EMISSION FACTOR

DOCUMENTATION FOR

AP-42 SECTION 1.1

BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

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1. INTRODUCTION

The document, "Compilation of Air Pollutant Emission Factors" (AP-42), has been published by the U.S. Environmental Protection Agency (EPA) since 1972. Supplements to AP-42 have been routinely published to add new emissions source categories and to update existing emission factors. An emission factor is an average value which relates the quantity (weight) of a pollutant emitted to a unit of activity of the source. In some cases, emission factors are presented in terms of an empirical formula to account for source variables. Emission factors are developed from source test data, material balance calculations, and engineering estimates. The uses for the emission factors reported in AP-42 include:

- Estimates of area-wide emissions;
- Emission estimates for a specific facility; and
- Evaluation of emissions relative to ambient air quality.

The EPA routinely updates AP-42 in order to respond to new emission factor needs of State and local air pollution control programs, industry, as well as the Agency itself. Section 1.1 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to bituminous and subbituminous coal combustion in stationary, external equipment.

The purpose of this EFD is to provide background information and to document the procedures used for the revision, update, and addition of emission factors for bituminous and subbituminous coal combustion. The scope of the present AP-42 Section 1.1 update is as follows:

- Update baseline, criteria emission factors with data identified since the prior updates;

- Modify equipment classifications to give separate treatment of tangentially-fired boilers and fluid bed combustors (FBCs);

- Extend emission factors to non-criteria species where data are available for volatile organic compounds (VOC) speciation, trace metals and other air toxics, and greenhouse gases [nitrous oxide (e.g., N_2O), carbon dioxide (CO_2)]; and

- Extend documentation and emission factor development for controlled operation to reflect advances in control development and the increased importance of emission controls for combustion sources.

Data from approximately 20 test reports were used to revise and update emission factors for existing source categories; determine new emission factors for additional non-criteria pollutants; and add FBC units as a new source category.

The update of Section 1.1 of AP-42 began with a review of the existing version of Section 1.1. Spot checks were made on the quality of existing emission factors by recalculating emission factors from selected primary data references contained in the background files. These recalculated emission factors were then compared against those in the existing version of AP-42.

An extensive literature review was undertaken to improve technology descriptions, update usage trends, and collect new test reports for criteria and non-criteria emissions. The new test reports were subjected to data quality review as outlined in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). Test reports containing sufficiently high quality data ratings were combined with existing data to revise emission factors or to produce new emission factors, as appropriate. When sufficient new data were obtained that were of higher quality than existing data, old lower-quality data were removed from the existing emission factor averages. In some cases, data sources and test reports were identified during the literature review but were not received in sufficient time to incorporate into emission factor development. This information has been placed in the background files for use in future updates.

Several new emission factors for non-criteria pollutants have been added. These new emission factors pertain to total organic compounds (TOC), speciated volatile organic compounds (speciated VOC), air toxics, N_2O, CO_2, and fugitive emissions. Additionally, in this revision, the information on control technologies for particulate matter (PM), PM less than 10 microns (PM-10), sulfur oxide (SO_x), and nitrogen oxides (NO_x) emissions has been revised and updated. Add-on controls for non-criteria pollutants are not covered here because these controls have not been demonstrated on commercial scale combustors for this source category. Finally, because fluidized bed combustion of coal is finding increased commercial application in industrial and utility systems, a new source category for this combustion configuration has been added.

Including the introduction (Chapter 1), this EFD contains five chapters. Chapter 2 provides an overall characterization of bituminous and subbituminous coal combustion usage. This includes a breakdown of coal application by industry, an overview of the different source categories, a description of emissions, and a description of the technology used to control emissions resulting from coal combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emissions data reports, and the quality rating system for both emission data and emission factors. Chapter 4 details pollutant emission factor development. It includes the review of specific data sets and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.1. Appendix A provides conversion factors and example calculations for emission factor development from test data. Appendix B contains an example of spot checking data from the fourth edition AP-42 primary references. Appendix C contains a marked-up copy of the 1988 AP-42 Section 1.1 indicating where changes have been made as a result of this update.

2. SOURCE DESCRIPTION

The amount and type of coal consumed, design of combustion equipment, and application of emission control technology have a direct bearing on emissions from coal-fired combustion equipment. This chapter characterizes bituminous and subbituminous coal combustion processes, and emission control technologies which are commercially available in the United States.

