emission factors were not calculated for compounds shown in Table B-4, regardless of the number of measured values.

Table B-4
Compounds for Which VOC Method 0031 is Not Applicable

Artifact
Allyl chloride (3-Chloropropene)
Acetone
2-Butanone (Methyl ethyl ketone)
Chloroethane
Chloromethyl methyl ether
Acetonitrile
Acetaldehyde [a]
Acrolein [a]
2-Propanol (Isopropyl alcohol)
Bromomethane
Chloroethane
Vinyl chloride

[a] This compound was not sampled as part of the 2010 ICR. Historical data used in the development of emission factors for this compound were not obtained using Method 0031 or similar Tenax-based methods; therefore, emission factors were calculated and reported for this compound where sufficient data were available.

EPRI's preliminary review of selected ICR data sets in 2010 indicated the following issues for SVOC compounds.

Elevated field blanks – EPRI's reviews of the SVOC data noted the detection of some chemicals in the field blanks at levels that could imply a possible positive bias to the associated samples. Commonly detected compounds in the field blanks included benzoic acid, bis(2-ethylhexyl)phthalate, and polycyclic aromatic hydrocarbons (PAHs). Not all data sets reviewed by EPRI reported field blanks. In addition, since many contractors do not uncap field blank tubes while in the field, a negative result in the field blanks does not rule out contamination. Thus, it is not always possible to determine if detection in a sample is due to contamination.

Suspected artifacts – SVOCs have been reported to be produced from breakdown of the XAD-2 sorbent after exposure to oxidants such as ozone, NO_x and molecular halogens [15]. Since the preliminary review of ICR data, EPRI has compiled a list of SVOC artifacts that have been reported in the literature and measured at EGUs as shown in Table B-5. It is possible that some SVOCs detected in the ICR samples originated from reactions between the hot stack gas and components of the sampling train. Potential artifacts have been noted with an asterisk in the emission factor tables of this report but test results were not corrected based on this information.

Table B-5
Summary of Reported SVOC Artifacts for XAD-2 Resin Sampling Media

Artifact
2-Methylnaphthalene
Benzoic acid
Biphenyl
Bis-2-ethylhexyl phthalate [13]
Butylbenzylphthalate [13]
Dibutylphthalate [13, 15]
Diethylphthalate [13, 15]
Dimethylphthalate [13]
Di-n-butyl phthalate [13]
Di-n-octyl phthalate [13]
2,4-Dinitrotoluene
Napthalene
2-Nitrophenol
4-Nitrophenol
Styrene

Source: Reference 15 unless noted.

The level of effort required to perform a comprehensive review of artifacts and background levels in blanks for every one of the hundreds of VOC and SVOC compound reported in the 2010 ICR data set would have been prohibitive. In addition, that type of evaluation requires access to the detailed laboratory reports, which were often not provided or were not accessible in the EPA docket files or in the ERT files that were posted to the EPA's MATS ICR web site. Therefore, such issues remain in the data set used by EPRI, and emission factors for the VOC and SVOC compounds noted above, as well as possibly other compounds, are likely biased high.

Significant Background Contamination for Dioxin/furan Compounds

Background contamination – Dioxins and furans are ubiquitous in the environment. They can be formed during combustion of any carbon-containing fuel, in the presence of chlorine and when the temperature and other factors are conducive. The test method is so sensitive that some laboratories report dioxin/furan congeners in method blanks on a routine basis. Insufficient cleaning of sample trains is a frequent cause of sample contamination. An EPRI study found that is possible to eliminate most, if not all, spurious detections of dioxin/furans by pre-proofing reagents, pre-cleaning and certifying sorbents, using carefully cleaned equipment, and employing careful sampling practices [16]. However, it is unlikely that many of the ICR tests were conducted using these extra quality control measures, due to the extra expense and the compressed timeframe of the ICR sampling period.

Many of the ICR dioxin/furan tests reviewed by EPRI in 2010 had detectable levels in the method or field blanks. In some cases, the amounts observed in the blanks were similar to those in the samples, indicating that the emissions for that unit are due to contamination of the sample. As not all ICR tests reported method or field blanks in their documentation, it was not always possible for EPRI to evaluate the contribution of background contamination to the sample. The presence of background contamination will bias emissions high. In addition, laboratory reports were often not available for ICR sites. Therefore, no attempt was to made to remove sites from the data set based on background contamination.

Detection Limits for Nondetect Data

The detection or reporting limits in the EPA's ICR database were used at the starting point for EPRI's development of emission factors. However, EPRI noted several problems with detection limit reporting that represent a limitation inherent to many data sets used for development of emission factors.

Basis of detection limit was not provided — Very few ICR data packages provided sufficient detail on the detection or reporting limit used for nondetected emissions for EPRI to determine if there were equivalent bases for different reports. The method used to derive the detection limit was rarely stated in the ERT submissions or emissions spreadsheet. In some cases, an explanation was included in the stack test report, but more often the information was simply not provided. EPRI routinely noted the lack of documentation in preliminary ICR data reviews.

Bases of detection limits were not consistent — Where the basis was provided, many nondetect values were not "analytical detection limits", as required by EPA for the ICR. EPRI assumes that EPA's definition of an analytical detection limit is a method detection limit (MDL), developed following the procedure in CFR Part 136, Appendix B. However, this procedure cannot be applied to some of the ICR methods that will not accommodate replicate analysis (i.e., direct-reading methods). Many of the "nondetect" values reported by laboratories were stated to be reporting limits, which represent the laboratory's best estimate of the lowest concentration that can be measured accurately in a particular sample matrix. A reporting limit is always higher than the method detection limit, but there is no set procedure for determining a reporting limit — it differs from one laboratory to the next.

Chlorine(Cl2) by Method 26/26A

As a late addition to the requirements of the 2010 ICR, EPA required stack testers to measure Cl_2 using EPA Method 26A. At the time this requirement was added, many facilities had already completed or contracted for ICR testing and did not perform this test; only a small subset of ICR facilities reported Cl_2 results. In general, EPA Method 26A (isokinetic) or Method 26 (non-isokinetic) was used to collect stack gas samples for HCl and Cl_2 emissions. These methods use a dilute sulfuric acid solution to collect HCl, followed by a dilute sodium hydroxide solution to capture Cl_2. In some of the ICR tests, the concentration of the sodium hydroxide solution was increased in an attempt to raise the pH of the solution and simultaneously capture hydrogen cyanide.

Method 26/26A has not been used as extensively for Cl_2 measurement as for HCl. Some published studies have identified systematic biases in the method that could potentially lead to Cl_2 being measured as HCl under some flue gas conditions [17]. EPRI is investigating the accuracy of these test methods, but results of our study are not available at this time.

An initial review of currently available Cl_2 measurements revealed some suspect results, as some of the reported HCl values were identical to the Cl_2 values. Available data were reviewed for likely sources of error involving the sampling approach, laboratory analysis by ion chromatography, and the calculation and reporting of results. The resulting modified data set was then used to examine possible emission factor approaches; these emission factors will updated by EPRI when results of the Method 26/26A study are completed.

Summary of Data Review Findings - The following observations were made in EPRI's data quality review that in some cases led to eliminating data from emission factor calculations, and in other cases indicate that there may be a positive bias in Cl_2 measurements.

- One 2010 ICR sampling contractor modified the Method 26/26A sampling approach by eliminating the sulfuric acid impinger solution fraction, attempting to collect both HCl and Cl_2 in the sodium hydroxide impinger solution (ORIS No: 1374 - Units 001 and 002, ORIS No. 4125 - Unit B-09, ORIS No. 50951 - Unit Config1, and ORIS No. 976 - Unit 123). Without the sulfuric acid absorbing solution preceding the sodium hydroxide impingers, separation of HCl and Cl_2 is impossible as both substances are measured by ion chromatography as chloride. The same laboratory result for total chloride was erroneously reported to EPA as both HCl and Cl_2. Because historical data indicates that Cl_2 emissions are typically much lower than HCl, EPRI used these values in calculating HCl emissions, but omitted them from the Cl_2 emissions factor calculations.
- EPRI obtained and reviewed detailed laboratory records of instrumental analysis of the sodium hydroxide solutions from several ICR test sites analyzed at two commercial laboratories. At the first lab, ion chromatograms were available in the EPA's electronic files from three of the five sites listed above (ORIS No: 1374 - Units 001 and 002, and ORIS No. 976 - Unit 123). In these analyses, the chloride peak integration includes the area from a matrix artifact peak that co-elutes with chloride. The interfering peak appears to be related to the sample's concentration of bicarbonate/carbonate that exceeds the strength of the chromatography eluent. The presence of carbonates in the sample is from the reaction of flue gas carbon dioxide with the sodium hydroxide impinger solution.
- EPRI also requested and received a data package from a second laboratory, which performed the analytical work for many of the ICR sites reporting Cl_2 results. All samples reviewed were diluted by a factor of approximately 4x to 6x. The dilution rendered the chloride and carbonate peaks indistinguishable, making separation and integration of the chloride component impossible. In both of these cases, co-integration of the carbonate interference may produce a high bias in the reported Cl_2 result. Since EPRI had access to only a small subset of the Cl_2 test laboratory packages, we cannot determine the extent to which ion chromatography problems may have biased the results. The interferences associated with the ion chromatography analysis of the sodium hydroxide impinger solutions may be widely varied based on the type of separation column and eluent used, the strength of the sodium hydroxide solution and the sample dilution, and the experience of the analyst in making appropriate determinations related to peak identification and area integration.

In conclusion, there may potentially be both negative biases [17] and positive biases in the Cl_2 results (as indicated by the ion chromatography results).

Screened Measurements – A limited number of tests for chlorine were conducted at coal-fired plants during the 2010 ICR, and there are also some pre-2010 measurements available from various sources. EPRI determined that some of these measurements suffered from serious data quality issues as noted above; however, when those were omitted, there were some data available for evaluation.

Theoretical calculations conducted by Niksa for EPRI indicate that Cl_2 can form from HCl as the flue gas cools from about 1900 to 1100°F [18]. Gas-phase reactions were determined to be too slow to produce Cl_2 under these conditions; however, the modeling indicated that heterogeneous reactions of HCl adsorbed to unburned carbon can lead to Cl_2 formation. The rate constants for this reaction have not been established. These calculations lend credence to analytical measurements from both the 2010 ICR and historical test sites.

The measured values are typically a very low percentage of the coal chloride quantity. And, in many instances uncovered during data reviews, the sampling and/or analytical procedures used were improper or incompatible. However, sufficient sets of data have been conducted per the stated method, based on EPRI current knowledge of the sampling and analytical methods, to provide a basis for preliminary estimates of emissions from three groups of coal fired plants. Emission factors presented here may be updated in the future based on this on-going EPRI research. The currently available data sets used are plotted in Figure B-3 below. Power fit correlations of the coal chloride concentration versus emissions were developed for bituminous coal units with ESPs, and for those with FGD systems. Passing flue gas through a second control device probably helps consume some of the oxidant, thereby lowering emissions. Although all of the test data is from wet FGD systems, it is probable that dry FGD systems would have similar effectiveness. The other data sets show no discernible trend and a combined KM-median value has been calculated for all other types of systems (subbituminous and lignite coals). Table B-6 provides the correlation coefficients and statistics. Table B-7 provides the statistics for the KM factor.

Only a single site firing 100% petroleum coke was analyzed for chlorine (Cl_2) as part of the 2010 ICR. The measured value from this one site was approximately 4,000 lb/TBtu.

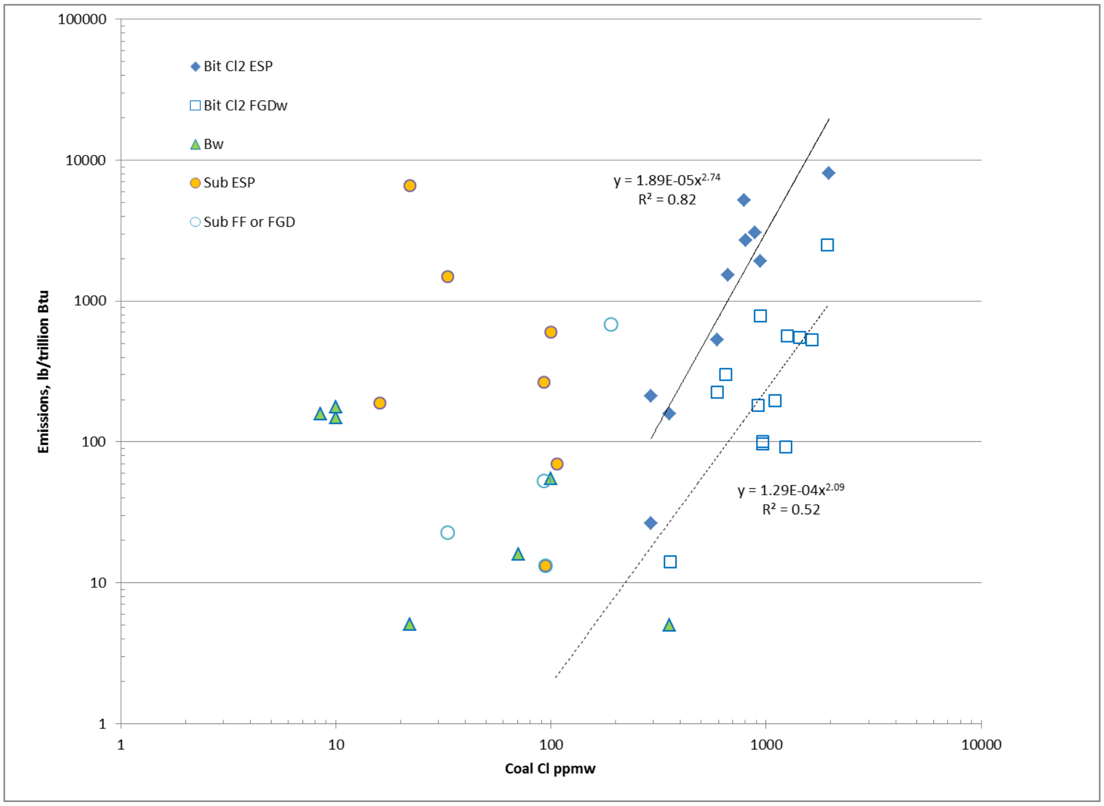


Figure B-3
Coal Cl vs. Cl_2 Emissions

Table B-6
Chlorine (Cl_2) Emission Correlations for Bituminous Coal (lb/trillion Btu) vs. Coal Cl (ppmw)

Control	A	b	N pairs	r2	P value
ESP	1.89E-05	2.74	10	0.82	3.00E-04
FGD	1.29E-04	2.09	14	0.52	3.60E-03

Table B-7
Chlorine (Cl_2) Emission Factor for Subbituminous (Sub), Western Bituminous (Bw), and Lignite Coals (lb/trillion Btu)

CAS	Sites Tested	Sites Detected	Sites Used	Emission Factor	Emission Factor Method
7782-50-5	19	12	19	53	KM Median

References

1. Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI, Palo Alto, CA: 2002. 1005402.
2. Data Quality Evaluation of Hazardous Air Pollutants Measurements for the US Environmental Protection Agency's Electric Utility Steam Generating Units Information Collection Request. EPRI, Palo Alto, CA: 2010. 1021216.
3. EPRI Comments Concerning Select Technical Aspects of the U.S. EPA "Mercury and Air Toxics Substances" (MATS) Rule. April 13, 2012; EPA docket document EPA-HQ-OAR-2009-0234-17621.
4. U.S. Code of Federal Regulations. 40 CFR Parts 60 and 63. Vol. 77, No. 32. pp 9304 to 9513.
5. Helsel, Dennis R. "More Than Obvious: Better Methods for Interpreting Non-Detect Data." Environmental Science and Technology, October 15, 2005.
6. Helsel, Dennis R. Statistics for Censored Environmental Data Using Minitab and R, Second Edition. 2012 John Wiley & Sons, Inc. Published 2012 by John Wiley & Sons, Inc.
7. Pellizzari, E.D., and K.J. Krost, Chemical Transformations during Ambient Air Sampling for Organic Vapors. Anal. Chem. 1984, v. 56, pp.1813-1819.
8. Kleno, J.G., et al. Degradation of the Adsorbent Tenax TA by Nitrogen Oxides, Ozone, Hydrogen Peroxide, OH Radical, and Limonene Oxidation Products. Environ. Sci. Technol. 2002, v. 36, pp. 4121-4126.
9. Lee, J.H. et al. Ozone Artifacts and Carbonyl Measurements Using Tenax GR, Tenax TA, Carbopack B, and Carbopack X Adsorbents. J. Air & Waste Manage. Assoc., 2006, v. 56, pp. 1503–1517.
10. Bowyer, J.R.; Pleil, J.D. Supercritical Fluid Extraction as a Means of Cleaning and Desorbing Common Air Sampling Sorbents; Chemosphere 1995, 31, 2905-2918.
11. Clausen, P.A.; Wolkoff, P. Degradation Products of Tenax TA Formed during Sampling and Thermal Desorption Analysis: Indicators of Reactive Species Indoors; Atmos. Environ. 1997, 31, 715-725.
12. http://www.testamericainc.com/services/source-air-testing/test-methods/method-0030method-0031-for-volatile-organics-in-stack-gas-emissions/method-0030_0031-fundamentals.aspx
13. Guidance for Data Usability. Appendix XII. Summary of Common Laboratory Contaminants, Concentration Requirements and Risk Assessment Implications. EPA Office of Solid Waste and Emergency Response (OSWER). 1992. *www.epa.gov/oswer/riskassessment/datause/pdf/parta_14.pdf*
14. EPA. METHOD 0031. SAMPLING METHOD FOR VOLATILE ORGANIC COMPOUNDS (SMVOC). www.epa.gov/osw/hazard/testmethods/sw846/pdfs/0031.pdf *1996.*
15. Middleditch, B. Analytical Artifacts: GC, MS, HPLC, TLC and PC. 1989. Out of print. books.google.com/books?isbn=008085849X

16. EPRI. Improvements in Stack Test Methods for PCDDs and PCDFs: Field Tests at a Coal-Fired Power Plant, EPRI, Palo Alto, CA. 1005403. 2004.

17. Sun, J.Q, et. al. The Effect of Coal Combustion Flue Gas Components on Low-Level Chlorine Speciation Using EPA Method 26A. ISSN 1047-3289 J. Air & Waste Manage. Assoc., June 2000, **50**:936-940.

18. Estimates For Cl_2 Stack Emissions, Niksa Energy Associates LLC 1745 Terrace Drive, Belmont, CA 94002. Prepared for EPRI, June 12, 2013.

C
FILTERABLE PARTICULATE AND TOTAL MERCURY EMISSION VALUES USED FOR EMISSION ESTIMATES

Table C-1 summarizes the filterable particulate matter (FPM) values obtained from 2014 EIA 860 sources as well as the final FPM values selected for each unit and used as inputs for estimating particulate phase metals emissions using the EPRI correlations. Where EIA FPM values exceeded the MATS FPM limit of 0.03 lb/MMBtu for existing coal-fired units, the MATS limit of 0.03 lb/MMBtu was generally assigned or data from sister units with similar controls were used. In cases where 2014 EIA FPM values were reported as zero or a value was not reported, other sources of information were used to select an appropriate FPM value as noted in Table C-1 or the default value was assigned.

This table also documents the final total mercury values used to estimate emissions for each unit. Seven months of hourly data from EPA's Air Markets Program Data (AMPD) files were utilized (September 2015 through March 2016), for those units reporting. The variables extracted from the AMPD file were the boiler identification fields, the operating date and hour, gross load, heat input, and mercury (Hg) mass emissions. It should be noted that those lines of hourly data, which did not report either heat or emissions data, were omitted. The unit emission rate was calculated by dividing the total Hg mass emissions by the total heat for the seven-month period. AMPD data were available for approximately 240 units. AMPD values were used when they were at or below the existing unit MATS limits (non-lignite = 1.2 lb/TBtu and lignite = 4 lb/TBtu). When AMPD data were not available, default average values of 0.5 lb/TBtu (non-lignite) or 2.5 lb/TBtu (lignite) were assigned. The 0.5 lb/TBtu and 2.5 lb/TBtu default values were derived from the data for approximately 240 units with total mercury measurement data in the AMPD database based on the average of reported data for units in each fuel group. For 100% petroleum coke-fired units, EPRI's KM-based total mercury factor of 0.08 lb/TBtu was used.