2.1 CHARACTERIZATION OF BITUMINOUS AND SUBBITUMINOUS COALS APPLICATIONS

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous, and lignite. These classifications are made according to heating value as well as relative amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Formulas and tables for classifying coals based on these properties are given in Reference 1.

In general, bituminous coals have heating values of 5,800 to 7,800 kcal/kg (10,500 to 14,000 Btu/lb) while the heating values of subbituminous coals are lower at 4,600 to 6,400 kcal/kg (8,300 to 11,500 Btu/lb).[1] Subbituminous coals are typically higher in volatile matter, moisture, and oxygen contents than bituminous coals and, as a result, are lower in fixed carbon content. Because of their high heating values and high volatile contents, both bituminous and subbituminous coals burn easily when pulverized to fine powder. Because of its characteristically lower sulfur content and higher moisture content, SO_2 and NO_x emissions are generally lower for combustion of subbituminous coals relative to bituminous coals.

In 1990, a total of almost 860 million short tons of coal were consumed by the utility, industrial, commercial/institutional, and residential sectors.[2] These four sectors can be described as follows: (1) utility boilers producing steam for generation of electricity; (2) industrial boilers generating steam or hot water for process heat, generation of electricity, or space heat; (3) boilers for space-heating of commercial and institutional facilities; and (4) residential furnaces for space- heating purposes. As shown in Table 2-1, the utility sector consumed the most fuel [over 700 million metric tons (770 million short tons)]. The residential usage of coal for space heating has generally declined since 1973 as stoker- and hand-fired furnaces and boilers have been replaced by oil, gas, and electric heating systems.[2] Of the total coal produced in 1989, approximately 67 percent was bituminous, 24 percent subbituminous, 9 percent lignite, and less than 1 percent anthracite.[1]

2.2 PROCESS DESCRIPTIONS

Coal-fired boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and the firing configuration (suspension, stoker, or fluidized bed). Table 2-2 summarizes boiler type usage by sector. Most of the installed capacity of firetube and cast iron units is oil- and gas-fired[3]; however, a description of these designs for coal is included here for completeness.

A watertube boiler is one in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes. Coal-fired watertube boilers consist of pulverized coal, cyclone, stoker, fluidized bed, and handfeed units. Pulverized coal and cyclone boilers are types of suspension systems because some or all of the combustion takes place while the fuel is suspended in the furnace volume. In stoker-fired systems and most handfeed units, the fuel is primarily burned on the bottom of the furnace or on a grate. Some fine particles are entrained in upwardly flowing air, however, and are burned in suspension in the upper furnace volume. In a fluidized bed combustor, the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the "freeboard" space.

2.2.1 Suspension Firing

In pulverized coal-fired (PC-fired) boilers the fuel is pulverized to the consistency of light powder and pneumatically injected through the burners into the furnace. Combustion in PC-fired units takes place almost entirely while the coal is suspended in the furnace volume. PC-fired boilers are classified as either dry bottom or wet bottom, depending on whether the ash is removed in solid or molten state. In dry bottom furnaces, coals with high fusion temperatures are burned, resulting in dry ash. In wet bottom furnaces, coals with low fusion temperatures are used, resulting in molten ash or slag. Wet bottom furnaces are also referred to as slag tap furnaces.

Depending upon the location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into three different firing types. These are:

- Single and opposed wall, also known as face firing;
- Tangential, also known as corner firing; and
- Cyclone.

Wall-fired boilers can be either single wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed wall-fired, with burners mounted on two opposing walls. PC-fired suspension boilers usually are characterized by very high combustion efficiencies, and are generally receptive to low-NO_x burners and other combustion modification techniques. Tangential or corner-fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that is essentially the burner. Because of the large flame volumes and relatively slow mixing, tangential boilers tend to be lower NO_x emitters for baseline uncontrolled operation. Cyclone furnaces are often categorized as a PC-fired system even though the coal burned in a cyclone is crushed to a maximum size of about 4.75 mm (4 mesh). The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension while larger particles adhere to the molten layer of slag on the combustion chamber wall. Cyclone boilers are high-temperature, wet bottom-type systems. Because of their high furnace heat release rate, cyclones are high NO_x emitters and are generally more difficult to control with combustion modifications.

2.2.2 Stoker Firing

Stoker firing systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications.[4] Most packaged stoker units designed for coal firing are less than 29 MW (100 million Btu/hr) heat input.[5] Field erected units with capacities in excess of 116 MW (400 million Btu/hr) are common. Stoker systems can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. These systems differ in how fuel is supplied to either a moving or stationary grate for burning. One important similarity among all stokers is that all design types use underfeed air to combust the coal char on the grate, combined with one or more levels of overfire air introduced above the grate. This helps ensure complete combustion of volatiles and low combustion emissions.

Underfeed stokers are generally of two types: the horizontal-feed, side-ash-discharge type shown in Figure 2-1; and the gravity-feed, rear-ash-discharge type shown in Figure 2-2. The horizontal-feed, side-ash-discharge type of stoker is used primarily in small boilers supplying relatively constant steam loads of less than about 14,000 kg/hr (30,000 lb/hr).[1] The gravity-feed, rear-ash-discharge underfeed stoker can be as large as 150 MW (500 million Btu/hr) heat input capacity[1], although there are a few underfeed coal stokers of up to 440 MW (1500 million Btu/hr)[3].

An overfeed stoker, shown in Figure 2-3, uses a moving grate assembly. Coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. Caking bituminous coals can cause agglomeration and matting which can restrict the airflow through the grate causing further combustion problems.[5] The three types of grates used with overfeed coal stokers are the chain, travelling, and water-cooled vibrating grates. These overfeed stoker systems are often referred to by the type of grate employed. Overfeed coal-fired systems typically range up to 100 MW (350 million Btu/hr) heat input.

In a spreader stoker, shown in Figure 2-4, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, and air flow velocity. Generally, fuels with finer size distributions, higher volatile matter contents, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.[6] Heat input capacities of spreader stokers typically range from 1 to 130 MW (5 to 450 million Btu/hr).[3] Unlike overfeed stokers, fuels with the potential to cake have little negative effect on spreader stokers and can be generally fired with success in these units.[5]

2.2.3 Fluidized Bed Combustion

Fluidized bed combustion boilers, while not constituting a significant percentage of the total boiler population, have nonetheless gained popularity in the last decade, and today generate steam for industries, cogenerators, independent power producers, and utilities. Fluidized bed combustion is a boiler design which can lower sulfur dioxide (SO_2) and NO_x emissions without the use of post-combustion or add-on controls. A calcium-based limestone or dolomitic sorbent is often used for the bed material to capture SO_2 evolved during combustion. The sulfur is retained as a solid sulfate and is removed from the flue gas stream by the particulate control device. Emissions of thermal NO_x are reduced because FBCs are able to operate at lower combustion temperatures compared to the more conventional designs, thus reducing the fixation of atmospheric nitrogen. Typical maximum firing temperatures for FBCs are 930°C (1700°F) compared with typical furnace-exit-gas-temperatures of 1430°C (2600°F) for dry bottom boilers and up to 1760°C (3200°F) for wet bottom boilers.[1] Conversion of fuel nitrogen to NO_x is also suppressed with FBC compared to suspension firing.

There are two major categories of FBC systems: (1) atmospheric, operating at or near ambient pressures, and (2) pressurized, operating from 4 to 30 atmospheres (60 to 450 psig). Pressurized FBC systems are being demonstrated at two utility sites in the U.S.; however, they are not yet considered fully commercialized. The remainder of this section will therefore describe only atmospheric FBCs.

Figures 2-5 and 2-6 show the two principal types of atmospheric FBC boilers, bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, ranging between 1.5 and 3.6 m/s (5 and 12 ft/s), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 m/s (30 ft/s) to promote the carryover or circulation of the solids. High temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high volume recycle rate which increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.[7]

2.2.4 Handfeed Units

Small, coal-fired boilers and furnaces are sometimes found in small industrial, commercial, institutional, or residential applications. Small firetube boilers in these installations are sometimes capable of being hand-fired. From an emissions standpoint, handfeed units can have high carbon monoxide (CO) and VOC emissions because of generally low combustion efficiencies due, in part, to the presence of quench surfaces. Most small units may not have particulate controls while some are only equipped with simple cyclone or multiclone collectors. Small boilers and furnaces without particulate controls do not generally have emission factors as high as large uncontrolled industrial boilers because typical combustion intensities and firebox velocities are lower in the smallest units. Lower firebox velocities mean that smaller quantities of particulate matter are entrained in the combustion gases.