Table C-1
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1001#1	CAYUGA 1	0.01	0.01	2014 EIA	0.41	0.41	AMPD Actual
1001#2	CAYUGA 2	0.01	0.01	2014 EIA	0.53	0.53	AMPD Actual
1004#HRSG1	EDWARDSPORT IGCC		0.001	WebFIRE		0.50	0.5 default (non-Lig)
1004#HRSG2	EDWARDSPORT IGCC		0.001	WebFIRE		0.50	0.5 default (non-Lig)
10043#B01	Logan Generating Plant	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10075#1	TACONITE HARBOR ENERGY CENTER	0.03	0.03	2014 EIA	0.784693	0.78	AMPD Actual
10075#2	TACONITE HARBOR ENERGY CENTER	0.03	0.03	2014 EIA	0.684967	0.68	AMPD Actual
1008#2	GALLAGHER 2	0.01	0.01	2014 EIA	0.03	0.03	AMPD Actual
1008#4	GALLAGHER 4	0.01	0.01	2014 EIA	0.05	0.05	AMPD Actual
10113#CFB1	John B Rich Memorial Power Station	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10113#CFB2	John B Rich Memorial Power Station	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1012#2	CULLEY 2	0.02	0.02	2014 EIA	0.53015	0.53	AMPD Actual
1012#3	CULLEY 3	0.01	0.01	2014 EIA	0.61474	0.61	AMPD Actual
10143#ABB01	Colver Power Project	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10151#BLR1A	Grant Town Power Plant	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10151#BLR1B	Grant Town Power Plant	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10343#SG-101	MT. CARMEL	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10377#1A	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
10377#1B	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10377#1C	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10377#2A	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10377#2B	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10377#2C	James River Cogeneration	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#1A	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#1B	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#1C	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#2A	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#2B	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10378#2C	Primary Energy Southport	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10379#1A	Primary Energy Roxboro	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10379#1B	Primary Energy Roxboro	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10379#1C	Primary Energy Roxboro	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10380#A BLR	Elizabethtown		0.0143	2010 Modeling		0.50	0.5 default (non-Lig)
10380#B BLR	Elizabethtown		0.0143	2010 Modeling		0.50	0.5 default (non-Lig)
10384#1A	Edgecombe Genco LLC	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10384#1B	Edgecombe Genco LLC	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10384#2A	Edgecombe Genco LLC	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10384#2B	Edgecombe Genco LLC	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1040#1	WHITEWATER VALLEY 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1040#2	WHITEWATER VALLEY 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1047#4	LANSING 4	0.03	0.03	2014 EIA	0.49113	0.49	AMPD Actual
10495#6	Rumford Cogeneration	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
10495#7	Rumford Cogeneration	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
10566#BOIL1	Chambers Cogeneration LP (Carney's Point)	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10566#BOIL2	Chambers Cogeneration LP (Carney's Point)	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10603#31	Ebensburg Power Co	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10641#B1	Cambria Cogen	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10641#B2	Cambria Cogen	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10671#1A	AES Shady Point Inc	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10671#1B	AES Shady Point Inc	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10671#2A	AES Shady Point Inc	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10671#2B	AES Shady Point Inc	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
10672#1A	Cedar Bay Generating Co LP	0	0.005	WebFIRE		0.50	0.5 default (non-Lig)
10672#1B	Cedar Bay Generating Co LP	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10672#1C	Cedar Bay Generating Co LP	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10673#A	AES HAWAII	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10673#B	AES HAWAII	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
10678#BLR1	AES Warrior Run Cogeneration Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1073#3	PRAIRIE CREEK 3	0.09	0.03	0.03 default	0.31961	0.32	AMPD Actual
1073#4	PRAIRIE CREEK 4	0.02	0.02	2014 EIA	0.29375	0.29	AMPD Actual
10743#CFB1	Morgantown Energy Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10743#CFB2	Morgantown Energy Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
10768#CFB	Rio Bravo Jasmin	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
10769#CFB	Rio Bravo Poso	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
10784#BLR1	Colstrip Energy LP	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
108#SGU1	HOLCOMB 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1082#3	COUNCIL BLUFFS 3 (SCOTT ENERGY CENTER)	0.02	0.02	2014 EIA	0.75686	0.76	AMPD Actual
1082#4	COUNCIL BLUFFS 4 (SCOTT ENERGY CENTER)	0.01	0.01	2014 EIA	0.45702	0.46	AMPD Actual
10849#BLR1	SILVER BAY POWER	0.07	0.03	0.03 default		0.50	0.5 default (non-Lig)
10849#BLR2	SILVER BAY POWER	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1091#3	GEORGE NEAL 3	0.01	0.01	2014 EIA	0.23289	0.23	AMPD Actual
1104#1	BURLINGTON (IA) 1	0.04	0.03	0.03 default	0.49265	0.49	AMPD Actual
113#1	CHOLLA 1	0	0.01	Sister Unit 2014 EIA		0.50	0.5 default (non-Lig)
113#3	CHOLLA 3	0	0.02	Sister Unit 2014 EIA		0.50	0.5 default (non-Lig)
113#4	CHOLLA 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1131#7	STREETER 7	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
1167#8	MUSCATINE 8	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1167#9	MUSCATINE 9	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1241#1	LA CYGNE 1	0.12	0.03	0.03 default		0.50	0.5 default (non-Lig)
1241#2	LA CYGNE 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1250#4	LAWRENCE (KS) 4	0	0.03	2010 Modeling		0.50	0.5 default (non-Lig)
1250#5	LAWRENCE (KS) 5	0	0.03	0.03 default		0.50	0.5 default (non-Lig)
1252#9	TECUMSEH 7	0	0.03	0.03 default		0.50	0.5 default (non-Lig)
127#1	OKLAUNION 1	0.02	0.02	2014 EIA	0.42463	0.42	AMPD Actual
130#1	CROSS 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
130#2	CROSS 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
130#3	CROSS 3	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
130#4	CROSS 4	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
1355#1	EW BROWN 1	0.07	0.006	Utility info		0.50	0.5 default (non-Lig)
1355#2	EW BROWN 2	0.07	0.006	Utility info		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1355#3	EW BROWN 3	0.07	0.006	Utility info		0.50	0.5 default (non-Lig)
1356#1	GHENT 1	0.04	0.005	Utility info	0.05975	0.06	AMPD Actual
1356#2	GHENT 2	0.04	0.005	Utility info		0.50	0.5 default (non-Lig)
1356#3	GHENT 3	0.03	0.005	2014 EIA		0.50	0.5 default (non-Lig)
1356#4	GHENT 4	0.04	0.008	Utility info	0.27864	0.28	AMPD Actual
136#1	SEMINOLE (FL) 1	0.02	0.02	2014 EIA	0.89053	0.89	AMPD Actual
136#2	SEMINOLE (FL) 2	0.02	0.02	2014 EIA	0.48224	0.48	AMPD Actual
1364#1	MILL CREEK (KY) 1	0.04	0.005	Utility info		0.50	0.5 default (non-Lig)
1364#2	MILL CREEK (KY) 2	0.04	0.005	Utility info		0.50	0.5 default (non-Lig)
1364#3	MILL CREEK (KY) 3	0.05	0.010	Utility info		0.50	0.5 default (non-Lig)
1364#4	MILL CREEK (KY) 4	0.04	0.005	Utility info		0.50	0.5 default (non-Lig)
1374#1	ELMER SMITH 1	0.07	0.03	0.03 default		0.50	0.5 default (non-Lig)
1374#2	ELMER SMITH 2	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
1378#1	PARADISE 1	0.07	0.03	0.03 default	0.669959	0.67	AMPD Actual
1378#2	PARADISE 2	0.05	0.03	0.03 default	0.708601	0.71	AMPD Actual
1378#3	PARADISE 3	0.01	0.01	2014 EIA	0.27728	0.28	AMPD Actual
1379#1	SHAWNEE (KY) 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#2	SHAWNEE (KY) 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#3	SHAWNEE (KY) 3	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#4	SHAWNEE (KY) 4	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1379#5	SHAWNEE (KY) 5	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#6	SHAWNEE (KY) 6	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#7	SHAWNEE (KY) 7	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#8	SHAWNEE (KY) 8	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1379#9	SHAWNEE (KY) 9	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1381#C1	COLEMAN (KY) 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1381#C2	COLEMAN (KY) 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1381#C3	COLEMAN (KY) 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1382#H1	HENDERSON TWO 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1382#H2	HENDERSON TWO 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1384#1	JS COOPER 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1384#2	JS COOPER 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1393#1A	R S Nelson 1	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
1393#2A	R S Nelson 2	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
1393#6	RS NELSON 6	0.07	0.03	0.03 default		0.50	0.5 default (non-Lig)
1552#1	CP CRANE 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1552#2	CP CRANE 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1554#2	HA WAGNER 2	0.01	0.01	2014 EIA	0.04969	0.05	AMPD Actual
1554#3	HA WAGNER 3	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1571#1	CHALK POINT 1	0	0.003	WebFIRE	0.0899	0.09	AMPD Actual
1571#2	CHALK POINT 2	0	0.003	WebFIRE	0.106	0.11	AMPD Actual
1572#1	DICKERSON 1	0.01	0.01	2014 EIA	0.57328	0.57	AMPD Actual
1572#2	DICKERSON 2	0.01	0.01	2014 EIA	0.4873	0.49	AMPD Actual
1572#3	DICKERSON 3	0.01	0.01	2014 EIA	0.56968	0.57	AMPD Actual
1573#1	MORGANTOWN 1	0.01	0.01	2014 EIA	0.08374	0.08	AMPD Actual
1573#2	MORGANTOWN 2	0.01	0.01	2014 EIA	0.19349	0.19	AMPD Actual
160#2	APACHE 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
160#3	APACHE 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1606#1	MOUNT TOM 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1619#1	BRAYTON POINT 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1619#2	BRAYTON POINT 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1619#3	BRAYTON POINT 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
165#1	GRDA 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
165#2	GRDA 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1702#1	DE KARN 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1702#2	DE KARN 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1710#1	JH CAMPBELL 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1710#2	JH CAMPBELL 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1710#3	JH CAMPBELL 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1733#1	MONROE (MI) 1	0.12	0.03	0.03 default		0.50	0.5 default (non-Lig)
1733#2	MONROE (MI) 2	0.12	0.03	0.03 default		0.50	0.5 default (non-Lig)
1733#3	MONROE (MI) 3	0.12	0.03	0.03 default		0.50	0.5 default (non-Lig)
1733#4	MONROE (MI) 4	0.12	0.03	0.03 default		0.50	0.5 default (non-Lig)
1740#3	RIVER ROUGE 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1743#1	ST CLAIR 1	0.17	0.03	0.03 default		0.50	0.5 default (non-Lig)
1743#2	ST CLAIR 2	0.17	0.03	0.03 default		0.50	0.5 default (non-Lig)
1743#3	ST CLAIR 3	0.17	0.03	0.03 default		0.50	0.5 default (non-Lig)
1743#4	ST CLAIR 4	0.17	0.03	0.03 default		0.50	0.5 default (non-Lig)
1743#6	ST CLAIR 6	0.15	0.03	0.03 default		0.50	0.5 default (non-Lig)
1743#7	ST CLAIR 7	0.15	0.03	0.03 default		0.50	0.5 default (non-Lig)
1745#9A	TRENTON CHANNEL 9	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1769#5	PRESQUE ISLE 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1769#6	PRESQUE ISLE 6	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1769#7	PRESQUE ISLE 7	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1769#8	PRESQUE ISLE 8	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1769#9	PRESQUE ISLE 9	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1825#3	JB SIMS 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1831#4	ECKERT 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1831#5	ECKERT 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
1831#6	ECKERT 6	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1832#1	ERICKSON 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1843#3	SHIRAS 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
1866#8	WYANDOTTE 7	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
1893#1	CLAY BOSWELL 1	0.015	0.015	2014 EIA		0.50	0.5 default (non-Lig)
1893#2	CLAY BOSWELL 2	0.015	0.015	2014 EIA		0.50	0.5 default (non-Lig)
1893#3	CLAY BOSWELL 3	0.015	0.015	2014 EIA	0.233303	0.23	AMPD Actual
1893#4	CLAY BOSWELL 4	0.015	0.015	2014 EIA	4.315109	0.50	0.5 default (non-Lig)
1915#1	ALLEN S KING 1	0.01	0.01	2014 EIA	0.58143	0.58	AMPD Actual
1943#2	HOOT LAKE 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
1943#3	HOOT LAKE 3	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
207#1	ST JOHNS RIVER 1	0.01	0.01	2014 EIA	0.89976	0.90	AMPD Actual
207#2	ST JOHNS RIVER 2	0.01	0.01	2014 EIA	0.8925	0.89	AMPD Actual
2076#1	ASBURY 1	0.13	0.03	0.03 default	0.08648	0.09	AMPD Actual
2079#5A	HAWTHORN 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2080#2	MONTROSE 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2080#3	MONTROSE 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2094#1	SIBLEY (MO) 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
2094#2	SIBLEY (MO) 2	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
2094#3	SIBLEY (MO) 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
2103#1	LABADIE 1	0.015	0.015	2014 EIA		0.50	0.5 default (non-Lig)
2103#2	LABADIE 2	0.015	0.015	2014 EIA		0.50	0.5 default (non-Lig)
2103#3	LABADIE 3	0.025	0.025	2014 EIA		0.50	0.5 default (non-Lig)
2103#4	LABADIE 4	0.015	0.015	2014 EIA		0.50	0.5 default (non-Lig)
2104#3	MERAMEC 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2104#4	MERAMEC 4	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2107#1	SIOUX 1	0.01	0.01	2014 EIA	0.37557	0.38	AMPD Actual
2107#2	SIOUX 2	0.01	0.01	2014 EIA	0.61192	0.61	AMPD Actual
2167#1	NEW MADRID 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2167#2	NEW MADRID 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2168#MB1	THOMAS HILL 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2168#MB2	THOMAS HILL 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2168#MB3	THOMAS HILL 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2240#8	LD WRIGHT 8	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
2277#1	SHELDON 1	0.00416	0.00416	2014 EIA	0.26	0.26	AMPD Actual
2277#2	SHELDON 2	0.000807	0.000807	2014 EIA	0.26	0.26	AMPD Actual
2291#4	NORTH OMAHA 4	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2291#5	NORTH OMAHA 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2324#4	REID GARDNER 4	0.03	0.03	2014 EIA	0.32207	0.32	AMPD Actual
2364#1	MERRIMACK 1	0.08	0.03	0.03 default	0.37408	0.37	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
2364#2	MERRIMACK 2	0.02	0.02	2014 EIA	0.25774	0.26	AMPD Actual
2367#4	SCHILLER 4	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
2367#6	SCHILLER 6	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
2378#2	BL ENGLAND 2	0.05	0.03	0.03 default	0.21757	0.22	AMPD Actual
2403#2	HUDSON 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2408#1	MERCER 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2408#2	MERCER 2	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2442#4	FOUR CORNERS 4	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2442#5	FOUR CORNERS 5	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2451#1	SAN JUAN (NM) 1	0	0.01	2010 Modeling	0.02298	0.02	AMPD Actual
2451#2	SAN JUAN (NM) 2	0	0.01	2010 Modeling	0.02069	0.02	AMPD Actual
2451#3	SAN JUAN (NM) 3	0	0.01	2010 Modeling	1.62226	0.50	0.5 default (non-Lig)
2451#4	SAN JUAN (NM) 4	0	0.01	2010 Modeling	0.1707	0.17	AMPD Actual
2535#1	CAYUGA 1(MILLIKEN 1)	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
2535#2	CAYUGA 2(MILLIKEN 2)	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
26#5	GASTON (AL) 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2706#1	ASHEVILLE 1	0	0.003	WebFIRE	0.30	0.30	AMPD Actual
2706#2	ASHEVILLE 2	0	0.003	WebFIRE	0.27	0.27	AMPD Actual
2712#1	ROXBORO 1	0.01	0.01	2014 EIA	0.46	0.46	AMPD Actual
2712#2	ROXBORO 2	0.01	0.01	2014 EIA	0.44	0.44	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
2712#3A	ROXBORO 3	0.01	0.01	2014 EIA	0.18	0.18	AMPD Actual
2712#3B	ROXBORO 3	0.01	0.01	2014 EIA	0.17	0.17	AMPD Actual
2712#4A	ROXBORO 4	0.01	0.01	2014 EIA	0.68	0.68	AMPD Actual
2712#4B	ROXBORO 4	0.01	0.01	2014 EIA	0.69	0.69	AMPD Actual
2718#1	ALLEN 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2718#2	ALLEN 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2718#3	ALLEN 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2718#4	ALLEN 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2718#5	ALLEN 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2721#5	CLIFFSIDE 5	0	0.004	WebFIRE	0.51	0.51	AMPD Actual
2721#6	CLIFFSIDE 6	0	0.002	WebFIRE	0.31	0.31	AMPD Actual
2727#1	MARSHALL (NC) 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2727#2	MARSHALL (NC) 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2727#3	MARSHALL (NC) 3		0.005	1/2 U1 and U2 2014 EIA		0.50	0.5 default (non-Lig)
2727#4	MARSHALL (NC) 4		0.005	1/2 U1 and U2 2014 EIA		0.50	0.5 default (non-Lig)
2790#B1	HESKETT 1	0.02	0.02	2014 EIA		2.50	2.5 default (Lig)
2790#B2	HESKETT 2	0	0.007	WebFIRE		0.50	0.5 default (non-Lig)
2817#1	LELAND OLDS 1	0.01	0.01	2014 EIA	2.13868	2.14	AMPD Actual (Lig)
2817#2	LELAND OLDS 2	0.01	0.01	2014 EIA	1.35064	1.35	AMPD Actual (Lig)
2823#B1	MR YOUNG 1	0.01	0.01	2014 EIA	2.72321	2.72	AMPD Actual (Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
2823#B2	MR YOUNG 2	0.01	0.01	2014 EIA	3.65952	3.66	AMPD Actual (Lig)
2824#1	STANTON (ND) 1	0.012	0.012	2014 EIA	0.764	0.76	AMPD Actual
2824#10	STANTON (ND) 10	0.015	0.015	2014 EIA	0.87	0.87	AMPD Actual
2828#1	CARDINAL 1	0.01	0.01	2014 EIA	0.63925	0.64	AMPD Actual
2828#2	CARDINAL 2	0.01	0.01	2014 EIA	0.33503	0.34	AMPD Actual
2828#3	CARDINAL 3	0.01	0.01	2014 EIA	0.47308	0.47	AMPD Actual
2832#7	MIAMI FORT 7	0.01	0.01	2014 EIA	0.51195	0.51	AMPD Actual
2832#8	MIAMI FORT 8	0.01	0.01	2014 EIA	0.5853	0.59	AMPD Actual
2836#12	AVON LAKE 9	0.06	0.03	0.03 default		0.50	0.5 default (non-Lig)
2840#4	CONESVILLE 4	0.02	0.02	2014 EIA	0.59474	0.59	AMPD Actual
2840#5	CONESVILLE 5	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
2840#6	CONESVILLE 6	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
2850#1	JM STUART 1	0.01	0.01	2014 EIA	0.29978	0.30	AMPD Actual
2850#2	JM STUART 2	0.01	0.01	2014 EIA	0.35787	0.36	AMPD Actual
2850#3	JM STUART 3	0.01	0.01	2014 EIA	0.25298	0.25	AMPD Actual
2850#4	JM STUART 4	0.02	0.02	2014 EIA	0.40561	0.41	AMPD Actual
2866#1	WH SAMMIS 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2866#2	WH SAMMIS 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2866#3	WH SAMMIS 3	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2866#4	WH SAMMIS 4	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
2866#5	WH SAMMIS 5	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2866#6	WH SAMMIS 6	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
2866#7	WH SAMMIS 7	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
2876#1	KYGER CREEK 1	0	0.002	WebFIRE	0.47607	0.48	AMPD Actual
2876#2	KYGER CREEK 2	0	0.002	WebFIRE	0.46673	0.47	AMPD Actual
2876#3	KYGER CREEK 3	0	0.008	WebFIRE	0.68848	0.69	AMPD Actual
2876#4	KYGER CREEK 4	0	0.008	WebFIRE	0.57883	0.58	AMPD Actual
2876#5	KYGER CREEK 5	0	0.008	WebFIRE	0.71571	0.72	AMPD Actual
2878#1	FirstEnergy Bay Shore	0.22	0.03	0.03 default		0.08	KM FBC 100% Coke Factor
2952#4	MUSKOGEE 4	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
2952#5	MUSKOGEE 5	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
2952#6	MUSKOGEE 6	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
2963#3313	NORTHEASTERN 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
298#LIM1	LIMESTONE 1	0.01	0.01	2014 EIA		2.50	2.5 default (Lig)
298#LIM2	LIMESTONE 2	0.01	0.01	2014 EIA		2.50	2.5 default (Lig)
3#4	BARRY 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3#5	BARRY 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3118#1	CONEMAUGH 1	0	0.003	WebFIRE	0.32709	0.33	AMPD Actual
3118#2	CONEMAUGH 2	0	0.005	WebFIRE	0.41606	0.42	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
3122#1	HOMER CITY 1	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
3122#2	HOMER CITY 2	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
3122#3	HOMER CITY 3	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
3130#1	SEWARD	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3130#2	SEWARD	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3136#1	KEYSTONE (PA) 1	0.03	0.03	2014 EIA	0.17635	0.18	AMPD Actual
3136#2	KEYSTONE (PA) 2	0.02	0.02	2014 EIA	0.2356	0.24	AMPD Actual
3140#1	BRUNNER ISLAND 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
3140#2	BRUNNER ISLAND 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
3140#3	BRUNNER ISLAND 3	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
3149#1	MONTOUR 1	0.02	0.02	2014 EIA	0.06093	0.06	AMPD Actual
3149#2	MONTOUR 2	0.01	0.01	2014 EIA	0.14865	0.15	AMPD Actual
3297#WAT1	WATEREE (SC) 1	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
3297#WAT2	WATEREE (SC) 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3298#WIL1	AM WILLIAMS 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
3393#1	TH ALLEN 1	0.06	0.03	0.03 default	3.090955	0.50	0.5 default (non-Lig)
3393#2	TH ALLEN 2	0.04	0.03	0.03 default	3.090955	0.50	0.5 default (non-Lig)
3393#3	TH ALLEN 3	0.05	0.03	0.03 default	3.090955	0.50	0.5 default (non-Lig)
3396#1	BULL RUN (TN) 1	0.02	0.02	2014 EIA	0.19852	0.20	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
3399#1	CUMBERLAND 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3399#2	CUMBERLAND 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
3403#1	GALLATIN 1	0.02	0.02	2014 EIA	3.360655	0.50	0.5 default (non-Lig)
3403#2	GALLATIN 2	0.02	0.02	2014 EIA	3.568666	0.50	0.5 default (non-Lig)
3403#3	GALLATIN 3	0.01	0.01	2014 EIA	2.148457	0.50	0.5 default (non-Lig)
3403#4	GALLATIN 4	0.01	0.01	2014 EIA	1.661036	0.50	0.5 default (non-Lig)
3406#1	JOHNSONVILLE (TN) 1		0.02	2010 Modeling		0.50	0.5 default (non-Lig)
3406#2	JOHNSONVILLE (TN) 2		0.02	2010 Modeling		0.50	0.5 default (non-Lig)
3406#3	JOHNSONVILLE (TN) 3		0.02	2010 Modeling		0.50	0.5 default (non-Lig)
3406#4	JOHNSONVILLE (TN) 4		0.02	2010 Modeling		0.50	0.5 default (non-Lig)
3407#1	KINGSTON 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#2	KINGSTON 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#3	KINGSTON 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#4	KINGSTON 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#5	KINGSTON 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#6	KINGSTON 6	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#7	KINGSTON 7	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#8	KINGSTON 8	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3407#9	KINGSTON 9	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3470#WAP5	WA PARISH 5	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
3470#WAP6	WA PARISH 6	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3470#WAP7	WA PARISH 7	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3470#WAP8	WA PARISH 8	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3497#1	BIG BROWN 1	0.05	0.03	0.03 default		2.50	2.5 default (Lig)
3497#2	BIG BROWN 2	0.05	0.03	0.03 default		2.50	2.5 default (Lig)
3797#3	CHESTERFIELD 3	0	0.003	WebFIRE	0.28759	0.29	AMPD Actual
3797#4	CHESTERFIELD 4	0	0.003	WebFIRE	0.31182	0.31	AMPD Actual
3797#5	CHESTERFIELD 5	0	0.003	WebFIRE	0.39991	0.40	AMPD Actual
3797#6	CHESTERFIELD 6	0	0.005	WebFIRE	0.22321	0.22	AMPD Actual
3809#1	YORKTOWN 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3809#2	YORKTOWN 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3845#BW21	CENTRALIA 1	0.04	0.03	0.03 default	0.8312	0.83	AMPD Actual
3845#BW22	CENTRALIA 2	0.04	0.03	0.03 default	0.52484	0.52	AMPD Actual
3935#1	AMOS 1	0.02	0.02	2014 EIA	0.67356	0.67	AMPD Actual
3935#2	AMOS 2	0.02	0.02	2014 EIA	0.58543	0.59	AMPD Actual
3935#3	AMOS 3	0.02	0.02	2014 EIA	0.56224	0.56	AMPD Actual
3943#1	FORT MARTIN 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3943#2	FORT MARTIN 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3944#1	HARRISON 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
3944#2	HARRISON 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
3944#3	HARRISON 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
3948#1	MITCHELL (WV) 1	0.02	0.02	2014 EIA	0.40414	0.40	AMPD Actual
3948#2	MITCHELL (WV) 2	0.01	0.01	2014 EIA	0.36224	0.36	AMPD Actual
3954#1	MOUNT STORM 1	0.01	0.01	2014 EIA	0.41121	0.41	AMPD Actual
3954#2	MOUNT STORM 2	0.01	0.01	2014 EIA	0.76512	0.77	AMPD Actual
3954#3	MOUNT STORM 3	0.01	0.01	2014 EIA	0.83458	0.83	AMPD Actual
4041#5	OAK CREEK (WI) 5	0.01	0.01	2014 EIA	0.46483	0.46	AMPD Actual
4041#6	OAK CREEK (WI) 6	0.01	0.01	2014 EIA	0.48143	0.48	AMPD Actual
4041#7	OAK CREEK (WI) 7	0.01	0.01	2014 EIA	0.42819	0.43	AMPD Actual
4041#8	OAK CREEK (WI) 8	0.01	0.01	2014 EIA	0.43396	0.43	AMPD Actual
4050#4	EDGEWATER (WI) 4	0.07	0.03	0.03 default	0.25835	0.26	AMPD Actual
4050#5	EDGEWATER (WI) 5	0.01	0.01	2014 EIA	0.45358	0.45	AMPD Actual
4072#7	JP PULLIAM 7	0.019	0.019	2014 EIA	0.815	0.82	AMPD Actual
4072#8	JP PULLIAM 8	0.0195	0.0195	2014 EIA	0.722	0.72	AMPD Actual
4078#3	WESTON (WI) 3	0.01	0.01	2014 EIA	0.843	0.84	AMPD Actual
4078#4	WESTON 4	0.01	0.01	2014 EIA	0.45781	0.46	AMPD Actual
4125#8	MANITOWOC 6	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
4125#9	MANITOWOC 9	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
4143#1	GENOA THREE	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
4158#BW41	DAVE JOHNSTON 1	0.01	0.01	2014 EIA	0.61455	0.61	AMPD Actual
4158#BW42	DAVE JOHNSTON 2	0.01	0.01	2014 EIA	0.72718	0.73	AMPD Actual
4158#BW43	DAVE JOHNSTON 3	0.01	0.01	2014 EIA	0.51388	0.51	AMPD Actual
4158#BW44	DAVE JOHNSTON 4	0.01	0.01	2014 EIA	0.7852	0.79	AMPD Actual
4162#1	NAUGHTON 1	0.01	0.01	2014 EIA	0.64047	0.64	AMPD Actual
4162#2	NAUGHTON 2	0.01	0.01	2014 EIA	0.79735	0.80	AMPD Actual
4162#3	NAUGHTON 3	0.05	0.03	0.03 default	0.84021	0.84	AMPD Actual
4271#B1	MADGETT 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
469#4	CHEROKEE (CO) 4	0	0.01	2010 Modeling	0.55473	0.55	AMPD Actual
47#5	COLBERT 5		0.01	2010 Modeling		0.50	0.5 default (non-Lig)
470#1	COMANCHE (CO) 1	0	0.01	2010 Modeling	0.56559	0.57	AMPD Actual
470#2	COMANCHE (CO) 2	0	0.01	2010 Modeling	0.43197	0.43	AMPD Actual
470#3	COMANCHE 3	0	0.01	2010 Modeling	1.1099	1.11	AMPD Actual
477#5	VALMONT 5	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
492#5	DRAKE 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
492#6	DRAKE 6	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
492#7	DRAKE 7	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
4941#1	NAVAJO 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
4941#2	NAVAJO 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
4941#3	NAVAJO 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
50039#1	Kline Township Cogen Facil	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
50202#1	WPS POWER Niagara	0	0.02	2010 Modeling		0.50	0.5 default (non-Lig)
50611#031	Westwood	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50776#BLR1	Panther Creek Energy Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50776#BLR2	Panther Creek Energy Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
508#4	LAMAR REPOWERING PROJECT		0.01	2010 Modeling		0.50	0.5 default (non-Lig)
50835#1	TES Filer City	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50835#2	TES Filer City	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50879#BLR1	Wheeler Frackville Energy Co Inc	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50888#BLR1	NORTHAMPTON	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
50931#BLR1	Yellowstone Energy LP	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
50931#BLR2	Yellowstone Energy LP	0.01	0.01	2014 EIA		0.08	KM FBC 100% Coke Factor
50951#1	Sunnyside Cogeneration Associates	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
50974#UNIT 1	SCRUBGRASS	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
50974#UNIT 2	SCRUBGRASS	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
50976#AAB01	Indiantown Cogeneration Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
51#1	DOLET HILLS 1	0.02	0.02	2014 EIA	1.77597	1.78	AMPD Actual (Lig)
52007#BLR1	Mecklenburg Cogeneration Facility	0	0.005	WebFIRE		0.50	0.5 default (non-Lig)
52007#BLR2	Mecklenburg Cogeneration Facility	0	0.005	WebFIRE		0.50	0.5 default (non-Lig)
52071#5A	SANDOW 5	0.03	0.03	2014 EIA	2.14134	2.14	AMPD Actual (Lig)
52071#5B	SANDOW 5	0.03	0.03	2014 EIA	2.73354	2.73	AMPD Actual (Lig)
525#H1	HAYDEN 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
525#H2	HAYDEN 2	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
527#1	NUCLA 4	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54035#BLR1	Westmoreland LG&E Partners Roanoke Valley 1	0.1	0.004	2010 Modeling		0.50	0.5 default (non-Lig)
54081#1A	Spruance Genco LLC	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
54081#1B	Spruance Genco LLC	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
54081#2A	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54081#2B	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54081#3A	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54081#3B	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54081#4A	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54081#4B	Spruance Genco LLC	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
54304#1A	Birchwood Power Facility	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
54634#1	St Nicholas Cogeneration Project	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
54755#BLR2	Westmoreland LG&E Partners Roanoke Valley 2	0.1	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
55076#AA001	RED HILLS GENERATION FACILITY	0.01	0.01	2014 EIA		2.50	2.5 default (Lig)
55076#AA002	RED HILLS GENERATION FACILITY	0.01	0.01	2014 EIA		2.50	2.5 default (Lig)
55479#3	WYGEN I	0.1	0.03	0.03 default		0.50	0.5 default (non-Lig)
55749#PC1	HARDIN GENERATING	0	0.02	2010 Modeling	0.49336	0.49	AMPD Actual
55856#PC1	PRAIRIE STATE 1	0	0.002	WebFIRE	0.49947	0.50	0.5 default (non-Lig)
55856#PC2	PRAIRIE STATE 2	0	0.003	WebFIRE	0.55628	0.56	AMPD Actual
56#1	CR LOWMAN 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
56#2	CR LOWMAN 2	0.07	0.03	0.03 default		0.50	0.5 default (non-Lig)
56#3	CR LOWMAN 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
56068#18	ELM ROAD 1	0.01	0.01	2014 EIA	0.53946	0.54	AMPD Actual
56068#19	ELM ROAD 2	0.01	0.01	2014 EIA	0.55373	0.55	AMPD Actual
56224#BLR100	TS POWER (NEWMONT/BOULDER VALLEY)	0.01	0.01	2014 EIA	0.44973	0.45	AMPD Actual
56319#1	WYGEN II	0.1	0.03	0.03 default		0.50	0.5 default (non-Lig)
564#1	CH STANTON 1	0.01	0.01	2014 EIA	0.64229	0.64	AMPD Actual
564#2	CH STANTON 2	0.01	0.01	2014 EIA	0.09514	0.10	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
56456#BLR1	PLUM POINT 1	0.01	0.01	2014 EIA	0.83286	0.83	AMPD Actual
56564#1	J. TURK (FULTON, AK)	0.03	0.03	2014 EIA	0.56074	0.56	AMPD Actual
56596#1	WYGEN III	0.1	0.03	0.03 default		0.50	0.5 default (non-Lig)
56609#1	DRY FORK	0.01	0.01	2014 EIA	0.88631	0.89	AMPD Actual
56611#S01	SANDY CREEK ENERGY STATION	0.01	0.01	2014 EIA	0.68275	0.68	AMPD Actual
56671#UHA01	LONGVIEW	0.01	0.01	2014 EIA	0.31901	0.32	AMPD Actual
56786#1	SPIRITWOOD STATION	0.006	0.006	2014 EIA	1.206	1.21	AMPD Actual (Lig)
568#BHB3	BRIDGEPORT HARBOR 3	0.006	0.006	2014 EIA		0.50	0.5 default (non-Lig)
56808#1	VIRGINIA CITY HYBRID ENERGY CENTER	0.006	0.006	2014 EIA	0.00125	0.00125	AMPD Actual
56808#2	VIRGINIA CITY HYBRID ENERGY CENTER	0	0.001	WebFIRE	0.00121	0.00121	AMPD Actual
59#1	PLATTE 1	0.08	0.03	0.03 default		0.50	0.5 default (non-Lig)
594#4	INDIAN RIVER (DE) 4	0.01	0.01	2014 EIA	0.35106	0.35	AMPD Actual
60#1	WHELAN ENERGY CENTER 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
60#2	WHELAN ENERGY CENTER 2	0	0.0011	WebFIRE	1.01544	1.02	AMPD Actual
6002#1	MILLER 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6002#2	MILLER 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6002#3	MILLER 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6002#4	MILLER 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6004#1	PLEASANTS 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6004#2	PLEASANTS 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6009#1	WHITE BLUFF 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6009#2	WHITE BLUFF 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6016#1	DUCK CREEK 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6017#1	NEWTON 1		0.03	0.03 default	0.59308	0.59	AMPD Actual
6017#2	NEWTON 2		0.02	2010 Modeling	0.72731	0.73	AMPD Actual
6018#2	EAST BEND 2	0.02	0.02	2014 EIA	0.65	0.65	AMPD Actual
6019#1	ZIMMER 1	0	0.008	WebFIRE	0.68564	0.69	AMPD Actual
602#1	BRANDON SHORES 1	0	0.03	2010 Modeling	0.33363	0.33	AMPD Actual
602#2	BRANDON SHORES 2	0	0.03	2010 Modeling	0.47799	0.48	AMPD Actual
6021#C1	CRAIG 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
6021#C2	CRAIG 2	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
6021#C3	CRAIG 3	0	0.01	2010 Modeling	0.74129	0.74	AMPD Actual
6030#1	COAL CREEK 1	0.007	0.007	2014 EIA	4.09	2.50	2.5 default (Lig)
6030#2	COAL CREEK 2	0.004	0.004	2014 EIA	3.27	3.27	AMPD Actual (Lig)
6031#2	KILLEN 2	0.01	0.01	2014 EIA	0.35277	0.35	AMPD Actual
6034#1	BELLE RIVER 1	0.1	0.03	0.03 default		0.50	0.5 default (non-Lig)
6034#2	BELLE RIVER 2	0.1	0.03	0.03 default		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6041#1	HL SPURLOCK 1	0	0.002	WebFIRE	0.18957	0.19	AMPD Actual
6041#2	HL SPURLOCK 2	0	0.002	WebFIRE	0.48862	0.49	AMPD Actual
6041#3	HL SPURLOCK 3 (GILBERT)	0	0.007	WebFIRE	0.02064	0.02	AMPD Actual
6041#4	HL SPURLOCK 4	0	0.003	WebFIRE	0.04269	0.04	AMPD Actual
6052#1	WANSLEY 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6052#2	WANSLEY 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6055#2B1	BIG CAJUN TWO 1	0.03	0.03	2014 EIA	0.77524	0.78	AMPD Actual
6055#2B3	BIG CAJUN TWO 3	0.03	0.03	2014 EIA	0.69984	0.70	AMPD Actual
6061#1	MORROW 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6061#2	MORROW 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6064#N1	NEARMAN CREEK 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6065#1	IATAN 1	0.01	0.01	2014 EIA	0.46206	0.46	AMPD Actual
6065#2	IATAN 2	0.01	0.01	2014 EIA	0.27527	0.28	AMPD Actual
6068#1	JEFFREY 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6068#2	JEFFREY 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6068#3	JEFFREY 3	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
6071#1	TRIMBLE COUNTY 1	0.01	0.010	2014 EIA		0.50	0.5 default (non-Lig)
6071#2	TRIMBLE COUNTY 2	0.01	0.006	2014 EIA	0.21808	0.22	AMPD Actual
6073#1	VJ DANIEL 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6073#2	VJ DANIEL 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6076#1	COLSTRIP 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
6076#2	COLSTRIP 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
6076#3	COLSTRIP 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6076#4	COLSTRIP 4	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6077#1	GERALD GENTLEMAN 1	0.00461	0.00461	2014 EIA		0.50	0.5 default (non-Lig)
6077#2	GERALD GENTLEMAN 2	0.00318	0.00318	2014 EIA		0.50	0.5 default (non-Lig)
6082#1	SOMERSET	0.07	0.03	0.03 default		0.50	0.5 default (non-Lig)
6085#14	RM SCHAHFER 14	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6085#15	RM SCHAHFER 15	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6085#17	RM SCHAHFER 17	0.01	0.01	2014 EIA	0.74769	0.75	AMPD Actual
6085#18	RM SCHAHFER 18	0.01	0.01	2014 EIA	0.61184	0.61	AMPD Actual
6089#B1	LEWIS & CLARK 1	0.05	0.03	0.03 default	1.27647	0.50	0.5 default (non-Lig)
6090#1	SHERBURNE COUNTY 1	0.01	0.01	2014 EIA	0.82706	0.83	AMPD Actual
6090#2	SHERBURNE COUNTY 2	0.01	0.01	2014 EIA	0.77485	0.77	AMPD Actual
6090#3	SHERBURNE COUNTY 3	0	0.02	2010 Modeling	0.30618	0.31	AMPD Actual
6094#1	BRUCE MANSFIELD 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6094#2	BRUCE MANSFIELD 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6094#3	BRUCE MANSFIELD 3	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6095#1	SOONER 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6095#2	SOONER 2	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6096#1	NEBRASKA CITY 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6096#2	NEBRASKA CITY 2	0.01	0.01	2014 EIA	0.54449	0.54	AMPD Actual
6098#1	BIG STONE 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6101#BW91	WYODAK I	0.01	0.01	2014 EIA	0.83052	0.83	AMPD Actual
6106#1SG	BOARDMAN (OR) 1	0	0.006	WebFIRE		0.50	0.5 default (non-Lig)
6113#1	GIBSON 1	0.01	0.01	2014 EIA	0.36	0.36	AMPD Actual
6113#2	GIBSON 2	0.03	0.01	U1 2014 EIA (control changes since 2014)	0.24	0.24	AMPD Actual
6113#3	GIBSON 3	0.02	0.01	U1 2014 EIA (control changes since 2014)	0.31	0.31	AMPD Actual
6113#4	GIBSON 4	0.03	0.01	U1 2014 EIA (control changes since 2014)	0.41	0.41	AMPD Actual
6113#5	GIBSON 5	0.04	0.02	1/2 2010 Modeling	0.56	0.56	AMPD Actual
6124#1	MCINTOSH (GA) 1	0.002	0.002	2014 EIA		0.50	0.5 default (non-Lig)
6136#1	GIBBONS CREEK 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
6137#1	AB BROWN 1	0.01	0.01	2014 EIA	0.94991	0.95	AMPD Actual
6137#2	AB BROWN 2	0.01	0.01	2014 EIA	0.6181	0.62	AMPD Actual
6138#1	FLINT CREEK (AR) 1	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
6139#1	WELSH 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6139#3	WELSH 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6146#1	MARTIN LAKE 1	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)
6146#2	MARTIN LAKE 2	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6146#3	MARTIN LAKE 3	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)
6147#1	MONTICELLO (TX) 1	0.02	0.02	2014 EIA		2.50	2.5 default (Lig)
6147#2	MONTICELLO (TX) 2	0.02	0.02	2014 EIA		2.50	2.5 default (Lig)
6147#3	MONTICELLO (TX) 3	0.05	0.03	0.03 default		2.50	2.5 default (Lig)
6155#1	RUSH ISLAND 1	0.015	0.015	2014 EIA	0.81408	0.81	AMPD Actual
6155#2	RUSH ISLAND 2	0.015	0.015	2014 EIA	0.82888	0.83	AMPD Actual
6165#1	HUNTER 1	0.02	0.02	2014 EIA	0.23822	0.24	AMPD Actual
6165#2	HUNTER 2	0.01	0.01	2014 EIA	0.19251	0.19	AMPD Actual
6165#3	HUNTER 3	0.01	0.01	2014 EIA	0.0634	0.06	AMPD Actual
6166#MB1	ROCKPORT 1	0.04	0.03	0.03 default	0.86968	0.87	AMPD Actual
6166#MB2	ROCKPORT 2	0.04	0.03	0.03 default	0.65168	0.65	AMPD Actual
6170#1	PLEASANT PRAIRIE 1	0.01	0.01	2014 EIA	0.59247	0.59	AMPD Actual
6170#2	PLEASANT PRAIRIE 2	0.01	0.01	2014 EIA	0.48966	0.49	AMPD Actual
6177#U1B	CORONADO 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6177#U2B	CORONADO 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6178#1	COLETO CREEK 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6179#1	FAYETTE(SEYMOR) (TX) 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6179#2	FAYETTE(SEYMOR) (TX) 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6179#3	FAYETTE(SEYMOR) (TX) 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6180#1	OAK GROVE 1	0.01	0.01	2014 EIA	1.31144	1.31	AMPD Actual (Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6180#2	OAK GROVE 2	0.01	0.01	2014 EIA	1.62209	1.62	AMPD Actual (Lig)
6181#1	JT DEELY 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6181#2	JT DEELY 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6183#SM-1	SAN MIGUEL 1	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)
6190#2	RODEMACHER 2 (Brame Energy Center 2)	0.02	0.02	2014 EIA	0.40514	0.41	AMPD Actual
6190#3-1	MADISON 3 (Brame Energy Center 3)	0.01	0.01	2014 EIA	0.52062	0.08	KM FBC 100% Coke Factor
6190#3-2	MADISON 3 (Brame Energy Center 3)	0.01	0.01	2014 EIA	0.38724	0.08	KM FBC 100% Coke Factor
6193#061B	HARRINGTON 1	0.05	0.03	0.03 default	0.9919	0.99	AMPD Actual
6193#062B	HARRINGTON 2	0.01	0.01	2014 EIA	0.58196	0.58	AMPD Actual
6193#063B	HARRINGTON 3	0.01	0.01	2014 EIA	1.01563	1.02	AMPD Actual
6194#171B	TOLK 1	0.01	0.01	2014 EIA	0.61257	0.61	AMPD Actual
6194#172B	TOLK 2	0.01	0.01	2014 EIA	0.78183	0.78	AMPD Actual
6195#1	SOUTHWEST 1 (TWITTY ENERGY CENTER)	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
6195#2	SOUTHWEST 2 (TWITTY ENERGY CENTER)	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6204#1	LARAMIE RIVER 1	0.01	0.01	2014 EIA	0.70976	0.71	AMPD Actual
6204#2	LARAMIE RIVER 2	0.01	0.01	2014 EIA	0.78028	0.78	AMPD Actual
6204#3	LARAMIE RIVER 3	0.02	0.02	2014 EIA	0.72518	0.73	AMPD Actual
6213#1SG1	MEROM 1	0	0.006	WebFIRE		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
6213#2SG1	MEROM 2	0	0.004	WebFIRE		0.50	0.5 default (non-Lig)
6248#1	PAWNEE 1	0.01	0.01	2014 EIA	0.89657	0.90	AMPD Actual
6249#1	WINYAH 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6249#2	WINYAH 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6249#3	WINYAH 3	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
6249#4	WINYAH 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6250#1A	MAYO 1	0.01	0.01	2014 EIA	0.48	0.48	AMPD Actual
6250#1B	MAYO 1	0.01	0.01	2014 EIA	0.47	0.47	AMPD Actual
6254#1	OTTUMWA 1	0.03	0.03	2014 EIA	0.56015	0.56	AMPD Actual
6257#1	SCHERER 1	0.003	0.003	2014 EIA		0.50	0.5 default (non-Lig)
6257#2	SCHERER 2	0.006	0.006	2014 EIA		0.50	0.5 default (non-Lig)
6257#3	SCHERER 3	0.002	0.002	2014 EIA		0.50	0.5 default (non-Lig)
6257#4	SCHERER 4	0.005	0.005	2014 EIA		0.50	0.5 default (non-Lig)
6264#1	MOUNTAINEER 1	0.02	0.02	2014 EIA	0.32111	0.32	AMPD Actual
628#1	CRYSTAL RIVER 1	0.04	0.03	0.03 default		0.50	0.5 default (non-Lig)
628#2	CRYSTAL RIVER 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
628#4	CRYSTAL RIVER 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
628#5	CRYSTAL RIVER 5	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6288#1	HEALY 1	0.01	0.01	2014 EIA		2.50	2.5 default (Lig)
6288#2	HEALY 2		0.02	Sister U1 2014 EIA		2.50	2.5 default (Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
641#4	CRIST 4	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
641#5	CRIST 5	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
641#6	CRIST 6	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
641#7	CRIST 7	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
645#BB01	BIG BEND (FL) 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
645#BB02	BIG BEND (FL) 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
645#BB03	BIG BEND (FL) 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
645#BB04	BIG BEND (FL) 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6469#B1	ANTELOPE VALLEY 1	0.01	0.01	2014 EIA	2.6452	2.65	AMPD Actual (Lig)
6469#B2	ANTELOPE VALLEY 2	0.01	0.01	2014 EIA	3.37805	3.38	AMPD Actual (Lig)
6481#1SGA	INTERMOUNTAIN 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6481#2SGA	INTERMOUNTAIN 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
663#B2	DEERHAVEN 2	0.01	0.01	2014 EIA	0.78673	0.79	AMPD Actual
6639#G1	GREEN 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
6639#G2	GREEN 2	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
6641#1	INDEPENDENCE 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6641#2	INDEPENDENCE 2	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6648#4	SANDOW 4	0.06	0.03	0.03 default		2.50	2.5 default (Lig)
6664#101	LOUISA 1	0.02	0.02	2014 EIA	0.86095	0.86	AMPD Actual
667#1	NORTHSIDE 1	0.01	0.01	2014 EIA	0.00419	0.08	KM FBC 100% Coke Factor

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
667#2	NORTHSIDE 2	0.01	0.01	2014 EIA	0.01737	0.08	KM FBC 100% Coke Factor
6705#1	WARRICK 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6705#2	WARRICK 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6705#3	WARRICK 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
6705#4	WARRICK 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
676#3	MCINTOSH (FL) 3	0.02	0.02	2014 EIA	0.34955	0.35	AMPD Actual
6761#101	RAWHIDE 1	0.01	0.01	2014 EIA	1.15162	1.15	AMPD Actual
6768#1	SIKESTON 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6772#1	HUGO 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
6823#W1	DB WILSON 1	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
703#1BLR	BOWEN 1	0.013	0.013	2014 EIA		0.50	0.5 default (non-Lig)
703#2BLR	BOWEN 2	0.003	0.003	2014 EIA		0.50	0.5 default (non-Lig)
703#3BLR	BOWEN 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
703#4BLR	BOWEN 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
7030#U1	TNP ONE 1 (TWIN OAKS)	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)
7030#U2	TNP ONE 2 (TWIN OAKS)	0.03	0.03	2014 EIA		2.50	2.5 default (Lig)
708#1	HAMMOND 1	0.026	0.026	2014 EIA		0.50	0.5 default (non-Lig)
708#2	HAMMOND 2	0.026	0.026	2014 EIA		0.50	0.5 default (non-Lig)
708#3	HAMMOND 3	0.026	0.026	2014 EIA		0.50	0.5 default (non-Lig)
708#4	HAMMOND 4	0.026	0.026	2014 EIA		0.50	0.5 default (non-Lig)

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
7097#BLR1	SPRUCE 1	0.02	0.02	2014 EIA		0.50	0.5 default (non-Lig)
7097#BLR2	SPRUCE 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
7210#COP1	COPE 1	0	0.01	2010 Modeling		0.50	0.5 default (non-Lig)
7213#1	CLOVER 1	0	0.004	WebFIRE		0.50	0.5 default (non-Lig)
7213#2	CLOVER 2	0	0.004	WebFIRE		0.50	0.5 default (non-Lig)
7343#4	GEORGE NEAL 4	0.03	0.03	2014 EIA	0.36149	0.36	AMPD Actual
7504#2	NEIL SIMPSON 6 (II 2)	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
7737#B001	KAPSTONE(Cogen South)	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
7790#1-1	BONANZA 1	0	0.00514	WebFIRE		0.50	0.5 default (non-Lig)
7902#1	PIRKEY 1	0.03	0.03	2014 EIA	2.47165	2.47	AMPD Actual (Lig)
8#10	GORGAS TWO 10	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
8#8	GORGAS TWO 8	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
8#9	GORGAS TWO 9	0.05	0.03	0.03 default		0.50	0.5 default (non-Lig)
8023#1	COLUMBIA (WI) 1	0	0.002	WebFIRE	0.61271	0.61	AMPD Actual
8023#2	COLUMBIA (WI) 2	0.01	0.01	2014 EIA	0.53256	0.53	AMPD Actual
8042#1	BELEWS CREEK 1	0.01	0.01	2014 EIA	0.28	0.28	AMPD Actual
8042#2	BELEWS CREEK 2	0.01	0.01	2014 EIA	0.21	0.21	AMPD Actual
8066#BW71	JIM BRIDGER 1	0.01	0.01	2014 EIA	0.87548	0.88	AMPD Actual
8066#BW72	JIM BRIDGER 2	0.01	0.01	2014 EIA	0.87062	0.87	AMPD Actual
8066#BW73	JIM BRIDGER 3	0.01	0.01	2014 EIA	0.2912	0.29	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
8066#BW74	JIM BRIDGER 4	0.02	0.02	2014 EIA	1.03184	1.03	AMPD Actual
8069#1	HUNTINGTON 1	0.01	0.01	2014 EIA	0.21034	0.21	AMPD Actual
8069#2	HUNTINGTON 2	0.01	0.01	2014 EIA	0.22339	0.22	AMPD Actual
8102#1	GAVIN 1	0.01	0.01	2014 EIA	0.73293	0.73	AMPD Actual
8102#2	GAVIN 2	0.02	0.02	2014 EIA	0.74492	0.74	AMPD Actual
8219#1	RD NIXON 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
8222#B1	COYOTE 1	0.01	0.01	2014 EIA	3.13632	3.14	AMPD Actual (Lig)
8223#1	SPRINGERVILLE 1	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
8223#2	SPRINGERVILLE 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
8223#3	SPRINGERVILLE 3	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
8223#4	SPRINGERVILLE 4	0.01	0.01	2014 EIA	0.81698	0.82	AMPD Actual
8224#1	NORTH VALMY 1	0.02	0.02	2014 EIA	0.31972	0.32	AMPD Actual
8224#2	NORTH VALMY 2	0.01	0.01	2014 EIA	0.12551	0.13	AMPD Actual
8226#1	CHESWICK 1	0.01	0.01	2014 EIA	0.3761	0.38	AMPD Actual
856#2	ED EDWARDS 2		0.03	2010 Modeling	0.81871	0.82	AMPD Actual
856#3	ED EDWARDS 3		0.03	2010 Modeling	0.27588	0.28	AMPD Actual
861#01	COFFEEN 1		0.0005	WebFIRE	0.17248	0.17	AMPD Actual
861#02	COFFEEN 2		0.0003	WebFIRE	0.40174	0.40	AMPD Actual
87#1	ESCALANTE	0	0.01	2010 Modeling	0.67596	0.68	AMPD Actual
876#1	KINCAID 1	0.01	0.01	2014 EIA	0.65511	0.66	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
876#2	KINCAID 2	0.01	0.01	2014 EIA	0.64573	0.65	AMPD Actual
879#51	POWERTON 5	0.03	0.03	2014 EIA	0.50918	0.51	AMPD Actual
879#52	POWERTON 5	0.03	0.03	2014 EIA	0.49817	0.50	0.5 default (non-Lig)
879#61	POWERTON 6	0.01	0.01	2014 EIA	0.33539	0.34	AMPD Actual
879#62	POWERTON 6	0.01	0.01	2014 EIA	0.33594	0.34	AMPD Actual
883#7	WAUKEGAN 7	0.02	0.02	2014 EIA	0.36658	0.37	AMPD Actual
883#8	WAUKEGAN 8	0.05	0.03	0.03 default	0.27752	0.28	AMPD Actual
884#4	WILL COUNTY 4	0.05	0.03	0.03 default	0.43779	0.44	AMPD Actual
887#1	JOPPA 1	0.03	0.03	2014 EIA	0.57034	0.57	AMPD Actual
887#2	JOPPA 2	0.03	0.03	2014 EIA	0.57471	0.57	AMPD Actual
887#3	JOPPA 3	0.03	0.03	2014 EIA	0.87433	0.87	AMPD Actual
887#4	JOPPA 4	0.03	0.03	2014 EIA	0.93594	0.94	AMPD Actual
887#5	JOPPA 5	0.03	0.03	2014 EIA	0.80562	0.81	AMPD Actual
887#6	JOPPA 6	0.03	0.03	2014 EIA	0.74026	0.74	AMPD Actual
889#1	BALDWIN 1	0.01	0.01	2014 EIA	0.71512	0.72	AMPD Actual
889#2	BALDWIN 2	0.01	0.01	2014 EIA	0.29221	0.29	AMPD Actual
889#3	BALDWIN 3	0.01	0.01	2014 EIA	0.31552	0.32	AMPD Actual
891#9	HAVANA 6	0.01	0.01	2014 EIA	0.25943	0.26	AMPD Actual
892#1	HENNEPIN 1	0.15	0.03	0.03 default	0.60967	0.61	AMPD Actual
892#2	HENNEPIN 2	0.15	0.03	0.03 default	0.59448	0.59	AMPD Actual

Table C-1 (continued)
FPM and Total Mercury Values Used for Emission Estimates

Plant ID#Boiler ID	Unit Name	2014 EIA-860 FPM Value (lb/MMBtu)	Final FPM for 2017 Base Year Modeling (lb/MMBtu)	FPM Selection Criteria	AMPD Reported Mercury a (lb/TBtu)	Total Mercury Value used for Modeling (lb/TBtu)	Total Mercury Selection Criteria [b]
963#31	DALLMAN 1	0.01	0.01	2014 EIA	0.27839	0.28	AMPD Actual
963#32	DALLMAN 2	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
963#33	DALLMAN 3	0.01	0.01	2014 EIA	1.38391	0.50	0.5 default (non-Lig)
963#41	DALLMAN 4	0	0.01	2010 Modeling	0.32692	0.33	AMPD Actual
976#123	NEW MARION 1,2,3	0.03	0.03	2014 EIA		0.50	0.5 default (non-Lig)
976#4	MARION (IL) 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
983#1	CLIFTY CREEK 1	0	0.003	WebFIRE	0.25414	0.25	AMPD Actual
983#2	CLIFTY CREEK 2	0	0.003	WebFIRE	0.16318	0.16	AMPD Actual
983#3	CLIFTY CREEK 3	0	0.003	WebFIRE	0.27674	0.28	AMPD Actual
983#4	CLIFTY CREEK 4	0.02	0.02	2014 EIA	0.65626	0.66	AMPD Actual
983#5	CLIFTY CREEK 5	0.02	0.02	2014 EIA	0.61333	0.61	AMPD Actual
983#6	CLIFTY CREEK 6	0.02	0.02	2014 EIA	0.71495	0.71	AMPD Actual
994#1	PETERSBURG 1	0.02	0.02	2014 EIA	0.42183	0.42	AMPD Actual
994#2	PETERSBURG 2	0.01	0.01	2014 EIA	0.20275	0.20	AMPD Actual
994#3	PETERSBURG 3	0.06	0.03	0.03 default		0.50	0.5 default (non-Lig)
994#4	PETERSBURG 4	0.01	0.01	2014 EIA		0.50	0.5 default (non-Lig)
995#7	BAILLY 7	0.01	0.01	2014 EIA	0.69464	0.69	AMPD Actual
995#8	BAILLY 8	0.01	0.01	2014 EIA	0.74719	0.75	AMPD Actual
997#12	MICHIGAN CITY 12	0.06	0.03	0.03 default		0.50	0.5 default (non-Lig)

a Seven months of hourly data from EPA's Air Markets Program Data (AMPD) files were utilized (September 2015 through March 2016), for those units reporting. The variables extracted from the AMPD file were the boiler identification fields, the operating date and hour, gross load, heat input, and mercury (Hg) mass emissions. It should be noted that those lines of hourly data, which did not report either heat or emissions data, were omitted. Each individual unit emission rate was calculated by dividing the total Hg mass emissions by the total heat input for the seven-month period.

[b] Lig = lignite

D
SUPPORTING INFORMATION FOR IMPACTS OF MATS CONTROLS ON HAPS AND ADJUSTMENTS TO EXISTING EMISSION FACTORS

MATS controls for PM, Hg, and HCl expected to be in place by the year 2017 may also impact other HAPs species; therefore, current EPRI 2014 EFH emission factors and correlations were reviewed to determine if any adjustments were warranted to obtain a more representative estimate of emissions for the post-MATS industry scenario.

Species for which current EPRI 2014 EFH correlations or emission factors were evaluated included the following: mercury, selenium, and acid gases (HCl and HF). MATS controls examined for potential impacts on secondary HAPs species included: activated carbon injection (ACI), halogenated activated carbon injection (HACI), fuel bromine addition (FuelBr), wet FGD system additives used to control mercury re-emissions (FGDadd), and alkali dry sorbent injection (DSI) for acid gas control.

A discussion of such adjustments used in the 2017 base case emission modeling is presented below by chemical species and MATS control type. In addition, a small number of newer control type configurations not represented in the data sets used to develop EPRI latest set of 2014 emission correlations and factors were identified (e.g., wet electrostatic precipitators). Selection of appropriate emission factors or correlations for these newer control types is also discussed.

Mercury

The one change in speciated mercury emission factors is for units that use wet FGD scrubbers for SO_2 control. As shown previously Section 4, the current average emission factors or emission correlations for wet FGD configurations are based on coal Cl levels (expressed as % of total stack mercury as elemental). These factors, while valid for a pre-MATS scenario, may not be valid for a post-MATS scenario. The historical data used to develop these factors was based primarily on speciated mercury data collected as part of the 1999 Hg ICR and likely included plants with varying amounts of flue gas bypass of the scrubber which will impact the mercury speciation profile at the stack. In addition, the historical data may have included plants with significant re-emission of mercury (as elemental mercury) which will also impact the speciation profile. Current wet FGD scrubbers have been optimized for compliance with MATS, i.e., they no longer have bypass, and reemission of mercury is controlled with FGD additives or other FGD operational changes for scrubbers where this issue has been found. The optimized MATS scrubbers are highly effective at removing oxidized mercury; therefore, while total mercury emissions will be at or below the MATS limit, nearly all the mercury exiting the stack will be present in the elemental form. The consensus of the MATS control practitioners on this project team was that a value of 95% elemental mercury at the stack for all units with wet scrubbers was an appropriate value to use for post-MATS emission estimates.

Dry sorbent injection (DSI) for HCl and/or SO_2 control has the potential to alter the mercury speciation profile in the flue gas if injected at a point in the process where it could remove halogens from the flue gas which otherwise would lead to oxidation of mercury (i.e. increasing the percentage elemental mercury in the flue gas). However, DSI for HCl control will most likely occur downstream of the air heater to avoid detrimental impact on the performance of PAC for mercury control; therefore, DSI will most likely not remove halogens from the flue gas at a point far enough upstream in the gas path to have an impact on mercury oxidation; mercury oxidation will already be established prior to DSI injection for HCl. Therefore, no change to existing factors and correlations for speciated mercury were warranted for MATS control configuration involving DSI for HCl.

Other MATS controls or combinations of MATS controls such as ACI, halogenated ACI, fuel bromine addition, and FGD additives were not expected to impact the speciation profile of mercury that is predicted using the current 2014 EFH factors and correlations. The one exception is the small number of units reporting the use of fuel bromine addition in combination with ESP-only PM controls. In this case, no data are available, but an increase in the percent oxidized mercury might be expected due to the presence of bromine in the flue gas. Therefore, the current recommendation in the absence of any measurement data is to use the existing correlation for the SCR ESPc configuration as a means to account for increased oxidized mercury levels at the stack.

Additional new categories of flue gas controls, not previously evaluated as part of the 2014 EFH development, were also considered in the emission estimation process. These control types were identified by reviewing the plant configuration database described previously in Section 2 and are listed in Table D-1 along with details as to how speciated mercury estimates were generated. The configurations are not explicitly defined as MATS controls, but required some decisions regarding whether it is appropriate or how to apply existing speciated mercury correlations and factors in the absence of stack measurement data. A significant number of plants were noted in the plant database as having DSI for SO_3 control [DSI(SO3)] so this category could be important in terms of the speciated mercury emissions inventory. In the case of DSI(SO_3), there is a potential for impact on mercury oxidation in the flue gas, since injection of sorbents such as trona may often occur upstream of the air heater in a region far enough upstream in the gas path where removal of halogens from the flue gas could change the oxidized mercury profile in the flue gas. However, information in the plant database indicated that DSI(SO_3) is only used in combination with wet FGD scrubbers, so for units with wet scrubbers + DSI(SO_3) the mercury profile at the stack will still remain at 95% elemental mercury as noted above.

Table D-1
Summary of Additional New Control Configurations Not Represented in the Current 2014 EFH – Speciated Mercury

New Configuration or Control Type	% Elemental Mercury Factor	Notes
ReACT	23	Multipollutant control technology. Dry scrubbing process using a moving activated coke bed (similar to activated carbon) downstream of FF particulate control device. Assume same as existing factor for FF (23% elemental) since ReACT will be in place downstream of a FF system. No measurement data on speciated mercury was identified.
FF CDS	use FF FGDd coal Cl correlation	SO_2/PM control. Assume same as FF FGDd correlation. No data identified.
ESPc CDS	94	SO_2/PM control. Assume same as ESPc FGDd factor. No data identified.
All FGDw with DSI(SO_3)	95	95% elemental assumed for all wet FGD configurations.
ESP or FF with FGDw and Wet ESP	99	Wet ESPs are expected to remove a high percentage of any remaining oxidized Hg exiting the wet FGD, so removals will be very high for oxidized Hg. 99% assumed. No data identified.

CDS = circulating dry scrubber, FBC = fluidized bed combustor, ESP = electrostatic precipitator, FF = fabric filter, DSI(SO3) = dry sorbent injection for SO3 control, FGDd = spray dryer, ESPc = cold-side electrostatic precipitator

The other new control categories with significant numbers of units are circulating dry scrubbers. No information on speciation of mercury at the stack for CDS systems was identified by EPRI. Therefore, since CDS systems are similar to dry FGD scrubbers in terms of reagent type and chemistry, the current emission factors for FF FGDd and ESPc FGDd were used to estimate emissions of speciated mercury for the two CDS technology combinations shown in Table D-1.

Selenium

ACI/HACI –The overall conclusion based on review of information from the literature and EPRI studies is that there is no consistent trend with regard to the ability of ACI and HACI to impact selenium emissions. Therefore, no modifications to existing selenium correlations or factors are warranted at this time for MATS categories involving ACI or HACI. Supporting references are provided below.

(EPRI, 2009) Analysis of Method 29 Metals Data from Mercury Control Demonstration Programs, Draft Report, September 2009

This study evaluated M29 particulate control device (PCD) inlet/outlet data from eight coal-fired units having data from both baseline and sorbent injection test periods. Only one site used a halogenated carbon. Four reports had total M29 measurements and four reports had vapor phase only measurements. Stack selenium emissions and removals across the ESP or FF PCD with and without carbon injection were compared by the authors to evaluate possible impacts of carbon injection on trace metals. For two of the four sites reporting total M29 concentrations (front and back half fractions) there was a general trend toward increased selenium removal across the PCD during period of carbon injection (PRB coal: 54% removal at baseline compared to >70% during carbon injection, and low S bituminous coal: 93% compared 98%). However, the one site using halogenated carbon showed a minimal decrease in selenium removal during carbon injection (ESPc, PRB coal: 86.4% ESP removal at baseline compared to 84.6% during halogenated carbon injection; ESP outlet emission 11 lb/TBtu at baseline versus 14.2 lb/TBtu with halogenated carbon injection). The fourth site did not report selenium concentrations above the detection limit, so no information could be gleaned from that data set.

Among the four sites reporting only vapor-phase M29 selenium stack data (back half), there was not a consistent trend observed in stack selenium emissions. At two sites (PRB, VS FGDw; and ND lignite, FF FGDd) selenium emissions increased by a factor of four during carbon injection, while at the two sites (Eastern bituminous, ESPc; and PRB, FF) selenium emissions decreased by a factor of four. Removal across the control devices could not be calculated for the vapor-phase only sites since only stack emissions data were available for comparison, so differences in coal selenium concentrations during each test condition cannot be taken into account.