The most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox. Cast iron boilers are also sometimes available as coal-fired units in a handfeed configuration. The HRT boilers are generally fired with gas or oil instead of coal. A two-pass HRT boiler is shown in Figure 2-7. A Scotch or shell boiler differs from the HRT boiler in that the boiler and furnace are contained in the same shell. In a two-pass unit, combustion occurs in the lower half of the unit, with the flue gases passing beneath the bottom of the water basin occupying the upper half. Like HRT boilers, coal is not as commonly used in Scotch boilers due to slagging and scaling.[3] More common gas- and oil-fired Scotch units are shown in Figures 2-8 and 2-9.

A vertical firetube boiler is a single-pass unit in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. Figures 2-10 and 2-11 show two types of vertical firetube boilers. Vertical boilers are small, with input capacities under 0.7 MW (2.5 million Btu/hr). A firebox boiler is constructed with an internal steel encased, water-jacketed firebox. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers. Currently available coal-fired firebox units employ mechanical stokers or are capable of being hand-fired. They are generally limited in size to below 7.3 MW (25 million Btu/hr) input capacity.[4] Cast iron boilers consist of several vertical sections of heat exchange tubes mounted above a firebox. Water enters each section at the bottom and is heated or converted to steam as it passes upward through the heat exchange tubes. Figure 2-12 shows a typical cast iron boiler.

2.3 EMISSIONS

Emissions from coal combustion depend on coal rank and composition, the design type and capacity of the boiler, the firing conditions, load, the type of control technologies, and the level of equipment maintenance. Baseline, uncontrolled sources are those without add-on air pollution control (APC) equipment, low-NO_x burners, or other modification for emission control. Baseline emission for SO_2 and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

Because of the inherent low NO_x emission characteristics of FBCs and the potential for in-situ SO_2 capture with calcium-based bed materials, uncontrolled emission factors for this source category were not developed in the same sense as with the other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline if no additional add-on NO_x control (such as ammonia injection) was in place. For SO_2 emissions, a correlation was developed from reported data on FBCs to relate SO_2 emissions with the coal sulfur content and the calcium to sulfur ratio in the bed.

For this update of AP-42, point source emissions of NO_x, SO_2, PM, PM-10, and CO are evaluated as criteria pollutants (those emissions which have established National Primary and Secondary Ambient Air Quality Standards[8]). This update includes point source emissions of some non-criteria pollutants (e.g., N_2O, VOCs, and air toxics) as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of CO_2 are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO or as carbon retained in the fly ash. Finally, fugitive emissions associated with the use of coal at the combustion source are being included in this update of AP-42.

The total 1985 emissions of PM, SO_2, and NO_x emissions resulting from bituminous coal combustion in the major use sectors are summarized in Table 2-3 shown below. Table 2-4 summarizes the federal New Source Performance Standards (NSPS)[9-12] applicable to PM, SO_2, and NO_x emissions from fossil fuel-fired boilers.

A general discussion of emissions of criteria and non-criteria pollutants from coal combustion is given in the following paragraphs.

2.3.1 Particulate Matter Emissions

Uncontrolled PM emission from coal-fired boilers include the ash in the fuel as well as unburned carbon resulting from incomplete combustion. Emission factors for PM have generally been expressed as a function of fuel ash content. Coal ash may either settle out in the boiler (bottom ash) or be carried out with the flue gas (fly ash). The distribution of ash between the bottom and fly ash fractions directly affects the PM emissions rate[13] and is a function of the following:

- Boiler firing method -- The type of firing is perhaps the most important factor in determining ash distribution. For example, stoker-fired units emit less fly ash than dry bottom, PC boilers; and

- Wet or dry bottom furnace -- Wet bottom cyclone furnaces remove approximately 70 percent of ash as slag or bottom ash; with dry bottom units, the inverse is roughly the case, where 70 percent of ash exits the boiler with the combustion gases to be treated by particulate collectors.

Boiler load also affects PM emissions from coal-fired boilers. In general, decreasing load tends to reduce PM emissions; however, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

Soot blowing is a source of intermittent PM emissions in coal-fired boilers. Steam soot blowing is used periodically to dislodge ash from heat transfer surfaces in the furnace, convective section, and economizer/preheater. On small boilers with single soot blowers, soot blowing may only take place for a few seconds once a shift. Large boilers may have numerous soot blowers installed and operated in a cycle which may approach "continuous" soot blowing.