(EPRI, 2011) Laboratory Evaluation of Selenium Transport over Solid Media and Slipstream Evaluation of Selenium Sorbents at a Texas-Lignite Power Plant, Draft Report, September 19, 2011

This study used data from the 2010 ICR to evaluate the coal-to-stack removal of selenium for various control device categories, including an assessment of impacts of ACI on coal-to-stack reduction. For the subbituminous units evaluated, the authors concluded there was no clear positive effect of ACI on Se removal/emissions for either ESP or FF units. For units firing bituminous coals, there were insufficient data to evaluate the effect of ACI.

(Jadhav, 2000) Mechanism of Selenium Sorption by Activated Carbon, Canadian Journal of Chemical Engineering, February 2000.

This study investigated the potential of activated carbon in capturing gas-phase selenium species in the low temperature range (125°C to 250°C) and attempted to identify the mechanism of interaction between selenium species and activated carbon. Selenium dioxide was chosen as the representative selenium species. Activated carbons with different structural properties were studied as adsorbents for selenium dioxide capture at low temperature. The capture mechanism was found to involve both physical and chemical adsorption in the low temperature range. At 125°C, only about 1.5 wt% of selenium was captured at equilibrium.

(Blythe, 2012) 2012 MEGA Paper on CPS Plant Spruce Selenium Testing

At Spruce (PRB coal, SCR, reverse-gas FF, FGDw) with the addition of about 30 ppm Br to the coal, the Se concentration in the fly ash dropped by 18% (29.0 ppm vs. 23.8 ppm selenium in the fly ash) with a corresponding 4-fold increase in total selenium concentration in the FGD slurry. A cursory selenium balance confirmed that the decrease in fly ash capture was equivalent to the mass of Se increase in the scrubber. Brominated PAC injection was also tested at Spruce during the same timeframe and was found to have minimal impact on selenium capture in the ash, unlike coal bromine addition.

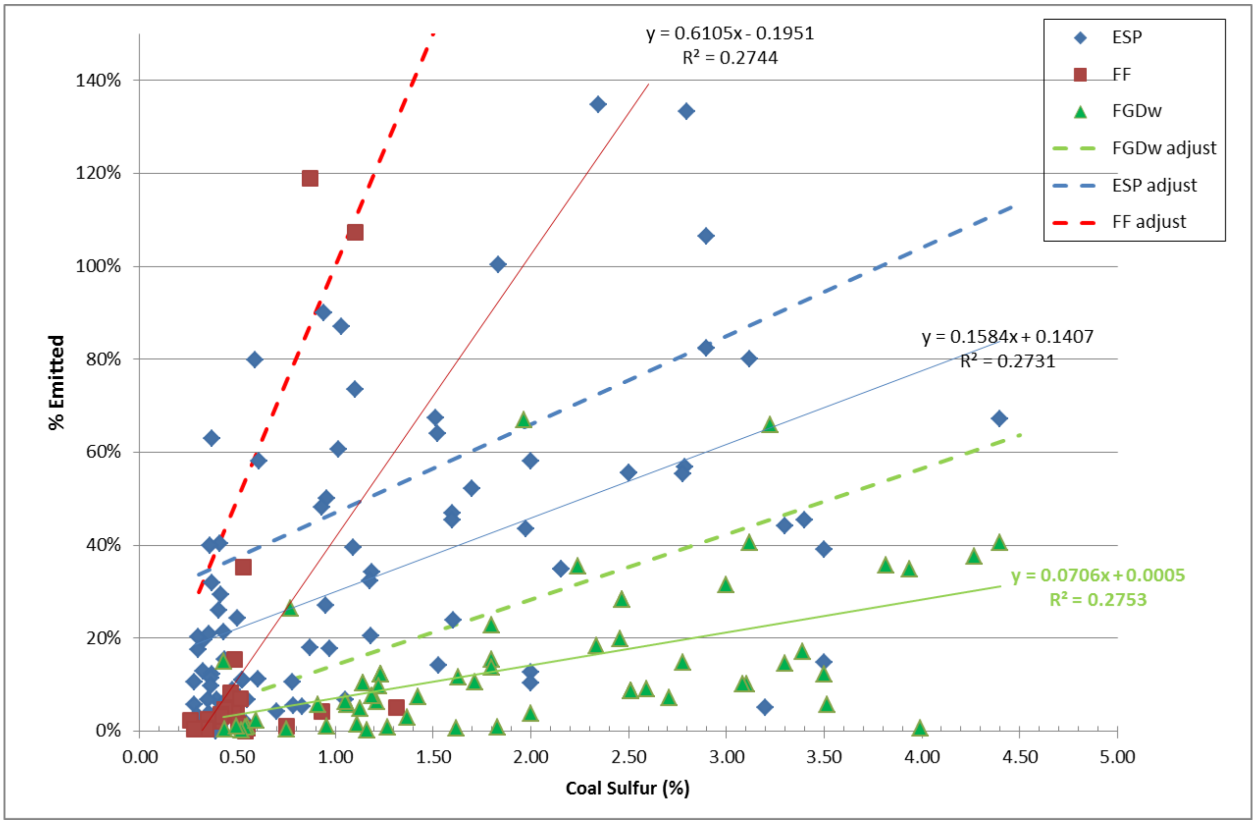
FuelBr –The conclusion based on review literature information is that fuel bromine addition may increase emissions of selenium for control configurations using only electrostatic precipitators (ESPs) or fabric filters (FFs), or any PM control in combination with wet flue gas desulfurization (FGD). The dosing rate of bromine may be important, but there is only limited data available to make any assessment in that regard. Table D-2 summarizes the adjustments to existing selenium emission factors and correlations that were used in this study based on this current body of information. Figure D-1 shows the existing selenium correlation equations (% of coal selenium emitted as a function of coal sulfur content), as well as the adjustment in the correlations to account for possible increases in emissions due to FuelBr addition for MATS control. Note that the adjustment to correlations shown in Figure D-1 as dashed lines are based on professional judgement given the currently available information described below. The dashed lines do not represent regression of specific data points for units using FuelBr MATS control for mercury since the data discussed below are not available in the appropriate form to plot on Figure D-1 (i.e., much of the data regarding impact of FuelBr on selenium are based on difference in fly ash selenium content rather than flue gas selenium measurements). Supporting references are provided following Figure D-1.

Table D-2
Summary of Current Emission Factor Categories for Units with Additional Fuel Bromine MATS Controls – Selenium

2014 EFH Category + MATS Combinations	% of Coal Se Emitted	Notes
ESP	Coal S correlation Examples for low and high S coals: Coal S = 0.5wt% % emitted = 22; Coal S = 4wt% % emitted = 78.	% coal Se emitted = [(multp*coal S wt%) + constant] * 100
+FuelBr (all combinations)	adjust slope by 1.2x and double the intercept constant (increases % emitted values for all coal S levels) Examples for low and high S coals: 0.5% S = 38% emitted 4% S = 100% emitted	Data presented at MEGA 2012 show evidence that fuel Br addition may increase the amount of Se emitted. At Spruce, there was 18% less Se captured in the ash collected in the FF for low S PRB site during 30 ppm Br coal addition. Brominated PAC injection was also tested at Spruce, but no change on Se capture in ash was observed. No FF outlet gas selenium measurements were made to verify. (Blythe, 2012) For a low S bit coal site with ESPc using 250 ppm Br coal addition, selenium removals with the ash dropped from 70% (30% emitted) to only 20% (80% emitted). No ESP outlet gas selenium measurements to verify. (EPRI, 2010) B&W 2013 PowerGen Mitigent paper shows data for two sites with and without bromine addition: 1) Eastern Bit, SCR ESP FGDw measured vapor phase Se concentrations at the ESP inlet increased by 5X during fuel Br addition; 2) low S PRB, SCR ESP FGDw measured vapor phase selenium concentrations at the FGD inlet increased by 2.4X during bromine addition. The B&W paper cited numerous other references where significant increases in selenium levels in the FGD liquid were noted during bromine addition (however no flue gas Se measurements were taken in these test programs to verify impact on changes in flue gas or stack emission concentrations). (Madgi, 2013)
FF	Coal S correlation Coal S = 0.5wt% % emitted = 11; Coal S = 4wt% % emitted = 100.	% coal Se emitted = [(multp*coal S wt%) + constant] *100
+FuelBr (all combinations)	adjust slope to 1 and increase the intercept constant from -0.195 to 0 (increases % emitted values for all coal S levels).	Refer to above discussion for ESP + FuelBr ACI.

Table D-2 (continued)
Summary of Current Emission Factor Categories for Units with Additional Fuel Bromine MATS Controls – Selenium

2014 EFH Category + MATS Combinations	% of Coal Se Emitted	Notes
all with FGDw	Coal S correlation Coal S = 0.5wt% % emitted = 3.6; Coal S = 4wt% % emitted = 28.	% coal Se emitted = [(multp*coal S wt%) + constant] * 100
+FuelBr (all combinations)	increase predicted % emitted by values by 2x	Possible increase in Se emission from the scrubber (see ESP notes above) if FGD inlet vapor phase Se concentration increase by 2x to 5x as noted at some sites. Assuming Se removal across the scrubber remains constant, a 2X increase in inlet concentration will result in 2X higher % coal-stack emitted value.
+FuelBr FGDadd (all combinations)	increase predicted % emitted by values by 2x	Possible increase in Se emission from the scrubber (see ESP notes above) if FGD inlet vapor phase Se concentration increase by 2x to 5x. Assuming Se removal across the scrubber remains constant, a 2X increase in inlet concentration will result in 2X higher % coal-stack emitted value. No data to evaluate whether FGD reemissions additives will impact flue gas selenium emissions. FGD additives have been found to change the solid/liquid partitioning of selenium in the scrubber liquor, but it is unknown whether they will alter selenium emissions at the stack. (Blythe, 2015)
ESP FGDdsi	6.2	DSI for SO2 control
+FuelBr (all combinations)	no change	No impact of ACI on Se removal (see above for ESP). DSI for SO_2 assumed to negate any increase in selenium emission due to FuelBr. No data to confirm this assumption.
FF FGDd	0.5	
+FuelBr (all combinations)	1	Assume FuelBr results in 2X increase in Se emissions.



(Note: dashed regression line are based on professional judgement and not based on regression of specific data points for units using FuelBr controls for mercury).

Figure D-1
Existing Selenium Emission Correlations from 2014 EFH and Adjustments to Account for Fuel Bromine Addition

(Blythe, 2012) 2012 MEGA Paper on CPS Plant Spruce Selenium Testing

At Plant Spruce (PRB coal, SCR, reverse-gas FF, FGDw) with the addition of about 30 ppm Br to the coal, the selenium concentration in the fly ash dropped by 18% (29.0 ppm vs. 23.8 ppm) with a corresponding 4-fold increase in total selenium concentration in the FGD slurry. A cursory selenium balance confirmed that the decrease in fly ash capture was equivalent to the mass of Se increase in the scrubber. Brominated PAC injection was also tested at Spruce during the same timeframe and was found to have minimal impact on selenium capture in the ash, unlike coal bromine addition.

(EPRI, 2010) The Evaluation of Calcium Bromide Addition to Furnace and Carbon Addition to JBR for Mercury Control at Southern Company's Plant Yates Unit 1, Draft Report, October 2010

At Plant Yates (low S bituminous coal, ESPc, FGDw), the addition of 250 ppm Br to the coal resulted in a large reduction in selenium capture with the fly ash. By mass balance, at baseline the selenium captured with the fly ash was about 70% of the total selenium captured in the ESP and scrubber; with Br addition the selenium in the fly ash accounted for only 20% of the total selenium captured. There was a corresponding increase of selenium in the FGD liquor from 300 µg/L to 4900 µg/L during fuel bromine addition, supporting the observation that flue gas selenium removal by fly ash is reduced by bromine addition (i.e., more vapor phase selenium enters the FGD scrubber increasing the FGD liquid phase selenium concentrations).

(Madgil, 2013) Selenium Control Using Combustion Additive. PowerGen 2013. BR-1901

A B&W 2013 PowerGen paper related to Mitigent combustion additives presents selenium data for two sites with and without bromine addition:

1) Site 1 (Eastern bituminous coal, SCR ESP FGDw). Vapor phase selenium concentrations at the ESP inlet increased by 5X during fuel Br addition;

2) Site 2 (low S PRB coal, SCR ESP FGDw). Vapor phase Se concentrations at the FGD inlet increased by 2.4X during fuel bromine addition.

None of these selenium test data were generated during periods when the Mitigent reagent was being added. The paper references numerous other studies that documented increased selenium concentrations in the FGD liquor during fuel bromine addition suggesting a decrease in removal of selenium from the flue gas entering the scrubber, but flue gas measurements were not conducted as part of these studies.

(Blythe, 2015) Effects of Mercury Control Technologies on FGD Wastewater. International Water Conference. November, 2015. Orlando, FL. IWC 15-18.

This paper discusses the impacts of various MATS control technologies, including FuelBr and FGDadd on the behavior of selenium and mercury in the FGD wastewater process stream. Coal and fly ash selenium analysis results indicate that the increase is a result of reduced selenium capture with the fly ash during bromide addition to the coal, leading to higher selenium concentrations in the FGD inlet flue gas. Authors noted that the mechanism for this effect has not been determined, nor has it been determined why the effect is seen at some sites but not others. FGD re-emission additives were observed to lower the ORP of the scrubber liquor, which in term impact the speciation of selenium and possibly the solid/liquid partitioning of selenium in the liquor. However, it is unknown if FGD additives impact selenium emissions at the outlet of the scrubber.

FGDadd – FGD additives used to control mercury re-emissions are typically organic or inorganic based molecules that contain reduced sulfur groups, or are PAC-based reagents, and have been shown to change the solid/liquid partitioning of selenium and the speciation of selenium in the FGD absorber liquor. However, the impact on overall selenium removal in the scrubber and/or selenium stack emissions are unknown. EPRI is not aware of any studies which document the impact of various FGD additives on stack emission of selenium from units with wet FGD scrubbers. In the absence of such data, the current recommendation is no change to the existing FGDw selenium correlation shown previously in Figure D-1. Additional supporting information is documented in the reference cited above (Blythe, 2015).

DSI(HCl) – Injection of alkaline reagents is expected to reduce the concentration of selenium in the flue gas and enhance capture with the ash collected in the ESP or FF particulate control device. Table D-3 provides a summary of the various selenium emission factor categories where the impact of additional DSI(HCl) MATS control was considered.

Table D-3
Summary of Current Emission Factor Categories for Units with Additional DSI(HCl) MATS Configurations – Selenium

2014 EFH Category + MATS Combinations	Se EF, % of Coal Se Emitted	Notes
ESP	Coal S correlation Coal S = 0.5wt% % emitted = 22; Coal S = 4wt% % emitted = 78.	% coal Se emitted = [(multp*coal Swt%) + constant] * 100
+ DSI(HCl) (all combinations)	22	Alkaline DSI removes Se and decreases % coal Se emitted. AECOM SBS injection data for SO_3 control shows 60-90% removal of selenium with the ash across the ESP (~10-40% coal Se emitted at the ESP outlet) from the flue gas at a high S coal site. If DSI for HCl, assume the low S end of the correlation (0.5% S, 22% emitted) for alkaline ash coals hold true for Se emissions. (URS, 2014) Alkaline ash PRB coal sites also show significant capture of selenium with the ash supporting the assumption that DSI of alkaline reagents will remove selenium from the flue gas (Senior, 2011)
+FuelBr DSI(HCl) (all combinations)	See adjustments to ESP correlation above for FuelBr	See adjustments to ESP correlation above for FuelBr
FF	Coal S correlation Coal S = 0.5wt% % emitted = 11; Coal S = 4wt% % emitted = 100	% coal Se emitted = [(multp*coal Swt%) + constant] * 100
+ DSI(HCl) (all combinations)	11	Same rationale as above for +DSI(HCl). Use low end of S correlation at 0.5wt% S and 11% emitted.
ESP FGDdsi	6.2	FGDdsi refers DSI for SO_2 control
+ DSI(HCl) (all combinations)	no change	Assume DSI for HCl offers no added benefit for selenium removal over DSI for SO_2. Existing 2014 EFH factor of 6.2% of coal Se emitted is based on 2010 ICR test data for two subbituminous units at one station reporting the use of DSI for SO_2 control.

ESP = electrostatic precipitator, FF = fabric filter, FGDdsi = sorbent injection for SO_2 control; ESPc = cold-side electrostatic precipitator; SBS = sodium bisulfite; HL = hydrated lime

Data from two EPRI-sponsored DSI test programs were identified (EPRI 2015a, EPRI 2015b): Plant Bowen pilot baghouse testing consisting of baseline and hydrated lime injection at various rates; and Plant Stanton full-scale ESPc testing consisting of baseline and "advanced hydrate" as well as trona injection at various rates. Both test programs showed consistently lower selenium flue gas concentrations at the FF and ESP outlet during hydrated lime injection compared to baseline. Specific details from each report are presented below. It has also been documented that alkaline ash from PRB coals results in significant capture of selenium as noted in the paper below which presented a detailed mass balance evaluation of selenium data from several test sites (Senior, 2011). In addition, data for SBS alkali reagent injection to control SO_3 at a high sulfur site with ESP control resulted in 60-90% selenium removal with the ash across the ESP for a range of molar ratio injection rates and flue gas temperatures (URS, 2014). A draft report prepared by AECOM for EPRI regarding the integration of DSI and mercury controls also cites the potential for increased concentrations of selenium in the fly ash during injection of reagents such as hydrated lime and sodium-based sorbents (EPRI, 2014a), (EPRI, 2014b). Therefore, DSI of alkaline reagents to control HCl and/or SO_3 is also expected to remove flue gas selenium to some extent. The approach for units with ESP and FF PM control + DSI(HCl) is to use the low sulfur (0.5wt%, PRB alkaline ash coal) end of existing selenium correlations shown previously in Figure D-1. The resulting factors obtained from the correlations are 22% coal selenium emitted for ESP units and 11% for FF units. Highlights from supporting references are summarized below.

(Senior, 2011) Multimedia Emissions of Selenium from Coal-Fired Electric Utility Boilers. Air Quality VIII. October 2011.

This paper contains a detailed mass balance review of the multi-media fate of selenium for 11 units from 7 coal-fired plants where measurements were conducted. Alkaline ash PRB coal sites with fabric filters showed that nearly all the selenium in the coal was captured with the fly ash, compared to only about 40% for bituminous units equipped with ESPs. Information for alkaline ash coal sites were assumed to provide some indication of the impact of using alkaline sorbent injection.

(EPRI, 2015a) *Utility Pulse Jet Baghouse Performance 2015 Update: Studies at Plant Bowen Pilot December 28, 2015. 3002006153*

Report presents test data from a pilot-scale baghouse system at Plant Bowen treating a slip-steam of flue gas downstream of the air heater. Hydrated lime was injected upstream of the FF at various rates. Baghouse inlet and outlet concentrations are summarized below for selenium, arsenic, and HCl. Bowen fires an Eastern bituminous, medium sulfur (~2%), high chloride (~2000 mg/kg) coal with a relatively high selenium content (~2-3 mg/kg), based on 2015 Form 923 fuel shipment and USGS trace element data for coal sources that shipped to Bowen. As shown below, baseline selenium removal as about 14% compared to 51 to 72% during various hydrated lime injection tests. Selenium removals increased with increasing injection rates. Removals for arsenic also increased with increasing injection rate compared to baseline. DSI injection at the rates tested did not result in any removal of HCl across the FF compared to baseline.

Species	Injection Rate (lb/hr)	FF Inlet (mg/dscm)	FF Outlet (mg/dscm)	Inlet/Outlet Removal (%)
Arsenic	0 (baseline)	0.0067	0.0055	17.8
	HL 6 lb/hr	0.0083	0.0043	48.5
	HL 6 lb/hr (continuous)	0.0093	0.0043	53.1
	HL 12 lb/hr	0.0079	0.0035	56.2
Selenium	0 (baseline)	0.110	0.095	13.6
	HL 6 lb/hr	0.136	0.067	50.7
	HL 6 lb/hr (continuous)	0.173	0.058	66.8
	HL 12 lb/hr	0.151	0.042	72.4
HCl	0 (baseline)	142.0	121.7	14.2
	HL 6 lb/hr	138.0	157.4	-14.0
	HL 6 lb/hr (continuous)	142.1	179.4	-26.3
	HL 12 lb/hr	65.2	71.5	-9.7

(EPRI, 2015b) Mercury and Air Toxics Control. December 16, 2015. 3002006155

This report presents test data from full-scale DSI tests across the ESPc system at Plant Stanton. Hydrated lime (“advanced hydrate” from two vendors) and trona were injected upstream of the ESPc at various rates. ESPc outlet concentrations are summarized below for selenium, arsenic, and HCl. Stanton fires a PRB subbituminous, low sulfur (0.4%), low chloride (~20 mg/kg) coal with relatively low selenium content (~0.7 mg/kg) based on 2015 Form 923 fuel shipment and USGS trace element data for coal sources that shipped to Stanton. Selenium emissions at the ESP outlet were lowest at the middle injection rate for both sorbent types tested and were about 30 to 35% of the baseline (i.e., no DIS injection) selenium concentrations. Arsenic results were inconclusive. HCl concentrations decreased as the injection rate increased, with a maximum removal (calculated as the ratio of injection to baseline concentration) of 78% for the vendor A advanced hydrate and 91% for Vendor B trona ash shown below.

	Vendor A (Advanced Hydrate)		Vendor B (Advanced Hydrate As and Se, Trona HCl)	
Species	Injection Rate (lb/hr)	ESP Outlet (ppbv) or (ppmv HCl)	Injection Rate (lb/hr)	ESP Outlet (ppbv) or ppmv HCl)
Arsenic	0 (baseline)	0.05	0 (baseline)	0.05
	2025	0.13	1816	0.08
	3261	0.07	3196	0.23
Selenium	0 (baseline)	0.71	0 (baseline)	0.71
	2025	0.21	1816	0.25
	3261	0.40	3196	0.52
HCl	0 (baseline)	7.33	0 (baseline)	6.68
	429	6.17	403 (trona)	3.82
	841	4.98	1022 (trona)	2.17
	1530	3.14	1355 (trona)	1.85
	3015	2.15	2353 (trona)	0.57
	4042	1.62	-	-

(URS, 2014) Combined Mercury and SO_3 Removal Using SBS Injection. Power. July 1, 2014

This article presents full-scale test data for SBS showing 60%-90% capture of selenium with the fly ash in the ESP during injection, and 40% to 70% removal of HCl with the ESP ash during SBS injection at various molar ratios and flue gas temperatures. 40% HCl reduction was achieved at typical SBS injection rates, while higher removals were obtained at higher molar ratios that resulted in excess reagent being available to react with HCl.

(URS, 2008) Hg, HCl & Se Co-Removal with SO_3 Control. 2008 APC/PCUG Conference Savannah, Georgia. July 13-18, 2008.

The presentation cites test data for SBS showing selenium co-removal with the ash as a result of SBS injection. Baseline native selenium capture based on coal and ash measurement was about 20% compared to almost complete selenium capture during SBS injection.

(EPRI, 2014a) Integrating DSI and Mercury Controls. Draft report, October 2014.

Report notes that one of the balance of plant impacts for DSI controls such as hydrated lime and sodium-based sorbents is an increase in the selenium content of the collected fly ash. No specific fly ash or flue gas measurement data are presented, but numerous references to other studies are documented.

(EPRI, 2014b) Mercury and Air Toxics Control Update. 3002003403. December 18, 2014.

Report presents similar information as described above for the draft 2014 report, and also includes information regarding the cost tradeoffs between using DSI for selenium flue gas control upstream of a wet scrubber and treatment of the FGD wastewater to remove selenium capture from the flue gas in the wet scrubber.

Additional New Control Types – Table D-4 provides a summary of the selenium emission factor approach for new categories of control not considered in the previous 2014 EFH. Many only apply to a small number of coal-fired units. CDS controls and DSI(SO3) apply to largest number of units. The plant database shows that DSI(SO3) control is only used at units equipped with FGDw control. Based on the SBS data for selenium at the one high S coal-fired unit, the approach is to use one-half of the % emitted values predicted by the current 2014 EFH FGDw selenium correlation shown above in Figure D-1. Supporting references are described below.

Table D-4
Summary of Additional New Control Configuration Not Represented in the Current 2014 EFH - Selenium

New Configuration or Control Type	Se EF, % of Coal Se Emitted	Notes
All FGDw with DSI for SO_3 control	Use 1/2 of the current FGDw correlation predicted values when DSI(SO3) is present. If DSI for SO3 used in combination with FuelBr addition no change.	Injection of SBS, HL, or trona. DSI(SO3) is only reported in the plant database for units using FGDw. Reduce the current FGDw correlation predicted % emitted values by 50%. If DSI(SO3) used in combination with FuelBr addition, the ½ correction negates the 2X increase cited above for FuelBr + FGDw, so no net change in Se emissions. Alkaline DSI material will remove vapor phase Se. SBS data shows 60-90% Se removal possible in the ash during injection at various molar ratios and flue gas temperatures. If FGD inlet selenium concentrations are reduced by 50% due to DSI(SO3), then corresponding FGD outlet stack emission will be reduced by 50%, assuming selenium removal across the scrubber remains constant. (URS, 2014)
ReACT	Use existing FF-coal sulfur correlation	Multipollutant control technology. Activated coke adsorption with regeneration. Dry scrubber with moving activated coke bed. Use existing FF-coal sulfur correlation. EPRI test data for selenium not available in M29 test data set from a pilot unit. (EPRI, 2008)
FF CDS	0.5	SO_2/PM control. Assume same as existing FF FGDd factor. No data identified to date.
ESPc CDS	6.2	SO_2/PM control. Assume same as existing ESPc FGDdsi factor. No data identified to date.
ESP or FF with FGDw + Wet ESP	0.05	Significant reduction of Se by wet ESPs are expected. ICR data for units with FGDw + Wet ESP show some of the lowest selenium emissions for units tested in the 2010 ICR. Assume 99.95% overall reduction (0.05% of coal emitted)

CDS = circulating dry scrubber; FBC = fluidized bed combustor; ESP = electrostatic precipitator; FF = fabric filter, DSI(SO3) = dry sorbent injection for SO_3 control; DSI(SO2) = dry sorbent injection for SO_2 control; FGDd = spray dryer; ESPc = cold-side electrostatic precipitator

(EPRI, 2008) ReACT Process Evaluation at the North Valmy Station

This reference presents pilot scale test data for removal of acid gases and trace metals across the ReACT process; however, selenium data were not included in this presentation material, so it is unknown if selenium measurement were conducted.

HCl and HF

Adjustments to 2014 EFH emission factors were related to the use of DSI for control of HCl [DSI(HCl)]. Table D-5 below provides a summary of the HCl and HF factors used to estimate emissions and any modifications to current emission factors for HCl and HF are noted.

For units using DSI for HCl control, our assumption is that the DSI system will be optimized at each site to meet the MATS limit for HCl (or SO_2 surrogate limit), or some fraction of the MATS limit to ensure compliance with a 30-day rolling average. Therefore, for purpose of estimating HCl emissions, HCl emissions were estimated using the factors listed in Table D-5 (expressed as % of coal chloride emitted as HCl) and compared the resulting value to the MATS limit. If the predicted value is less than the limit, the predicted value was used. If the value is greater than the limit, emissions were set to the MATS limit of 0.002 lb/MMBtu.

For HF, a MATS limit does not exist; therefore, the approach used was to calculate the percent coal emitted value using the values listed in Table D-5.

There was no information or no technical basis for assuming that other MATS controls such as ACI, HACI, non-carbon sorbent injection (NCSI), FGDadd, or FuelBr would have an impact on emission of HCl or HF.

Additional New Control Types - Emission factor values assigned to new control types not considered in the 2014 EFH are listed in Table D-6. In the case of units using DSI for SO_3 control [DSI(SO3)], the plant database indicates that DSI(SO3) is only used in combination with wet FGD scrubbers. DSI(SO3) may provide some added removal of HCl and HF from the flue gas upstream of the scrubber. Full-scale test data for the SBS alkali injection technology at a high S coal site showed that at typical SBS alkali sorbent injection rates, roughly 40% HCl capture was achieved with the ash across the ESP, while elevated injection rates resulted in nearly 70% HCl capture (URS, 2008; URS, 2014). These results were consistent with previous SBS testing that showed SO_3 is preferentially removed, with excess sorbent available to remove HCl present in the flue gas. Results at a given plant will depend on the relative concentrations of SO_3 and HCl in the flue gas, and the overall sorbent injection rate. Assuming a 40% reduction in HCl entering the FGD scrubber, the resulting stack emissions of HCl would also be reduced by 40% assuming HCl removal across the scrubber is constant. However, since the amount of excess DSI reagent for SO_3 control is unknown for any given plant and no additional data were identified for other DSI(SO3) reagents such as hydrated lime or trona, it was determined that no change in existing 2014 EFH emission factors was warranted to account for DSI(SO3), especially since the wet FGD used in combination with DSI(SO3) will provide very effective control of HCl and HF acid gas species anyway. Any adjustment to the factors was deemed to be relatively small and likely have a minor impact on emission estimates; therefore, none were made.

Additional supporting references for new control technology types listed in Table D-6 are provided below:

(EPRI, 2008) ReACT Process Evaluation at the North Valmy Station

Presentation slides show pilot scale test data at Valmy for removal of acid gases and trace metals across the ReACT process. Test data show 70% removal of HF. HCl concentrations in the ReACT inlet flue gas were too low to accurately quantify removal.

Table D-5
Summary of Existing Emission Factor Categories having DSI(HCl) MATS Control – HCl/HF

	HCl			HF		
Control Category	Existing 2014 EFH EF (% Coal Emitted)	Adjusted EF with DSI(HCl) (% Coal Emitted)	Reason	Existing 2014 EFH EF (% Coal Emitted)	Adjusted EF with DSI(HCl) (% Coal Emitted)	Reason
ESP	88	23	EF for "all FGDdsi" (23%) or MATS limit	85	9.7	EF for "all FGDdsi" (9.7)
ESP Sub	40	23	EF for "all FGDdsi" (23%) or MATS limit	19	9.7	EF for "all FGDdsi" (9.7)
ESP FGDdsi	23	23	No change or MATS limit	9.7	9.7	No change
ESP FGDw	2.7	2.7	No change or MATS limit	3.4	3.4	No change
ESPh FGDdsi	23	23	No change or MATS limit	9.7	9.7	No change
FBC	39	23	EF for "all FGDdsi" (23%) or MATS limit	6.4	6.4	No change
FF	75	23	EF for "all FGDdsi" (23%) or MATS limit	65	9.7	EF for "all FGDdsi" (9.7)
FF Sub	21	21	No change or MATS limit	65	9.7	EF for "all FGDdsi" (9.7)
FF FGDd	13	13	No change or MATS limit	2.3	2.3	No change
FF FGDdbit	0.7	0.7	No change or MATS limit	2.3	2.3	No change
FF FGDdsi	23	23	No change or MATS limit	9.7	9.7	No change
FF FGDw	2.7	2.7	No change or MATS limit	3.4	3.4	No change
VS FGDw	2.7	2.7	No change or MATS limit	3.4	3.4	No change

Table D-6
Additional New Control Configuration Not Represented in the Current 2014 EFH – HCl/HF

New Configuration or Control Type	% of Coal Cl Emitted as HCl	% of Coal F Emitted as HF	Notes
ReACT	Use MATS limit or "FF Sub" (21)	Use MATS limit or "FF Sub" (65)	Multipollutant control technology. Activated coke adsorption with regeneration. Dry scrubber technology with moving activated coke bed and FF controls for particulate matter. EPRI pilot test data from Valmy show 70% removal of HF. HCl at inlet was too low to accurately quantify removals. (EPRI, 2008) Limited test data, therefore use existing "FF Sub" EFH category factors (21% HCl, 65% HF).
FF CDS	Use MATS limit or factors below, whichever is lowest 13 (sub/bitw) 0.7 (bit)	2.3	PM/SO_2 control. Assume same as FF FGDd by coal type. Use MATS limit or FF FGFDd factors whichever is lowest. No data identified to date.
ESPc CDS	Use MATS limit or 9.4	3.9	PM/SO_2 control. Assume ESP performance not as well as FF CDS, so used 9.4% for HCl and 3.9% for HF. No data identified.
ESPc FGDd	Use MATS limit or 9.4	3.9	PM/SO_2 control. Assume ESP performance not as well as FF FGDd, so used 9.4% for HCl and 3.9% for HF. No data identified.

Table D-6 (continued)
Additional New Control Configuration Not Represented in the Current 2014 EFH – HCl/HF

2014 EFH Category + MATS Combinations	% of Coal Cl Emitted as HCl	% of Coal F Emitted as HF	Notes
All configs with DSI for SO_3 control (only used with FGDw)	No change. Use existing “all FGDw” (2.7)	No change. Use existing “all FGDw” (3.4)	DSI(SO3) only reported in combination with FGDw based on Marchetti plant database. For example, injection of SBS, HL, or Trona. SBS data show 40-70% HCl removal with the ash across the ESP at varying SBS injection rates. Only one data point and the ability of DSI(SO3) to capture HCl will depend on site specific SO_3/HCl ratios and amount of excess DSI reagent injected; therefore, no change to existing FGDw emission factors are recommended. If PM control only with DSI(SO3), then a % emitted factor of 45% might be appropriate based on SBS data. (URS, 2014)
ESP or FF with FGDw + Wet ESP	1.0	3.4	Assume wet ESP will remove HCl/HF on the back end of a wet scrubber (already low HCl/HF at ~95% reduction anyway). Assume wet ESP will reduce any HCl left at the scrubber outlet to 1% emitted levels compared to current factor of 2.7% for the All FGDw category. Use All FGDw value of 3.4% for HF. No data for Wet ESPs identified.
IGCC	0.1	0.1	Best judgement

ESP = electrostatic precipitator, FF = fabric filter, FGDdsi = sorbent injection for SO_2 control; ESPc = cold-side electrostatic precipitator; CDS = circulating dry scrubber, FBC = fluidized bed combustor, ESP = electrostatic precipitator, FF = fabric filter, DSI(SO3) = dry sorbent injection for SO_3 control; FGDd = spray dryer; ESPc = cold-side electrostatic precipitator, IGCC = Integrated gasification combined cycle; sub = subbituminous; bit = bituminous; bitw = western bituminous; lig = lignite

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 (Plant ID = 1893). Table E-1 summarizes 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)	2015 Annual Heat Input (TBtu/yr)	Coal Hg (ppmw)	Coal As (ppmw)	Coal Se (ppmw)	Coal Cl (ppmw)	Coal Ash (wt%)	Coal Sulfur (wt%)	Filterable Particulate Emissions (lb/MMBtu)
1	9,036	5.40	0.051	2.18	0.77	13	5.1	0.30	0.015
2	9,036	5.47	0.051	2.18	0.77	13	5.1	0.30	0.015
3	9,036	26.44	0.051	2.18	0.77	13	5.1	0.30	0.015
4	9,036	35.86	0.051	2.18	0.77	13	5.1	0.30	0.015

Mercury

Total mercury emissions were calculated based factors derived from information reported in the EPA AMPD database from September 2015 through March 2016 as noted in Table E-2 and documented in Appendix C. When AMPD values were not reported, default average values were assigned. The default average for non-lignite and lignite coal-fired units were derived from unit average values obtained for approximately 240 units in the AMPD database that had reported total mercury emissions. When computing these averages, any units with total mercury emissions greater than the MATS limit of 1.2 lb/Tbtu (non-lignite, existing coal-fired units) or 4 lb/TBtu (lignite, existing coal-fired units) were set equal to their respective the MATS limit. Similar calculations were performed for lignite coal-fired units in the AMPD data set, resulting in an average default value of 2.5 lb/TBtu. The resulting data sets were used to compute the default average values.

Correlations or average factors were used to calculate three values: elemental mercury emissions, oxidized mercury emissions, and particulate mercury emissions associated with each coal-fired unit. Speciated mercury emission correlations were developed based on plant configuration as described in Section 4. Sample calculations for the Clay Boswell 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.

Table E-2
Total Mercury Emissions and Speciated Mercury Correlation Constants for Clay Boswell

Unit	NOx/PM/SO2 Control Config	MATS Control Config	Total Mercury (lb/TBtu)	Elemental Percentage Constants (%)		Particulate Percentage Constants (%)
				Ef	Ec	Pc
1	SNCR FF	Existing APC	0.5 [a]	0%	23%	1.0%
2	SNCR FF	Existing APC	0.5 [a]	0%	23%	1.0%
3	SCR FF FGDw	ACI	0.234 [b]	0%	95%	1.0%
4	SCNR FF FGDd (i.e., FF with circulating dry scrubber)	HACI	0.5 [c]	-16.2%	170%	1.0%

[a] The value calculated based on EPA AMPD information was erroneously low; therefore, average default value of 0.5 lb/TBtu was assigned.

[b] Based on reported AMPD data.

[c] The value calculated based on EPA AMPD information exceeded the MATS limit for mercury; therefore, average default value of 0.5 lb/TBtu was assigned. AMPD data available at the time of the analyses was not considered representative of final MATS mercury control performance.

Total Mercury Emissions

Table E-2 provides the final total mercury emission factor values used based on information from the EPA AMPD database. Units at Clay Boswell fired non-lignite coal. For Units 1 and 2, the information from the database resulted in erroneously low total mercury value; therefore, a default average value of 0.5 lb/TBtu for non-lignite units was assigned. For Unit 3 the AMPD value of 0.23 lb/Tbtu was selected. Unit 4 AMPD data resulted in a total mercury value greater than the MATS limit of 1.2 lb/TBtu, presumably since the measurement data did not reflect complete implementation of mercury MATS controls at this unit at the time data were collected and reported. Therefore, the default average value was also selected for Unit 4.

The mass of total mercury emitted is calculated as follows:

$$Hg_{Emit} = (Hg_{stk} * \ BTU_{consumed})$$

Where Hg_{Emit} is the total mass of Hg emitted, Hg_{stk} is the total mercury emission factors from Table E-2 and $BTU_{Consumed}$ is the total energy input in trillion BTU per year.

For Unit 1 this equation becomes:

$$Hg_{Emit} = (0.5 * 5.40) = 2.7 \text{ lbs Hg per year}$$

The results for the remaining units at Clay Boswell are in Table E-3.

Table E-3
Total Mercury Emitted at Clay Boswell per Year

Unit	Hg_{Emit} (lb/yr)
1	2.7
2	2.7
3	6.2
4	17.9

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-4 below shows the results for Clay Boswell.

Table E-4
Annual Mercury Emissions by Stack at Clay Boswell

Stack Emission Point	Hg_{emit} (lbs/yr)
1 (U1-3)	11.6
2 (U4)	17.9

Particulate Mercury Emissions

For particulate mercury emission fractions, a value of 1% of the total mercury was used for all coal-fired units. 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:

$$Hg_P = 2.7 * 1.0\% = 0.03 \text{ lbs particulate Hg per year}$$

Values for the remaining units at Clay Boswell are shown in Table E-5.

Table E-5
Particulate Mercury Emissions at Clay Boswell, by Unit

Unit	Hg_P (lbs /yr)
1	0.027
2	0.027
3	0.062
4	0.18

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. Cl is the chlorine content of the coal in parts per million by weight (ppmw). Values for Cl, E_c and E_f are taken from Tables E-1 and E-2.

An example calculation is shown below for Unit 1, with results for the other units provided in Table E-6:

$$\%E = 23\% + [0 * \ln(13)] = 23\%$$

Table E-6
Elemental Mercury Emission Percentage at Clay Boswell by Unit

Unit	Elemental Emission Percentage (%)
1	23
2	23
3	95
4	100*

*Set equal to the max limit for the coal Cl correlation for elemental mercury.

As described in Section 4, for all units with FGDw controls, the percentage of total mercury present as elemental mercury at the stack was assumed to be 95%; previous EPRI correlations for % elemental mercury were not used in these instances. 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, the elemental percentage was set to the defined upper limit of the correlation. These values are listed in Table E-7. This was the case for Unit 4, where the correlation for % elemental mercury resulted in a predicted value of 128%; therefore, the value was set to the upper limit of 100%. For Unit 4, the value predicted by the correlation is calculated as follows:

$$\%E = 170\% + [-16.2\% * \ln(13)] = 128\% \text{ (max = 100\%)}$$

Table E-7
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
ESPh	5	92
SCR ESPc	1	85
All FF FGDd	41	100

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

$$Hg_E = (Hg_{Emit} – Hg_P) * \%E$$

For Unit 1 this becomes:

$$Hg_E = (2.7 – 0.027) * 23\% = 0.61 \text{ lbs elemental Hg per yr}$$

The results for the remaining units at Clay Boswell are shown in Table E-8.

Table E-8
Emitted Elemental Mercury at Clay Boswell by Unit

Unit	HgE (lbs/yr)
1	0.61
2	0.61
3	5.8
4	17.7

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 Clay Boswell Unit 1:

$$Hg_{Ox} = 2.7 – (0.61 + 0.027) = 2.1 \text{ lbs oxidized Hg per year}$$

Values for the remaining units at Clay Boswell are shown in Table E-9.

Table E-9
Oxidized Mercury Emissions at Clay Boswell, by Unit

Unit	Hg_{Ox} (lbs Hg_{Ox}/yr)
1	2.1
2	2.1
3	0.3
4	0

Selenium

Selenium emission rates were estimated by calculating an annual mass of selenium input with the fuel, and then multiplying by a percent of coal emitted value.

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

$$Se_T = (Se_{Coal} * 10^6 * BTU_{Consumed})/Coal_{BTU}$$

Where Se_T is the total mass of Se input to the unit with the fuel, Se_{Coal} is the "blended" coal selenium concentration (Table E-1), $Coal_{BTU}$ is the "blended" Btu/lb value for the coal (Table E-1), $BTU_{Consumed}$ is the total energy input in trillion Btu per year (Table E-1), and 10^6 is a conversion factor. The equation below shows this calculation for Clay Boswell Unit 1:

$$Se_T = (0.77 * 10^6 *5.40)/9036 = 460.2 \text{ lbs Se input per year}$$

Values for the other units at Clay Boswell are shown in Table E-10.

Table E-10
Annual Fuel Selenium Input at Clay Boswell by Unit

Unit	Annual Se Input (lbs/yr)
1	460.2
2	466.1
3	2253.1
4	3055.8

Based on plant configuration, correlations were used for three of four (Units 1, 2, and 3) to calculate the % of coal selenium emitted. For Unit 4 (FF FGDd), the % of coal selenium emitted was an average factor of 0.5% emitted. Refer to Section 4 for correlation and factor details.

For the SNCR FF configuration on Units 1 and 2, the following FF correlation equation was used to calculate removal:

$$Se_{\%Emit} = (61.05\% * Sulfur_{Coal}) - 19.51\%$$

Where, $Se_{\%Emit}$ = % of coal selenium emitted and $Sulfur_{Coal}$ = weight percent sulfur in the coal.

A sample calculation is shown for Clay Boswell Unit 1:

$$Se_{\%Emit} = (61.05 * 0.3\%) - 19.51 = -1.2\%$$

In this case, the correlation predicts a value less than zero; therefore, the lower limit default value of 0.1 lb/TBtu was used for selenium. This lower limit value for the selenium correlations was selected based on review of the median estimated "blended" coal selenium concentration for all units and assuming 99.9% reduction as a reasonable non-zero lower limit. As discussed in Section 4, there are cases for which adjustments were made to various correlations and factors to account for impact of MATS controls on selenium emissions (e.g., fuel bromine addition for Hg control). However, for the units as Clay Boswell, the MATs control configurations were not categories for which adjustments were required.