2.3.2 Sulfur Oxide Emissions

Sulfur oxide emissions are generated during coal combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and about 1 to 3 percent is converted to sulfate particulate. Sulfur trioxide readily reacts with water vapor (both in air and in flue gases) to form sulfuric acid mist.

Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and, with the exception of fluidized bed combustors, are not affected by boiler type, size, or burner design[15]. There is some potential that stoker boilers firing high ash coal with a significant alkaline content could result in SO_2 emissions which are lower than a PC-fired boiler firing the same fuel due to sulfur retention as an alkali sulfate in the ash bed on the grate. In some cases, combustion of highly alkaline, Western subbituminous coals can result in 20 percent of the sulfur in the coal being retained in the bottom ash or fly ash.[16] However, the data reviewed did not justify the presentation of separate emission factors for stoker-fired systems. Therefore, as in the earlier versions of AP-42, a consistent SO_2 emission factor, based only on fuel sulfur content (within a coal rank), was retained for all combustion configurations, with the single exception of FBC units.

2.3.3 Nitrogen Oxide Emissions

Oxides of nitrogen formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x") or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x customarily refers to the composite of nitric oxide (NO), and nitrogen dioxide (NO_2).

Nitrous oxide is excluded, but is an oxide of definite interest. Test data have shown that for most stationary combustion systems, over 95 percent of the emitted NO_x is in the form of NO.[15]

The qualitative global kinetics of thermal NO_x formation have shown that NO_x formation rates are exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of the oxygen (O_2) concentration in the flame, and the residence time.[17] Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) nitrogen concentration, (3) oxygen concentration or flame stoichiometry, and (4) time of exposure at peak temperature. The emission trends resulting from changes in these factors are fairly consistent for all types of boilers -- an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in thermal NO_x production regardless of the boiler type.

Fuel nitrogen conversion is the more important NO_x forming mechanism in coal-fired combustion systems because of the high nitrogen content in the fuel. Fuel NO_x can account for 80 percent of the total NO_x emissions in coal firing.[18] The percent conversion of fuel nitrogen to NO_x can vary greatly. Anywhere from 5 to 60 percent of nitrogen in the coal can be converted to NO_x.[17] Furthermore, test data indicate that the percent of fuel nitrogen conversion decreases as the fuel nitrogen content increases.[19]

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. The NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), or some combination thereof may result in NO_x reductions of 5 to 60 percent. (See Section 2.4.1 for a discussion of these techniques). Load reduction can likewise decrease NO_x production. The NO_x emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. Levels of NO_x emissions do not decrease significantly in response to load reductions in some boilers and have, in some cases, been observed to increase (due to the higher excess air levels sometimes required to maintain stable combustion). It should be noted that the discussion of these variables, with the exception of excess air, applies to the NO_x emissions only of large coal-fired boilers. Low excess air firing is possible in many small boilers, but the resulting NO_x reductions are not nearly so significant.

Test data on pulverized coal combustion utility boilers indicate that N_2O emissions were always less than 10 ppm[20] and often less than 1 ppm in the units tested.[21] Generally, N_2O emissions from FBC boilers can be higher, but are generally less than 100 ppm with U.S. coals.[22] Some of the higher N_2O emissions that have been reported are from European FBC installations and pilot plant studies.[23] Some pilot plant configurations have been suspected of producing spuriously high N_2O emissions data which are not representative.

At the third N_2O workshop held in France in June 1988,[24] data were presented suggesting the presence of an N_2O sampling artifact in sampling containers awaiting analysis. Recent N_2O emissions data indicate that direct N_2O emissions from coal combustion units are considerably below the measurements made prior to 1988. The emission ranges quoted above are based on tests employing methods to minimize or eliminate the sampling artifact. Nevertheless, the N_2O formation and reaction mechanisms are still not well understood or well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O mechanism. Emissions can vary widely from unit to unit, or even at the same unit at different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature.[22] For this AP-42 update, an average emission factor based on reported test data was developed for conventional coal combustion systems, and a separate emission factor was developed for fluidized bed combustors.

2.3.4 Carbon Monoxide Emissions

The rate of CO emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion. These include:

- Insufficient oxygen availability;
- Extremely high levels of excess air leading to quenching (more common with industrial boilers);
- Poor fuel/air mixing;
- Cold wall flame quenching;
- Reduced combustion temperature;
- Decreased combustion gas residence time; and
- Load reduction (reduced combustion intensity).

Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

2.3.5 Organic Compound Emissions

Total organic compounds include VOCs which remain in a gaseous state in ambient air, semi-volatile organic compounds and condensible organic compounds. According to the Federal Register, VOC has been defined as any organic compound excluding CO, CO_2, carbonic acid, metallic carbides or carbonates, and ammonium carbonate which participates in atmospheric photochemical reactions. The following additional compounds have been deemed to be of "negligible photochemical reactivity" and so are exempt from the definition of VOC: methane, ethane, methyl chloroform, methylene chloride, and most chlorinated-fluorinated compounds (commonly referred to as CFCs). Although these compounds are considered "exempt" from most ozone control programs due to their low photochemical reactivity rates, they are of concern when developing complete emission inventories which are necessary for the design of effective ozone control strategies. The term TOC will be considered to include all organic compounds, i.e. VOCs plus the "exempt" compounds including methane and ethane, toxic compounds, aldehydes, perchloroethylene, semi-volatiles, and condensibles (as measured by EPA Reference Methods).[25]

Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, ethyl benzene, etc.).[26,27]

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups. Because of the dominance of PAH information (as opposed to other POM categories) in the literature, many reference sources have inaccurately used the terms POM and PAH interchangeably.

Polycyclic organic matter can be especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal exits as POM.[4] A few comments are in order concerning an extremely toxic subclass of PNA -- the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources[28] concluded that, although PCB formation is thermodynamically possible for combustion of fuels containing some chlorine (e.g., some coals and residual oil), it is unlikely due to short reaction residence times at conditions favoring PCBs and to low chlorine concentrations. Also with efficient mixing, oxygen availability, and adequate residence time at temperatures in the 800-1000 °C (1470-1830 °F) range, PCBs [together with polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF)] may be efficiently destroyed.[29] Other research has shown, however, that chlorinated PNAs can be formed via catalyzed reactions on fly ash particles at low temperatures in equipment downstream of the combustion device.[61]

Formaldehyde is formed and emitted during the combustion of hydrocarbon-based fuels including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Since formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion, large units with efficient combustion resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long retention times should have lower formaldehyde emission rates than do small, less efficient combustion units.[30,31]

2.3.6 Trace Element Emissions

Trace elements are also emitted from the combustion of coal. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments (CAAA-90)[32] are considered. The quantity of trace metals emitted depends on combustion temperature, fuel feed mechanism and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the partitioning of emissions into bottom ash and fly ash.

The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel;
- The combustion conditions;
- The type of particulate control device used, and its collection efficiency as a function of particle size; and
- The physical and chemical properties of the element itself.

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not.[4] Various classification schemes to describe this partitioning have been developed.[33-35] The classification scheme used by Baig et al.[35] is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment;

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size;
- Class 3: Elements which are intermediate between Class 1 and 2;
- Class 4: Volatile elements which are emitted in the gas phase.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of combustion controls on incremental trace metal emissions.[4] For example, several NO_x controls for boilers reduce peak flame temperatures [e.g., staged combustion, flue gas recirculation (FGR), reduced air preheat, and load reduction]. If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine particulate matter. Therefore, for combustors with particulate controls, lowered volatile metal emissions should result due to improved particulate removal. Flue gas emissions of Class 1 metals (the non-segregating trace metals) should remain relatively unchanged.

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metals should not be significantly affected.

Other combustion NO_x controls which decrease local O_2 concentrations (staged combustion and low NOx burners) may also reduce peak flame temperatures. Under these conditions, the effect of reduced combustion temperature is expected to be stronger than that of lowered O_2 concentrations.

2.3.7 Fugitive Emissions

Fugitive emissions are pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer or storage. Depending on how the fugitive emissions are measured, under what conditions, and for what specific type of operation used, emission factors tend to vary widely in validity, absolute value, and methodology of calculation.

The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during transfer operations from silos to trucks or rail cars.

2.4 CONTROL TECHNOLOGIES

Only controls for criteria pollutants are discussed here because controls specifically for non-criteria emissions have not been demonstrated or commercialized for coal combustion sources.

Control techniques may be classified into three broad categories: fuel treatment/substitution, combustion modification, and post-combustion control. Fuel treatment includes coal cleaning using physical, chemical, or biological processes. Combustion modification and post-combustion control are both applicable and widely commercialized for coal combustion sources. Combustion modification is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Post combustion control is applied to emissions of PM, SO_2, and, to some extent, NO_x for coal combustion.