Table E-11 shows the calculated % emitted (or lower limit lb/TBtu) values for all units at Clay Boswell based on their control configurations shown previously in Table E-2.

Table E-11
Selenium Factors for Clay Boswell, by Unit

Unit	Se Factor
1	0.1 lb/TBtu (Se_{stk})
2	0.1 lb/TBtu (Se_{stk})
3	2.2% coal Se emitted ($Se_{\%Emit}$)
4	0.5% coal Se emitted ($Se_{\%Emit}$)

These values were then combined with total heat input or total selenium fuel input values to calculate annual selenium emissions, $Se_{Emit,}$ using the equations below:

$Se_{Emit} = (Se_{stk} * BTU_{consumed})$, if Se factor is lb/TBtu basis

Or

$Se_{Emit} = (Se_T * Se_{\%Emit})$, if Se factor is % of coal Se emitted basis

Detailed calculations are shown for Clay Boswell Unit 1 and Unit 3 below:

Unit 1: $Se_{Emit} = (0.1 * 5.40) = 0.54$ lbs Se emitted per yr

Unit 3: $Se_{Emit} = (2253.1 * 2.2\%) = 49.6$ lbs Se emitted per yr

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

Table E-12
Selenium Emissions at Clay Boswell, by Unit

Unit	Se Emissions (lbs/yr)
1	0.54
2	0.55
3	49.6
4	15.4

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:

$EF_{As} = A_{As} * [(As_{Coal}/Ash_{Coal}) * Part_{Emit}]^{B_{As}}$

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/MMBtu, and B_{As} is a correlation coefficient for arsenic. Refer to Section 4 for details on particulate phase metals correlations and Table E-1 for correlation input values.

For Clay Boswell unit 1 this equation becomes:

$$EF_{As} = 2.70 * [(2.18/0.051) * 0.015]^{0.65} = 2.01 \text{ lbs As emitted per TBtu input}$$

Emission factors for the other units at Clay Boswell are shown in Table E-13. All values are identical since the input coal composition and stack FPM values are the same for all units.

Table E-13
Arsenic Emission Factors for Clay Boswell, by Unit

Unit	As Emission Factor (lb/TBtu)
1	2.01
2	2.01
3	2.01
4	2.01

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:

$$As_{Emit} = 2.01 * 5.40 = 10.9 \text{ lbs As emitted per yr}$$

Values for the remaining units at Clay Boswell are listed in Table E-14.

Table E-14
Annual Emission Rate for Arsenic at Clay Boswell, by Unit

Unit	As Emission Rate (lbs/yr)
1	10.9
2	11.0
3	53.2
4	72.2

The correlation methodology for all other metals, except selenium and mercury, are the same as that used above for arsenic. Table E-15 shows the correlation constants for all non-mercury trace elements considered in this report, as described in Section 4.

Table E-15
Correlation Coefficients for non-Mercury Trace Elements

Element	A	B
As	2.7	0.65
Be	0.42	0.53
Cd	0.72	0.31
Co	3.0	0.51
Cr	0.96	0.41
Mn	2.5	0.55
Ni	2.6	0.58
Pb	3.3	0.42
Sb	0.64	0.17

Hydrochloric Acid and Chlorine Gas (Cl_2)

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

$$Cl_T = (Cl_{Coal} * 10^6 * BTU_{Consumed})/Coal_{BTU}$$

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:

$$Cl_T = (13.2 * 10^6 * 5.40) / 9035.9 = 7{,}889 \text{ lbs Cl input per year}$$

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

Table E-16
Chloride Consumption at Clay Boswell, by Unit

Unit	Cl Consumption Rate (lbs/yr)
1	7,889
2	7,991
3	38,625
4	52,387

Once the input rate was calculated, percentage of coal emitted was applied based on plant configuration. These percentages are listed in Table E-17; configurations that apply to units at Clay Boswell highlighted.

Table E-17
% Coal Chloride Emitted as HCl by Plant Configuration and Coal Type

Configuration	% Coal Cl Emitted as HCl (HCl%Emit)
ESP bit or lig	88%
ESP sub	40%
All FGDw (Unit 3)	**2.7%**
FBC	39%
FF bit or lig	75%
FF sub (Unit 1 and 2)	**21%**
FF FGDd sub or bit western (Unit 4)	**13%**
FF FGDd bit	0.7%
All FGDdsi	23%

The equation below was used to calculate the total chloride emitted as hydrochloric acid (HCl):

$$HCl = Cl_T * HCl_{\%Emit}$$

For Clay Boswell Unit 1 (FF sub) this becomes:

$$HCl = 7{,}889 * 21\% = 1{,}657 \text{ lbs HCl emitted per yr}$$

Results for the remaining units at Clay Boswell are shown in Table E-18.

Table E-18
Total Chloride Emissions at Clay Boswell, by Unit

Unit	HCl Emissions (lbs/yr)
1	1,657
2	1,678
3	1,043
4	6,810

For Cl_2, emissions were estimated using the KM median emission factor of 53 lb/TBtu (EF_{Cl2}) for units with any type of control and firing subbituminous coal as described in Section 4 and Appendix B. Note that correlations based on coal Cl content are available for bituminous coal-fired units as described in Section 4.

The final Cl_2 emission rate, Cl_{2Emit}, for Unit 1 is calculated as follows:

$$Cl_{2Emit} = EF_{Cl2} * BTU_{Consumed}$$

$$Cl_{2Emit} = 53 * 5.40 = 286 \text{ lbs } Cl_2 \text{ emitted per yr}$$

Results for the remaining units at Clay Boswell are shown in Table E-19.

Table E-19
Cl_2 Emissions by Type from Clay Boswell

Unit	Cl2 Emissions (lbs/yr)
1	286
2	290
3	1,401
4	1,900

Benzene

A KM median emission factor of 2.0 lb/TBtu for all coal-fired boilers was used to calculate the emission of benzene. Emissions of other selected organic compounds were calculated the same way, using substance specific emission factors. Section 4 provides a complete listing of emission factors for the organic species considered evaluated in the risk assessment.

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:

$$Benzene_{Emit} = 2.0 * 5.40 = 10.8 \text{ lbs benzene emitted per yr}$$

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

Table E-20
Benzene Emissions from Clay Boswell, by Unit

Unit	Benzene Emission Rate (lbs/yr)
1	10.8
2	10.9
3	52.9
4	71.7

Unit emissions for individual HAPs compounds were summed for units with common stacks as described above for mercury to obtain the final stack emission point annual mass emission estimates for each compound.

F

STACK PARAMETERS AT COAL-FIRED POWER PLANT USED IN THE INHALAION PATHWAY RISK ASSESSMENT

Stack Parameters at Coal-Fired Power Plant Used in the Inhalaion Pathway Risk Assessment

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height (ft)	Stack Diam. (ft)	Stack Temp. (deg F)	Stack Velocity (ft/sec)	Heat Input (2015) (10^9 Btu/yr)
3	SOUTHERN-ALPC	BARRY	AL	3#4	600	13.7	280	92	16.18
3	SOUTHERN-ALPC	BARRY	AL	3#5S	600	31.0	134	57	29.18
8	SOUTHERN-ALPC	GORGAS TWO	AL	8#8S-10S	755	38.0	122	48.9	45.39
26	SOUTHERN-ALPC	GASTON (AL)	AL	26#5S	755	34.0	131	58	52.58
47	TVA	COLBERT	AL	47#5	500	21.0	310	97	0.01
51	CLECO	DOLET HILLS	LA	51#1	525	25.0	170	85	49.14
56	POWER SOUTH	CR LOWMAN	AL	56#CS004	400	19.7	130	40.3	11.59
56	POWER SOUTH	CR LOWMAN	AL	56#MS001	250	8.5	130	51	0.08
56	POWER SOUTH	CR LOWMAN	AL	56#MS03C	401	16.5	170	58	6.95
59	GRAND ISLAND	PLATTE	NE	59#1	412	12.0	250	54	6.48
60	HASTINGS	WHELAN ENERGY CENTER	NE	60#1	265	10.0	290	71.6	3.84
60	HASTINGS	WHELAN ENERGY CENTER	NE	60#2	275	14.6	176	79.8	10.84
87	TRI-STATE G&T	ESCALANTE	NM	87#1	450	20.0	126	50	14.99
108	SUNFLOWER	HOLCOMB	KS	108#STK1	474	16.4	180	118	15.53
113	AZ PUB SERV	CHOLLA	AZ	113#1	250	11.2	123	74	6.73
113	AZ PUB SERV	CHOLLA	AZ	113#3	550	22.6	127	81	13.94
113	AZ PUB SERV	CHOLLA	AZ	113#4	550	19.2	127	87	26.67
127	AEP PSO	OKLAUNION	TX	127#1	452	23.0	161	95	23.04
130	SANTEE	CROSS	SC	130#1	600	22.0	150	93	13.19
130	SANTEE	CROSS	SC	130#2	600	22.0	140	70	5.90
130	SANTEE	CROSS	SC	130#3	488	26.0	115	70	35.84
130	SANTEE	CROSS	SC	130#4	488	26.0	115	70	34.16
136	SEMINOLE	SEMINOLE (FL)	FL	136#1	695	37.5	125	64	76.39
160	AZ ELEC COOP	APACHE	AZ	160#2	400	23.5	130	54	9.13
160	AZ ELEC COOP	APACHE	AZ	160#3	400	23.5	130	54	11.60
165	GRDA	GRDA	OK	165#1	504	20.0	250	90	24.24
165	GRDA	GRDA	OK	165#2	504	20.0	140	80	21.44
207	JEA	ST JOHNS RIVER	FL	207#1	640	22.5	140	90	57.77
298	NRG ENERGY	LIMESTONE	TX	298#S1	563	27.0	140	90	42.99
298	NRG ENERGY	LIMESTONE	TX	298#S2	563	27.0	140	90	53.27
469	XCEL	CHEROKEE (CO)	CO	469#4	400	22.0	350	60	18.78
470	XCEL	COMANCHE	CO	470#1	500	23.4	300	60	24.43
470	XCEL	COMANCHE	CO	470#2	500	23.4	270	60	24.30
470	XCEL	COMANCHE	CO	470#3	500	30.5	160	68	42.84
477	XCEL	VALMONT	CO	477#5	250	17.9	165	60	10.31
492	COL SPRINGS	DRAKE	CO	492#5	200	10.6	320	53	2.50
492	COL SPRINGS	DRAKE	CO	492#6	200	12.6	320	55	5.60
492	COL SPRINGS	DRAKE	CO	492#7	250	15.0	310	60	7.80
508	LAMAR	LAMAR REPOWERING PROJECT	CO	508#4	225	8.0	325	70	0.01
525	XCEL	HAYDEN	CO	525#H1	250	22.0	160	64	11.51
525	XCEL	HAYDEN	CO	525#H2	395	24.0	160	65	19.70
527	TRI-STATE G&T	NUCLA	CO	527#N	215	12.0	290	74	5.13
564	ORLANDO	CH STANTON	FL	564#1	550	19.0	127	83	17.79
564	ORLANDO	CH STANTON	FL	564#2	550	19.0	127	83	23.02
568	PSE&G	BRIDGEPORT HARBOR	CT	568#BHS3	498	14.0	300	133	6.54
594	NRG Indian River Operations Inc	INDIAN RIVER (DE)	DE	594#4	400	24.0	160	67	7.15
602	TALEN ENERGY	BRANDON SHORES	MD	602#1	400	31.2	128	55	23.07
602	TALEN ENERGY	BRANDON SHORES	MD	602#2	400	31.2	128	55	32.40
628	DUKE ENERGY FLORIDA	CRYSTAL RIVER	FL	628#1	499	15.0	292	133	7.73
628	DUKE ENERGY FLORIDA	CRYSTAL RIVER	FL	628#2	503	16.0	300	160	18.74
628	DUKE ENERGY FLORIDA	CRYSTAL RIVER	FL	628#4	600	25.5	130	69	42.73
628	DUKE ENERGY FLORIDA	CRYSTAL RIVER	FL	628#5	600	25.5	130	69	33.04
641	SOUTHERN-GP	CRIST	FL	641#3	490	35.0	131	57	27.41
645	TECO	BIG BEND (FL)	FL	645#STK1	490	29.0	132	60	30.98
645	TECO	BIG BEND (FL)	FL	645#STK3	490	24.0	127	65	48.69
663	GAINESVILLE	DEERHAVEN	FL	663#STK2	350	18.5	177	62	9.07
667	JEA	NORTHSIDE	FL	667#1	495	15.0	200	63	15.02
667	JEA	NORTHSIDE	FL	667#2	495	15.0	200	63	12.54
676	LAKELAND	MCINTOSH (FL)	FL	676#5ST	300	20.0	188	64	15.37
703	SOUTHERN-GAPC	BOWEN	GA	703#1-2S	675	43.8	133	58	51.66
703	SOUTHERN-GAPC	BOWEN	GA	703#3-4S	675	48.1	133	58	75.34
708	SOUTHERN-GAPC	HAMMOND	GA	708#5	675	33.0	133	51	12.79

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height (ft)	Stack Diam. (ft)	Stack Temp. (deg F)	Stack Velocity (ft/sec)	Heat Input (2015) (10^9 Btu/yr)
856	DYNEGY MIDWEST	ED EDWARDS	IL	856#1	503	21.0	300	49	17.82
856	DYNEGY MIDWEST	ED EDWARDS	IL	856#2	503	25.0	285	41	15.16
861	DYNEGY MIDWEST	COFFEEN	IL	861#01	575	20.0	132	72.5	17.31
861	DYNEGY MIDWEST	COFFEEN	IL	861#02	575	26.0	133.6	72.5	17.31
876	DYNEGY	KINCAID	IL	876#3	615	29.6	315	120	54.70
879	NRG	POWERTON	IL	879#6	500	34.0	300	111	62.39
883	NRG	POWERTON	IL	883#5	450	14.1	300	119	13.00
883	NRG	POWERTON	IL	883#6	450	13.5	300	122	6.41
884	NRG	WILL COUNTY	IL	884#4	500	16.5	290	121	22.85
887	DYNEGY MIDWEST	JOPPA	IL	887#1	550	18.0	320	88	18.31
887	DYNEGY MIDWEST	JOPPA	IL	887#2	550	18.0	320	88	17.75
887	DYNEGY MIDWEST	JOPPA	IL	887#3	550	18.0	320	88	17.48
889	DYNEGY MIDWEST	BALDWIN	IL	889#1	605	19.6	160	96	37.22
889	DYNEGY MIDWEST	BALDWIN	IL	889#2	605	19.5	160	96	28.34
889	DYNEGY MIDWEST	BALDWIN	IL	889#3	605	19.5	160	107	40.08
891	DYNEGY MIDWEST	HAVANA	IL	891#6	500	20.0	160	81	22.37
892	DYNEGY MIDWEST	HENNEPIN	IL	892#1	275	14.5	288	89	16.95
963	SPRING-IL	DALLMAN	IL	963#3132	451	14.2	140	75	3.95
963	SPRING-IL	DALLMAN	IL	963#33	500	15.0	140	65	8.68
963	SPRING-IL	DALLMAN	IL	963#41	454	15.0	133	59	9.63
976	SO IL PWR COOP	MARION (IL)	IL	976#4	400	15.0	129	65	20.49
976	SO IL PWR COOP	NEW MARION	IL	976#123	200	12.0	340	40	7.74
983	OVEC	CLIFTY CREEK	IN	983#14	982	44.1	133	51	56.19
994	AES	PETERSBURG	IN	994#2	612	32.5	123	77	41.76
994	AES	PETERSBURG	IN	994#3	615	22.0	166	88	21.44
994	AES	PETERSBURG	IN	994#4	615	22.0	150	83	32.70
995	NIPSCO	BAILLY	IN	995#78A	480	20.2	130	90	16.65
997	NIPSCO	MICHIGAN CITY	IN	997#12	505	21.0	325	87	17.82
1001	DUKE ENERGY INDIANA	CAYUGA	IN	1001#3	575	33.2	130	66	51.54
1004	DUKE ENERGY INDIANA	EDWARDSPORT IGCC	IN	1004#1	174.8	18.5	263.9	59.1	12.56
1004	DUKE ENERGY INDIANA	EDWARDSPORT IGCC	IN	1004#2	174.8	18.5	263.9	59.1	12.56
1008	DUKE ENERGY INDIANA	GALLAGHER	IN	1008#A	550	13.6	263	144	3.22
1008	DUKE ENERGY INDIANA	GALLAGHER	IN	1008#B	550	12.3	263	165	2.83
1012	VECTREN	CULLEY	IN	1012#4	499	20.0	128	61	15.26
1040	IMPA	WHITEWATER VALLEY	IN	1040#1	325	11.7	328	57	0.69
1047	ALLIANT	LANSING	IA	1047#4	499	15.3	265	81	10.47
1073	ALLIANT	PRAIRIE CREEK	IA	1073#3	201	12.4	342	30	0.92
1073	ALLIANT	PRAIRIE CREEK	IA	1073#4	200	13.0	329	72	2.12
1082	MIDAMER	COUNCIL BLUFFS (SCOTT ENERGY	IA	1082#3	550	25.0	165	76	39.82
1082	MIDAMER	COUNCIL BLUFFS (SCOTT ENERGY	IA	1082#4	550	24.7	165	96	56.03
1091	MIDAMER	GEORGE NEAL	IA	1091#3	400	20.0	325	110	18.94
1104	ALLIANT	BURLINGTON (IA)	IA	1104#1	306	11.7	350	125	11.42
1131	CEDAR FALLS	STREETER	IA	1131#7	307	8.5	335	45	0.03
1167	MUSCATINE	MUSCATINE	IA	1167#8	220	8.5	338	89	0.92
1167	MUSCATINE	MUSCATINE	IA	1167#9	300	11.5	176	80	8.49
1241	KCP&L	LA CYGNE	KS	1241#1A	604	31.3	133	58	33.19
1241	KCP&L	LA CYGNE	KS	1241#2A	604	28.5	132	63	41.19
1250	WESTSTAR ENERGY	LAWRENCE (KS)	KS	1250#4N	170	8.0	170	60	5.79
1250	WESTSTAR ENERGY	LAWRENCE (KS)	KS	1250#5	355	18.1	166	38	18.39
1252	WESTSTAR ENERGY	TECUMSEH	KS	1252#9	225	11.5	271	46	4.32
1355	LGE-KU	EW BROWN	KY	1355#CS123	561	31.0	128	57.9	23.52
1356	LGE-KU	GHENT	KY	1356#1	662	26.5	125	50.3	27.03
1356	LGE-KU	GHENT	KY	1356#2-3	581	37.0	125	49.1	60.24
1356	LGE-KU	GHENT	KY	1356#4	662	26.5	125	48	35.69
1364	LGE-KU	MILL CREEK (KY)	KY	1364#2	615	28.0	125	88	30.86
1364	LGE-KU	MILL CREEK (KY)	KY	1364#3	600	18.0	125	89	23.64
1364	LGE-KU	MILL CREEK (KY)	KY	1364#4	615	25.0	125	87	29.43
1374	OWENSBORO	ELMER SMITH	KY	1374#3	420	25.1	130	55	25.40
1378	TVA	PARADISE	KY	1378#1	600	26.0	125	72.6	39.37
1378	TVA	PARADISE	KY	1378#2	600	26.0	125	72.6	40.59
1378	TVA	PARADISE	KY	1378#MS3MN	600	37.0	132	50	44.05

Stack Parameters at Coal-Fired Power Plant Used in the Inhalaion Pathway Risk Assessment

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height	Stack Diam.	Stack Temp.	Stack Velocity	Heat Input (2015)
					(ft)	(ft)	(deg F)	(ft/sec)	(10^9 Btu/yr)
1379	TVA	SHAWNEE (KY)	KY	1379#1-5	800	28.0	314	96.5	38.70
1379	TVA	SHAWNEE (KY)	KY	1379#6-10	800	28.0	300	97.1	29.87
1381	BIG RIVERS	COLEMAN (KY)	KY	1381#CSS	450	29.8	133	65	31.95
1382	HMP&L	HENDERSON TWO	KY	1382#HSS	350	22.6	128	43	16.02
1384	EAST KY PWR COOP	JS COOPER	KY	1384#1	260	18.0	310	74	5.62
1393	ENTERGY	R S Nelson	LA	1393#CFB	425	13.3	280	88	16.19
1393	ENTERGY	RS NELSON	LA	1393#6	500	31.8	277	99	26.15
1552	Avenue Capital Group	CP CRANE	MD	1552#1	353	10.9	310	98	1.86
1552	Avenue Capital Group	CP CRANE	MD	1552#2	353	10.9	310	95	3.17
1554	TALEN ENERGY	HA WAGNER	MD	1554#2	287	10.2	278	75	1.71
1554	TALEN ENERGY	HA WAGNER	MD	1554#3	346	13.8	294	94	12.33
1571	NRG	CHALK POINT	MD	1571#6	400	21.1	128	55	14.45
1572	NRG	DICKERSON	MD	1572#6	400	26.3	128	55	5.99
1573	NRG	MORGANTOWN	MD	1573#3	400	26.9	128	55	19.05
1573	NRG	MORGANTOWN	MD	1573#4	400	26.9	128	55	24.09
1606	FirstLight Power Resources Services LLC	MOUNT TOM	MA	1606#1	370	10.0	160	90	0.01
1619	DYNEGY	BRAYTON POINT	MA	1619#1	352	14.0	160	103	5.96
1619	DYNEGY	BRAYTON POINT	MA	1619#2	352	14.0	160	103	5.36
1619	DYNEGY	BRAYTON POINT	MA	1619#3	352	19.5	160	87	11.95
1702	CMS	DE KARN	MI	1702#1	350	18.0	325	60	9.94
1702	CMS	DE KARN	MI	1702#2	350	18.0	325	60	10.50
1710	CMS	JH CAMPBELL	MI	1710#1	400	19.0	265	157	33.79
1710	CMS	JH CAMPBELL	MI	1710#2	647	27.3	275	82	55.57
1733	DTE ENERGY	MONROE (MI)	MI	1733#1	805	28.0	127	142	79.67
1733	DTE ENERGY	MONROE (MI)	MI	1733#3	805	28.0	127	142	83.89
1740	DTE ENERGY	RIVER ROUGE	MI	1740#3	425	12.8	290	138	12.69
1743	DTE ENERGY	ST CLAIR	MI	1743#1	599	26.6	300	84	29.17
1743	DTE ENERGY	ST CLAIR	MI	1743#6	425	13.8	280	156	11.42
1743	DTE ENERGY	ST CLAIR	MI	1743#7	600	16.0	280	131	19.00
1745	DTE ENERGY	TRENTON CHANNEL	MI	1745#7	562	16.0	280	127	20.89
1769	WE ENERGIES	PRESQUE ISLE	MI	1769#1	400	12.8	337	75	6.49
1769	WE ENERGIES	PRESQUE ISLE	MI	1769#2	410	16.5	290	74	14.35
1825	GRAND HAVEN	JB SIMS	MI	1825#3	360	17.0	171	64	2.18
1831	LANSING	ECKERT	MI	1831#2	619	13.8	290	106	5.70
1832	LANSING	ERICKSON	MI	1832#1	475	17.0	285	36	11.78
1843	MARQUETTE	SHIRAS	MI	1843#3	350	9.5	165	46	3.85
1866	WYANDOTTE	WYANDOTTE	MI	1866#8	180	6.5	302	61	0.29
1893	ALLETE	CLAY BOSWELL	MN	1893#S3	700	29.0	190	48	37.31
1893	ALLETE	CLAY BOSWELL	MN	1893#S4	600	20.0	158	101	35.86
1915	XCEL	ALLEN S KING	MN	1915#1	785	18.5	169	108	29.27
1943	OTTER TAIL	HOOT LAKE	MN	1943#2	225	13.4	314	87	3.55
2076	EMPIRE DISTRICT	ASBURY	MO	2076#2	465	14.0	152	87	11.29
2079	KCP&L	HAWTHORN	MO	2079#5A	600	21.2	150	90	35.71
2080	KCP&L	MONTROSE	MO	2080#2	450	15.0	290	120	11.57
2094	KCP&L Greater Missouri Operations Co	SIBLEY (MO)	MO	2094#1	700	13.5	300	122	21.27
2103	AMEREN-UE	LABADIE	MO	2103#1	700	20.5	300	111	46.45
2103	AMEREN-UE	LABADIE	MO	2103#2	700	20.5	300	111	43.45
2103	AMEREN-UE	LABADIE	MO	2103#3	700	20.5	300	111	77.50
2104	AMEREN-UE	MERAMEC	MO	2104#3	350	14.0	355	126	7.17
2104	AMEREN-UE	MERAMEC	MO	2104#4	350	15.5	360	128	10.38
2107	AMEREN-UE	SIOUX	MO	2107#3	496.5	23.0	135	55	51.12
2167	ASSOCIATED	NEW MADRID	MO	2167#1	800	20.0	325	117	65.49
2168	ASSOCIATED	THOMAS HILL	MO	2168#E1	411	16.0	340	60	10.26
2168	ASSOCIATED	THOMAS HILL	MO	2168#E2	400	16.0	340	60	16.21
2168	ASSOCIATED	THOMAS HILL	MO	2168#E3	620	29.0	290	50	49.62
2240	FREEMONT	LD WRIGHT	NE	2240#8	196	10.0	300	40	3.68
2277	NPPD	SHELDON	NE	2277#1	176	11.6	290	60	6.17
2277	NPPD	SHELDON	NE	2277#2	176	11.6	323	71	5.22
2291	OPPD	NORTH OMAHA	NE	2291#B	204	9.6	276	121	7.10
2291	OPPD	NORTH OMAHA	NE	2291#C	204	11.5	274	120	10.91
2324	NV ENERGY	REID GARDNER	NV	2324#4	500	17.0	153	77	4.64
2364	PSNH	MERRIMACK	NH	2364#1	445	8.5	130	100	2.59
2364	PSNH	MERRIMACK	NH	2364#2	445	14.5	130	91	6.08

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height	Stack Diam.	Stack Temp.	Stack Velocity	Heat Input (2015)
					(ft)	(ft)	(deg F)	(ft/sec)	(10^9 Btu/yr)
2367	PSNH	SCHILLER	NH	2367#4	226	8.0	390	74	1.23
2367	PSNH	SCHILLER	NH	2367#6	226	8.0	390	75	1.10
2378	RC CAPE MAY HOLDINGS	BL ENGLAND	NJ	2378#1	475	23.3	130	84	1.51
2403	PSE&G	HUDSON	NJ	2403#2	498	17.5	279	114	4.94
2408	PSE&G	MERCER	NJ	2408#1	326	17.6	269	90	1.73
2408	PSE&G	MERCER	NJ	2408#2	325	17.6	269	90	1.62
2442	AZ PUB SERV	FOUR CORNERS	NM	2442#4	380	40.3	145	80	99.24
2451	PSNM	SAN JUAN (NM)	NM	2451#1	400	18.0	124	88	17.63
2451	PSNM	SAN JUAN (NM)	NM	2451#2	400	18.0	124	88	21.92
2451	PSNM	SAN JUAN (NM)	NM	2451#3	400	25.0	124	96	32.05
2451	PSNM	SAN JUAN (NM)	NM	2451#4	400	25.0	124	96	28.66
2535	UPSTATE NY POWER PRODUCERS	CAYUGA 1(MILLIKEN)	NY	2535#1A	374	12.0	120	77	1.05
2535	UPSTATE NY POWER PRODUCERS	CAYUGA 2(MILLIKEN)	NY	2535#1A	374	12.0	120	77	4.75
2706	DUKE ENERGY PROGRESS	ASHEVILLE	NC	2706#0	327	16.5	127	45.5	8.26
2706	DUKE ENERGY PROGRESS	ASHEVILLE	NC	2706#2B	327	16.5	127	50	8.60
2712	DUKE ENERGY PROGRESS	ROXBORO	NC	2712#1	400	12.7	125	136	15.14
2712	DUKE ENERGY PROGRESS	ROXBORO	NC	2712#2	400	19.0	125	103	34.67
2712	DUKE ENERGY PROGRESS	ROXBORO	NC	2712#3	800	24.0	125	80	20.50
2712	DUKE ENERGY PROGRESS	ROXBORO	NC	2712#4	800	24.0	125	80	24.73
2718	DUKE ENERGY CAROLINAS	ALLEN	NC	2718#CS125	365	29.5	127	39	8.62
2718	DUKE ENERGY CAROLINAS	ALLEN	NC	2718#CS34	365	29.5	130	34	8.70
2721	DUKE ENERGY CAROLINAS	CLIFFSIDE	NC	2721#5	500	20.8	125	87	9.65
2721	DUKE ENERGY CAROLINAS	CLIFFSIDE	NC	2721#6	550	38.3	130	66	28.16
2727	DUKE ENERGY CAROLINAS	MARSHALL (NC)	NC	2727#2	281	15.3	120	87	17.62
2727	DUKE ENERGY CAROLINAS	MARSHALL (NC)	NC	2727#3	281	19.5	120	90	24.75
2727	DUKE ENERGY CAROLINAS	MARSHALL (NC)	NC	2727#4	281	19.5	120	90	28.59
2790	MDU	HESKETT	ND	2790#S1	300	7.2	441	67	0.10
2790	MDU	HESKETT	ND	2790#S2	300	12.0	340	64	5.30
2817	BASIN ELECTRIC	LELAND OLDS	ND	2817#1	350	17.5	142	62	16.02
2817	BASIN ELECTRIC	LELAND OLDS	ND	2817#2A	600	26.9	142	39	25.61
2823	MINNKOTA	MR YOUNG	ND	2823#S1	564	25.0	145	80.1	18.27
2823	MINNKOTA	MR YOUNG	ND	2823#S2	550	30.0	142	55.3	37.42
2824	GREAT RIVER ENG	STANTON (ND)	ND	2824#1	255	15.0	270	48	11.53
2828	CARDINAL	CARDINAL	OH	2828#1A	1000	29.1	130	50	29.98
2828	CARDINAL	CARDINAL	OH	2828#2A	1000	29.1	130	50	29.09
2828	CARDINAL	CARDINAL	OH	2828#3A	370	45.1	116	17.5	28.03
2832	DYNEGY MIDWEST	MIAMI FORT	OH	2832#7A	800	23.5	129	70	29.70
2832	DYNEGY MIDWEST	MIAMI FORT	OH	2832#8A	800	23.5	131	71	34.57
2836	NRG	AVON LAKE	OH	2836#7	600	24.0	285	95	25.76
2840	AEP GENERATION RESOURCES	CONESVILLE	OH	2840#4	800	26.0	125	79	25.40
2840	AEP GENERATION RESOURCES	CONESVILLE	OH	2840#3	800	26.0	125	83	30.08
2850	AES	JM STUART	OH	2850#5	800	26.0	128	50	100.95
2866	FIRST ENERGY	WH SAMMIS	OH	2866#3	850	31.2	130	62	26.89
2866	FIRST ENERGY	WH SAMMIS	OH	2866#4	850	26.7	130	56	31.24
2866	FIRST ENERGY	WH SAMMIS	OH	2866#CS	850	54.8	130	54.4	39.02
2876	OVEC	KYGER CREEK	OH	2876#15	838	39.0	130	51	38.76
2878	FIRST ENERGY	FirstEnergy Bay Shore	OH	2878#1	302	12.0	307	88	13.23
2952	OG&E	MUSKOGEE	OK	2952#4	350	24.0	264	46	2.99
2952	OG&E	MUSKOGEE	OK	2952#5	350	24.0	264	46	26.14
2952	OG&E	MUSKOGEE	OK	2952#6	500	21.5	264	96	22.67
2963	AEP PSO	NORTHEASTERN	OK	2963#3334	600	27.0	280	40	34.03
3118	NRG	CONEMAUGH	PA	3118#3	525	28.0	130	70	108.86
3122	NRG	HOMER CITY	PA	3122#1	790	24.0	282	75	29.80
3122	NRG	HOMER CITY	PA	3122#2	790	24.0	282	75	29.54
3122	NRG	HOMER CITY	PA	3122#3A	861	27.0	120	56	34.25
3130	NRG	SEWARD	PA	3130#1	604	17.3	142	100	18.71
3136	NRG	KEYSTONE (PA)	PA	3136#FGD1	563	33.0	124	53	51.29
3136	NRG	KEYSTONE (PA)	PA	3136#FGD2	563	33.0	124	53	42.92
3140	TALEN ENERGY	BRUNNER ISLAND	PA	3140#3	600	43.4	130	51.9	49.97
3149	TALEN ENERGY	MONTOUR	PA	3149#3	700	30.7	130	51.9	65.10
3297	SCANA	WATEREE (SC)	SC	3297#WAT0	400	28.0	132	58	33.07
3298	SCANA	AM WILLIAMS	SC	3298#WIL2	400	26.0	131	56	36.50
3393	TVA	TH ALLEN	TN	3393#1	400	12.8	277	161	9.33
3393	TVA	TH ALLEN	TN	3393#2	400	12.8	277	161	12.39
3393	TVA	TH ALLEN	TN	3393#3	400	12.8	277	161	12.37

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height (ft)	Stack Diam. (ft)	Stack Temp. (deg F)	Stack Velocity (ft/sec)	Heat Input (2015) (10^9 Btu/yr)
3396	TVA	BULL RUN (TN)	TN	3396#1A	500	33.0	126	50	23.20
3399	TVA	CUMBERLAND	TN	3399#1A	635.5	38.5	119	64.5	83.01
3399	TVA	CUMBERLAND	TN	3399#2A	635.5	38.5	119	64.5	60.22
3403	TVA	GALLATIN	TN	3403#1-2	501	25.0	179.3	57.4	20.69
3403	TVA	GALLATIN	TN	3403#3-4	502	25.0	177.5	62.3	20.27
3406	TVA	JOHNSONVILLE (TN)	TN	3406#1-10	600	32.3	305	136	29.91
3407	TVA	KINGSTON	TN	3407#1-5	1000	26.0	131	56	21.41
3407	TVA	KINGSTON	TN	3407#6-9	1000	26.0	131	56	21.80
3470	NRG ENERGY	WA PARISH	TX	3470#S5	600	24.0	330	103	44.19
3470	NRG ENERGY	WA PARISH	TX	3470#S6	600	24.0	330	103	40.25
3470	NRG ENERGY	WA PARISH	TX	3470#S7	500	22.0	330	103	33.37
3470	NRG ENERGY	WA PARISH	TX	3470#S8	500	22.0	170	84	39.16
3497	LUMINANT	BIG BROWN	TX	3497#1	400	21.5	335	122	43.21
3497	LUMINANT	BIG BROWN	TX	3497#2	400	21.5	335	122	42.01
3797	DOMINION VA POWER	CHESTERFIELD	VA	3797#3	200	13.0	130	46	1.33
3797	DOMINION VA POWER	CHESTERFIELD	VA	3797#4	200	13.0	130	73	3.44
3797	DOMINION VA POWER	CHESTERFIELD	VA	3797#5	200	17.0	130	71	20.91
3797	DOMINION VA POWER	CHESTERFIELD	VA	3797#6	419	20.0	130	100	40.98
3809	DOMINION VA POWER	YORKTOWN	VA	3809#1-2	325	17.0	278	74	2.82
3845	TRANS ALTA	CENTRALIA	WA	3845#1	470	29.0	137	55	28.40
3845	TRANS ALTA	CENTRALIA	WA	3845#2	470	29.0	137	55	27.95
3935	AEP	AMOS	WV	3935#1	903	33.7	128	50	79.27
3935	AEP	AMOS	WV	3935#2	903	42.5	128	50	61.80
3943	FIRST ENERGY	FORT MARTIN	WV	3943#3	550	35.0	132	50	74.34
3944	FIRST ENERGY	HARRISON	WV	3944#3	1000	45.0	133	61	117.53
3948	AEP	MITCHELL (WV)	WV	3948#1	1000	47.7	128	48.9	53.80
3954	DOMINION VA POWER	MOUNT STORM	WV	3954#1-2	741	29.0	115	96	65.94
3954	DOMINION VA POWER	MOUNT STORM	WV	3954#3	579	21.0	115	106	33.71
4041	WEC ENERGY GROUP	OAK CREEK (WI)	WI	4041#1	368	26.6	135	58	23.70
4041	WEC ENERGY GROUP	OAK CREEK (WI)	WI	4041#2	368	26.6	137	59	29.97
4050	ALLIANT	EDGEWATER (WI)	WI	4050#3-4	550	17.0	300	85	15.26
4050	ALLIANT	EDGEWATER (WI)	WI	4050#5	550	18.0	275	112	25.53
4072	WEC ENERGY GROUP	JP PULLIAM	WI	4072#S13	377	11.0	355	61	1.45
4072	WEC ENERGY GROUP	JP PULLIAM	WI	4072#S14	377	15.5	350	65	3.25
4078	WEC ENERGY GROUP	WESTON	WI	4078#3	496	16.0	333	126	14.24
4078	WEC ENERGY GROUP	WESTON	WI	4078#4	500	19.4	163	69	28.70
4125	MANITOWOC	MANITOWOC	WI	4125#S10	250	12.0	375	50	0.73
4125	MANITOWOC	MANITOWOC	WI	4125#S20	250	14.0	350	53	0.52
4143	DAIRYLAND	GENOA THREE	WI	4143#S1	500	15.3	335	110	14.74
4158	PACIFICORP	DAVE JOHNSTON	WY	4158#BD41	500	11.0	290	93	8.85
4158	PACIFICORP	DAVE JOHNSTON	WY	4158#BD42	500	11.0	290	93	9.27
4158	PACIFICORP	DAVE JOHNSTON	WY	4158#BD43	500	15.0	156	124	14.91
4158	PACIFICORP	DAVE JOHNSTON	WY	4158#BD44	249	23.0	165	50	25.04
4162	PACIFICORP	NAUGHTON	WY	4162#1	200	14.0	120	87	12.91
4162	PACIFICORP	NAUGHTON	WY	4162#2	224	15.5	120	97	17.64
4162	PACIFICORP	NAUGHTON	WY	4162#3	470	27.5	120	42	22.19
4271	DAIRYLAND	MADGETT	WI	4271#S1	700	17.5	347	110	16.95
4941	SRP	NAVAJO	AZ	4941#1R	775	24.5	122	106	52.55
4941	SRP	NAVAJO	AZ	4941#2R	775	24.5	122	106	47.58
4941	SRP	NAVAJO	AZ	4941#3R	775	24.5	122	106	40.73
6002	SOUTHERN-ALPC	MILLER	AL	6002#1S-2S	700	43.8	135	55	100.06
6002	SOUTHERN-ALPC	MILLER	AL	6002#3S-4S	700	43.8	135	55	82.55
6004	FIRST ENERGY	PLEASANTS	WV	6004#3	640	41.0	130	48	74.71
6009	ENTERGY	WHITE BLUFF	AR	6009#1	1000	25.7	262	90	64.86
6016	DYNEGY MIDWEST	DUCK CREEK	IL	6016#02	589.5	21.8	141	66.3	22.70
6017	DYNEGY MIDWEST	NEWTON	IL	6017#1	530	21.0	325	110	27.81
6017	DYNEGY MIDWEST	NEWTON	IL	6017#2	530	20.0	325	131	24.21
6018	DUKE ENERGY KENTUCKY	EAST BEND	KY	6018#2	650	23.5	173	110	44.06
6019	DYNEGY MIDWEST	ZIMMER	OH	6019#1	573	40.0	147	52	57.96
6021	TRI-STATE G&T	CRAIG	CO	6021#C1	600	25.0	164	73	30.20
6021	TRI-STATE G&T	CRAIG	CO	6021#C2	600	25.0	164	73	26.45
6021	TRI-STATE G&T	CRAIG	CO	6021#C3	600	25.0	165	73	24.85
6030	GREAT RIVER ENG	COAL CREEK	ND	6030#1	675	25.9	210	87	46.52
6030	GREAT RIVER ENG	COAL CREEK	ND	6030#2	675	29.0	210	87	46.64