Particulate emissions may be categorized as either filterable or condensible. Filterable emissions are generally considered to be the particles that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling train. Particles less than 0.3 microns and vapors pass through the filter. Condensible particulate matter (CPM) is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensible particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

2.4.1 Fuel Treatment/Substitution

Fuel treatment (or benefication) and fuel substitution are pre-combustion techniques for reducing NO_x, SO_2, and PM emissions from combustion sources. Fuel substitution involves the use of naturally occurring clean fuels, whereas benefication provides a physically or a chemically cleaned fuel.

Naturally occurring low sulfur coals may allow a source to meet SO_2 emission limits or reduce emissions with no additional controls. Low sulfur coal is sometimes defined as run-of-mine (ROM) coal which can comply with a given emission standard. Although the terms "high" and "low" are dependent on the specifics of the fuel analysis (and the area where the coal was mined), generally the break point between high and low sulfur coal is considered to be around 1100 ng/J (2.5 lbs SO_2 per million Btu of heat input).[36] This is roughly equivalent to 1.5 percent sulfur for bituminous coals, and about 1.0 percent for subbituminous coals. Nearly 85 percent of the reserve base of low sulfur coal is located in states west of the Mississippi River. The bulk of western coals are, however, of a lower rank than are the Eastern coals.

Low sulfur western coals can be burned in stoker-fired systems as long as there is sufficient undergrate air to handle any caking that may occur. Also, many low sulfur western coals have low ash fusion temperatures which may cause slagging on the grate for some stoker designs.

Pulverized coal and FBC boilers can be designed for almost any type of coal. However, once a design is set (especially for PC systems), substitutions are limited to coals with compatible combustion characteristics and ash properties. Fluidized bed boilers are generally more tolerant of alternate or "off-spec" fuels. The choice of alternate coal will depend on the type of pulverizer at the boiler site (for PC-fired systems), the spacing of watertubes in the steam generator and superheater sections, and the materials used in the furnace wall.[37] Also, the higher resistivity of the fly ash from the combustion of low sulfur coal may affect the particulate control performance of the ESP.

Physical coal benefication consists of a series of steps including size reduction, classification, cleaning, dewatering and drying, waste disposal, and pollution control. Basic physical coal cleaning techniques have been commercial for at least 50 years.[36] Currently, more than 50 percent of domestic coal is cleaned to some level before use.[36] There are in excess of 500 coal cleaning plants in the U.S., most of which are located east of the Mississippi River. Although coal cleaning was originally envisioned as an ash reduction technology, it also accomplishes reduction in SO_2 emissions. The level of reduction is dependent on the pyritic (inorganic) sulfur content and the nature and extent of cleaning operations (primarily crushing) done on the feed coal. Current, commercial physical coal cleaning plants are capable of removing 20 to 50 percent of the pyritic sulfur.[36] Assuming the high range to be achievable, and using published levels of pyritic and total sulfur for individual coals,[38] the total possible reduction in SO_2 emissions for common bituminous coals are:

- Illinois No. 6: 27%
- Upper Freeport: 47%
- Upper Kittanning: 11%

These reduction values are shown for illustration purposes only since the ratio of pyritic to organic sulfur can vary substantially alon ghe length of a seam (e.g., reductions could bary between 20 and 40 percent for Illinois No. 6 coal). It is evident that the degree of SO_2 removal available with physical coal benefication depends on the cleaning process as well as the coal type and pyritic/organic sulfur ratio. It is also clear that the removal of SO_2 is well below the 90 percent level usually required under the New Source Performance Standards (NSPS).[10-12]

Several chemical and biological benefication processes are under development, but are not yet commercialized for full-scale coal combustion applications. These advanced cleaning processes are being designed to work on the organically bound sulfur as opposed to most of the physical processes which are aimed at the pyritic sulfur. The goals of the research and development efforts which have been funded by the U.S. Department of Energy, the Electric Power Research Institute, and private industry is to produce a coal that can meet the NSPS and Clean Air Act Amendments of 1990 SO_2 emission limits without additional controls.

2.4.2 Combustion Modification

Combustion modification includes any physical or operational change in the furnace or boiler apparatus itself.[4,39-44] Maintenance of the burner system, for example, is important to assure proper mixing and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units for maximum operating efficiency and emission control, particularly of smoke and CO.