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height (ft)	Stack Diam. (ft)	Stack Temp. (deg F)	Stack Velocity (ft/sec)	Heat Input (2015) (10^9 Btu/yr)
6031	AES	KILLEN	OH	6031#2	900	33.0	125	29	36.27
6034	DTE ENERGY	BELLE RIVER	MI	6034#1	665	25.5	330	90	40.66
6034	DTE ENERGY	BELLE RIVER	MI	6034#2	665	25.5	290	90	34.40
6041	EAST KY PWR COOP	HL SPURLOCK	KY	6041#1B	650	15.0	130	96.3	10.35
6041	EAST KY PWR COOP	HL SPURLOCK	KY	6041#2	805	22.0	130	77	26.12
6041	EAST KY PWR COOP	HL SPURLOCK	KY	6041#3	650	15.0	150	52.5	10.06
6041	EAST KY PWR COOP	HL SPURLOCK	KY	6041#4	650	15.0	150	52.5	13.05
6052	SOUTHERN-GAPC	WANSLEY	GA	6052#1S	675	48.1	133	58	44.20
6055	LA GEN	BIG CAJUN TWO	LA	6055#2S1	600	26.5	296	75	32.53
6055	LA GEN	BIG CAJUN TWO	LA	6055#2S3	600	26.5	280	75	27.55
6061	SO MISS ELEC PWR	MORROW	MS	6061#1	405	23.7	125	47	2.81
6064	KCBPU	NEARMAN CREEK	KS	6064#NCHM	400	20.0	280	44	14.09
6065	KCP&L	IATAN	MO	6065#1	615	28.5	133	100	36.96
6065	KCP&L	IATAN	MO	6065#2	615	30.3	133	100	51.50
6068	WESTSTAR ENERGY	JEFFREY	KS	6068#1	600	25.5	130	78	43.17
6068	WESTSTAR ENERGY	JEFFREY	KS	6068#2	600	25.5	130	78	39.73
6068	WESTSTAR ENERGY	JEFFREY	KS	6068#3	600	25.5	130	78	42.92
6071	LGE-KU	TRIMBLE COUNTY	KY	6071#1	760	18.0	125	120	30.98
6071	LGE-KU	TRIMBLE COUNTY	KY	6071#2	760	20.6	133	92	49.65
6073	SOUTHERN-MSPC	VJ DANIEL	MS	6073#1	621	37.0	132	51	26.00
6076	TALEN ENERGY	COLSTRIP	MT	6076#1	500	16.5	130	100	20.99
6076	TALEN ENERGY	COLSTRIP	MT	6076#2	500	16.5	130	100	18.73
6076	TALEN ENERGY	COLSTRIP	MT	6076#3	692	24.0	130	105	58.18
6076	TALEN ENERGY	COLSTRIP	MT	6076#4	692	24.0	130	105	60.55
6077	NPPD	GERALD GENTLEMAN	NE	6077#1	553	27.8	330	56	41.46
6077	NPPD	GERALD GENTLEMAN	NE	6077#2	550	28.0	300	56	47.07
6082	UPSTATE NY POWER PRODUCERS	SOMERSET	NY	6082#1	613	26.7	125	70	6.32
6085	NIPSCO	RM SCHAHFER	IN	6085#14	500	21.0	160	92	6.25
6085	NIPSCO	RM SCHAHFER	IN	6085#15	500	21.0	160	102	22.14
6085	NIPSCO	RM SCHAHFER	IN	6085#17	496	18.0	160	104	14.41
6085	NIPSCO	RM SCHAHFER	IN	6085#18	496	18.0	160	104	20.33
6089	MDU	LEWIS & CLARK	MT	6089#1	250	8.7	145	57	3.03
6090	XCEL	SHERBURNE COUNTY	MN	6090#1	650	32.5	175	105	76.10
6090	XCEL	SHERBURNE COUNTY	MN	6090#3	650	26.0	175	84	50.65
6094	FIRST ENERGY	BRUCE MANSFIELD	PA	6094#1	950	38.0	124	83	88.52
6094	FIRST ENERGY	BRUCE MANSFIELD	PA	6094#2	600	26.9	125	86	50.02
6095	OG&E	SOONER	OK	6095#1	500	20.0	264	102	31.38
6095	OG&E	SOONER	OK	6095#2	500	20.0	264	102	27.14
6096	OPPD	NEBRASKA CITY	NE	6096#1	700	23.7	288	98	48.04
6096	OPPD	NEBRASKA CITY	NE	6096#2	400	23.0	271	90	38.03
6098	OTTER TAIL	BIG STONE	SD	6098#1	498	24.2	288	75	16.27
6101	PACIFICORP	WYODAK	WY	6101#BD91	400	20.0	150	102	31.06
6106	PORTLAND G&E	BOARDMAN (OR)	OR	6106#1S	656	22.0	268	86	24.15
6113	DUKE ENERGY INDIANA	GIBSON	IN	6113#1-2	620	35.4	130	73	73.05
6113	DUKE ENERGY INDIANA	GIBSON	IN	6113#3	620	25.0	130	73	24.46
6113	DUKE ENERGY INDIANA	GIBSON	IN	6113#C	500	23.5	145	70	21.71
6113	DUKE ENERGY INDIANA	GIBSON	IN	6113#D	500	23.5	125	70	33.50
6124	SOUTHERN-GAPC	MCINTOSH (GA)	GA	6124#1	400	11.5	307	79	1.51
6136	TMPA	GIBBONS CREEK	TX	6136#1	465	20.0	160	86	23.23
6137	VECTREN	AB BROWN	IN	6137#1	496	14.0	130	100	14.83
6137	VECTREN	AB BROWN	IN	6137#2	496	14.0	130	100	12.32
6138	AEP - SWEPCO	FLINT CREEK (AR)	AR	6138#1	540	20.0	280	91	32.00
6139	AEP - SWEPCO	WELSH	TX	6139#1	300	16.8	264	129	22.67
6139	AEP - SWEPCO	WELSH	TX	6139#3	300	16.8	264	129	21.43
6146	LUMINANT	MARTIN LAKE	TX	6146#1	452	23.0	160	120	46.00
6146	LUMINANT	MARTIN LAKE	TX	6146#2	452	23.0	160	120	38.97
6146	LUMINANT	MARTIN LAKE	TX	6146#3	452	23.0	160	120	31.43
6147	LUMINANT	MONTICELLO (TX)	TX	6147#1	400	21.5	335	122	16.91
6147	LUMINANT	MONTICELLO (TX)	TX	6147#2	400	21.5	335	122	13.21
6147	LUMINANT	MONTICELLO (TX)	TX	6147#3	460	25.5	160	98	29.94
6155	AMEREN-UE	RUSH ISLAND	MO	6155#1	700	20.7	260	100	37.30
6155	AMEREN-UE	RUSH ISLAND	MO	6155#2	700	20.7	260	100	37.85
6165	PACIFICORP	HUNTER	UT	6165#1	600	24.0	138	65	32.76
6165	PACIFICORP	HUNTER	UT	6165#2	600	24.0	138	65	30.77
6165	PACIFICORP	HUNTER	UT	6165#3	600	24.0	119	66	33.96

Stack Parameters at Coal-Fired Power Plant Used in the Inhalaion Pathway Risk Assessment

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height	Stack Diam.	Stack Temp.	Stack Velocity	Heat Input (2015)
					(ft)	(ft)	(deg F)	(ft/sec)	(10^9 Btu/yr)
6166	AEP	ROCKPORT	IN	6166#MS	1038	42.5	315	131	125.53
6170	WEC ENERGY GROUP	PLEASANT PRAIRIE	WI	6170#1	450	26.6	135	62	38.10
6170	WEC ENERGY GROUP	PLEASANT PRAIRIE	WI	6170#2	450	26.6	135	62	36.61
6177	SRP	CORONADO	AZ	6177#U1SA	400	24.5	140	60.1	24.32
6177	SRP	CORONADO	AZ	6177#U2SA	400	24.5	140	60.1	28.35
6178	INTERNATIONAL POWER PLC	COLETO CREEK	TX	6178#1	409	20.0	350	117	32.49
6179	LCRA	FAYETTE(SEYMOR) (TX)	TX	6179#1	600	28.0	136	95	37.75
6179	LCRA	FAYETTE(SEYMOR) (TX)	TX	6179#2	600	28.0	136	95	31.19
6179	LCRA	FAYETTE(SEYMOR) (TX)	TX	6179#3	533	25.8	140	88	23.97
6180	LUMINANT	OAK GROVE	TX	6180#1	450	32.8	138	56	67.89
6180	LUMINANT	OAK GROVE	TX	6180#2	450	32.6	138	56	61.61
6181	SAPSB	JT DEELY	TX	6181#1-2	700	36.8	270	55	35.06
6183	SAN MIGUEL	SAN MIGUEL	TX	6183#SM-1	450	20.0	160	100	27.49
6190	CLECO	MADISON 3 (Brame Energy Cent	LA	6190#3-1	450	18.0	170	55	15.76
6190	CLECO	MADISON 3 (Brame Energy Cent	LA	6190#3-2	450	18.0	170	55	16.38
6190	CLECO	RODEMACHER 2 (Brame Energy (	LA	6190#2	265	18.0	350	94	23.08
6193	XCEL	HARRINGTON	TX	6193#061S	250	18.9	326	88	21.35
6193	XCEL	HARRINGTON	TX	6193#062S	300	19.0	313	97	21.52
6193	XCEL	HARRINGTON	TX	6193#063S	300	19.0	300	97	18.35
6194	XCEL	TOLK	TX	6194#171S	400	22.5	270	105	29.50
6194	XCEL	TOLK	TX	6194#172S	400	22.5	270	105	37.11
6195	SPRING-MO	SOUTHWEST (TWITTY ENERGY CE	MO	6195#1	385	11.0	131	90	5.35
6195	SPRING-MO	SOUTHWEST (TWITTY ENERGY CE	MO	6195#2	513	14.0	163	86	13.96
6204	BASIN ELECTRIC	LARAMIE RIVER	WY	6204#1	604	28.6	135	50	26.74
6204	BASIN ELECTRIC	LARAMIE RIVER	WY	6204#2	604	28.6	135	50	40.89
6204	BASIN ELECTRIC	LARAMIE RIVER	WY	6204#3	604	28.6	150	65	41.64
6213	HOOSIER	MEROM	IN	6213#ST	704	26.9	177	103	53.65
6248	XCEL	PAWNEE	CO	6248#1	550	23.5	185	75	37.01
6249	SANTEE	WINYAH	SC	6249#1	404	20.0	125	52	10.66
6249	SANTEE	WINYAH	SC	6249#2	404	20.0	130	52	10.17
6249	SANTEE	WINYAH	SC	6249#3	400	16.0	130	75	12.25
6249	SANTEE	WINYAH	SC	6249#4	400	16.0	125	76	8.60
6250	DUKE ENERGY PROGRESS	MAYO	NC	6250#1	380	30.5	120	50	28.55
6254	ALLIANT	OTTUMWA	IA	6254#1	600	25.0	274	91	39.54
6257	SOUTHERN-GAPC	SCHERER	GA	6257#1-2S	870	48.1	133	57	87.38
6257	SOUTHERN-GAPC	SCHERER	GA	6257#3-4S	847	48.1	133	57	94.69
6264	AEP	MOUNTAINEER	WV	6264#1A	1000	42.5	129	50	74.50
6288	GOLDEN VALLEY	HEALY	AK	6288#1	250	8.0	320	61	2.57
6288	GOLDEN VALLEY	HEALY	AK	6288#2	250	8.7	310	65	0.88
6469	BASIN ELECTRIC	ANTELOPE VALLEY	ND	6469#S1	600	23.0	185	67	36.97
6469	BASIN ELECTRIC	ANTELOPE VALLEY	ND	6469#S2	600	23.0	145	63	37.83
6481	INTERMOUNTAIN/LADWP	INTERMOUNTAIN	UT	6481#9CCA	714	39.6	135	86	115.22
6639	BIG RIVERS	GREEN	KY	6639#G1	350	15.0	130	73	14.76
6639	BIG RIVERS	GREEN	KY	6639#G2	350	15.0	130	73	14.07
6641	ENTERGY	INDEPENDENCE	AR	6641#1	1000	37.5	321	114	56.38
6648	LUMINANT	SANDOW	TX	6648#4	400	21.5	180	98	44.99
6664	MIDAMER	LOUISA	IA	6664#101	610	30.0	160	73	41.91
6705	ALCOA	WARRICK	IN	6705#244A	381	23.4	132	54	39.30
6705	ALCOA	WARRICK	IN	6705#244B	500	19.5	132	59.5	21.49
6761	PLATTE RIVER	RAWHIDE	CO	6761#101	505	17.5	160	83	19.55
6768	SIKESTON	SIKESTON	MO	6768#1	450	24.1	131	62	13.90
6772	WESTERN FARMERS	HUGO	OK	6772#1	500	24.0	300	56	27.43
6823	BIG RIVERS	DB WILSON	KY	6823#W1	600	22.0	130	54	34.11
7030	MAJOR OAK POWER	TNP ONE (TWIN OAKS)	TX	7030#SK-1	340	12.5	320	80	12.80
7030	MAJOR OAK POWER	TNP ONE (TWIN OAKS)	TX	7030#SK-2	340	12.5	320	80	15.03
7097	SAPSB	SPRUCE	TX	7097#STK1	525	25.6	135	65	20.72
7097	SAPSB	SPRUCE	TX	7097#STK2	602	28.0	133	60	25.55
7210	SCANA	COPE	SC	7210#COP1	525	23.0	151	46	20.64
7213	DOMINION VA POWER	CLOVER	VA	7213#1	444	22.3	125	58	25.14
7213	DOMINION VA POWER	CLOVER	VA	7213#2	444	22.3	127	58	29.64
7343	MIDAMER	GEORGE NEAL	IA	7343#4	469	25.8	237	63	43.70
7504	BLACK HILLS	NEIL SIMPSON 6 (II 2)	WY	7504#2	295	9.2	284	61	8.39
7737	SCANA	KAPSTONE(Cogen South)	SC	7737#1	395	11.0	309	49	12.66
7790	DESERT	BONANZA	UT	7790#1-1	600	26.0	120	50	35.04

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height	Stack Diam.	Stack Temp.	Stack Velocity	Heat Input (2015)
					(ft)	(ft)	(deg F)	(ft/sec)	(10^9 Btu/yr)
7902	AEP - SWEPCO	PIRKEY	TX	7902#1	525	25.0	149	85	48.85
8023	ALLIANT	COLUMBIA (WI)	WI	8023#1	500	21.0	288	120	27.44
8023	ALLIANT	COLUMBIA (WI)	WI	8023#2	650	21.0	293	120	24.79
8042	DUKE ENERGY CAROLINAS	BELEWS CREEK	NC	8042#1A	500	36.0	126	45.8	55.08
8042	DUKE ENERGY CAROLINAS	BELEWS CREEK	NC	8042#2A	500	36.0	127	41.7	59.83
8066	PACIFICORP	JIM BRIDGER	WY	8066#BD71	500	24.0	138	82	35.72
8066	PACIFICORP	JIM BRIDGER	WY	8066#BD72	500	24.0	135	82	38.82
8066	PACIFICORP	JIM BRIDGER	WY	8066#BD73	500	24.0	141	82	26.86
8066	PACIFICORP	JIM BRIDGER	WY	8066#BD74	500	31.0	126	49	38.31
8069	PACIFICORP	HUNTINGTON	UT	8069#1	600	24.0	138	55	33.44
8069	PACIFICORP	HUNTINGTON	UT	8069#2	600	24.0	138	64	27.87
8102	AEP GENERATION RESOURCES	GAVIN	OH	8102#11	830	42.0	125	48	80.92
8102	AEP GENERATION RESOURCES	GAVIN	OH	8102#12	830	42.0	125	48	59.23
8219	COL SPRINGS	RD NIXON	CO	8219#1	460	17.5	270	64	16.09
8222	MDU	COYOTE	ND	8222#S1	498	21.0	213	87	23.15
8223	TUCSON	SPRINGERVILLE	AZ	8223#1	500	20.0	166	84	21.07
8223	TUCSON	SPRINGERVILLE	AZ	8223#2	500	20.0	166	84	27.53
8223	TUCSON	SPRINGERVILLE	AZ	8223#3	495	20.0	205	95	26.89
8223	TUCSON	SPRINGERVILLE	AZ	8223#4	495	20.0	205	95	28.78
8224	NV ENERGY	NORTH VALMY	NV	8224#1	500	19.0	269	67	12.93
8224	NV ENERGY	NORTH VALMY	NV	8224#2	455	17.0	266	67	3.16
8226	NRG	CHESWICK	PA	8226#2	553	27.0	130	53.5	21.56
10043	Logan Generating Co	Logan Generating Plant	NJ	10043#JPE01	430	12.0	178	101	6.67
10075	ALLETE	TACONITE HARBOR ENERGY CEN	MN	10075#S1	220	10.0	293	63	4.83
10075	ALLETE	TACONITE HARBOR ENERGY CEN	MN	10075#S2	220	10.0	293	63	4.70
10113	Gilberton Power Co	John B Rich Memorial Power Sta	PA	10113#1	326	7.0	325	85	8.36
10143	A C Power Colver Operations	Colver Power Project	PA	10143#STACK	400	12.0	285	75	10.41
10151	Edison Mission Op & Maintenace	Grant Town Power Plant	WV	10151#1	327	11.5	325	85	7.22
10343	El Paso Merchant Energy Co	MT. CARMEL	PA	10343#TG1	306	9.0	300	64	4.48
10377	Cogentrix -James River Cogeneration Co	James River Cogeneration	VA	10377#UNIT1	198	8.7	175	60	3.26
10377	Cogentrix -James River Cogeneration Co	James River Cogeneration	VA	10377#UNIT2	198	8.7	175	60	1.77
10378	Primary Energy of North Carolina LLC	Primary Energy Southport	NC	10378#UNIT1	198	8.7	330	54	4.37
10378	Primary Energy of North Carolina LLC	Primary Energy Southport	NC	10378#UNIT2	198	8.7	310	58	4.15
10379	Primary Energy of North Carolina LLC	Primary Energy Roxboro	NC	10379#1	198	8.7	310	50	1.30
10379	Primary Energy of North Carolina LLC	Primary Energy Roxboro	NC	10379#2	198	8.7	310	50	1.28
10379	Primary Energy of North Carolina LLC	Primary Energy Roxboro	NC	10379#3	198	8.7	310	50	1.36
10380	NORTH CAROLINA POWER HOLDINGS	Elizabethtown	NC	10380#1	180	7.0	302	61	0.00
10384	Edgecombe Operating Services LLC	Edgecombe Genco LLC	NC	10384#UNIT1	198	8.7	143	57	1.61
10384	Edgecombe Operating Services LLC	Edgecombe Genco LLC	NC	10384#UNIT2	198	8.7	143	57	1.39
10495	Rumford Cogeneration Co	Rumford Cogeneration	ME	10495#CGNSTK	415	19.0	339	112	7.02
10566	Chambers Cogeneration LP	Chambers Cogeneration LP (Car	NJ	10566#STACK1	475	10.0	174	65	5.15
10566	Chambers Cogeneration LP	Chambers Cogeneration LP (Car	NJ	10566#STACK2	475	10.0	174	65	5.55
10603	Power Systems Operations Inc	Ebensburg Power Co	PA	10603#1	250	8.7	320	73	3.01
10641	Cambria CoGen Co	Cambria Cogen	PA	10641#1	230	7.5	325	80	8.11
10671	AES SHADY POINT	AES Shady Point Inc	OK	10671#1-2	350	34.0	325	85	21.85
10672	Caryle Group	Cedar Bay Generating Co LP	FL	10672#1	415	13.6	300	115.402	6.45
10673	AES HAWAII	AES HAWAII	HI	10673#STACK1	285	10.9	310	115	15.08
10678	AES WARRIOR	AES Warrior Run Cogeneration F	MD	10678#STK1	267	12.1	320	60	13.00
10743	Morgantown Energy Associates	Morgantown Energy Facility	WV	10743#1	340	8.4	325	85	6.47
10768	Contellation Oper Services	Rio Bravo Jasmin	CA	10768#UP9	180	6.0	280	49	0.01
10769	Constellation Oper Services	Rio Bravo Poso	CA	10769#UP8	180	6.0	297	46	0.01
10784	Rosebud Operating Services Inc	Colstrip Energy LP	MT	10784#1	250	8.4	325	61	4.60
10849	Cleveland Cliffs Inc	SILVER BAY POWER	MN	10849#STK1	216	7.5	300	87	0.01
10849	Cleveland Cliffs Inc	SILVER BAY POWER	MN	10849#STK2	216	10.2	300	61	0.01
50039	Northeastern Power Company	Kline Township Cogen Facil	PA	50039#GEN1	250	8.0	345	94	5.74
50202	WPS POWER DEV	WPS POWER Niagara	NY	50202#GEN1	220	8.0	302	61	0.45
50611	WPS POWER DEV	Westwood	PA	50611#GEN1	320	8.1	302	61	3.31
50776	Constellation Oper Services	Panther Creek Energy Facility	PA	50776#1	350	7.7	325	70	6.42
50835	TES Filer City Station LP	TES Filer City	MI	50835#1	249	9.0	160	58	6.67
50879	Wheelabrator Environmental Sys	Wheeler Frackville Energy Co In	PA	50879#1	335	8.0	325	74	3.97
50888	Northampton Generating Co LP	NORTHAMPTON	PA	50888#ST1	275	9.5	320	80	5.33
50931	Rosebud Operating Serv Inc	Yellowstone Energy LP	MT	50931#1	198	8.7	310	50	8.74
50951	Sunnyside Operations Associate	Sunnyside Cogeneration Associa	UT	50951#GEN1	258	8.4	325	73	4.71
50974	Buzzard Power Corporation	SCRUBGRASS	PA	50974#1	363	12.0	315	79	4.24
50976	US Operating Services Company	Indiantown Cogeneration Facilit	FL	50976#JP	495	16.0	170	100	8.02

Stack Parameters at Coal-Fired Power Plant Used in the Inhalaion Pathway Risk Assessment

Plant ID Number	OPERATOR	STATION	STATE	STACK ID	Stack Height	Stack Diam.	Stack Temp.	Stack Velocity	Heat Input (2015)
					(ft)	(ft)	(deg F)	(ft/sec)	(10^9 Btu/yr)
52007	DOMINION VA POWER	Mecklenburg Cogeneration Faci	VA	52007#S	275	12.5	160	60	4.02
52071	LUMINANT	SANDOW	TX	52071#5A	335	16.0	162	75	27.80
52071	LUMINANT	SANDOW	TX	52071#5B	335	16.0	162	75	8.55
54035	Westmoreland Partners	Westmoreland LG&E Partners Ro	NC	54035#ST1	375	9.1	165	67	2.01
54081	Spruance Operating Services LLC	Spruance Genco LLC	VA	54081#UNIT1	250	8.7	145	63	2.17
54081	Spruance Operating Services LLC	Spruance Genco LLC	VA	54081#UNIT2	250	8.7	145	63	2.39
54081	Spruance Operating Services LLC	Spruance Genco LLC	VA	54081#UNIT3	250	8.7	145	63	2.58
54081	Spruance Operating Services LLC	Spruance Genco LLC	VA	54081#UNIT4	250	8.7	145	63	2.51
54304	Birchwood Power Partners LP	Birchwood Power Facility	VA	54304#1HJ	402	15.8	150	60	5.97
54634	Schuylkill Energy Resource Inc	St Nicholas Cogeneration Projec	PA	54634#SNCP	316	11.5	325	70	10.56
54755	Westmoreland Partners	Roanoke Valley	NC	54755#GEN2	380	8.5	225	61	4.02
55076	Choctaw Generating LP	RED HILLS GENERATION FACILITY	MS	55076#C1	350	24.7	310	73	33.21
55479	BLACK HILLS	WYGEN	WY	55479#0001	295	9.2	194	61	7.49
55749	ROCKY MOUNTAIN POWER	HARDIN GENERATING	MT	55749#STK1	250	9.0	158	126	6.41
55856	PRAIRIE STATE	PRAIRIE STATE	IL	55856#PC2	700	28.0	134	63.5	103.43
56068	WEC ENERGY GROUP	ELM ROAD	WI	56068#18	550	25.0	130	59.1	33.79
56068	WEC ENERGY GROUP	ELM ROAD	WI	56068#19	550	25.0	130	59.1	32.28
56224	NEWMONT MINING	TS POWER (NEWMONT/BOULDE	NV	56224#STK100	358	15.9	188	67.6	9.17
56319	BLACK HILLS	WYGEN	WY	56319#2	397	10.3	160	91	8.26
56456	Plum Point Energy Associates LLC	PLUM POINT	AR	56456#S1	475	22.0	154	82.5	39.50
56564	AEP - SWEPCO	J. TURK (FULTON, AK)	AR	56564#1	643	21.5	190	100	29.54
56596	BLACK HILLS	WYGEN	WY	56596#5	400	10.3	160	90.7	8.66
56609	BASIN ELECTRIC	DRY FORK	WY	56609#STACK	500	20.0	160	81	33.73
56611	SANDY CREEK	SANDY CREEK ENERGY STATION	TX	56611#S1	360	28.0	173	71	32.95
56671	LONGVIEW POWER	LONGVIEW	WV	56671#UHN02	554	19.5	135	86	27.51
56786	GREAT RIVER ENG	SPIRITWOOD STATION	ND	56786#1	199	7.5	169	132	4.97
56808	DOMINION VA POWER	VIRGINIA CITY HYBRID ENERGY C	VA	56808#1	500	22.6	152	75.6	27.95

G
EMISSIONS OF HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS (POUNDS PER YEAR)

Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants (pounds per year)

Plant ID Number	Plant Name	As	Be	Cd	Co	Cr	Mn	Ni	Pb	Sb	HCl	Cl_2	HF	Se	Hg (total)	PMHg	Elem. Hg	Oxid. Hg	1,1-Dichloro-ethane	1,2,4-Trichloro-benzene	1,2-Dibromo-ethane	1,4-Dichloro-benzene	2,3,7,8-TCDD equiv.
3	BARRY	69.16	10.26	9.85	31.75	192.77	429.78	183.70	98.31	19.17	46078.00	774.08	14463.34	1373.73	22.68	0.23	17.83	4.62	49.90	127.02	22.23	113.41	5.9E-05
8	GORGAS TWO	182.87	16.74	18.00	45.98	323.14	745.07	273.79	180.98	22.45	20121.95	314.98	8156.66	409.77	22.70	0.23	21.34	1.12	49.93	127.09	22.24	113.48	5.9E-05
26	GASTON (AL)	90.10	9.55	16.28	32.05	204.44	416.31	186.65	110.13	21.43	84080.78	5899.53	9219.20	644.99	26.29	0.26	24.73	1.30	57.84	147.23	25.77	131.46	6.8E-05
47	COLBERT	0.01	0.00	0.00	0.01	0.03	0.06	0.03	0.02	0.00	749.57	38.42	34.72	0.70	0.01	0.00	0.00	0.00	0.01	0.03	0.00	0.03	1.3E-08
51	DOLET HILLS	69.55	7.96	9.29	30.81	166.99	359.69	145.22	87.45	20.90	19670.02	2604.57	11020.33	3882.08	87.28	0.87	82.08	4.32	54.06	137.60	24.08	122.86	6.4E-05
56	CR LOWMAN	61.87	1.55	2.03	4.75	28.53	56.82	27.96	15.38	3.00	12306.38	921.33	1122.51	147.27	3.52	0.04	3.31	0.17	7.74	19.69	3.45	17.58	9.1E-06
59	PLATTE	16.31	1.12	1.58	5.85	32.76	128.78	28.99	19.17	2.88	983.84	343.66	914.32	2.80	3.24	0.03	3.21	0.00	7.13	18.16	3.18	16.21	8.4E-06
60	WHELAN ENERGY CENTER	7.55	0.67	1.58	4.59	20.47	69.07	22.24	10.97	4.11	3436.49	777.93	5998.94	67.65	12.93	0.13	12.57	0.23	16.15	41.10	7.19	36.69	1.9E-05
87	ESCALANTE	6.88	1.89	2.33	6.03	23.34	76.63	25.47	30.26	5.65	5416.17	794.48	3578.94	218.43	10.13	0.10	9.53	0.50	16.49	41.97	7.35	37.48	1.9E-05
108	HOLCOMB	27.97	2.05	3.22	11.34	60.37	228.93	55.95	34.61	6.32	2215.27	823.25	2190.28	6.71	7.77	0.08	7.69	0.00	17.09	43.49	7.61	38.83	2.0E-05
113	CHOLLA	29.51	6.68	7.33	20.00	81.59	278.01	84.91	108.04	16.62	14672.10	2152.20	9695.16	632.67	20.30	0.20	19.10	1.01	44.67	113.70	19.90	101.52	5.3E-05
127	OKLAUNION	46.07	3.31	5.02	17.97	97.23	372.87	88.81	56.11	9.64	726.11	1221.19	4802.91	143.61	9.78	0.10	9.20	0.48	25.35	64.52	11.29	57.60	3.0E-05
130	CROSS	203.84	9.37	14.41	38.35	195.30	380.68	205.02	105.89	26.23	139996.50	72007.74	12146.83	2250.11	35.00	0.35	32.92	1.73	77.00	196.00	34.30	175.00	9.1E-05
136	SEMINOLE (FL)	282.49	23.51	20.81	68.47	463.83	968.35	396.68	241.58	35.00	93268.68	5440.86	12046.78	1473.48	51.17	0.51	48.13	2.53	84.03	213.89	37.43	190.98	9.9E-05
160	APACHE	12.28	2.96	3.49	9.47	38.43	141.38	40.80	47.71	8.12	6320.17	1098.78	5033.05	201.12	10.37	0.10	9.75	0.51	22.80	58.05	10.16	51.83	2.7E-05
165	GRDA	73.53	5.45	8.84	30.63	160.92	605.61	150.90	91.85	17.84	13671.04	2421.43	33367.22	522.40	22.84	0.23	19.91	2.71	50.26	127.92	22.39	114.22	5.9E-05
207	ST JOHNS RIVER	95.72	9.83	10.56	32.41	184.35	390.94	186.45	91.94	22.37	28230.79	480.18	10890.88	221.88	51.75	0.52	48.67	2.56	63.55	161.77	28.31	144.44	7.5E-05
298	LIMESTONE	86.87	9.67	14.57	45.44	225.53	588.58	216.03	117.95	35.28	24204.56	5101.54	20705.62	1474.86	240.64	2.41	226.32	11.91	105.88	269.52	47.17	240.64	1.3E-04
469	CHEROKEE (CO)	8.27	1.82	2.56	6.85	25.97	160.09	30.17	29.36	6.10	3964.62	473.25	3534.21	7.38	10.42	0.10	7.79	2.52	20.66	52.58	9.20	46.95	2.4E-05
470	COMANCHE	55.30	3.95	8.68	26.24	119.96	408.87	127.52	64.71	21.09	9310.29	3558.53	9467.62	29.02	58.05	0.58	57.47	0.00	73.86	188.00	32.90	167.86	8.7E-05
477	VALMONT	4.20	0.94	1.35	3.58	13.41	81.98	15.75	15.09	3.28	2177.57	259.71	1941.17	4.05	5.16	0.05	3.86	1.25	11.35	28.88	5.05	25.79	1.3E-05
492	DRAKE	20.15	1.33	2.35	7.84	39.56	144.43	38.48	22.19	4.98	3283.73	710.06	2792.64	17.99	6.70	0.07	6.30	0.33	14.74	37.51	6.56	33.49	1.7E-05
508	LAMAR REPOWERING PROJECT	0.01	0.00	0.00	0.00	0.02	0.10	0.02	0.02	0.00	20.00	0.53	4.62	0.00	0.01	0.00	0.00	0.00	0.01	0.03	0.00	0.03	1.3E-08
525	HAYDEN	13.09	2.90	4.14	11.01	41.46	254.50	48.45	46.75	9.98	6588.07	787.29	5872.86	12.26	15.60	0.16	11.67	3.77	34.33	87.38	15.29	78.01	4.1E-05
527	NUCLA	0.64	0.18	0.38	0.84	2.63	14.15	3.64	2.75	1.20	10262.76	8.87	2687.22	1.57	2.57	0.03	1.42	1.12	5.64	14.37	2.51	12.83	6.7E-06
564	CH STANTON	85.28	9.19	11.93	28.09	169.31	338.15	165.33	91.42	17.57	81629.67	35573.85	6514.70	2390.44	13.62	0.14	12.81	0.67	44.90	114.28	20.00	102.04	5.3E-05
568	BRIDGEPORT HARBOR	17.21	1.14	1.52	4.77	25.85	94.56	24.46	16.17	2.90	11560.18	346.40	29670.26	0.65	3.27	0.03	0.74	2.49	7.19	18.30	3.20	16.34	8.5E-06
594	INDIAN RIVER (DE)	42.14	1.52	1.27	6.18	33.64	65.69	33.02	18.90	3.19	4238.17	2097.73	843.62	7.58	2.51	0.03	1.40	1.08	7.86	20.02	3.50	17.87	9.3E-06
602	BRANDON SHORES	278.45	10.18	9.05	42.44	226.59	435.03	228.84	126.97	23.61	110928.19	16802.78	9808.00	1033.86	23.18	0.23	21.80	1.15	61.01	155.30	27.18	138.66	7.2E-05
628	CRYSTAL RIVER	228.31	15.69	14.48	53.77	271.53	767.42	278.48	162.21	32.02	88682.89	4651.07	15808.78	573.39	37.89	0.38	35.63	1.88	83.35	212.16	37.13	189.43	9.9E-05
641	CRIST	66.42	7.30	10.05	21.80	141.65	293.29	127.63	80.80	12.34	54813.17	53637.60	4299.73	322.33	13.70	0.14	12.89	0.68	30.15	76.74	13.43	68.52	3.6E-05
645	BIG BEND (FL)	324.90	21.11	29.52	66.48	446.50	929.73	389.38	259.46	35.78	159334.94	22441.86	13062.59	1589.24	39.83	0.40	37.46	1.97	87.63	223.07	39.04	199.17	1.0E-04
663	DEERHAVEN	15.89	1.76	1.47	6.80	29.70	65.22	31.84	15.64	3.81	6038.98	3173.81	952.36	11.51	7.14	0.07	3.90	3.17	9.98	25.40	4.44	22.68	1.2E-05
667	NORTHSIDE	6.06	1.43	5.24	9.37	19.29	44.10	90.95	18.19	2.12	9177.53	1460.69	0.00	27.56	2.20	0.02	1.84	0.34	30.32	77.17	13.50	68.90	3.6E-05
676	MCINTOSH (FL)	37.75	4.18	6.31	12.15	87.02	184.99	74.09	50.82	6.90	30734.06	43366.74	2527.91	207.42	5.37	0.05	5.05	0.27	16.90	43.03	7.53	38.42	2.0E-05
703	BOWEN	193.47	20.73	34.90	72.35	418.03	873.08	405.37	230.33	48.99	254016.71	204675.64	22254.57	1847.65	63.50	0.64	59.73	3.14	139.71	355.62	62.23	317.52	1.7E-04
708	HAMMOND	47.90	4.08	3.92	13.25	72.57	162.44	68.13	40.18	6.28	25575.77	3970.91	1949.49	131.35	6.39	0.06	6.01	0.32	14.07	35.81	6.27	31.97	1.7E-05
856	ED EDWARDS	82.37	5.68	7.99	29.60	165.72	650.94	146.77	96.95	14.62	15395.67	1747.77	38413.07	504.14	18.77	0.19	16.05	2.54	36.27	92.33	16.16	82.44	4.3E-05
861	COFFEEN	5.53	0.63	2.25	5.47	20.08	58.72	26.00	9.92	7.46	1090.81	1834.55	7215.21	48.06	9.94	0.10	9.35	0.49	38.08	96.92	16.96	86.54	4.5E-05
876	KINCAID	69.26	5.41	9.59	31.98	161.30	588.86	156.95	90.50	20.31	13330.25	2899.10	32529.43	586.30	35.58	0.36	29.95	5.27	60.17	153.16	26.80	136.75	7.1E-05
879	POWERTON	120.85	8.66	13.19	47.03	254.20	975.87	232.35	146.75	25.58	16748.42	3306.67	37102.61	334.36	26.18	0.26	5.18	20.73	68.63	174.69	30.57	155.97	8.1E-05
883	POWERTON	42.08	2.98	4.39	15.90	87.16	337.39	78.69	50.56	8.28	5211.21	1028.86	11544.35	104.04	6.54	0.07	6.26	0.22	21.35	54.35	9.51	48.53	2.5E-05
884	WILL COUNTY	59.69	4.08	5.66	21.10	118.93	469.41	104.68	69.77	10.25	10666.43	1210.89	26613.35	338.16	10.00	0.10	8.65	1.25	25.13	63.97	11.20	57.12	3.0E-05
887	JOPPA	127.53	5.84	8.35	30.69	170.57	666.59	152.07	99.50	15.43	13253.22	1867.13	41036.45	542.62	29.64	0.30	26.40	2.95	38.75	98.64	17.26	88.07	4.6E-05
889	BALDWIN	138.04	6.95	12.18	40.81	206.81	757.59	200.36	116.26	25.61	10381.24	3626.19	9647.63	29.57	20.93	0.21	20.72	0.00	75.26	191.57	33.53	171.05	8.9E-05
891	HAVANA	28.99	2.26	3.97	13.27	67.18	245.88	65.16	37.75	8.36	3394.77	1185.80	3154.87	9.67	5.80	0.06	5.75	0.00	24.61	62.65	10.96	55.93	2.9E-05
892	HENNEPIN	42.39	2.92	4.11	15.22	85.25	334.91	75.49	49.88	7.52	4153.38	898.11	67527.76	1.69	10.15	0.10	2.31	7.73	18.64	47.45	8.30	42.36	2.2E-05
963	DALLMAN	19.76	2.07	4.63	7.19	45.27	85.57	43.60	25.36	6.08	36635.91	11863.23	2929.44	676.92	7.49	0.07	7.05	0.37	20.15	51.29	8.98	45.79	2.4E-05
976	MARION (IL)	38.57	4.83	8.92	15.44	102.07	201.82	93.74	58.20	10.87	31532.28	832.36	5605.02	724.62	14.11	0.14	11.78	2.19	31.05	79.04	13.83	70.57	3.7E-05
983	CLIFTY CREEK	102.86	10.15	14.26	32.33	207.67	413.36	189.32	110.31	21.28	112386.65	13733.53	8904.40	983.99	24.55	0.25	23.09	1.22	61.81	157.34	27.53	140.48	7.3E-05
994	PETERSBURG	303.00	17.08	13.50	48.33	284.72	589.45	280.72	148.25	25.95	40896.49	1214.17	8628.79	3499.94	27.07	0.27	25.46	1.34	59.55	151.58	26.53	135.34	7.0E-05
995	BAILLY	35.55	3.67	3.46	11.33	62.22	122.18	65.40	31.51	7.17	14312.44	479.16	2653.46	303.32	12.02	0.12	11.31	0.60	18.31	46.61	8.16	41.62	2.2E-05
997	MICHIGAN CITY	99.44	4.19	4.35	18.29	105.37	341.84	94.88	61.72	8.46	35647.22	944.65	2429.04	10.08	8.91	0.09	7.49	1.34	19.61	49.91	8.73	44.56	2.3E-05
1001	CAYUGA	109.33	11.28	10.48	34.92	190.88	374.32	201.36	96.38	22.17	40279.79	1175.79	8215.60	3209.46	23.52	0.24	22.12	1.16	56.70	144.32	25.26	128.86	6.7E-05

Plant ID Number	Plant Name	5-Methyl-chrysene	Acet-aldehyde	Acrolein	B(a)P equiv.	Benzene	Benzyl-chloride	bis(2-Ethlyhexyl) phthalate	Carbon disulfide	Chloro-form	Formal-dehyde	Iso-phorone	m/p-Xylene	Methyl chloroform	Methylene chloride	Naphtha-lene	n-Hexane	Phenol	Propion-aldehyde	Tetrachloro-ethylene	Toluene	Vinyl acetate	2,4-Dinitro-toluene
3	BARRY	0.04	136.09	158.77	0.42	90.73	86.19	108.87	79.39	7.44	18.15	199.60	0.91	11.34	861.91	13.75	99.80	88.01	226.82	2.43	71.67	15.88	122.48
8	GORGAS TWO	0.04	136.17	158.87	0.42	90.78	86.24	108.94	79.43	7.44	18.16	199.72	0.91	11.35	862.42	13.75	99.86	88.06	226.95	2.43	71.72	15.89	122.55
26	GASTON (AL)	0.05	157.75	184.04	0.48	105.17	99.91	126.20	92.02	8.62	21.03	231.36	1.05	13.15	999.07	15.93	115.68	102.01	262.91	2.82	83.08	18.40	141.97
47	COLBERT	0.00	0.03	0.04	0.00	0.02	0.02	0.02	0.02	0.00	0.00	0.04	0.00	0.00	0.19	0.00	0.02	0.02	0.05	0.00	0.02	0.00	0.03
51	DOLET HILLS	0.04	147.43	172.00	0.45	98.29	93.37	117.94	86.00	8.06	19.66	216.23	0.98	12.29	933.72	14.89	108.11	95.34	245.71	2.63	77.65	17.20	132.69
56	CR LOWMAN	0.01	21.10	24.61	0.06	14.07	13.36	16.88	12.31	1.15	2.81	30.94	0.14	1.76	133.62	2.13	15.47	13.64	35.16	0.38	11.11	2.46	18.99
59	PLATTE	0.01	19.45	22.69	0.06	12.97	12.32	15.56	11.35	1.06	2.59	28.53	0.13	1.62	123.20	1.96	14.27	12.58	32.42	0.35	10.24	2.27	17.51
60	WHELAN ENERGY CENTER	0.01	44.03	51.37	0.14	29.36	27.89	35.23	25.69	2.41	5.87	64.58	0.29	3.67	278.88	4.45	32.29	28.48	73.39	0.79	23.19	5.14	39.63
87	ESCALANTE	0.01	44.97	52.47	0.14	29.98	28.48	35.98	26.23	2.46	6.00	65.96	0.30	3.75	284.81	4.54	32.98	29.08	74.95	0.80	23.68	5.25	40.47
108	HOLCOMB	0.01	46.60	54.37	0.14	31.07	29.51	37.28	27.18	2.55	6.21	68.34	0.31	3.88	295.13	4.71	34.17	30.13	77.66	0.83	24.54	5.44	41.94
113	CHOLLA	0.04	121.82	142.13	0.37	81.22	77.15	97.46	71.06	6.66	16.24	178.67	0.81	10.15	771.54	12.30	89.34	78.78	203.04	2.18	64.16	14.21	109.64
127	OKLAUNION	0.02	69.12	80.64	0.21	46.08	43.78	55.30	40.32	3.78	9.22	101.38	0.46	5.76	437.79	6.98	50.69	44.70	115.21	1.24	36.41	8.06	62.21
130	CROSS	0.06	209.99	244.99	0.64	140.00	133.00	168.00	122.50	11.48	28.00	307.99	1.40	17.50	1329.97	21.21	154.00	135.80	349.99	3.75	110.60	24.50	189.00
136	SEMINOLE (FL)	0.07	229.17	267.37	0.70	152.78	145.14	183.34	133.68	12.53	30.56	336.12	1.53	19.10	1451.42	23.15	168.06	148.20	381.95	4.09	120.70	26.74	206.25
160	APACHE	0.02	62.20	72.56	0.19	41.46	39.39	49.76	36.28	3.40	8.29	91.22	0.41	5.18	393.90	6.28	45.61	40.22	103.66	1.11	32.76	7.26	55.98
165	GRDA	0.04	137.06	159.91	0.42	91.37	86.81	109.65	79.95	7.49	18.27	201.02	0.91	11.42	868.06	13.84	100.51	88.63	228.44	2.45	72.19	15.99	123.36
207	ST JOHNS RIVER	0.05	173.32	202.21	0.53	115.55	109.77	138.66	101.11	9.48	23.11	254.21	1.16	14.44	1097.72	17.51	127.10	112.08	288.87	3.10	91.28	20.22	155.99
298	LIMESTONE	0.09	288.77	336.89	0.89	192.51	182.89	231.01	168.45	15.79	38.50	423.52	1.93	24.06	1828.85	29.17	211.76	186.74	481.28	5.16	152.08	33.69	259.89
469	CHEROKEE (CO)	0.02	56.34	65.73	0.17	37.56	35.68	45.07	32.86	3.08	7.51	82.63	0.38	4.69	356.80	5.69	41.31	36.43	93.90	1.01	29.67	6.57	50.70
470	COMANCHE	0.06	201.43	235.00	0.62	134.28	127.57	161.14	117.50	11.01	26.86	295.43	1.34	16.79	1275.70	20.34	147.71	130.26	335.71	3.60	106.08	23.50	181.28
477	VALMONT	0.01	30.94	36.10	0.09	20.63	19.60	24.75	18.05	1.69	4.13	45.38	0.21	2.58	195.98	3.13	22.69	20.01	51.57	0.55	16.30	3.61	27.85
492	DRAKE	0.01	40.19	46.89	0.12	26.79	25.45	32.15	23.45	2.20	5.36	58.95	0.27	3.35	254.55	4.06	29.47	25.99	66.99	0.72	21.17	4.69	36.17
508	LAMAR REPOWERING PROJECT	0.00	0.03	0.04	0.00	0.02	0.02	0.02	0.02	0.00	0.00	0.04	0.00	0.00	0.19	0.00	0.02	0.02	0.05	0.00	0.02	0.00	0.03
525	HAYDEN	0.03	93.62	109.22	0.29	62.41	59.29	74.89	54.61	5.12	12.48	137.30	0.62	7.80	592.91	9.46	68.65	60.54	156.03	1.67	49.30	10.92	84.26
527	NUCLA	0.00	15.39	17.96	0.05	10.26	9.75	12.32	8.98	0.84	2.05	22.58	0.10	1.28	97.50	1.55	11.29	9.95	25.66	0.28	8.11	1.80	13.85
564	CH STANTON	0.04	122.44	142.85	0.38	81.63	77.55	97.96	71.43	6.69	16.33	179.59	0.82	10.20	775.48	12.37	89.79	79.18	204.07	2.19	64.49	14.29	110.20
568	BRIDGEPORT HARBOR	0.01	19.61	22.88	0.06	13.07	12.42	15.69	11.44	1.07	2.61	28.76	0.13	1.63	124.18	1.98	14.38	12.68	32.68	0.35	10.33	2.29	17.65
594	INDIAN RIVER (DE)	0.01	21.45	25.02	0.07	14.30	13.58	17.16	12.51	1.17	2.86	31.46	0.14	1.79	135.83	2.17	15.73	13.87	35.75	0.38	11.30	2.50	19.30
602	BRANDON SHORES	0.05	166.39	194.12	0.51	110.93	105.38	133.11	97.06	9.10	22.19	244.04	1.11	13.87	1053.82	16.81	122.02	107.60	277.32	2.97	87.63	19.41	149.75
628	CRYSTAL RIVER	0.07	227.32	265.20	0.70	151.54	143.97	181.85	132.60	12.43	30.31	333.40	1.52	18.94	1439.67	22.96	166.70	147.00	378.86	4.06	119.72	26.52	204.59
641	CRIST	0.02	82.22	95.92	0.25	54.81	52.07	65.78	47.96	4.49	10.96	120.59	0.55	6.85	520.73	8.30	60.29	53.17	137.03	1.47	43.30	9.59	74.00
645	BIG BEND (FL)	0.07	239.00	278.84	0.73	159.33	151.37	191.20	139.42	13.07	31.87	350.54	1.59	19.92	1513.68	24.14	175.27	154.55	398.34	4.27	125.87	27.88	215.10
663	DEERHAVEN	0.01	27.21	31.75	0.08	18.14	17.23	21.77	15.87	1.49	3.63	39.91	0.18	2.27	172.33	2.75	19.95	17.60	45.35	0.49	14.33	3.17	24.49
667	NORTHSIDE	0.02	82.68	96.46	0.25	55.12	52.36	66.14	48.23	4.52	11.02	121.26	0.55	6.89	523.64	8.35	60.63	53.47	137.80	1.48	43.55	9.65	74.41
676	MCINTOSH (FL)	0.01	46.10	53.78	0.14	30.73	29.20	36.88	26.89	2.52	6.15	67.61	0.31	3.84	291.97	4.66	33.81	29.81	76.84	0.82	24.28	5.38	41.49
703	BOWEN	0.11	381.03	444.53	1.17	254.02	241.32	304.82	222.26	20.83	50.80	558.84	2.54	31.75	2413.16	38.48	279.42	246.40	635.04	6.81	200.67	44.45	342.92
708	HAMMOND	0.01	38.36	44.76	0.12	25.58	24.30	30.69	22.38	2.10	5.12	56.27	0.26	3.20	242.97	3.87	28.13	24.81	63.94	0.69	20.20	4.48	34.53
856	ED EDWARDS	0.03	98.93	115.42	0.30	65.95	62.66	79.14	57.71	5.41	13.19	145.10	0.66	8.24	626.56	9.99	72.55	63.97	164.88	1.77	52.10	11.54	89.04
861	COFFEEN	0.03	103.84	121.15	0.32	69.23	65.77	83.07	60.57	5.68	13.85	152.30	0.69	8.65	657.67	10.49	76.15	67.15	173.07	1.86	54.69	12.11	93.46
876	KINCAID	0.05	164.10	191.45	0.50	109.40	103.93	131.28	95.72	8.97	21.88	240.68	1.09	13.67	1039.30	16.57	120.34	106.12	273.50	2.93	86.43	19.14	147.69
879	POWERTON	0.06	187.17	218.36	0.57	124.78	118.54	149.74	109.18	10.23	24.96	274.52	1.25	15.60	1185.41	18.90	137.26	121.04	311.95	3.34	98.58	21.84	168.45
883	POWERTON	0.02	58.24	67.94	0.18	38.82	36.88	46.59	33.97	3.18	7.76	85.41	0.39	4.85	368.84	5.88	42.71	37.66	97.06	1.04	30.67	6.79	52.41
884	WILL COUNTY	0.02	68.54	79.96	0.21	45.69	43.41	54.83	39.98	3.75	9.14	100.53	0.46	5.71	434.09	6.92	50.26	44.32	114.23	1.22	36.10	8.00	61.69
887	JOPPA	0.03	105.69	123.30	0.32	70.46	66.93	84.55	61.65	5.78	14.09	155.01	0.70	8.81	669.35	10.67	77.50	68.34	176.14	1.89	55.66	12.33	95.12
889	BALDWIN	0.06	205.26	239.47	0.63	136.84	130.00	164.20	119.73	11.22	27.37	301.04	1.37	17.10	1299.96	20.73	150.52	132.73	342.09	3.67	108.10	23.95	184.73
891	HAVANA	0.02	67.12	78.31	0.21	44.75	42.51	53.70	39.15	3.67	8.95	98.44	0.45	5.59	425.10	6.78	49.22	43.40	111.87	1.20	35.35	7.83	60.41
892	HENNEPIN	0.02	50.84	59.31	0.16	33.89	32.20	40.67	29.65	2.78	6.78	74.56	0.34	4.24	321.96	5.13	37.28	32.87	84.73	0.91	26.77	5.93	45.75
963	DALLMAN	0.02	54.95	64.11	0.17	36.64	34.80	43.96	32.06	3.00	7.33	80.60	0.37	4.58	348.04	5.55	40.30	35.54	91.59	0.98	28.94	6.41	49.46
976	MARION (IL)	0.03	84.69	98.80	0.26	56.46	53.64	67.75	49.40	4.63	11.29	124.21	0.56	7.06	536.35	8.55	62.10	54.76	141.14	1.51	44.60	9.88	76.22
983	CLIFTY CREEK	0.05	168.58	196.68	0.52	112.39	106.77	134.86	98.34	9.22	22.48	247.25	1.12	14.05	1067.67	17.03	123.63	109.02	280.97	3.01	88.79	19.67	151.72
994	PETERSBURG	0.05	162.41	189.48	0.50	108.27	102.86	129.93	94.74	8.88	21.65	238.20	1.08	13.53	1028.59	16.40	119.10	105.02	270.68	2.90	85.54	18.95	146.17
995	BAILLY	0.01	49.94	58.26	0.15	33.29	31.63	39.95	29.13	2.73	6.66	73.25	0.33	4.16	316.29	5.04	36.62	32.29	83.23	0.89	26.30	5.83	44.95
997	MICHIGAN CITY	0.02	53.47	62.38	0.16	35.65	33.86	42.78	31.19	2.92	7.13	78.42	0.36	4.46	338.65	5.40	39.21	34.58	89.12	0.96	28.16	6.24	48.12
1001	CAYUGA	0.05	154.63	180.40	0.47	103.09	97.93	123.71	90.20	8.45	20.62	226.79	1.03	12.89	979.33	15.62	113.40	100.00	257.72	2.76	81.44	18.04	139.17

Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants (pounds per year)

Plant ID Number	Plant Name	As	Be	Cd	Co	Cr	Mn	Ni	Pb	Sb	HCl	Cl_2	HF	Se	Hg (total)	PMHg	Elem. Hg	Oxid. Hg	1,1-Dichloro-ethane	1,2,4-Trichloro-benzene	1,2-Dibromo-ethane	1,4-Dichloro-benzene	2,3,7,8-TCDD equiv.
1004	EDWARDSPORT IGCC	11.36	1.56	2.45	6.42	27.67	45.95	36.15	12.70	7.21	726.84	372.31	117.73	2.51	12.56	0.13	11.81	0.62	27.62	70.32	12.31	62.78	3.3E-05
1008	GALLAGHER	7.33	0.92	0.87	3.78	15.60	32.12	17.36	8.16	2.34	12099.53	16857.04	2458.63	7.58	0.25	0.00	0.06	0.19	6.65	16.94	2.96	15.12	7.9E-06
1012	CULLEY	35.47	3.59	3.24	10.93	60.63	120.15	63.13	30.80	6.71	13068.79	443.57	2431.85	302.89	9.29	0.09	8.74	0.46	16.78	42.72	7.48	38.14	2.0E-05
1040	WHITEWATER VALLEY	1.13	0.14	0.13	0.49	2.27	4.47	2.42	1.19	0.29	656.65	353.52	649.64	50.79	0.35	0.00	0.17	0.17	0.76	1.94	0.34	1.73	9.0E-07
1047	LANSING	25.73	1.78	2.52	9.30	51.94	203.67	46.11	30.36	4.62	1588.92	555.01	1476.63	4.53	5.14	0.05	5.09	0.00	11.52	29.32	5.13	26.18	1.4E-05
1073	PRAIRIE CREEK	6.61	0.47	0.69	2.50	13.69	53.01	12.36	7.94	1.30	1385.60	161.30	3545.05	169.18	0.92	0.01	0.79	0.11	3.35	8.52	1.49	7.61	4.0E-06
1082	COUNCIL BLUFFS (SCOTT ENERGY CENTER)	141.19	10.69	17.95	61.30	316.92	1178.20	301.53	179.65	36.84	14543.81	5080.19	13516.04	41.43	55.75	0.56	55.19	0.00	105.44	268.39	46.97	239.63	1.2E-04
1091	GEORGE NEAL	23.77	1.86	3.31	11.01	55.46	202.27	54.03	31.10	7.01	2863.94	1003.71	2670.40	8.18	4.41	0.04	4.37	0.00	20.83	53.03	9.28	47.34	2.5E-05
1104	BURLINGTON (IA)	28.60	1.97	2.77	10.27	57.50	225.94	50.91	33.65	5.07	5331.58	605.26	13302.60	659.27	5.63	0.06	4.87	0.70	12.56	31.98	5.60	28.55	1.5E-05
1131	STREETER	0.08	0.01	0.01	0.03	0.16	0.34	0.15	0.09	0.01	2406.48	163.39	91.17	2.53	0.01	0.00	0.00	0.01	0.03	0.08	0.01	0.07	3.9E-08
1167	MUSCATINE	11.22	0.89	1.60	5.30	26.46	95.98	25.96	14.79	3.44	695.19	498.46	2836.56	120.24	4.70	0.05	4.37	0.28	10.35	26.33	4.61	23.51	1.2E-05
1241	LA CYGNE	156.68	11.42	16.51	59.24	324.34	1229.40	294.96	186.73	31.44	3512.60	3942.52	15480.39	156.82	37.19	0.37	34.98	1.84	81.83	208.28	36.45	185.97	9.7E-05
1250	LAWRENCE (KS)	58.78	4.07	5.79	21.34	118.96	465.92	105.76	69.48	10.65	762.12	1281.75	5041.07	41.26	12.09	0.12	11.37	0.60	26.60	67.71	11.85	60.46	3.1E-05
1252	TECUMSEH	10.46	0.73	1.03	3.80	21.17	82.89	18.83	12.36	1.90	1158.45	228.72	2566.31	82.06	2.16	0.02	1.86	0.28	4.75	12.08	2.11	10.79	5.6E-06
1355	EW BROWN	35.09	3.73	3.96	12.52	66.81	126.60	71.45	32.86	9.03	16941.63	473.05	3755.22	631.67	11.76	0.12	11.06	0.58	25.87	65.85	11.52	58.80	3.1E-05
1356	GHENT	163.91	13.76	16.76	48.68	260.30	503.68	270.41	129.25	35.35	191874.83	16126.43	15666.08	6855.61	40.07	0.40	37.68	1.98	105.53	268.62	47.01	239.84	1.2E-04
1364	MILL CREEK (KY)	120.75	7.98	9.06	27.28	161.29	306.83	155.65	79.26	19.24	64916.68	3521.93	8364.89	1118.86	26.53	0.27	24.96	1.31	58.37	148.59	26.00	132.67	6.9E-05
1374	ELMER SMITH	94.42	8.02	6.42	23.15	151.06	314.67	133.92	78.09	11.90	21082.29	639.61	4012.21	729.18	12.70	0.13	11.94	0.63	27.94	71.12	12.45	63.50	3.3E-05
1378	PARADISE	428.41	22.51	22.00	67.19	447.14	921.76	389.29	232.61	36.70	118627.90	7279.66	13355.72	11741.79	40.98	0.41	38.54	2.03	93.10	236.99	41.47	211.60	1.1E-04
1379	SHAWNEE (KY)	168.54	11.66	16.49	60.93	340.27	1334.25	302.04	198.86	30.28	15304.69	3634.21	33558.26	10.30	34.29	0.34	13.87	20.07	75.43	192.00	33.60	171.43	8.9E-05
1381	COLEMAN (KY)	65.46	6.01	5.97	19.60	120.30	235.03	112.13	59.75	12.49	63899.21	9870.52	5033.94	609.24	15.97	0.16	15.02	0.79	35.14	89.46	15.66	79.87	4.2E-05
1382	HENDERSON TWO	33.74	3.08	3.03	10.00	61.63	120.77	57.23	30.66	6.31	32041.03	5756.80	2524.17	642.95	8.01	0.08	7.53	0.40	17.62	44.86	7.85	40.05	2.1E-05
1384	JS COOPER	21.22	1.71	1.16	5.56	30.35	73.59	28.95	15.71	2.70	6232.04	7868.59	742.07	6.64	2.81	0.03	1.62	1.16	6.19	15.75	2.76	14.06	7.3E-06
1393	R S Nelson	75.55	6.15	9.74	34.45	163.90	684.54	378.63	99.34	14.74	67329.10	2243.68	32685.53	786.84	14.37	0.14	9.16	5.06	46.57	118.53	20.74	105.83	5.5E-05
1552	CP CRANE	11.40	0.76	1.08	3.99	21.59	80.62	19.64	12.39	2.10	3618.40	266.70	2963.36	0.50	2.52	0.03	0.57	1.92	5.54	14.09	2.47	12.58	6.5E-06
1554	HA WAGNER	7.91	1.17	1.46	5.49	20.21	39.42	24.44	10.57	4.41	205778.40	137132.71	10630.18	755.31	6.25	0.06	0.36	5.83	15.45	39.33	6.88	35.12	1.8E-05
1571	CHALK POINT	37.03	1.61	1.76	7.58	36.14	64.56	39.42	19.09	5.21	28903.78	4027.61	2471.60	548.80	1.40	0.01	1.31	0.07	15.90	40.47	7.08	36.13	1.9E-05
1572	DICKERSON	28.32	1.27	1.12	4.64	24.91	56.64	25.50	12.82	2.54	11987.40	1934.53	1155.44	213.53	3.25	0.03	3.06	0.16	6.59	16.78	2.94	14.98	7.8E-06
1573	MORGANTOWN	241.11	9.07	7.69	36.50	197.50	393.59	194.50	108.64	18.99	86272.88	12427.00	7621.32	1576.97	6.26	0.06	5.88	0.31	47.45	120.78	21.14	107.84	5.6E-05
1606	MOUNT TOM	0.03	0.00	0.00	0.01	0.05	0.10	0.04	0.02	0.00	1.22	0.12	1.30	0.01	0.01	0.00	0.00	0.00	0.01	0.03	0.00	0.03	1.3E-08
1619	BRAYTON POINT	38.30	3.19	3.18	11.38	57.52	121.19	58.53	29.68	6.96	25747.65	1218.35	2809.16	154.28	8.66	0.09	3.03	5.54	19.04	48.47	8.48	43.28	2.3E-05
1702	DE KARN	26.29	2.02	3.54	11.38	56.78	208.63	56.60	32.80	7.63	3329.86	1083.55	2908.49	8.82	10.22	0.10	10.12	0.00	22.49	57.24	10.02	51.11	2.7E-05
1710	JH CAMPBELL	105.31	8.46	15.08	50.00	248.37	894.06	244.76	138.55	32.59	33856.13	4736.03	27862.34	39.33	44.68	0.45	31.35	12.88	98.29	250.21	43.79	223.40	1.2E-04
1733	MONROE (MI)	782.76	43.74	39.66	176.77	968.10	3130.51	1060.45	556.86	80.05	139514.14	8668.60	32612.89	1238.15	81.78	0.82	76.91	4.05	179.91	457.96	80.14	408.90	2.1E-04
1740	RIVER ROUGE	19.04	1.83	2.08	8.20	38.18	114.67	39.52	20.57	4.99	25374.29	672.42	7072.22	409.52	6.34	0.06	2.84	3.44	13.96	35.52	6.22	31.72	1.6E-05
1743	ST CLAIR	727.18	11.51	7.59	40.77	249.51	526.79	223.09	147.73	16.36	60849.91	1612.52	15370.31	1380.82	15.21	0.15	4.43	10.63	33.47	85.19	14.91	76.06	4.0E-05
1745	TRENTON CHANNEL	80.78	3.77	4.46	17.71	97.16	314.61	90.65	55.79	9.13	41786.98	1107.36	12053.78	504.00	10.45	0.10	5.53	4.81	22.98	58.50	10.24	52.23	2.7E-05
1769	PRESQUE ISLE	37.64	2.61	4.02	11.77	59.37	232.97	62.34	39.24	8.52	6725.54	1104.42	12966.22	2.08	10.42	0.10	2.37	7.94	22.92	58.35	10.21	52.10	2.7E-05
1825	JB SIMS	4.44	0.53	0.88	1.57	11.32	23.40	9.68	6.68	0.95	4369.38	1534.85	349.38	67.07	1.09	0.01	1.03	0.05	2.40	6.12	1.07	5.46	2.8E-06
1831	ECKERT	6.81	0.54	0.97	3.21	16.05	58.23	15.75	8.97	2.08	2661.03	302.09	6639.41	88.07	2.85	0.03	2.45	0.37	6.27	15.96	2.79	14.25	7.4E-06
1832	ERICKSON	13.82	1.10	1.99	6.57	32.72	118.49	32.18	18.27	4.29	5500.65	624.45	13724.42	192.00	5.89	0.06	5.07	0.76	12.96	32.99	5.77	29.46	1.5E-05
1843	SHIRAS	5.07	0.41	0.66	2.26	11.22	39.66	11.11	6.22	1.44	2943.60	203.99	543.55	1.84	1.92	0.02	1.91	0.00	4.23	10.78	1.89	9.62	5.0E-06
1866	WYANDOTTE	0.24	0.05	0.05	0.16	0.65	4.27	0.69	0.76	0.11	573.23	1.24	150.09	0.09	0.14	0.00	0.08	0.06	0.32	0.80	0.14	0.72	3.7E-07
1893	CLAY BOSWELL	147.23	10.14	15.14	47.69	248.31	972.41	246.94	157.76	30.74	11188.14	3877.92	55541.47	66.03	29.53	0.30	24.79	4.45	80.49	204.87	35.85	182.92	9.5E-05
1915	ALLEN S KING	35.14	2.77	5.00	16.55	82.78	300.48	81.14	46.29	10.72	4440.87	1551.21	4127.05	12.65	17.02	0.17	16.85	0.00	32.19	81.95	14.34	73.17	3.8E-05
1943	HOOT LAKE	17.18	0.97	1.05	3.03	17.10	78.97	17.73	13.93	1.88	3096.69	188.32	4546.25	58.79	1.78	0.02	1.39	0.37	3.91	9.95	1.74	8.88	4.6E-06
2076	ASBURY	28.82	2.25	3.44	10.14	59.94	215.53	52.23	35.26	5.06	13093.23	598.62	1551.36	5.34	0.98	0.01	0.96	0.01	12.42	31.63	5.53	28.24	1.5E-05
2079	HAWTHORN	42.06	3.33	6.05	19.95	99.49	360.38	97.78	55.57	13.01	5242.59	1892.78	5035.82	15.44	17.86	0.18	17.68	0.00	39.28	100.00	17.50	89.28	4.6E-05
2080	MONTROSE	13.81	1.09	1.97	6.52	32.58	118.20	31.96	18.21	4.23	5259.14	613.05	13473.76	182.06	5.78	0.06	5.02	0.70	12.72	32.39	5.67	28.92	1.5E-05
2094	SIBLEY (MO)	27.88	2.19	3.90	12.59	64.39	233.86	62.12	36.27	7.92	19561.99	1127.18	24696.35	446.35	10.63	0.11	7.35	3.18	23.39	59.55	10.42	53.17	2.8E-05
2103	LABADIE	296.83	16.10	25.17	88.82	474.23	1802.49	438.35	272.25	49.30	54264.75	6410.49	140892.03	1831.60	60.48	0.60	52.52	7.35	133.05	338.67	59.27	302.38	1.6E-04
2104	MERAMEC	35.11	2.52	3.83	13.69	74.09	284.15	67.67	42.76	7.34	8166.59	930.26	20445.50	263.81	8.78	0.09	7.58	1.10	19.31	49.15	8.60	43.88	2.3E-05
2107	SIOUX	68.36	6.82	13.33	29.98	170.66	509.06	160.26	96.95	19.48	30042.65	2709.31	9977.08	369.54	25.14	0.25	23.65	1.24	56.23	143.13	25.05	127.80	6.6E-05
2167	NEW MADRID	84.55	6.59	11.59	38.77	196.08	717.37	190.29	110.15	24.44	30573.80	3470.84	76283.36	975.25	32.74	0.33	27.10	5.32	72.04	183.37	32.09	163.72	8.5E-05

Plant ID Number	Plant Name	5-Methyl-chrysene	Acet-aldehyde	Acrolein	B(a)P equiv.	Benzene	Benzyl-chloride	bis(2-Ethlyhexyl) phthalate	Carbon disulfide	Chloro-form	Formal-dehyde	Iso-phorone	m/p-Xylene	Methyl chloroform	Methylene chloride	Naphtha-lene	n-Hexane	Phenol	Propion-aldehyde	Tetrachloro-ethylene	Toluene	Vinyl acetate	2,4-Dinitro-toluene
1004	EDWARDSPORT IGCC	0.02	75.34	87.89	0.23	50.23	47.71	60.27	43.95	4.12	10.05	110.50	0.50	6.28	477.14	7.61	55.25	48.72	125.56	1.35	39.68	8.79	67.80
1008	GALLAGHER	0.01	18.15	21.17	0.06	12.10	11.49	14.52	10.59	0.99	2.42	26.62	0.12	1.51	114.95	1.83	13.31	11.74	30.25	0.32	9.56	2.12	16.33
1012	CULLEY	0.01	45.77	53.40	0.14	30.51	28.99	36.62	26.70	2.50	6.10	67.13	0.31	3.81	289.89	4.62	33.57	29.60	76.29	0.82	24.11	5.34	41.19
1040	WHITEWATER VALLEY	0.00	2.07	2.42	0.01	1.38	1.31	1.66	1.21	0.11	0.28	3.04	0.01	0.17	13.13	0.21	1.52	1.34	3.46	0.04	1.09	0.24	1.87
1047	LANSING	0.01	31.42	36.65	0.10	20.94	19.90	25.13	18.33	1.72	4.19	46.08	0.21	2.62	198.97	3.17	23.04	20.32	52.36	0.56	16.55	3.67	28.27
1073	PRAIRIE CREEK	0.00	9.13	10.65	0.03	6.09	5.78	7.30	5.33	0.50	1.22	13.39	0.06	0.76	57.82	0.92	6.70	5.90	15.22	0.16	4.81	1.07	8.22
1082	COUNCIL BLUFFS (SCOTT ENERGY CENTER)	0.09	287.56	335.48	0.88	191.71	182.12	230.05	167.74	15.72	38.34	421.75	1.92	23.96	1821.20	29.04	210.88	185.95	479.26	5.14	151.45	33.55	258.80
1091	GEORGE NEAL	0.02	56.81	66.28	0.17	37.88	35.98	45.45	33.14	3.11	7.58	83.33	0.38	4.73	359.82	5.74	41.66	36.74	94.69	1.02	29.92	6.63	51.13
1104	BURLINGTON (IA)	0.01	34.26	39.97	0.11	22.84	21.70	27.41	19.98	1.87	4.57	50.25	0.23	2.85	216.98	3.46	25.12	22.15	57.10	0.61	18.04	4.00	30.83
1131	STREETER	0.00	0.09	0.10	0.00	0.06	0.06	0.07	0.05	0.00	0.01	0.13	0.00	0.01	0.56	0.01	0.07	0.06	0.15	0.00	0.05	0.01	0.08
1167	MUSCATINE	0.01	28.21	32.92	0.09	18.81	17.87	22.57	16.46	1.54	3.76	41.38	0.19	2.35	178.69	2.85	20.69	18.25	47.02	0.50	14.86	3.29	25.39
1241	LA CYGNE	0.07	223.16	260.36	0.68	148.77	141.34	178.53	130.18	12.20	29.75	327.30	1.49	18.60	1413.36	22.54	163.65	144.31	371.94	3.99	117.53	26.04	200.85
1250	LAWRENCE (KS)	0.02	72.55	84.64	0.22	48.37	45.95	58.04	42.32	3.97	9.67	106.41	0.48	6.05	459.49	7.33	53.20	46.92	120.92	1.30	38.21	8.46	65.30
1252	TECUMSEH	0.00	12.95	15.10	0.04	8.63	8.20	10.36	7.55	0.71	1.73	18.99	0.09	1.08	81.99	1.31	9.49	8.37	21.58	0.23	6.82	1.51	11.65
1355	EW BROWN	0.02	70.56	82.32	0.22	47.04	44.69	56.45	41.16	3.86	9.41	103.48	0.47	5.88	446.87	7.13	51.74	45.63	117.60	1.26	37.16	8.23	63.50
1356	GHENT	0.09	287.81	335.78	0.88	191.87	182.28	230.25	167.89	15.73	38.37	422.12	1.92	23.98	1822.81	29.07	211.06	186.12	479.69	5.14	151.58	33.58	259.03
1364	MILL CREEK (KY)	0.05	159.20	185.74	0.49	106.14	100.83	127.36	92.87	8.70	21.23	233.50	1.06	13.27	1008.29	16.08	116.75	102.95	265.34	2.84	83.85	18.57	143.28
1374	ELMER SMITH	0.02	76.20	88.89	0.23	50.80	48.26	60.96	44.45	4.17	10.16	111.75	0.51	6.35	482.57	7.70	55.88	49.27	126.99	1.36	40.13	8.89	68.58
1378	PARADISE	0.08	253.92	296.24	0.78	169.28	160.82	203.14	148.12	13.88	33.86	372.42	1.69	21.16	1608.16	25.65	186.21	164.20	423.20	4.54	133.73	29.62	228.53
1379	SHAWNEE (KY)	0.06	205.71	240.00	0.63	137.14	130.28	164.57	120.00	11.25	27.43	301.71	1.37	17.14	1302.83	20.78	150.85	133.03	342.85	3.68	108.34	24.00	185.14
1381	COLEMAN (KY)	0.03	95.85	111.82	0.29	63.90	60.70	76.68	55.91	5.24	12.78	140.58	0.64	7.99	607.04	9.68	70.29	61.98	159.75	1.71	50.48	11.18	86.26
1382	HENDERSON TWO	0.01	48.06	56.07	0.15	32.04	30.44	38.45	28.04	2.63	6.41	70.49	0.32	4.01	304.39	4.85	35.25	31.08	80.10	0.86	25.31	5.61	43.26
1384	JS COOPER	0.01	16.87	19.68	0.05	11.25	10.69	13.50	9.84	0.92	2.25	24.75	0.11	1.41	106.86	1.70	12.37	10.91	28.12	0.30	8.89	1.97	15.19
1393	R S Nelson	0.04	127.00	148.17	0.39	84.67	80.43	101.60	74.08	6.94	16.93	186.27	0.85	10.58	804.34	12.83	93.13	82.13	211.67	2.27	66.89	14.82	114.30
1552	CP CRANE	0.00	15.10	17.61	0.05	10.06	9.56	12.08	8.81	0.83	2.01	22.14	0.10	1.26	95.61	1.52	11.07	9.76	25.16	0.27	7.95	1.76	13.59
1554	HA WAGNER	0.01	42.14	49.16	0.13	28.09	26.69	33.71	24.58	2.30	5.62	61.81	0.28	3.51	266.89	4.26	30.90	27.25	70.23	0.75	22.19	4.92	37.93
1571	CHALK POINT	0.01	43.36	50.58	0.13	28.90	27.46	34.68	25.29	2.37	5.78	63.59	0.29	3.61	274.59	4.38	31.79	28.04	72.26	0.77	22.83	5.06	39.02
1572	DICKERSON	0.01	17.98	20.98	0.06	11.99	11.39	14.38	10.49	0.98	2.40	26.37	0.12	1.50	113.88	1.82	13.19	11.63	29.97	0.32	9.47	2.10	16.18
1573	MORGANTOWN	0.04	129.41	150.98	0.40	86.27	81.96	103.53	75.49	7.07	17.25	189.80	0.86	10.78	819.59	13.07	94.90	83.68	215.68	2.31	68.16	15.10	116.47
1606	MOUNT TOM	0.00	0.03	0.04	0.00	0.02	0.02	0.02	0.02	0.00	0.00	0.04	0.00	0.00	0.19	0.00	0.02	0.02	0.05	0.00	0.02	0.00	0.03
1619	BRAYTON POINT	0.02	51.93	60.59	0.16	34.62	32.89	41.55	30.29	2.84	6.92	76.17	0.35	4.33	328.90	5.25	38.08	33.58	86.55	0.93	27.35	6.06	46.74
1702	DE KARN	0.02	61.33	71.56	0.19	40.89	38.84	49.07	35.78	3.35	8.18	89.96	0.41	5.11	388.44	6.19	44.98	39.66	102.22	1.10	32.30	7.16	55.20
1710	JH CAMPBELL	0.08	268.08	312.76	0.82	178.72	169.78	214.46	156.38	14.65	35.74	393.18	1.79	22.34	1697.82	27.08	196.59	173.36	446.80	4.79	141.19	31.28	241.27
1733	MONROE (MI)	0.15	490.68	572.45	1.50	327.12	310.76	392.54	286.23	26.82	65.42	719.66	3.27	40.89	3107.61	49.56	359.83	317.30	817.79	8.77	258.42	57.25	441.61
1740	RIVER ROUGE	0.01	38.06	44.41	0.12	25.37	24.11	30.45	22.20	2.08	5.07	55.82	0.25	3.17	241.06	3.84	27.91	24.61	63.44	0.68	20.05	4.44	34.26
1743	ST CLAIR	0.03	91.27	106.49	0.28	60.85	57.81	73.02	53.24	4.99	12.17	133.87	0.61	7.61	578.07	9.22	66.93	59.02	152.12	1.63	48.07	10.65	82.15
1745	TRENTON CHANNEL	0.02	62.68	73.13	0.19	41.79	39.70	50.14	36.56	3.43	8.36	91.93	0.42	5.22	396.98	6.33	45.97	40.53	104.47	1.12	33.01	7.31	56.41
1769	PRESQUE ISLE	0.02	62.51	72.93	0.19	41.68	39.59	50.01	36.47	3.42	8.34	91.69	0.42	5.21	395.92	6.31	45.84	40.43	104.19	1.12	32.92	7.29	56.26
1825	JB SIMS	0.00	6.55	7.65	0.02	4.37	4.15	5.24	3.82	0.36	0.87	9.61	0.04	0.55	41.51	0.66	4.81	4.24	10.92	0.12	3.45	0.76	5.90
1831	ECKERT	0.01	17.10	19.95	0.05	11.40	10.83	13.68	9.97	0.93	2.28	25.08	0.11	1.42	108.30	1.73	12.54	11.06	28.50	0.31	9.01	1.99	15.39
1832	ERICKSON	0.01	35.35	41.24	0.11	23.56	22.39	28.28	20.62	1.93	4.71	51.84	0.24	2.95	223.86	3.57	25.92	22.86	58.91	0.63	18.62	4.12	31.81
1843	SHIRAS	0.00	11.55	13.47	0.04	7.70	7.31	9.24	6.74	0.63	1.54	16.93	0.08	0.96	73.13	1.17	8.47	7.47	19.24	0.21	6.08	1.35	10.39
1866	WYANDOTTE	0.00	0.86	1.00	0.00	0.57	0.54	0.69	0.50	0.05	0.11	1.26	0.01	0.07	5.45	0.09	0.63	0.56	1.43	0.02	0.45	0.10	0.77
1893	CLAY BOSWELL	0.07	219.51	256.09	0.67	146.34	139.02	175.60	128.04	12.00	29.27	321.94	1.46	18.29	1390.20	22.17	160.97	141.95	365.84	3.92	115.61	25.61	197.55
1915	ALLEN S KING	0.03	87.80	102.44	0.27	58.54	55.61	70.24	51.22	4.80	11.71	128.78	0.59	7.32	556.09	8.87	64.39	56.78	146.34	1.57	46.24	10.24	79.02
1943	HOOT LAKE	0.00	10.66	12.44	0.03	7.11	6.75	8.53	6.22	0.58	1.42	15.63	0.07	0.89	67.51	1.08	7.82	6.89	17.77	0.19	5.61	1.24	9.59
2076	ASBURY	0.01	33.88	39.53	0.10	22.59	21.46	27.11	19.77	1.85	4.52	49.70	0.23	2.82	214.60	3.42	24.85	21.91	56.47	0.61	17.85	3.95	30.50
2079	HAWTHORN	0.03	107.14	124.99	0.33	71.43	67.85	85.71	62.50	5.86	14.29	157.14	0.71	8.93	678.54	10.82	78.57	69.28	178.56	1.91	56.43	12.50	96.42
2080	MONTROSE	0.01	34.70	40.48	0.11	23.13	21.98	27.76	20.24	1.90	4.63	50.89	0.23	2.89	219.77	3.50	25.45	22.44	57.83	0.62	18.28	4.05	31.23
2094	SIBLEY (MO)	0.02	63.80	74.44	0.20	42.54	40.41	51.04	37.22	3.49	8.51	93.58	0.43	5.32	404.08	6.44	46.79	41.26	106.34	1.14	33.60	7.44	57.42
2103	LABADIE	0.11	362.86	423.33	1.11	241.91	229.81	290.29	211.67	19.84	48.38	532.19	2.42	30.24	2298.10	36.65	266.10	234.65	604.76	6.48	191.11	42.33	326.57
2104	MERAMEC	0.02	52.66	61.43	0.16	35.10	33.35	42.12	30.72	2.88	7.02	77.23	0.35	4.39	333.49	5.32	38.61	34.05	87.76	0.94	27.73	6.14	47.39
2107	SIOUX	0.05	153.36	178.92	0.47	102.24	97.13	122.69	89.46	8.38	20.45	224.92	1.02	12.78	971.26	15.49	112.46	99.17	255.60	2.74	80.77	17.89	138.02
2167	NEW MADRID	0.06	196.46	229.21	0.60	130.98	124.43	157.17	114.60	10.74	26.20	288.15	1.31	16.37	1244.26	19.84	144.07	127.05	327.44	3.51	103.47	22.92	176.82

Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants (pounds per year)

Plant ID Number	Plant Name	As	Be	Cd	Co	Cr	Mn	Ni	Pb	Sb	HCl	Cl_2	HF	Se	Hg (total)	PMHg	Elem. Hg	Oxid. Hg	1,1-Dichloro-ethane	1,2,4-Trichloro-benzene	1,2-Dibromo-ethane	1,4-Dichloro-benzene	2,3,7,8-TCDD equiv.
2168	THOMAS HILL	142.29	8.84	13.75	48.63	260.17	990.39	240.05	149.49	26.88	30731.28	3488.72	76676.27	978.77	32.91	0.33	27.23	5.35	72.41	184.31	32.25	164.56	8.6E-05
2240	LD WRIGHT	8.62	0.60	0.87	3.17	17.59	68.61	15.72	10.25	1.61	425.12	195.12	519.12	1.59	1.84	0.02	1.82	0.00	4.05	10.31	1.80	9.20	4.8E-06
2277	SHELDON	5.81	0.53	1.25	3.65	16.12	53.84	17.66	8.59	3.25	2793.45	604.04	45417.35	447.80	2.96	0.03	0.67	2.26	12.54	31.91	5.58	28.49	1.5E-05
2291	NORTH OMAHA	23.69	1.83	3.19	10.72	54.48	200.07	52.65	30.67	6.72	4833.40	954.27	10707.38	342.40	9.00	0.09	7.82	1.09	19.81	50.41	8.82	45.01	2.3E-05
2324	REID GARDNER	5.44	0.94	1.03	3.14	16.07	87.84	14.64	15.71	1.93	999.98	7.35	1169.82	13.19	1.49	0.01	1.41	0.07	5.11	13.00	2.27	11.60	6.0E-06
2364	MERRIMACK	65.90	2.76	1.95	10.39	57.60	117.46	51.46	31.12	4.29	17080.97	1860.76	1359.31	247.55	2.54	0.03	2.39	0.13	9.54	24.29	4.25	21.69	1.1E-05
2367	SCHILLER	14.09	1.13	0.79	2.94	20.65	50.93	17.28	11.16	1.26	4658.99	147.50	1275.80	85.71	1.16	0.01	0.23	0.92	2.56	6.52	1.14	5.82	3.0E-06
2378	BL ENGLAND	16.21	0.56	0.37	2.03	11.98	25.00	10.57	6.81	0.80	3017.70	382.30	251.27	55.10	0.33	0.00	0.31	0.02	1.66	4.22	0.74	3.77	2.0E-06
2403	HUDSON	22.79	1.31	1.35	5.14	28.09	99.93	25.29	17.44	2.48	7389.51	261.57	737.30	3.07	2.47	0.02	2.29	0.16	5.43	13.82	2.42	12.34	6.4E-06
2408	MERCER	12.43	0.70	0.55	3.04	13.60	34.42	13.49	7.32	1.51	1864.07	932.78	366.04	3.30	1.67	0.02	0.94	0.71	3.68	9.38	1.64	8.37	4.4E-06
2442	FOUR CORNERS	40.76	11.44	14.60	37.23	141.69	459.61	156.97	182.43	36.35	20841.15	86.70	23693.40	918.90	49.62	0.50	46.67	2.46	109.16	277.87	48.63	248.10	1.3E-04
2451	SAN JUAN (NM)	19.15	4.10	6.12	19.63	62.20	365.62	96.54	43.35	18.11	13667.62	69.59	23891.96	274.94	20.92	0.21	19.67	1.04	66.78	170.00	29.75	151.78	7.9E-05
2535	CAYUGA 1(MILLIKEN)	50.93	1.84	1.30	6.93	39.57	80.81	35.78	22.15	2.91	11593.81	1343.46	960.14	211.15	2.90	0.03	2.73	0.14	6.38	16.23	2.84	14.49	7.5E-06
2706	ASHEVILLE	25.97	1.44	1.70	7.39	30.94	59.50	35.43	15.64	5.62	29380.97	2589.18	2809.83	250.83	4.79	0.05	4.51	0.24	18.54	47.20	8.26	42.15	2.2E-05
2712	ROXBORO	327.78	8.74	7.39	34.80	168.37	347.14	174.15	91.08	19.22	90472.68	20636.03	7532.77	1399.77	20.59	0.21	19.37	1.02	49.76	126.66	22.17	113.09	5.9E-05
2718	ALLEN	26.37	2.84	3.27	11.25	50.31	108.58	53.87	26.52	6.89	34639.82	5770.16	2780.83	450.01	8.66	0.09	8.14	0.43	19.05	48.50	8.49	43.30	2.3E-05
2721	CLIFFSIDE	29.45	3.21	4.42	14.56	58.58	117.93	70.35	28.77	12.15	63661.57	5157.46	6502.45	757.73	13.66	0.14	12.85	0.68	41.58	105.85	18.52	94.51	4.9E-05
2727	MARSHALL (NC)	142.40	6.68	6.96	29.73	127.93	242.54	141.09	65.99	19.57	106681.94	14581.04	7837.22	1563.79	26.67	0.27	25.08	1.32	58.68	149.35	26.14	133.35	6.9E-05
2790	HESKETT	11.14	0.51	0.87	1.99	10.18	22.26	9.52	7.39	1.96	11614.80	286.44	1407.01	4.82	2.90	0.03	1.78	1.09	5.94	15.13	2.65	13.51	7.0E-06
2817	LELAND OLDS	88.62	4.02	6.84	15.96	81.93	185.18	76.46	59.05	15.31	12283.34	2206.32	4885.20	1240.23	68.85	0.69	64.76	3.41	45.79	116.56	20.40	104.07	5.4E-05
2823	MR YOUNG	125.11	5.59	9.34	21.67	112.35	247.72	103.79	81.91	20.73	26152.31	2951.46	6272.17	1522.63	186.69	1.87	175.58	9.24	61.26	155.93	27.29	139.22	7.2E-05
2824	STANTON (ND)	33.82	2.09	2.69	7.17	37.48	164.04	41.65	29.61	5.36	2616.04	611.24	2679.85	44.68	9.15	0.09	7.72	1.34	12.69	32.29	5.65	28.83	1.5E-05
2828	CARDINAL	356.14	11.03	10.26	40.36	213.59	497.83	223.43	105.71	23.20	86847.26	6627.93	11361.54	1730.73	23.01	0.23	21.64	1.14	62.83	159.93	27.99	142.80	7.4E-05
2832	MIAMI FORT	171.91	12.51	14.45	46.42	245.37	475.34	239.67	127.21	26.55	109665.47	8455.25	9785.50	6347.42	35.43	0.35	33.33	1.75	70.69	179.94	31.49	160.66	8.4E-05
2836	AVON LAKE	305.45	9.72	6.51	33.71	206.94	453.25	186.31	120.17	13.69	1979204.40	121151.58	118390.62	2858.04	12.88	0.13	2.55	10.20	28.34	72.13	12.62	64.40	3.3E-05
2840	CONESVILLE	397.64	16.25	13.09	49.82	304.96	828.51	301.65	142.37	24.78	76594.19	4653.14	12737.68	1810.87	30.59	0.31	28.77	1.51	61.03	155.36	27.19	138.71	7.2E-05
2850	JM STUART	268.70	20.78	33.19	68.91	441.11	885.53	400.89	251.87	41.92	201894.76	45029.23	16260.05	1598.97	33.39	0.33	31.40	1.65	111.04	282.65	49.46	252.37	1.3E-04
2866	WH SAMMIS	294.08	13.85	12.28	54.76	259.40	534.05	265.41	137.34	29.46	136893.82	13527.69	10493.52	2292.36	35.13	0.35	33.04	1.74	77.28	196.72	34.43	175.64	9.1E-05
2876	KYGER CREEK	107.76	5.19	5.71	18.83	100.12	246.94	112.38	44.22	13.31	41429.91	2109.68	8897.49	1479.77	23.00	0.23	21.64	1.14	42.63	108.52	18.99	96.89	5.0E-05
2878	FirstEnergy Bay Shore	2.91	0.69	2.51	4.50	9.26	21.17	43.66	8.73	1.02	4406.01	701.26	1111.43	13.23	1.06	0.01	0.24	0.81	14.55	37.05	6.48	33.08	1.7E-05
2952	MUSKOGEE	114.08	7.53	11.07	40.18	220.49	854.19	198.84	127.97	20.87	12133.15	2587.13	29029.00	928.28	24.41	0.24	21.31	2.85	53.70	136.68	23.92	122.03	6.3E-05
2963	NORTHEASTERN	43.42	3.39	5.99	19.99	100.95	368.85	98.12	56.66	12.66	9133.98	1803.34	20234.41	14.71	17.01	0.17	3.87	12.97	37.43	95.27	16.67	85.06	4.4E-05
3118	CONEMAUGH	205.72	10.73	12.24	52.76	235.60	410.96	257.78	117.88	37.13	217722.97	21976.64	17181.68	5203.48	40.52	0.41	38.11	2.01	119.75	304.81	53.34	272.15	1.4E-04
3122	HOMER CITY	721.63	16.71	12.83	64.41	366.77	737.07	348.61	210.56	30.46	127588.18	259530.70	12006.10	1363.07	31.90	0.32	20.03	11.55	70.17	178.62	31.26	159.49	8.3E-05
3130	SEWARD	19.54	0.95	1.45	5.32	22.30	36.13	28.02	11.35	5.29	37426.47	991.80	6237.49	15.06	9.36	0.09	5.75	3.51	20.58	52.40	9.17	46.78	2.4E-05
3136	KEYSTONE (PA)	614.80	25.40	19.12	99.36	536.98	1070.41	496.36	290.83	44.45	188411.97	26149.27	14914.55	4921.13	19.16	0.19	18.02	0.95	103.63	263.78	46.16	235.51	1.2E-04
3140	BRUNNER ISLAND	453.42	18.10	12.21	65.42	374.27	803.44	328.98	200.11	25.61	95707.27	9949.01	8223.57	2476.68	24.99	0.25	23.50	1.24	54.97	139.92	24.49	124.93	6.5E-05
3149	MONTOUR	374.56	16.18	12.58	64.47	342.29	681.82	318.14	180.14	29.64	126577.86	13547.00	10335.61	896.39	6.86	0.07	6.45	0.34	71.61	182.28	31.90	162.75	8.5E-05
3297	WATEREE (SC)	194.48	9.84	6.95	35.68	176.96	453.32	172.34	92.45	16.51	55874.26	5056.00	5356.99	641.74	16.53	0.17	15.55	0.82	36.37	92.59	16.20	82.67	4.3E-05
3298	AM WILLIAMS	80.43	7.73	5.89	29.05	131.34	307.25	139.23	68.35	15.85	73002.95	10469.27	6482.06	2246.78	18.25	0.18	17.16	0.90	40.15	102.20	17.89	91.25	4.7E-05
3393	TH ALLEN	85.52	4.28	6.01	22.29	124.86	490.68	110.52	73.06	10.99	6646.14	1312.16	14723.13	573.80	12.38	0.12	10.67	1.58	27.23	69.32	12.13	61.89	3.2E-05
3396	BULL RUN (TN)	89.83	7.44	5.17	23.75	125.40	299.74	124.05	65.72	11.47	30562.09	1892.69	4299.21	213.55	4.61	0.05	4.33	0.23	25.52	64.97	11.37	58.01	3.0E-05
3399	CUMBERLAND	379.46	41.39	58.82	123.88	840.69	1790.71	718.10	491.54	65.85	163692.10	8365.75	22624.76	9214.99	71.62	0.72	67.35	3.54	157.55	401.05	70.18	358.08	1.9E-04
3403	GALLATIN	41.49	3.37	6.42	20.69	100.96	360.52	101.17	55.93	14.27	6214.22	2170.64	5775.08	17.70	20.48	0.20	20.27	0.00	45.05	114.68	20.07	102.39	5.3E-05
3406	JOHNSONVILLE (TN)	55.66	4.92	6.27	21.57	116.27	448.31	108.19	74.29	12.29	43027.63	1585.16	18578.11	611.07	14.95	0.15	7.84	6.97	32.90	83.74	14.66	74.77	3.9E-05
3407	KINGSTON	79.48	7.21	8.04	26.67	151.72	380.25	145.93	78.26	16.94	22440.12	2289.63	7803.83	1546.37	21.60	0.22	20.32	1.07	47.52	120.96	21.17	108.00	5.6E-05
3470	WA PARISH	250.58	7.81	13.31	45.15	231.92	858.25	221.96	131.12	27.57	9414.01	3844.08	141157.76	96.14	36.26	0.36	32.33	3.57	79.78	203.08	35.54	181.32	9.4E-05
3497	BIG BROWN	167.17	14.92	18.59	65.66	363.11	1149.31	318.67	202.33	37.48	177873.00	4516.85	345760.96	10885.34	213.06	2.13	48.51	162.41	93.75	238.63	41.76	213.06	1.1E-04
3797	CHESTERFIELD	102.80	7.56	7.70	32.99	140.28	278.14	158.70	72.44	22.51	123765.77	16922.47	9900.58	972.59	17.51	0.18	16.47	0.87	68.07	173.27	30.32	154.71	8.0E-05
3809	YORKTOWN	12.95	1.00	0.56	3.27	16.77	44.57	16.44	8.81	1.45	299473.70	32628.03	15112.66	239.55	1.41	0.01	0.28	1.12	3.10	7.88	1.38	7.04	3.7E-06
3845	CENTRALIA	145.60	9.47	12.69	36.34	189.45	804.27	200.10	139.40	25.35	3288.51	2986.68	12680.89	136.91	38.28	0.38	36.00	1.89	61.99	157.79	27.61	140.88	7.3E-05
3935	AMOS	439.59	34.84	28.06	130.93	618.94	1302.76	611.71	325.94	63.19	259502.86	23191.22	19669.33	2331.42	84.34	0.84	79.32	4.17	155.18	395.00	69.12	352.68	1.8E-04
3943	FORT MARTIN	215.59	12.04	11.20	53.33	251.26	465.69	250.37	125.47	29.42	132397.74	11744.02	10953.59	3529.29	37.17	0.37	34.96	1.84	81.78	208.15	36.43	185.85	9.7E-05
3944	HARRISON	482.06	25.92	20.89	109.38	544.85	1038.19	500.52	266.92	50.76	193833.92	16884.97	15762.21	8328.42	58.76	0.59	55.27	2.91	129.28	329.07	57.59	293.81	1.5E-04

Plant ID Number	Plant Name	5-Methyl-chrysene	Acet-aldehyde	Acrolein	B(a)P equiv.	Benzene	Benzyl-chloride	bis(2-Ethlyhexyl) phthalate	Carbon disulfide	Chloro-form	Formal-dehyde	Iso-phorone	m/p-Xylene	Methyl chloroform	Methylene chloride	Naphtha-lene	n-Hexane	Phenol	Propion-aldehyde	Tetrachloro-ethylene	Toluene	Vinyl acetate	2,4-Dinitro-toluene
2168	THOMAS HILL	0.06	197.47	230.39	0.61	131.65	125.07	157.98	115.19	10.80	26.33	289.63	1.32	16.46	1250.67	19.94	144.81	127.70	329.12	3.53	104.00	23.04	177.73
2240	LD WRIGHT	0.00	11.04	12.89	0.03	7.36	6.99	8.84	6.44	0.60	1.47	16.20	0.07	0.92	69.95	1.12	8.10	7.14	18.41	0.20	5.82	1.29	9.94
2277	SHELDON	0.01	34.19	39.89	0.10	22.79	21.65	27.35	19.94	1.87	4.56	50.15	0.23	2.85	216.54	3.45	25.07	22.11	56.99	0.61	18.01	3.99	30.77
2291	NORTH OMAHA	0.02	54.02	63.02	0.17	36.01	34.21	43.21	31.51	2.95	7.20	79.22	0.36	4.50	342.10	5.46	39.61	34.93	90.03	0.97	28.45	6.30	48.61
2324	REID GARDNER	0.00	13.93	16.25	0.04	9.28	8.82	11.14	8.12	0.76	1.86	20.42	0.09	1.16	88.19	1.41	10.21	9.01	23.21	0.25	7.33	1.62	12.53
2364	MERRIMACK	0.01	26.02	30.36	0.08	17.35	16.48	20.82	15.18	1.42	3.47	38.17	0.17	2.17	164.81	2.63	19.08	16.83	43.37	0.46	13.71	3.04	23.42
2367	SCHILLER	0.00	6.99	8.15	0.02	4.66	4.43	5.59	4.08	0.38	0.93	10.25	0.05	0.58	44.26	0.71	5.12	4.52	11.65	0.12	3.68	0.82	6.29
2378	BL ENGLAND	0.00	4.53	5.28	0.01	3.02	2.87	3.62	2.64	0.25	0.60	6.64	0.03	0.38	28.67	0.46	3.32	2.93	7.54	0.08	2.38	0.53	4.07
2403	HUDSON	0.00	14.81	17.27	0.05	9.87	9.38	11.84	8.64	0.81	1.97	21.72	0.10	1.23	93.77	1.50	10.86	9.57	24.68	0.26	7.80	1.73	13.33
2408	MERCER	0.00	10.05	11.72	0.03	6.70	6.36	8.04	5.86	0.55	1.34	14.74	0.07	0.84	63.64	1.01	7.37	6.50	16.75	0.18	5.29	1.17	9.04
2442	FOUR CORNERS	0.09	297.71	347.33	0.91	198.48	188.55	238.17	173.67	16.28	39.70	436.65	1.98	24.81	1885.53	30.07	218.32	192.52	496.19	5.32	156.80	34.73	267.94
2451	SAN JUAN (NM)	0.05	182.14	212.49	0.56	121.43	115.35	145.71	106.25	9.96	24.29	267.14	1.21	15.18	1153.54	18.40	133.57	117.78	303.56	3.25	95.93	21.25	163.92
2535	CAYUGA 1(MILLIKEN)	0.01	17.39	20.29	0.05	11.59	11.01	13.91	10.14	0.95	2.32	25.51	0.12	1.45	110.14	1.76	12.75	11.25	28.98	0.31	9.16	2.03	15.65
2706	ASHEVILLE	0.02	50.57	59.00	0.16	33.72	32.03	40.46	29.50	2.76	6.74	74.18	0.34	4.21	320.30	5.11	37.09	32.70	84.29	0.90	26.64	5.90	45.52
2712	ROXBORO	0.04	135.71	158.33	0.42	90.47	85.95	108.57	79.16	7.42	18.09	199.04	0.90	11.31	859.49	13.71	99.52	87.76	226.18	2.42	71.47	15.83	122.14
2718	ALLEN	0.02	51.96	60.62	0.16	34.64	32.91	41.57	30.31	2.84	6.93	76.21	0.35	4.33	329.08	5.25	38.10	33.60	86.60	0.93	27.37	6.06	46.76
2721	CLIFFSIDE	0.03	113.41	132.31	0.35	75.60	71.82	90.73	66.15	6.20	15.12	166.33	0.76	9.45	718.24	11.45	83.17	73.34	189.01	2.03	59.73	13.23	102.07
2727	MARSHALL (NC)	0.05	160.02	186.69	0.49	106.68	101.35	128.02	93.35	8.75	21.34	234.70	1.07	13.34	1013.48	16.16	117.35	103.48	266.70	2.86	84.28	18.67	144.02
2790	HESKETT	0.00	16.21	18.92	0.05	10.81	10.27	12.97	9.46	0.89	2.16	23.78	0.11	1.35	102.69	1.64	11.89	10.48	27.02	0.29	8.54	1.89	14.59
2817	LELAND OLDS	0.04	124.89	145.70	0.38	83.26	79.09	99.91	72.85	6.83	16.65	183.17	0.83	10.41	790.95	12.61	91.58	80.76	208.14	2.23	65.77	14.57	112.40
2823	MR YOUNG	0.05	167.06	194.91	0.51	111.38	105.81	133.65	97.45	9.13	22.28	245.03	1.11	13.92	1058.07	16.87	122.51	108.03	278.44	2.98	87.99	19.49	150.36
2824	STANTON (ND)	0.01	34.60	40.36	0.11	23.07	21.91	27.68	20.18	1.89	4.61	50.74	0.23	2.88	219.12	3.49	25.37	22.37	57.66	0.62	18.22	4.04	31.14
2828	CARDINAL	0.05	171.35	199.91	0.53	114.24	108.52	137.08	99.96	9.37	22.85	251.32	1.14	14.28	1085.25	17.31	125.66	110.81	285.59	3.06	90.25	19.99	154.22
2832	MIAMI FORT	0.06	192.79	224.92	0.59	128.53	122.10	154.23	112.46	10.54	25.71	282.76	1.29	16.07	1220.99	19.47	141.38	124.67	321.31	3.44	101.54	22.49	173.51
2836	AVON LAKE	0.02	77.28	90.16	0.24	51.52	48.95	61.83	45.08	4.22	10.30	113.35	0.52	6.44	489.46	7.81	56.67	49.98	128.81	1.38	40.70	9.02	69.56
2840	CONESVILLE	0.05	166.46	194.20	0.51	110.97	105.42	133.17	97.10	9.10	22.19	244.14	1.11	13.87	1054.23	16.81	122.07	107.64	277.43	2.97	87.67	19.42	149.81
2850	JM STUART	0.09	302.84	353.32	0.93	201.89	191.80	242.27	176.66	16.56	40.38	444.17	2.02	25.24	1918.00	30.59	222.08	195.84	504.74	5.41	159.50	35.33	272.56
2866	WH SAMMIS	0.06	210.77	245.90	0.65	140.51	133.49	168.62	122.95	11.52	28.10	309.13	1.41	17.56	1334.89	21.29	154.57	136.30	351.29	3.77	111.01	24.59	189.69
2876	KYGER CREEK	0.03	116.27	135.65	0.36	77.52	73.64	93.02	67.83	6.36	15.50	170.53	0.78	9.69	736.40	11.74	85.27	75.19	193.79	2.08	61.24	13.57	104.65
2878	FirstEnergy Bay Shore	0.01	39.69	46.31	0.12	26.46	25.14	31.76	23.15	2.17	5.29	58.22	0.26	3.31	251.39	4.01	29.11	25.67	66.16	0.71	20.91	4.63	35.72
2952	MUSKOGEE	0.04	146.44	170.85	0.45	97.63	92.75	117.15	85.42	8.01	19.53	214.78	0.98	12.20	927.46	14.79	107.39	94.70	244.07	2.62	77.13	17.08	131.80
2963	NORTHEASTERN	0.03	102.08	119.09	0.31	68.05	64.65	81.66	59.54	5.58	13.61	149.71	0.68	8.51	646.48	10.31	74.86	66.01	170.13	1.82	53.76	11.91	91.87
3118	CONEMAUGH	0.10	326.58	381.02	1.00	217.72	206.84	261.27	190.51	17.85	43.54	478.99	2.18	27.22	2068.37	32.99	239.50	211.19	544.31	5.83	172.00	38.10	293.93
3122	HOMER CITY	0.06	191.38	223.28	0.59	127.59	121.21	153.11	111.64	10.46	25.52	280.69	1.28	15.95	1212.09	19.33	140.35	123.76	318.97	3.42	100.79	22.33	172.24
3130	SEWARD	0.02	56.14	65.50	0.17	37.43	35.56	44.91	32.75	3.07	7.49	82.34	0.37	4.68	355.55	5.67	41.17	36.30	93.57	1.00	29.57	6.55	50.53
3136	KEYSTONE (PA)	0.08	282.62	329.72	0.87	188.41	178.99	226.09	164.86	15.45	37.68	414.51	1.88	23.55	1789.91	28.54	207.25	182.76	471.03	5.05	148.85	32.97	254.36
3140	BRUNNER ISLAND	0.04	149.92	174.90	0.46	99.95	94.95	119.93	87.45	8.20	19.99	219.88	1.00	12.49	949.48	15.14	109.94	96.95	249.86	2.68	78.96	17.49	134.93
3149	MONTOUR	0.06	195.31	227.86	0.60	130.20	123.69	156.24	113.93	10.68	26.04	286.45	1.30	16.28	1236.93	19.73	143.22	126.30	325.51	3.49	102.86	22.79	175.77
3297	WATEREE (SC)	0.03	99.20	115.73	0.30	66.13	62.83	79.36	57.87	5.42	13.23	145.49	0.66	8.27	628.26	10.02	72.75	64.15	165.33	1.77	52.24	11.57	89.28
3298	AM WILLIAMS	0.03	109.50	127.76	0.34	73.00	69.35	87.60	63.88	5.99	14.60	160.61	0.73	9.13	693.53	11.06	80.30	70.81	182.51	1.96	57.67	12.78	98.55
3393	TH ALLEN	0.02	74.27	86.65	0.23	49.52	47.04	59.42	43.33	4.06	9.90	108.93	0.50	6.19	470.40	7.50	54.47	48.03	123.79	1.33	39.12	8.67	66.85
3396	BULL RUN (TN)	0.02	69.61	81.21	0.21	46.41	44.09	55.69	40.61	3.81	9.28	102.10	0.46	5.80	440.88	7.03	51.05	45.02	116.02	1.24	36.66	8.12	62.65
3399	CUMBERLAND	0.13	429.69	501.31	1.32	286.46	272.14	343.75	250.65	23.49	57.29	630.22	2.86	35.81	2721.39	43.40	315.11	277.87	716.16	7.68	226.31	50.13	386.72
3403	GALLATIN	0.04	122.87	143.34	0.38	81.91	77.82	98.29	71.67	6.72	16.38	180.20	0.82	10.24	778.16	12.41	90.10	79.45	204.78	2.20	64.71	14.33	110.58
3406	JOHNSONVILLE (TN)	0.03	89.73	104.68	0.28	59.82	56.83	71.78	52.34	4.91	11.96	131.60	0.60	7.48	568.26	9.06	65.80	58.02	149.54	1.60	47.26	10.47	80.75
3407	KINGSTON	0.04	129.60	151.20	0.40	86.40	82.08	103.68	75.60	7.08	17.28	190.08	0.86	10.80	820.81	13.09	95.04	83.81	216.00	2.32	68.26	15.12	116.64
3470	WA PARISH	0.07	217.59	253.85	0.67	145.06	137.81	174.07	126.93	11.89	29.01	319.13	1.45	18.13	1378.07	21.98	159.57	140.71	362.65	3.89	114.60	25.39	195.83
3497	BIG BROWN	0.08	255.67	298.28	0.78	170.45	161.92	204.54	149.14	13.98	34.09	374.98	1.70	21.31	1619.25	25.82	187.49	165.33	426.12	4.57	134.65	29.83	230.10
3797	CHESTERFIELD	0.06	185.65	216.59	0.57	123.77	117.58	148.52	108.30	10.15	24.75	272.28	1.24	15.47	1175.77	18.75	136.14	120.05	309.41	3.32	97.77	21.66	167.08
3809	YORKTOWN	0.00	8.45	9.86	0.03	5.63	5.35	6.76	4.93	0.46	1.13	12.39	0.06	0.70	53.50	0.85	6.20	5.46	14.08	0.15	4.45	0.99	7.60
3845	CENTRALIA	0.05	169.06	197.23	0.52	112.70	107.07	135.25	98.62	9.24	22.54	247.95	1.13	14.09	1070.70	17.07	123.98	109.32	281.76	3.02	89.04	19.72	152.15
3935	AMOS	0.13	423.21	493.75	1.30	282.14	268.04	338.57	246.87	23.14	56.43	620.71	2.82	35.27	2680.36	42.74	310.36	273.68	705.36	7.56	222.89	49.37	380.89
3943	FORT MARTIN	0.07	223.02	260.19	0.68	148.68	141.25	178.42	130.10	12.19	29.74	327.10	1.49	18.59	1412.48	22.53	163.55	144.22	371.70	3.98	117.46	26.02	200.72
3944	HARRISON	0.11	352.58	411.34	1.08	235.05	223.30	282.06	205.67	19.27	47.01	517.11	2.35	29.38	2232.98	35.61	258.56	228.00	587.63	6.30	185.69	41.13	317.32

Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants (pounds per year)

Plant ID Number	Plant Name	As	Be	Cd	Co	Cr	Mn	Ni	Pb	Sb	HCl	Cl_2	HF	Se	Hg (total)	PMHg	Elem. Hg	Oxid. Hg	1,1-Dichloro-ethane	1,2,4-Trichloro-benzene	1,2-Dibromo-ethane	1,4-Dichloro-benzene	2,3,7,8-TCDD equiv.
3948	MITCHELL (WV)	130.04	11.43	9.56	45.07	204.99	412.98	205.53	107.19	23.01	103182.90	9565.17	7245.50	908.12	20.70	0.21	19.47	1.02	59.18	150.64	26.36	134.50	7.0E-05
3954	MOUNT STORM	271.77	14.27	14.59	69.25	349.23	627.03	329.67	159.61	38.32	136362.70	8852.44	17737.89	2703.56	66.51	0.67	62.56	3.29	109.62	279.03	48.83	249.14	1.3E-04
4041	OAK CREEK (WI)	64.04	5.06	9.15	30.23	151.06	547.99	148.20	84.44	19.62	1666.42	2844.48	11187.25	316.43	24.14	0.24	22.70	1.19	59.04	150.27	26.30	134.17	7.0E-05
4050	EDGEWATER (WI)	67.84	5.00	8.02	27.92	147.40	556.71	137.60	84.30	16.07	12981.36	2162.27	21379.46	283.99	15.53	0.16	12.25	3.12	44.88	114.23	19.99	101.99	5.3E-05
4072	JP PULLIAM	8.62	0.63	0.98	3.47	18.54	70.42	17.14	10.64	1.92	1068.07	249.43	2798.75	266.38	3.53	0.04	3.01	0.48	5.18	13.18	2.31	11.77	6.1E-06
4078	WESTON	51.23	4.05	7.32	24.18	120.84	438.36	118.56	67.55	15.70	7209.74	2275.83	60788.96	51.04	25.14	0.25	15.74	9.15	47.23	120.23	21.04	107.35	5.6E-05
4125	MANITOWOC	0.27	0.06	0.24	0.42	0.87	1.99	4.11	0.82	0.10	414.72	66.01	0.00	1.25	0.10	0.00	0.06	0.04	1.37	3.49	0.61	3.11	1.6E-06
4143	GENOA THREE	17.42	1.38	2.50	8.25	41.19	149.26	40.46	23.01	5.38	2236.79	781.31	2078.72	6.37	7.37	0.07	7.30	0.00	16.22	41.28	7.22	36.85	1.9E-05
4158	DAVE JOHNSTON	61.97	3.44	6.45	20.97	103.00	369.17	102.63	57.18	14.18	6060.95	2117.10	5632.64	69.06	27.32	0.27	27.05	0.00	43.94	111.85	19.57	99.86	5.2E-05
4162	NAUGHTON	145.30	5.32	10.25	31.55	218.08	542.66	144.49	164.85	20.43	867.66	2111.12	5780.42	1362.52	32.71	0.33	30.77	1.62	43.82	111.53	19.52	99.58	5.2E-05
4271	MADGETT	21.09	1.65	2.95	9.80	49.29	179.63	48.08	27.63	6.26	4549.69	898.25	10078.89	7.32	8.47	0.08	1.93	6.46	18.64	47.45	8.30	42.37	2.2E-05
4941	NAVAJO	83.10	14.97	15.25	58.17	219.22	1454.96	291.04	163.78	35.39	19256.46	130.35	34752.83	1263.85	44.16	0.44	41.53	2.19	97.14	247.27	43.27	220.78	1.1E-04
6002	MILLER	212.97	16.90	30.78	101.38	504.85	1826.90	496.87	281.82	66.35	5431.63	9678.05	38063.50	1170.91	91.30	0.91	85.87	4.52	200.87	511.29	89.48	456.51	2.4E-04
6004	PLEASANTS	381.98	17.60	15.26	59.12	331.54	841.12	336.47	156.04	31.43	86386.36	4866.92	15817.68	2748.51	37.36	0.37	35.13	1.85	82.18	209.19	36.61	186.78	9.7E-05
6009	WHITE BLUFF	117.70	8.61	13.50	47.59	253.68	962.74	234.84	145.52	26.46	30122.59	3437.83	75557.92	1034.98	32.43	0.32	28.04	4.06	71.35	181.62	31.78	162.16	8.4E-05
6016	DUCK CREEK	26.68	2.11	3.84	12.66	63.13	228.65	62.07	35.26	8.26	715.21	1202.86	4730.83	35.99	11.35	0.11	10.67	0.56	24.97	63.55	11.12	56.74	3.0E-05
6017	NEWTON	121.07	8.89	12.15	48.69	257.90	1063.96	434.24	149.19	24.26	75358.30	2756.57	62955.42	1195.13	34.10	0.34	26.20	7.55	57.21	145.63	25.49	130.03	6.8E-05
6018	EAST BEND	153.08	12.21	10.19	39.22	232.68	488.11	211.17	122.09	19.99	88112.93	16325.57	6875.01	841.36	28.76	0.29	27.05	1.42	48.46	123.36	21.59	110.14	5.7E-05
6019	ZIMMER	153.77	10.43	9.97	40.31	200.87	382.92	204.51	102.15	23.57	79712.10	5088.69	8830.68	6000.60	39.74	0.40	37.37	1.97	63.76	162.29	28.40	144.90	7.5E-05
6021	CRAIG	46.34	5.60	8.24	21.91	61.46	430.44	69.67	102.74	18.08	19842.46	2719.07	8396.91	369.41	31.65	0.32	30.68	0.65	56.43	143.65	25.14	128.26	6.7E-05
6030	COAL CREEK	111.66	5.59	11.54	24.29	114.48	236.19	115.27	80.36	29.33	28991.06	4937.54	10492.78	456.82	268.81	2.69	252.82	13.31	102.48	260.85	45.65	232.90	1.2E-04
6031	KILLEN	67.54	6.68	11.38	21.96	141.23	280.53	129.46	79.31	14.42	72534.88	14682.40	5820.91	574.77	12.79	0.13	12.03	0.63	39.89	101.55	17.77	90.67	4.7E-05
6034	BELLE RIVER	382.14	21.31	22.82	66.13	376.17	1746.83	387.30	307.45	40.29	150116.59	3978.09	49028.33	1390.94	37.53	0.38	22.66	14.49	82.56	210.16	36.78	187.65	9.8E-05
6041	HL SPURLOCK	58.67	2.44	3.85	9.41	47.72	96.84	52.65	23.20	7.60	46226.47	32057.45	7744.12	18.11	0.76	0.01	0.44	0.32	25.42	64.72	11.33	57.78	3.0E-05
6052	WANSLEY	63.92	8.11	15.07	25.65	174.17	346.64	156.67	100.39	17.50	88409.87	33473.60	7069.03	620.02	22.10	0.22	20.79	1.09	48.63	123.77	21.66	110.51	5.7E-05
6055	BIG CAJUN TWO	138.76	9.71	14.03	51.33	283.92	1105.86	254.21	165.30	26.10	21596.79	3184.50	51442.05	1785.09	44.50	0.45	38.53	5.53	66.09	168.24	29.44	150.21	7.8E-05
6061	MORROW	8.45	0.70	0.45	2.49	11.95	30.40	12.41	6.12	1.29	5624.50	1583.85	603.71	225.00	1.41	0.01	1.32	0.07	3.09	7.87	1.38	7.03	3.7E-06
6064	NEARMAN CREEK	23.67	1.76	2.83	9.85	51.88	195.25	48.54	29.62	5.63	2138.59	747.01	1987.46	6.09	7.05	0.07	6.98	0.00	15.50	39.46	6.91	35.24	1.8E-05
6065	IATAN	103.58	8.22	14.94	49.24	245.33	888.14	241.32	136.98	32.18	2572.93	4688.55	18439.92	144.86	31.26	0.31	29.40	1.55	97.31	247.70	43.35	221.16	1.2E-04
6068	JEFFREY	150.67	7.82	14.11	46.66	233.30	846.64	228.77	130.45	30.24	2604.56	4380.42	17228.05	184.31	41.32	0.41	38.87	2.05	90.91	231.42	40.50	206.62	1.1E-04
6071	TRIMBLE COUNTY	123.32	12.25	16.06	43.18	249.86	517.28	242.48	126.82	29.89	161271.73	34530.38	13398.06	4672.33	26.32	0.26	24.75	1.30	88.70	225.78	39.51	201.59	1.0E-04
6073	VJ DANIEL	24.16	3.18	4.42	13.57	61.79	305.19	63.58	52.32	9.51	4095.22	17.44	6493.02	218.35	13.00	0.13	12.23	0.64	28.60	72.81	12.74	65.01	3.4E-05
6076	COLSTRIP	373.77	16.96	24.16	61.50	307.31	1303.34	355.54	238.48	51.13	38833.86	6292.90	27185.09	485.44	59.37	0.59	55.83	2.94	130.61	332.46	58.18	296.84	1.5E-04
6077	GERALD GENTLEMAN	53.46	4.79	10.88	32.39	145.84	491.90	157.17	78.20	27.04	21698.59	4691.99	352786.85	8.85	44.26	0.44	10.08	33.74	97.38	247.88	43.38	221.32	1.2E-04
6082	SOMERSET	75.17	2.34	1.56	8.33	50.79	106.95	45.57	30.03	3.37	12633.12	1940.92	1118.51	114.40	3.16	0.03	2.97	0.16	6.95	17.69	3.10	15.79	8.2E-06
6085	RM SCHAHFER	100.50	5.44	10.27	20.08	123.17	294.72	114.69	70.14	13.45	48073.36	2116.58	6210.00	610.61	23.21	0.23	21.83	1.15	38.21	97.26	17.02	86.84	4.5E-05
6089	LEWIS & CLARK	7.18	0.46	0.64	1.65	8.33	35.64	9.54	6.50	1.33	1528.29	160.53	693.49	39.09	1.51	0.02	1.42	0.07	3.33	8.48	1.48	7.57	3.9E-06
6090	SHERBURNE COUNTY	125.80	9.54	17.76	46.39	213.61	797.38	246.21	139.48	43.34	12596.64	6717.91	24230.59	345.95	76.23	0.76	72.46	3.01	139.43	354.91	62.11	316.88	1.6E-04
6094	BRUCE MANSFIELD	709.98	33.16	26.06	135.98	703.25	1364.91	649.21	360.37	62.27	174051.64	10442.07	21011.21	4606.94	69.27	0.69	65.15	3.43	152.40	387.93	67.89	346.36	1.8E-04
6095	SOONER	127.38	9.00	13.25	48.06	263.59	1020.79	237.83	152.95	24.99	14352.03	3101.70	34802.72	1112.91	29.26	0.29	25.61	3.36	64.37	163.86	28.68	146.31	7.6E-05
6096	NEBRASKA CITY	122.30	9.33	15.85	53.83	276.73	1024.69	264.62	156.51	32.78	18667.96	4562.03	33934.21	930.08	44.73	0.45	41.36	2.92	94.68	241.01	42.18	215.19	1.1E-04
6098	BIG STONE	27.64	2.05	3.28	11.45	60.41	227.66	56.44	34.51	6.52	2468.39	862.21	2293.96	7.03	8.13	0.08	8.05	0.00	17.90	45.55	7.97	40.67	2.1E-05
6101	WYODAK	30.40	2.49	4.82	15.44	74.84	265.77	75.47	41.33	10.78	4713.17	1646.32	4380.10	53.70	25.80	0.26	25.54	0.00	34.17	86.98	15.22	77.66	4.0E-05
6106	BOARDMAN (OR)	22.28	1.85	3.64	11.56	55.54	195.98	56.47	30.56	8.25	6483.23	1280.00	14362.25	258.86	12.08	0.12	10.44	1.52	26.57	67.62	11.83	60.38	3.1E-05
6113	GIBSON	353.20	14.31	12.59	42.51	241.18	485.02	246.07	123.80	24.97	38123.71	985.19	8800.79	3216.24	25.97	0.26	24.43	1.29	60.73	154.59	27.05	138.03	7.2E-05
6124	MCINTOSH (GA)	0.51	0.05	0.14	0.38	1.57	4.98	1.84	0.81	0.40	328.33	80.29	900.88	28.81	0.76	0.01	0.67	0.08	1.67	4.24	0.74	3.79	2.0E-06
6136	GIBBONS CREEK	47.08	3.37	5.10	18.28	99.08	380.53	90.34	57.22	9.75	732.20	1231.43	4843.19	163.35	11.62	0.12	10.93	0.58	25.56	65.06	11.38	58.09	3.0E-05
6137	AB BROWN	58.12	6.09	6.86	18.71	107.29	212.55	108.90	56.07	11.73	34303.95	1794.63	4330.62	474.46	21.70	0.22	20.41	1.07	29.87	76.02	13.30	67.88	3.5E-05
6138	FLINT CREEK (AR)	83.89	5.73	7.94	29.61	167.03	659.52	146.95	98.01	14.37	7843.45	1696.03	4512.35	13.83	16.00	0.16	15.84	0.00	35.20	89.60	15.68	80.00	4.2E-05
6139	WELSH	56.79	4.43	7.79	26.06	131.77	481.96	127.92	74.01	16.44	10809.27	2337.34	175742.66	4.41	22.05	0.22	5.02	16.81	48.51	123.48	21.61	110.25	5.7E-05
6146	MARTIN LAKE	251.31	15.79	16.25	57.61	332.11	787.39	274.11	179.34	33.26	40092.24	3731.28	15624.53	2615.00	176.00	1.76	165.53	8.71	77.44	197.12	34.50	176.00	9.2E-05
6147	MONTICELLO (TX)	100.32	6.37	8.88	30.96	166.65	568.32	151.15	93.57	18.03	14200.47	2287.34	59437.37	2126.43	107.89	1.08	77.93	28.89	47.47	120.84	21.15	107.89	5.6E-05
6155	RUSH ISLAND	124.88	9.28	15.00	52.16	274.29	1031.15	257.04	156.49	29.95	35051.42	3982.84	87536.42	1144.67	61.74	0.62	53.37	7.75	82.66	210.41	36.82	187.87	9.8E-05
6165	HUNTER	55.47	5.09	9.76	24.99	149.12	394.57	127.40	81.98	20.85	24233.62	323.22	10253.06	462.07	8.08	0.08	7.60	0.40	71.21	181.25	31.72	161.83	8.4E-05

Plant ID Number	Plant Name	5-Methyl-chrysene	Acet-aldehyde	Acrolein	B(a)P equiv.	Benzene	Benzyl-chloride	bis(2-Ethlyhexyl) phthalate	Carbon disulfide	Chloro-form	Formal-dehyde	Iso-phorone	m/p-Xylene	Methyl chloroform	Methylene chloride	Naphtha-lene	n-Hexane	Phenol	Propion-aldehyde	Tetrachloro-ethylene	Toluene	Vinyl acetate	2,4-Dinitro-toluene
3948	MITCHELL (WV)	0.05	161.40	188.30	0.49	107.60	102.22	129.12	94.15	8.82	21.52	236.72	1.08	13.45	1022.18	16.30	118.36	104.37	269.00	2.88	85.00	18.83	145.26
3954	MOUNT STORM	0.09	298.97	348.79	0.92	199.31	189.34	239.17	174.40	16.34	39.86	438.48	1.99	24.91	1893.45	30.20	219.24	193.33	498.28	5.34	157.45	34.88	269.07
4041	OAK CREEK (WI)	0.05	161.01	187.84	0.49	107.34	101.97	128.81	93.92	8.80	21.47	236.15	1.07	13.42	1019.72	16.26	118.07	104.12	268.35	2.88	84.80	18.78	144.91
4050	EDGEWATER (WI)	0.04	122.39	142.79	0.38	81.59	77.52	97.91	71.40	6.69	16.32	179.51	0.82	10.20	775.15	12.36	89.75	79.15	203.99	2.19	64.46	14.28	110.15
4072	JP PULLIAM	0.00	14.12	16.47	0.04	9.41	8.94	11.29	8.24	0.77	1.88	20.71	0.09	1.18	89.42	1.43	10.35	9.13	23.53	0.25	7.44	1.65	12.71
4078	WESTON	0.04	128.82	150.29	0.40	85.88	81.59	103.06	75.15	7.04	17.18	188.94	0.86	10.74	815.86	13.01	94.47	83.30	214.70	2.30	67.85	15.03	115.94
4125	MANITOWOC	0.00	3.74	4.36	0.01	2.49	2.37	2.99	2.18	0.20	0.50	5.48	0.02	0.31	23.66	0.38	2.74	2.42	6.23	0.07	1.97	0.44	3.36
4143	GENOA THREE	0.01	44.23	51.60	0.14	29.48	28.01	35.38	25.80	2.42	5.90	64.86	0.29	3.69	280.09	4.47	32.43	28.60	73.71	0.79	23.29	5.16	39.80
4158	DAVE JOHNSTON	0.04	119.84	139.81	0.37	79.89	75.90	95.87	69.90	6.55	15.98	175.76	0.80	9.99	758.96	12.10	87.88	77.49	199.73	2.14	63.11	13.98	107.85
4162	NAUGHTON	0.04	119.50	139.41	0.37	79.66	75.68	95.60	69.71	6.53	15.93	175.26	0.80	9.96	756.82	12.07	87.63	77.27	199.16	2.14	62.94	13.94	107.55
4271	MADGETT	0.02	50.84	59.32	0.16	33.90	32.20	40.68	29.66	2.78	6.78	74.57	0.34	4.24	322.02	5.14	37.29	32.88	84.74	0.91	26.78	5.93	45.76
4941	NAVAJO	0.08	264.93	309.09	0.81	176.62	167.79	211.95	154.55	14.48	35.32	388.57	1.77	22.08	1677.92	26.76	194.29	171.32	441.56	4.73	139.53	30.91	238.44
6002	MILLER	0.16	547.81	639.12	1.68	365.21	346.95	438.25	319.56	29.95	73.04	803.46	3.65	45.65	3469.49	55.33	401.73	354.25	913.02	9.79	288.52	63.91	493.03
6004	PLEASANTS	0.07	224.13	261.49	0.69	149.42	141.95	179.31	130.74	12.25	29.88	328.73	1.49	18.68	1419.52	22.64	164.36	144.94	373.56	4.00	118.04	26.15	201.72
6009	WHITE BLUFF	0.06	194.59	227.03	0.60	129.73	123.24	155.68	113.51	10.64	25.95	285.40	1.30	16.22	1232.43	19.65	142.70	125.84	324.32	3.48	102.49	22.70	175.13
6016	DUCK CREEK	0.02	68.09	79.43	0.21	45.39	43.12	54.47	39.72	3.72	9.08	99.86	0.45	5.67	431.22	6.88	49.93	44.03	113.48	1.22	35.86	7.94	61.28
6017	NEWTON	0.05	156.03	182.04	0.48	104.02	98.82	124.83	91.02	8.53	20.80	228.85	1.04	13.00	988.20	15.76	114.42	100.90	260.05	2.79	82.18	18.20	140.43
6018	EAST BEND	0.04	132.17	154.20	0.41	88.11	83.71	105.74	77.10	7.23	17.62	193.85	0.88	11.01	837.07	13.35	96.92	85.47	220.28	2.36	69.61	15.42	118.95
6019	ZIMMER	0.05	173.88	202.86	0.53	115.92	110.12	139.10	101.43	9.51	23.18	255.02	1.16	14.49	1101.23	17.56	127.51	112.44	289.80	3.11	91.58	20.29	156.49
6021	CRAIG	0.05	153.91	179.56	0.47	102.61	97.48	123.13	89.78	8.41	20.52	225.73	1.03	12.83	974.76	15.54	112.87	99.53	256.52	2.75	81.06	17.96	138.52
6030	COAL CREEK	0.08	279.48	326.06	0.86	186.32	177.01	223.59	163.03	15.28	37.26	409.91	1.86	23.29	1770.06	28.23	204.95	180.73	465.81	4.99	147.19	32.61	251.54
6031	KILLEN	0.03	108.80	126.94	0.33	72.53	68.91	87.04	63.47	5.95	14.51	159.58	0.73	9.07	689.08	10.99	79.79	70.36	181.34	1.94	57.30	12.69	97.92
6034	BELLE RIVER	0.07	225.17	262.70	0.69	150.12	142.61	180.14	131.35	12.31	30.02	330.26	1.50	18.76	1426.11	22.74	165.13	145.61	375.29	4.02	118.59	26.27	202.66
6041	HL SPURLOCK	0.02	69.34	80.90	0.21	46.23	43.92	55.47	40.45	3.79	9.25	101.70	0.46	5.78	439.15	7.00	50.85	44.84	115.57	1.24	36.52	8.09	62.41
6052	WANSLEY	0.04	132.61	154.72	0.41	88.41	83.99	106.09	77.36	7.25	17.68	194.50	0.88	11.05	839.89	13.39	97.25	85.76	221.02	2.37	69.84	15.47	119.35
6055	BIG CAJUN TWO	0.05	180.25	210.30	0.55	120.17	114.16	144.20	105.15	9.85	24.03	264.37	1.20	15.02	1141.61	18.21	132.19	116.56	300.42	3.22	94.93	21.03	162.23
6061	MORROW	0.00	8.44	9.84	0.03	5.62	5.34	6.75	4.92	0.46	1.12	12.37	0.06	0.70	53.43	0.85	6.19	5.46	14.06	0.15	4.44	0.98	7.59
6064	NEARMAN CREEK	0.01	42.28	49.33	0.13	28.19	26.78	33.83	24.67	2.31	5.64	62.02	0.28	3.52	267.80	4.27	31.01	27.34	70.47	0.76	22.27	4.93	38.06
6065	IATAN	0.08	265.39	309.62	0.81	176.93	168.08	212.31	154.81	14.51	35.39	389.24	1.77	22.12	1680.80	26.80	194.62	171.62	442.32	4.74	139.77	30.96	238.85
6068	JEFFREY	0.07	247.95	289.27	0.76	165.30	157.03	198.36	144.64	13.55	33.06	363.66	1.65	20.66	1570.34	25.04	181.83	160.34	413.25	4.43	130.59	28.93	223.15
6071	TRIMBLE COUNTY	0.07	241.91	282.23	0.74	161.27	153.21	193.53	141.11	13.22	32.25	354.80	1.61	20.16	1532.08	24.43	177.40	156.43	403.18	4.32	127.40	28.22	217.72
6073	VJ DANIEL	0.02	78.01	91.01	0.24	52.01	49.41	62.41	45.51	4.26	10.40	114.41	0.52	6.50	494.06	7.88	57.21	50.45	130.02	1.39	41.09	9.10	70.21
6076	COLSTRIP	0.11	356.20	415.57	1.09	237.47	225.59	284.96	207.78	19.47	47.49	522.43	2.37	29.68	2255.95	35.98	261.21	230.34	593.67	6.36	187.60	41.56	320.58
6077	GERALD GENTLEMAN	0.08	265.58	309.85	0.81	177.06	168.20	212.47	154.92	14.52	35.41	389.52	1.77	22.13	1682.03	26.82	194.76	171.74	442.64	4.75	139.87	30.98	239.03
6082	SOMERSET	0.01	18.95	22.11	0.06	12.63	12.00	15.16	11.05	1.04	2.53	27.79	0.13	1.58	120.01	1.91	13.90	12.25	31.58	0.34	9.98	2.21	17.05
6085	RM SCHAHFER	0.03	104.21	121.58	0.32	69.47	66.00	83.37	60.79	5.70	13.89	152.84	0.69	8.68	660.00	10.53	76.42	67.39	173.68	1.86	54.88	12.16	93.79
6089	LEWIS & CLARK	0.00	9.09	10.60	0.03	6.06	5.75	7.27	5.30	0.50	1.21	13.33	0.06	0.76	57.55	0.92	6.66	5.88	15.14	0.16	4.79	1.06	8.18
6090	SHERBURNE COUNTY	0.11	380.26	443.64	1.17	253.51	240.83	304.21	221.82	20.79	50.70	557.71	2.54	31.69	2408.31	38.41	278.86	245.90	633.76	6.79	200.27	44.36	342.23
6094	BRUCE MANSFIELD	0.12	415.64	484.91	1.27	277.09	263.24	332.51	242.46	22.72	55.42	609.60	2.77	34.64	2632.37	41.98	304.80	268.78	692.73	7.43	218.90	48.49	374.07
6095	SOONER	0.05	175.57	204.83	0.54	117.05	111.19	140.45	102.41	9.60	23.41	257.50	1.17	14.63	1111.93	17.73	128.75	113.53	292.61	3.14	92.47	20.48	158.01
6096	NEBRASKA CITY	0.08	258.23	301.27	0.79	172.15	163.54	206.58	150.63	14.12	34.43	378.73	1.72	21.52	1635.44	26.08	189.37	166.99	430.38	4.61	136.00	30.13	232.41
6098	BIG STONE	0.01	48.80	56.94	0.15	32.54	30.91	39.04	28.47	2.67	6.51	71.58	0.33	4.07	309.10	4.93	35.79	31.56	81.34	0.87	25.70	5.69	43.92
6101	WYODAK	0.03	93.19	108.72	0.29	62.13	59.02	74.55	54.36	5.09	12.43	136.68	0.62	7.77	590.19	9.41	68.34	60.26	155.31	1.66	49.08	10.87	83.87
6106	BOARDMAN (OR)	0.02	72.45	84.53	0.22	48.30	45.89	57.96	42.26	3.96	9.66	106.26	0.48	6.04	458.87	7.32	53.13	46.85	120.75	1.29	38.16	8.45	65.21
6113	GIBSON	0.05	165.64	193.24	0.51	110.42	104.90	132.51	96.62	9.05	22.08	242.93	1.10	13.80	1049.04	16.73	121.47	107.11	276.06	2.96	87.24	19.32	149.07
6124	MCINTOSH (GA)	0.00	4.54	5.30	0.01	3.03	2.88	3.64	2.65	0.25	0.61	6.67	0.03	0.38	28.78	0.46	3.33	2.94	7.57	0.08	2.39	0.53	4.09
6136	GIBBONS CREEK	0.02	69.70	81.32	0.21	46.47	44.15	55.76	40.66	3.81	9.29	102.23	0.46	5.81	441.46	7.04	51.12	45.08	116.17	1.25	36.71	8.13	62.73
6137	AB BROWN	0.02	81.45	95.03	0.25	54.30	51.59	65.16	47.51	4.45	10.86	119.46	0.54	6.79	515.87	8.23	59.73	52.67	135.76	1.46	42.90	9.50	73.31
6138	FLINT CREEK (AR)	0.03	96.00	112.00	0.29	64.00	60.80	76.80	56.00	5.25	12.80	140.80	0.64	8.00	608.01	9.70	70.40	62.08	160.00	1.72	50.56	11.20	86.40
6139	WELSH	0.04	132.30	154.35	0.41	88.20	83.79	105.84	77.18	7.23	17.64	194.04	0.88	11.03	837.91	13.36	97.02	85.56	220.50	2.36	69.68	15.44	119.07
6146	MARTIN LAKE	0.06	211.20	246.41	0.65	140.80	133.76	168.96	123.20	11.55	28.16	309.77	1.41	17.60	1337.63	21.33	154.88	136.58	352.01	3.77	111.23	24.64	190.08
6147	MONTICELLO (TX)	0.04	129.47	151.05	0.40	86.31	82.00	103.58	75.53	7.08	17.26	189.89	0.86	10.79	819.99	13.08	94.95	83.73	215.79	2.31	68.19	15.11	116.53
6155	RUSH ISLAND	0.07	225.44	263.02	0.69	150.30	142.78	180.36	131.51	12.32	30.06	330.65	1.50	18.79	1427.81	22.77	165.33	145.79	375.74	4.03	118.73	26.30	202.90
6165	HUNTER	0.06	194.20	226.56	0.60	129.46	122.99	155.36	113.28	10.62	25.89	284.82	1.29	16.18	1229.92	19.61	142.41	125.58	323.66	3.47	102.28	22.66	174.78

H

TIER 1 INHALATION SCREENING ASSESSMENT RESULTS

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
3	BARRY	1.83E-06	51%	31%	10%	0.061	26%	24%	17%	0.109	Arsenic
8	GORGAS TWO	2.19E-06	53%	31%	9%	0.050	23%	36%	6%	0.135	Arsenic
26	GASTON (AL)	1.16E-06	45%	34%	10%	0.089	14%	9%	59%	0.073	Cadmium
47	COLBERT	1.64E-10	46%	32%	12%	0.000	1%	0%	85%	0.000	HCl
51	DOLET HILLS	1.08E-06	44%	35%	10%	0.061	23%	12%	45%	0.055	Arsenic
56	CR LOWMAN	2.49E-06	52%	31%	9%	0.138	11%	15%	55%	0.151	Arsenic
59	PLATTE	5.68E-07	50%	33%	10%	0.023	19%	19%	39%	0.033	Arsenic
60	WHELAN ENERGY CENTER	3.88E-07	37%	33%	12%	0.042	26%	5%	53%	0.023	Cadmium
87	ESCALANTE	4.63E-07	31%	35%	13%	0.049	26%	5%	52%	0.038	Cadmium
108	HOLCOMB	6.14E-07	47%	34%	10%	0.030	22%	15%	43%	0.033	Arsenic
113	CHOLLA	1.45E-06	33%	36%	12%	0.131	25%	6%	50%	0.109	Cadmium
127	OKLAUNION	8.79E-07	48%	34%	10%	0.041	21%	16%	42%	0.049	Arsenic
130	CROSS	4.87E-06	58%	25%	9%	2.152	2%	2%	93%	0.330	Arsenic
136	SEMINOLE (FL)	3.00E-06	55%	30%	9%	0.119	15%	21%	41%	0.190	Arsenic
160	APACHE	6.43E-07	34%	35%	12%	0.059	25%	6%	51%	0.048	Cadmium
165	GRDA	1.69E-06	47%	34%	10%	0.087	21%	14%	42%	0.092	Arsenic
207	ST JOHNS RIVER	1.63E-06	48%	31%	10%	0.054	36%	23%	11%	0.092	Arsenic
298	LIMESTONE	1.63E-06	40%	35%	11%	0.121	25%	8%	50%	0.086	Cadmium
469	CHEROKEE (CO)	1.72E-07	32%	34%	13%	0.014	36%	6%	35%	0.013	Cadmium
470	COMANCHE	1.01E-06	38%	34%	12%	0.095	27%	6%	54%	0.060	Cadmium
477	VALMONT	2.51E-07	31%	34%	13%	0.021	37%	6%	35%	0.020	Cadmium
492	DRAKE	7.41E-07	44%	34%	11%	0.049	22%	10%	44%	0.038	Arsenic
508	LAMAR REPOWERING	5.15E-10	39%	34%	12%	0.000	21%	7%	43%	0.000	Cadmium

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
	PROJECT										
525	HAYDEN	5.03E-07	32%	34%	13%	0.042	37%	6%	35%	0.039	Cadmium
527	NUCLA	5.14E-08	21%	29%	13%	0.007	48%	2%	3%	0.005	Cadmium
564	CH STANTON	2.61E-06	48%	32%	10%	0.889	3%	2%	91%	0.145	Arsenic
568	BRIDGEPORT HARBOR	2.24E-07	55%	28%	9%	0.014	14%	14%	28%	0.021	HF
594	INDIAN RIVER (DE)	6.46E-07	71%	19%	6%	0.049	6%	15%	72%	0.053	Arsenic
602	BRANDON SHORES	5.15E-06	70%	19%	6%	0.461	6%	12%	73%	0.418	Arsenic
628	CRYSTAL RIVER	4.05E-06	52%	29%	10%	0.194	20%	17%	39%	0.243	Arsenic
641	CRIST	1.40E-06	47%	34%	10%	0.862	1%	1%	95%	0.077	Cadmium
645	BIG BEND (FL)	7.05E-06	58%	27%	8%	0.626	7%	10%	72%	0.478	Arsenic
663	DEERHAVEN	4.85E-07	49%	31%	11%	0.087	6%	4%	84%	0.028	Arsenic
667	NORTHSIDE	4.02E-07	20%	21%	33%	0.054	28%	2%	56%	0.053	Cadmium
676	MCINTOSH (FL)	1.10E-06	46%	35%	10%	0.921	1%	1%	97%	0.065	Cadmium
703	BOWEN	1.82E-06	45%	33%	11%	1.425	2%	1%	95%	0.115	Cadmium
708	HAMMOND	6.33E-07	56%	28%	9%	0.061	6%	9%	74%	0.041	Arsenic
856	ED EDWARDS	1.27E-06	49%	33%	10%	0.058	18%	17%	36%	0.073	Arsenic
861	COFFEEN	2.71E-07	25%	30%	13%	0.056	30%	2%	60%	0.021	Cadmium
876	KINCAID	4.51E-07	44%	34%	11%	0.029	22%	11%	45%	0.023	Arsenic
879	POWERTON	7.11E-07	48%	34%	10%	0.035	20%	15%	41%	0.039	Arsenic
883	POWERTON	7.07E-07	48%	34%	10%	0.033	20%	16%	39%	0.040	Arsenic
884	WILL COUNTY	7.98E-07	50%	33%	10%	0.035	17%	17%	35%	0.046	Arsenic
887	JOPPA	1.67E-06	49%	33%	10%	0.078	18%	16%	36%	0.095	Arsenic
889	BALDWIN	2.49E-06	44%	34%	11%	0.147	23%	12%	47%	0.128	Arsenic
891	HAVANA	7.36E-07	44%	34%	11%	0.044	23%	12%	47%	0.038	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
892	HENNEPIN	9.89E-07	49%	33%	10%	0.054	15%	14%	30%	0.076	HF
963	DALLMAN	1.06E-06	37%	37%	12%	0.502	4%	1%	91%	0.091	Cadmium
976	MARION (IL)	2.15E-06	41%	36%	11%	0.099	27%	14%	29%	0.158	Cadmium
983	CLIFTY CREEK	7.24E-07	48%	32%	10%	0.095	8%	6%	75%	0.040	Arsenic
994	PETERSBURG	4.33E-06	54%	29%	10%	0.131	23%	28%	20%	0.271	Arsenic
995	BAILLY	9.31E-07	51%	30%	10%	0.036	25%	21%	28%	0.055	Arsenic
997	MICHIGAN CITY	8.40E-07	65%	23%	7%	0.028	14%	31%	29%	0.064	Arsenic
1001	CAYUGA	1.75E-06	51%	30%	10%	0.063	27%	22%	23%	0.104	Arsenic
1004	EDWARDSPORT IGCC	3.86E-07	37%	30%	13%	0.026	50%	9%	28%	0.024	Cadmium
1008	GALLAGHER	1.25E-07	45%	32%	12%	0.203	1%	0%	97%	0.014	Chlorine
1012	CULLEY	1.14E-06	52%	29%	10%	0.042	25%	22%	27%	0.068	Arsenic
1040	WHITEWATER VALLEY	3.81E-08	47%	32%	11%	0.010	4%	3%	87%	0.002	Arsenic
1047	LANSING	4.85E-07	49%	33%	10%	0.020	20%	18%	40%	0.028	Arsenic
1073	PRAIRIE CREEK	2.45E-07	49%	34%	10%	0.012	18%	16%	37%	0.014	Arsenic
1082	COUNCIL BLUFFS	2.12E-06	46%	34%	11%	0.116	23%	13%	46%	0.112	Arsenic
1091	GEORGE NEAL	3.07E-07	44%	34%	11%	0.019	24%	11%	48%	0.016	Arsenic
1104	BURLINGTON (IA)	5.88E-07	49%	33%	10%	0.027	18%	17%	36%	0.034	Arsenic
1131	STREETER	4.29E-09	49%	32%	10%	0.007	0%	0%	88%	0.001	HCl
1167	MUSCATINE	5.73E-07	43%	34%	11%	0.036	24%	11%	48%	0.029	Arsenic
1241	LA CYGNE	2.90E-06	48%	33%	10%	0.132	21%	16%	42%	0.163	Arsenic
1250	LAWRENCE (KS)	2.82E-06	49%	33%	10%	0.118	20%	18%	40%	0.161	Arsenic
1252	TECUMSEH	5.00E-07	49%	33%	10%	0.022	19%	17%	38%	0.029	Arsenic
1355	EW BROWN	7.65E-07	48%	31%	11%	0.032	32%	18%	24%	0.043	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
1356	GHENT	3.74E-06	47%	31%	11%	0.480	11%	6%	70%	0.203	Arsenic
1364	MILL CREEK (KY)	2.83E-06	48%	32%	10%	0.186	20%	11%	50%	0.158	Arsenic
1374	ELMER SMITH	2.71E-06	55%	29%	9%	0.077	21%	30%	20%	0.174	Arsenic
1378	PARADISE	8.08E-06	54%	30%	9%	0.356	14%	19%	46%	0.511	Arsenic
1379	SHAWNEE (KY)	1.02E-06	49%	33%	10%	0.044	19%	18%	38%	0.058	Arsenic
1381	COLEMAN (KY)	1.46E-06	50%	31%	10%	0.218	7%	5%	79%	0.086	Arsenic
1382	HENDERSON TWO	1.44E-06	51%	31%	10%	0.237	6%	5%	81%	0.085	Arsenic
1384	JS COOPER	3.53E-07	57%	27%	9%	0.124	2%	3%	93%	0.023	Arsenic
1393	R S Nelson	8.12E-07	37%	28%	24%	0.053	21%	9%	42%	0.045	Cadmium
1552	CP CRANE	3.04E-07	50%	32%	10%	0.014	19%	16%	39%	0.018	Arsenic
1554	HA WAGNER	2.59E-07	39%	32%	13%	2.456	0%	0%	98%	0.171	Chlorine
1571	CHALK POINT	1.11E-06	64%	21%	8%	0.155	7%	7%	77%	0.083	Arsenic
1572	DICKERSON	6.63E-07	68%	20%	7%	0.064	6%	11%	74%	0.052	Arsenic
1573	MORGANTOWN	5.38E-06	70%	19%	6%	0.427	6%	14%	70%	0.438	Arsenic
1606	MOUNT TOM	1.17E-09	52%	31%	10%	0.000	30%	29%	14%	0.000	Arsenic
1619	BRAYTON POINT	1.19E-06	47%	32%	11%	0.074	19%	12%	50%	0.065	Arsenic
1702	DE KARN	5.46E-07	45%	33%	11%	0.033	24%	12%	48%	0.029	Arsenic
1710	JH CAMPBELL	1.16E-06	43%	34%	11%	0.075	23%	10%	47%	0.059	Arsenic
1733	MONROE (MI)	5.21E-06	60%	25%	9%	0.172	16%	28%	31%	0.366	Arsenic
1740	RIVER ROUGE	3.59E-07	47%	32%	11%	0.023	20%	11%	40%	0.020	Arsenic
1743	ST CLAIR	5.27E-06	75%	17%	5%	0.130	10%	47%	21%	0.460	Arsenic
1745	TRENTON CHANNEL	8.05E-07	62%	25%	8%	0.033	16%	24%	32%	0.058	Arsenic
1769	PRESQUE ISLE	7.33E-07	53%	28%	10%	0.041	21%	14%	43%	0.045	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
1825	JB SIMS	1.67E-07	43%	37%	10%	0.043	3%	3%	89%	0.011	Cadmium
1831	ECKERT	1.19E-07	43%	34%	11%	0.008	21%	10%	43%	0.006	Arsenic
1832	ERICKSON	3.98E-07	43%	34%	11%	0.028	21%	10%	43%	0.020	Arsenic
1843	SHIRAS	3.81E-07	45%	33%	11%	0.024	23%	11%	45%	0.020	Arsenic
1866	WYANDOTTE	1.87E-08	38%	35%	12%	0.001	33%	10%	5%	0.001	Cadmium
1893	CLAY BOSWELL	1.95E-06	52%	29%	10%	0.100	20%	16%	41%	0.118	Arsenic
1915	ALLEN S KING	5.13E-07	44%	34%	11%	0.032	24%	11%	48%	0.026	Arsenic
1943	HOOT LAKE	3.25E-07	65%	22%	7%	0.012	15%	27%	29%	0.024	Arsenic
2076	ASBURY	9.76E-07	49%	34%	10%	0.041	18%	18%	37%	0.055	Arsenic
2079	HAWTHORN	8.38E-07	43%	34%	11%	0.053	24%	11%	48%	0.042	Arsenic
2080	MONTROSE	2.34E-07	44%	34%	11%	0.016	21%	10%	43%	0.012	Arsenic
2094	SIBLEY (MO)	4.17E-07	44%	34%	11%	0.028	20%	10%	41%	0.021	Arsenic
2103	LABADIE	2.99E-06	47%	34%	10%	0.165	19%	13%	39%	0.163	Arsenic
2104	MERAMEC	5.45E-07	48%	34%	10%	0.028	19%	14%	38%	0.030	Arsenic
2107	SIOUX	2.21E-06	42%	35%	11%	0.128	22%	11%	45%	0.142	Cadmium
2167	NEW MADRID	7.55E-07	44%	34%	11%	0.050	21%	10%	42%	0.039	Arsenic
2168	THOMAS HILL	2.01E-06	47%	34%	10%	0.110	19%	13%	39%	0.110	Arsenic
2240	LD WRIGHT	4.70E-07	49%	33%	10%	0.020	20%	18%	40%	0.027	Arsenic
2277	SHELDON	3.09E-07	37%	34%	12%	0.046	19%	4%	38%	0.083	HF
2291	NORTH OMAHA	8.18E-07	45%	34%	11%	0.050	22%	11%	44%	0.042	Arsenic
2324	REID GARDNER	1.91E-07	38%	38%	11%	0.007	38%	17%	2%	0.011	Cadmium
2364	MERRIMACK	2.21E-06	70%	20%	6%	0.112	7%	21%	59%	0.179	Arsenic
2367	SCHILLER	5.38E-07	58%	28%	8%	0.017	12%	29%	30%	0.036	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
2378	BL ENGLAND	2.76E-07	73%	18%	5%	0.013	6%	24%	58%	0.024	Arsenic
2403	HUDSON	2.43E-07	61%	25%	8%	0.008	15%	27%	31%	0.017	Arsenic
2408	MERCER	1.75E-07	63%	23%	8%	0.017	7%	10%	76%	0.013	Arsenic
2442	FOUR CORNERS	8.27E-07	30%	35%	13%	0.044	56%	9%	2%	0.069	Cadmium
2451	SAN JUAN (NM)	1.49E-06	20%	35%	18%	0.107	59%	4%	3%	0.121	Cadmium
2535	CAYUGA 1(MILLIKEN)	2.35E-06	72%	19%	6%	0.117	7%	22%	59%	0.196	Arsenic
2706	ASHEVILLE	1.33E-06	58%	23%	9%	0.171	12%	7%	70%	0.090	Arsenic
2712	ROXBORO	6.64E-06	63%	23%	8%	1.038	5%	6%	83%	0.486	Arsenic
2718	ALLEN	9.67E-07	48%	31%	11%	0.192	6%	4%	82%	0.054	Arsenic
2721	CLIFFSIDE	6.19E-07	45%	29%	12%	0.100	13%	4%	70%	0.032	Arsenic
2727	MARSHALL (NC)	6.30E-06	57%	25%	9%	0.952	7%	6%	78%	0.419	Arsenic
2790	HESKETT	2.57E-07	65%	20%	6%	0.016	20%	16%	41%	0.019	Arsenic
2817	LELAND OLDS	2.00E-06	65%	20%	6%	0.109	23%	18%	46%	0.150	Arsenic
2823	MR YOUNG	1.72E-06	65%	20%	6%	0.093	22%	19%	44%	0.131	Arsenic
2824	STANTON (ND)	9.09E-07	61%	23%	8%	0.040	19%	22%	39%	0.065	Arsenic
2828	CARDINAL	5.41E-06	67%	20%	7%	0.295	12%	19%	54%	0.419	Arsenic
2832	MIAMI FORT	2.18E-06	56%	27%	9%	0.156	12%	12%	60%	0.143	Arsenic
2836	AVON LAKE	1.90E-06	75%	17%	5%	1.025	0%	2%	85%	0.165	Arsenic
2840	CONESVILLE	3.52E-06	71%	18%	6%	0.121	12%	32%	38%	0.292	Arsenic
2850	JM STUART	4.08E-06	53%	29%	9%	0.681	5%	5%	83%	0.253	Arsenic
2866	WH SAMMIS	2.38E-06	60%	24%	8%	0.211	9%	11%	68%	0.166	Arsenic
2876	KYGER CREEK	7.85E-07	65%	20%	8%	0.038	20%	21%	41%	0.059	Arsenic
2878	FirstEnergy Bay Shore	1.97E-07	20%	21%	33%	0.026	27%	2%	55%	0.026	Cadmium

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
2952	MUSKOGEE	1.74E-06	48%	34%	10%	0.082	20%	16%	40%	0.098	Arsenic
2963	NORTHEASTERN	6.13E-07	44%	34%	11%	0.039	22%	11%	45%	0.031	Arsenic
3118	CONEMAUGH	3.78E-06	60%	23%	8%	0.511	10%	7%	73%	0.263	Arsenic
3122	HOMER CITY	5.47E-06	72%	18%	6%	3.718	1%	2%	97%	0.460	Arsenic
3130	SEWARD	3.92E-07	57%	22%	9%	0.038	23%	9%	46%	0.026	Arsenic
3136	KEYSTONE (PA)	9.71E-06	69%	20%	6%	0.657	6%	16%	67%	0.781	Arsenic
3140	BRUNNER ISLAND	3.93E-06	71%	20%	6%	0.174	7%	25%	54%	0.324	Arsenic
3149	MONTOUR	4.38E-06	68%	21%	6%	0.267	8%	17%	63%	0.347	Arsenic
3297	WATEREE (SC)	3.85E-06	68%	21%	7%	0.192	9%	21%	55%	0.304	Arsenic
3298	AM WILLIAMS	2.36E-06	53%	29%	10%	0.323	7%	6%	77%	0.144	Arsenic
3393	TH ALLEN	1.51E-06	49%	33%	10%	0.065	19%	18%	38%	0.087	Arsenic
3396	BULL RUN (TN)	1.93E-06	58%	27%	9%	0.082	14%	21%	44%	0.129	Arsenic
3399	CUMBERLAND	6.10E-06	47%	35%	10%	0.251	17%	18%	39%	0.342	Cadmium
3403	GALLATIN	8.63E-07	42%	34%	11%	0.059	25%	10%	50%	0.044	Cadmium
3406	JOHNSONVILLE (TN)	2.78E-07	47%	33%	10%	0.015	19%	13%	38%	0.015	Arsenic
3407	KINGSTON	9.11E-07	49%	31%	10%	0.046	22%	15%	44%	0.052	Arsenic
3470	WA PARISH	2.87E-06	46%	34%	11%	0.190	19%	11%	38%	0.209	HF
3497	BIG BROWN	1.68E-06	47%	34%	10%	0.114	14%	11%	29%	0.158	HF
3797	CHESTERFIELD	3.55E-06	53%	26%	10%	0.686	8%	4%	80%	0.220	Arsenic
3809	YORKTOWN	2.14E-07	60%	26%	8%	0.540	0%	0%	92%	0.036	Chlorine
3845	CENTRALIA	2.97E-06	58%	25%	9%	0.134	20%	20%	41%	0.199	Arsenic
3935	AMOS	3.67E-06	57%	27%	9%	0.269	10%	12%	63%	0.243	Arsenic
3943	FORT MARTIN	3.30E-06	61%	24%	8%	0.264	11%	12%	65%	0.235	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
3944	HARRISON	2.18E-06	63%	24%	7%	0.128	11%	17%	58%	0.160	Arsenic
3948	MITCHELL (WV)	7.64E-07	54%	28%	10%	0.069	10%	9%	68%	0.048	Arsenic
3954	MOUNT STORM	4.42E-06	59%	26%	8%	0.255	15%	16%	52%	0.305	Arsenic
4041	OAK CREEK (WI)	2.10E-06	43%	34%	11%	0.130	24%	11%	48%	0.106	Arsenic
4050	EDGEWATER (WI)	9.70E-07	47%	34%	10%	0.051	21%	14%	42%	0.053	Arsenic
4072	JP PULLIAM	2.13E-07	47%	34%	10%	0.011	20%	14%	41%	0.012	Arsenic
4078	WESTON	1.22E-06	43%	34%	11%	0.082	22%	10%	45%	0.062	Arsenic
4125	MANITOWOC	2.23E-08	20%	21%	33%	0.003	28%	2%	56%	0.003	Cadmium
4143	GENOA THREE	2.84E-07	43%	34%	11%	0.018	24%	11%	48%	0.014	Arsenic
4158	DAVE JOHNSTON	1.98E-06	43%	34%	11%	0.136	23%	10%	47%	0.099	Cadmium
4162	NAUGHTON	6.22E-06	52%	33%	7%	0.257	20%	20%	41%	0.379	Arsenic
4271	MADGETT	2.56E-07	44%	34%	11%	0.016	22%	11%	45%	0.013	Arsenic
4941	NAVAJO	1.94E-06	28%	39%	17%	0.086	43%	10%	2%	0.122	Cadmium
6002	MILLER	2.23E-06	43%	34%	11%	0.141	24%	11%	48%	0.112	Arsenic
6004	PLEASANTS	3.60E-06	68%	20%	7%	0.131	15%	29%	37%	0.285	Arsenic
6009	WHITE BLUFF	7.43E-07	47%	34%	10%	0.040	19%	13%	39%	0.041	Arsenic
6016	DUCK CREEK	7.07E-07	43%	34%	11%	0.044	24%	11%	48%	0.036	Arsenic
6017	NEWTON	1.31E-06	44%	31%	18%	0.062	16%	14%	33%	0.067	Arsenic
6018	EAST BEND	1.45E-06	56%	29%	9%	0.171	6%	7%	78%	0.094	Arsenic
6019	ZIMMER	1.47E-06	58%	25%	9%	0.085	15%	16%	52%	0.100	Arsenic
6021	CRAIG	7.99E-07	39%	29%	11%	0.088	26%	6%	52%	0.070	Cadmium
6030	COAL CREEK	8.92E-07	60%	20%	7%	0.071	25%	12%	51%	0.062	Arsenic
6031	KILLEN	1.05E-06	47%	33%	10%	0.200	5%	4%	83%	0.064	Cadmium

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
6034	BELLE RIVER	2.43E-06	65%	21%	7%	0.090	14%	27%	28%	0.184	Arsenic
6041	HL SPURLOCK	1.46E-06	49%	27%	10%	0.938	3%	1%	93%	0.084	Arsenic
6052	WANSLEY	6.45E-07	40%	37%	11%	0.233	3%	2%	91%	0.048	Cadmium
6055	BIG CAJUN TWO	1.34E-06	49%	33%	10%	0.062	19%	16%	38%	0.076	Arsenic
6061	MORROW	2.89E-07	57%	27%	9%	0.056	4%	5%	85%	0.019	Arsenic
6064	NEARMAN CREEK	5.35E-07	46%	34%	11%	0.027	22%	14%	44%	0.029	Arsenic
6065	IATAN	1.45E-06	43%	34%	11%	0.091	24%	11%	48%	0.073	Arsenic
6068	JEFFREY	3.38E-06	44%	34%	11%	0.210	24%	11%	48%	0.171	Arsenic
6071	TRIMBLE COUNTY	2.11E-06	47%	32%	10%	0.502	5%	3%	85%	0.116	Arsenic
6073	VJ DANIEL	4.36E-07	40%	34%	12%	0.017	46%	16%	1%	0.025	Cadmium
6076	COLSTRIP	5.90E-06	60%	23%	9%	0.285	20%	19%	41%	0.410	Arsenic
6077	GERALD GENTLEMAN	7.23E-07	37%	34%	12%	0.098	19%	4%	38%	0.173	HF
6082	SOMERSET	1.06E-06	75%	17%	5%	0.052	5%	24%	61%	0.092	Arsenic
6085	RM SCHAHFER	2.27E-06	45%	34%	10%	0.131	20%	12%	44%	0.147	Cadmium
6089	LEWIS & CLARK	4.36E-07	59%	23%	9%	0.022	20%	18%	41%	0.030	Arsenic
6090	SHERBURNE COUNTY	1.08E-06	48%	28%	11%	0.089	26%	9%	52%	0.060	Arsenic
6094	BRUCE MANSFIELD	6.00E-06	66%	22%	7%	0.225	14%	27%	40%	0.462	Arsenic
6095	SOONER	1.58E-06	48%	34%	10%	0.073	20%	16%	39%	0.089	Arsenic
6096	NEBRASKA CITY	1.31E-06	45%	34%	11%	0.077	23%	12%	45%	0.068	Arsenic
6098	BIG STONE	3.20E-07	46%	34%	11%	0.016	22%	14%	44%	0.017	Arsenic
6101	WYODAK	8.12E-07	42%	34%	12%	0.057	25%	9%	50%	0.042	Cadmium
6106	BOARDMAN (OR)	2.84E-07	41%	34%	12%	0.022	24%	8%	48%	0.015	Cadmium
6113	GIBSON	6.43E-06	52%	30%	10%	0.208	28%	25%	19%	0.386	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
6124	MCINTOSH (GA)	2.07E-08	32%	33%	13%	0.003	27%	3%	54%	0.001	Cadmium
6136	GIBBONS CREEK	1.12E-06	48%	34%	10%	0.052	21%	16%	42%	0.062	Arsenic
6137	AB BROWN	2.13E-06	50%	31%	10%	0.111	18%	15%	45%	0.123	Arsenic
6138	FLINT CREEK (AR)	9.91E-07	50%	33%	10%	0.040	19%	19%	38%	0.057	Arsenic
6139	WELSH	1.03E-06	44%	34%	11%	0.084	17%	8%	34%	0.136	HF
6146	MARTIN LAKE	4.12E-06	47%	35%	10%	0.184	20%	16%	40%	0.226	Arsenic
6147	MONTICELLO (TX)	1.37E-06	46%	34%	10%	0.080	19%	12%	38%	0.074	Arsenic
6155	RUSH ISLAND	1.42E-06	46%	34%	11%	0.082	20%	13%	40%	0.077	Arsenic
6165	HUNTER	2.25E-06	28%	44%	12%	0.097	48%	10%	9%	0.143	Cadmium
6166	ROCKPORT	8.91E-07	49%	32%	11%	0.040	18%	17%	36%	0.051	Arsenic
6170	PLEASANT PRAIRIE	2.30E-06	43%	34%	11%	0.151	24%	10%	49%	0.114	Cadmium
6177	CORONADO	2.04E-06	47%	32%	11%	0.126	24%	12%	48%	0.111	Arsenic
6178	COLETO CREEK	4.92E-07	44%	34%	11%	0.041	17%	8%	35%	0.067	HF
6179	FAYETTE(SEYMOR) (TX)	1.96E-06	44%	34%	11%	0.117	24%	11%	47%	0.100	Arsenic
6180	OAK GROVE	3.08E-06	40%	36%	11%	0.232	24%	8%	49%	0.162	Cadmium
6181	JT DEELY	3.30E-07	43%	34%	11%	0.029	17%	8%	35%	0.048	HF
6183	SAN MIGUEL	7.12E-07	41%	36%	11%	0.056	21%	8%	43%	0.036	Cadmium
6190	MADISON 3 (Brame Energy Center 3)	1.64E-06	33%	28%	27%	0.115	22%	7%	45%	0.111	Cadmium
6193	HARRINGTON	1.68E-06	47%	34%	10%	0.109	17%	11%	35%	0.134	HF
6194	TOLK	1.04E-06	44%	34%	11%	0.088	17%	8%	35%	0.143	HF
6195	SOUTHWEST (TWITTY ENERGY CENTER)	1.51E-06	48%	34%	10%	0.078	18%	15%	36%	0.085	Arsenic
6204	LARAMIE RIVER	3.06E-06	45%	34%	11%	0.175	23%	12%	46%	0.159	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
6213	MEROM	6.91E-07	47%	30%	11%	0.033	31%	15%	29%	0.037	Arsenic
6248	PAWNEE	6.93E-07	43%	34%	11%	0.044	24%	11%	48%	0.035	Arsenic
6249	WINYAH	3.22E-06	53%	28%	10%	0.394	9%	7%	73%	0.197	Arsenic
6250	MAYO	2.38E-06	62%	23%	8%	0.340	6%	7%	80%	0.172	Arsenic
6254	OTTUMWA	9.15E-07	49%	33%	10%	0.038	20%	18%	40%	0.052	Arsenic
6257	SCHERER	1.04E-06	39%	34%	12%	0.092	26%	7%	53%	0.060	Cadmium
6264	MOUNTAINEER	2.23E-06	67%	21%	7%	0.087	12%	27%	43%	0.173	Arsenic
6288	HEALY	3.21E-07	66%	20%	6%	0.022	16%	15%	33%	0.025	Arsenic
6469	ANTELOPE VALLEY	2.01E-06	64%	20%	6%	0.114	23%	18%	47%	0.151	Arsenic
6481	INTERMOUNTAIN	7.48E-07	28%	43%	13%	0.033	53%	10%	4%	0.050	Cadmium
6639	GREEN	5.98E-06	52%	28%	14%	0.423	7%	11%	66%	0.361	Arsenic
6641	INDEPENDENCE	3.39E-07	47%	34%	10%	0.019	19%	13%	39%	0.018	Arsenic
6648	SANDOW	1.33E-06	44%	35%	10%	0.076	22%	12%	45%	0.067	Arsenic
6664	LOUISA	8.82E-07	47%	34%	10%	0.042	21%	15%	43%	0.049	Arsenic
6705	WARRICK	3.74E-06	47%	31%	11%	0.256	16%	11%	53%	0.205	Arsenic
6761	RAWHIDE	6.46E-07	43%	34%	11%	0.042	24%	10%	49%	0.032	Arsenic
6768	SIKESTON	7.55E-07	47%	34%	10%	0.037	22%	15%	43%	0.041	Arsenic
6772	HUGO	7.56E-07	48%	34%	10%	0.039	19%	14%	38%	0.042	Arsenic
6823	DB WILSON	4.06E-06	53%	29%	12%	0.104	19%	32%	15%	0.251	Arsenic
7030	TNP ONE (TWIN OAKS)	1.37E-06	46%	35%	10%	0.075	19%	13%	39%	0.073	Arsenic
7097	SPRUCE	1.69E-06	42%	32%	17%	0.092	22%	12%	44%	0.082	Arsenic
7210	COPE	1.20E-06	56%	27%	9%	0.164	7%	6%	81%	0.078	Arsenic
7213	CLOVER	2.15E-06	47%	29%	11%	0.666	6%	2%	85%	0.118	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
7343	GEORGE NEAL	1.46E-06	50%	33%	10%	0.060	19%	19%	39%	0.084	Arsenic
7504	NEIL SIMPSON 6 (II 2)	4.32E-07	41%	34%	12%	0.031	25%	9%	50%	0.022	Cadmium
7737	KAPSTONE(Cogen South)	1.11E-06	56%	27%	10%	0.047	20%	21%	40%	0.072	Arsenic
7790	BONANZA	3.96E-07	25%	31%	13%	0.036	59%	4%	8%	0.036	Cadmium
7902	PIRKEY	1.71E-06	46%	35%	10%	0.081	21%	15%	42%	0.092	Arsenic
8023	COLUMBIA (WI)	4.65E-07	40%	34%	12%	0.039	26%	7%	52%	0.025	Cadmium
8042	BELEWS CREEK	6.77E-06	60%	24%	8%	0.802	7%	8%	76%	0.476	Arsenic
8066	JIM BRIDGER	4.32E-06	46%	34%	9%	0.272	25%	11%	50%	0.233	Arsenic
8069	HUNTINGTON	1.21E-06	27%	44%	13%	0.054	51%	9%	8%	0.080	Cadmium
8102	GAVIN	4.49E-06	68%	20%	7%	0.171	16%	28%	38%	0.356	Arsenic
8219	RD NIXON	4.57E-07	44%	34%	11%	0.027	23%	11%	47%	0.023	Arsenic
8222	COYOTE	5.99E-07	66%	20%	6%	0.030	22%	21%	45%	0.046	Arsenic
8223	SPRINGERVILLE	1.86E-06	37%	35%	12%	0.156	24%	7%	48%	0.120	Cadmium
8224	NORTH VALMY	4.48E-07	46%	36%	9%	0.025	21%	13%	43%	0.024	Arsenic
8226	CHESWICK	1.63E-06	65%	22%	7%	0.124	9%	13%	66%	0.122	Arsenic
10043	Logan Generating Plant	4.38E-07	50%	30%	10%	0.052	8%	7%	77%	0.025	Arsenic
10075	TACONITE HARBOR ENERGY CENTER	1.26E-06	56%	28%	9%	0.050	17%	22%	35%	0.083	Arsenic
10113	John B Rich Memorial Power Station	5.72E-07	62%	21%	8%	0.038	21%	15%	42%	0.041	Arsenic
10143	Colver Power Project	3.22E-07	59%	21%	9%	0.026	22%	11%	44%	0.022	Arsenic
10151	Grant Town Power Plant	1.71E-07	48%	27%	10%	0.017	23%	7%	47%	0.010	Arsenic
10343	MT. CARMEL	3.36E-07	63%	21%	8%	0.020	20%	16%	41%	0.025	Arsenic
10377	James River Cogeneration	1.10E-06	63%	24%	8%	0.045	15%	24%	46%	0.080	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
10378	Primary Energy Southport	1.79E-06	60%	26%	8%	2.477	0%	1%	98%	0.174	Chlorine
10379	Primary Energy Roxboro	6.25E-07	57%	27%	9%	0.984	0%	1%	98%	0.069	Chlorine
10380	Elizabethtown	3.97E-10	64%	23%	7%	0.000	3%	6%	85%	0.000	Arsenic
10384	Edgecombe Genco LLC	9.08E-07	60%	26%	9%	0.124	4%	7%	84%	0.063	Arsenic
10495	Rumford Cogeneration	1.81E-07	51%	31%	10%	0.009	19%	16%	38%	0.011	Arsenic
10566	Chambers Cogeneration LP (Carney's Point)	1.58E-06	67%	21%	7%	0.145	7%	11%	76%	0.123	Arsenic
10603	Ebensburg Power Co	1.83E-07	61%	21%	8%	0.013	21%	14%	43%	0.013	Arsenic
10641	Cambria Cogen	2.93E-07	53%	22%	9%	0.035	24%	7%	48%	0.018	Arsenic
10671	AES Shady Point Inc	2.33E-07	46%	32%	11%	0.015	20%	11%	41%	0.012	Arsenic
10672	Cedar Bay Generating Co LP	1.93E-07	50%	29%	11%	0.075	3%	2%	91%	0.011	Arsenic
10673	AES HAWAII	9.65E-07	52%	31%	10%	0.063	13%	12%	56%	0.058	Arsenic
10678	AES Warrior Run Cogeneration Facility	6.87E-07	54%	29%	9%	0.067	13%	9%	64%	0.043	Arsenic
10743	Morgantown Energy Facility	2.05E-07	50%	26%	10%	0.020	23%	8%	47%	0.012	Arsenic
10768	Rio Bravo Jasmin	8.42E-10	24%	42%	15%	0.000	21%	4%	43%	0.000	Cadmium
10769	Rio Bravo Poso	7.52E-10	25%	45%	14%	0.000	10%	2%	73%	0.000	Cadmium
10784	Colstrip Energy LP	2.21E-07	51%	24%	10%	0.021	22%	8%	44%	0.013	Arsenic
10849	SILVER BAY POWER	2.25E-09	49%	33%	10%	0.000	15%	14%	31%	0.000	HF
50039	Kline Township Cogen Facil	1.66E-07	53%	22%	10%	0.020	24%	7%	48%	0.010	Arsenic
50202	WPS POWER Niagara	7.74E-08	69%	19%	7%	0.046	1%	2%	96%	0.006	Arsenic
50611	Westwood	1.63E-07	58%	22%	9%	0.014	22%	10%	45%	0.011	Arsenic
50776	Panther Creek Energy	3.10E-07	59%	21%	9%	0.026	22%	11%	45%	0.021	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
	Facility										
50835	TES Filer City	1.05E-06	58%	24%	10%	0.037	25%	26%	26%	0.071	Arsenic
50879	Wheeler Frackville Energy Co Inc	1.36E-07	55%	22%	9%	0.014	23%	8%	47%	0.009	Arsenic
50888	NORTHAMPTON	2.38E-07	60%	21%	9%	0.018	22%	12%	44%	0.017	Arsenic
50931	Yellowstone Energy LP	2.62E-07	20%	21%	33%	0.035	28%	2%	56%	0.035	Cadmium
50951	Sunnyside Cogeneration Associates	7.59E-08	18%	38%	13%	0.017	25%	1%	51%	0.007	Cadmium
50974	SCRUBGRASS	2.29E-07	65%	20%	7%	0.012	19%	19%	39%	0.017	Arsenic
50976	Indiantown Cogeneration Facility	3.54E-07	50%	30%	11%	0.057	7%	5%	82%	0.021	Arsenic
52007	Mecklenburg Cogeneration Facility	2.38E-07	42%	32%	12%	0.043	11%	4%	79%	0.012	Arsenic
52071	SANDOW	2.30E-06	32%	46%	12%	0.114	22%	10%	44%	0.128	Cadmium
54035	Westmoreland LG&E Partners Roanoke Valley	1.56E-07	50%	28%	11%	0.058	4%	2%	91%	0.009	Arsenic
54081	Spruance Genco LLC	6.25E-07	45%	29%	11%	0.206	7%	2%	87%	0.033	Arsenic
54304	Birchwood Power Facility	3.34E-07	43%	33%	12%	0.055	9%	4%	81%	0.017	Arsenic
54634	St Nicholas Cogeneration Project	3.66E-07	59%	21%	9%	0.029	22%	12%	44%	0.025	Arsenic
54755	Westmoreland LG&E Partners Roanoke Valley	4.22E-07	55%	27%	10%	0.099	4%	4%	88%	0.027	Arsenic
55076	RED HILLS GENERATION FACILITY	5.10E-07	50%	30%	10%	0.037	21%	11%	42%	0.030	Arsenic
55479	WYGEN	9.11E-07	47%	34%	10%	0.043	21%	16%	43%	0.050	Arsenic
55749	HARDIN GENERATING	3.09E-07	50%	24%	11%	0.028	26%	9%	52%	0.018	Arsenic
55856	PRAIRIE STATE	1.52E-06	45%	29%	12%	0.901	3%	1%	91%	0.108	Cadmium
56068	ELM ROAD	4.37E-06	61%	24%	8%	0.184	19%	23%	39%	0.312	Arsenic

Plant No.	Name	Cancer Risk	As (%)	Cr VI (%)	Ni (%)	Hazard Index	Acrolein (%)	As (%)	Cl_2 (%)	Acute HQ	HAP
56224	TS POWER (NEWMONT/BOULDER VALLEY)	3.88E-07	43%	34%	11%	0.024	24%	11%	48%	0.020	Arsenic
56319	WYGEN	7.61E-07	48%	34%	10%	0.034	21%	16%	42%	0.043	Arsenic
56456	PLUM POINT	1.15E-06	43%	34%	11%	0.073	24%	10%	48%	0.058	Arsenic
56564	J. TURK (FULTON, AK)	8.28E-07	49%	33%	10%	0.034	20%	18%	39%	0.048	Arsenic
56596	WYGEN	7.87E-07	48%	34%	10%	0.036	21%	16%	42%	0.044	Arsenic
56609	DRY FORK	9.70E-07	43%	34%	11%	0.064	24%	10%	49%	0.048	Arsenic
56611	SANDY CREEK ENERGY STATION	7.82E-07	43%	34%	11%	0.049	24%	11%	48%	0.039	Arsenic
56671	LONGVIEW	1.52E-06	65%	20%	7%	0.165	9%	9%	72%	0.116	Arsenic
56786	SPIRITWOOD STATION	3.61E-07	62%	20%	7%	0.024	25%	15%	50%	0.026	Arsenic
56808	VIRGINIA CITY HYBRID ENERGY CENTER	2.82E-07	42%	24%	11%	0.026	47%	7%	5%	0.014	Arsenic

Programs:

Power Plant Multimedia Emissions Characterization

Air Pollutants and Toxics: Assessment and Models

3002013577

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com