2.4.2.1 Particulate Matter Control. Uncontrolled PM emissions from small stoker-fired and handfeed coal combustion sources can be minimized by employing good combustion practice. This involves operation of the combustion source within recommended load ranges, controlling the rate of load changes, and ensuring steady and uniform fuel introduction. Proper design of combustion air delivery systems can also minimize uncontrolled PM emissions. Insufficient combustion air will generate soot and condensible organic compound emissions. Conversely, the use of excessive air flow under the grate, beyond that necessary to complete char burnout and to cool the grate can give high PM emissions. Also, localized areas of high velocities near the fuel bed can entrain ash into the flue gases leaving the combustor. Excess air in these types of units should be introduced through overfire air ports where possible for volatile burnout and upper furnace temperature control.

Large industrial and utility boilers are generally well designed and maintained so that soot and condensible organic compound emissions are minimized. Particulate matter emissions are more a result of entrained fly ash in suspension-fired and FBC systems. Therefore, post combustion controls are necessary to reduce PM emissions from these sources.

2.4.2.2 Nitrogen Oxide Control. Combustion modifications, such as limited excess air firing, flue gas recirculation, staged combustion and reduced load operation, are primarily used to control NO_x emissions in large coal-fired facilities.

The formation of thermal NO_x occurs in part through the Zeldovich mechanism:

(2-1) $N_2 + O \longleftrightarrow NO + N$

(2-2) $N + O_2 \longleftrightarrow NO + O$

(2-3) $N + OH \longleftrightarrow NO + H$

Reaction (2-1) is generally the rate determining step due to its large activation energy.[4] On an overall, idealized, global basis, the thermal NO_x formation rate is related to N_2 concentration, combustion temperature, and O_2 concentration by the following equation:[4]

(2-4) $[NO] = k_1 \exp(-k_2/T)\,[N_2]\,[O_2]^{1/2}\,t$

where:

[ ] = mole fraction

T = temperature (°K)

t = residence time

k_1, k_2 = reaction rate coefficient constants

This idealized relationship suggests thermal NO_x formation can be controlled by four approaches: (1) reduction of peak temperature of reaction, (2) reduction of N_2 concentration, (3) reduction of oxygen level or stoichiometric ratio, and (4) reduction of the residence time of exposure at peak temperature. Typically, the N_2 mole fraction in hydrocarbon-air flames is on the order of 0.7 and is difficult to modify.[4] Therefore, combustion modification techniques to control thermal NO_x in boilers have focused on reducing oxygen level, peak temperature, and time of exposure at peak temperature in the primary flame zones of the furnaces. Equation 2-4 also shows that thermal NO_x formation depends exponentially on temperature, parabolically on oxygen concentration, and linearly on residence time. Therefore initial efforts to control NO_x emissions are often focused on methods to reduce peak flame temperatures.

In boilers fired on coal, the control of fuel NO_x is also very important in achieving the desired degree of NO_x reduction, since fuel NO_x can account for 80 percent of the total NO_x formed.[18,45,46] Fuel nitrogen conversion to NO_x is highly dependent on the fuel to air ratio in the combustion zone, and in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature.[47] In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

In the formation of both thermal and fuel NO_x, all of the above reactions and conversions do not take place at the same time, temperature, or rate. The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel-bound nitrogen and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels or the particle fineness of solid fuels.[48] Additionally, thermal NO_x is greatly increased by increased residence time at high temperatures under oxidizing conditions. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control approaches:

- Decrease residence time at high temperatures and oxidizing conditions (for oxidizing conditions):

  - Decreased adiabatic flame temperature through dilution,

  - Decreased combustion intensity,

  - Increased flame cooling,

  - Decreased primary flame zone residence time,

- Decrease primary flame zone O_2 level:

  - Decreased overall O_2 level,

  - Controlled (delayed) mixing of fuel and air, and

  - Use of fuel-rich primary flame zone.

Tables 2-5 and 2-6 summarize available NO_x control techniques currently in use of under full-scale demonstration on pulverized coal-fired boilers and stoker coal-fired boilers, respectively.

For cyclone boilers, natural gas reburning has been investigated as a combustion modification NO_x control technique. In this process, natural gas is injected into a furnace reburn zone downstream from the cyclone burners. The injection of additional fuel creates a fuel-rich zone in which NO_x from the cyclone burners is converted to molecular nitrogen and water vapor. Additional air is injected downstream of the reburn zone to complete the combustion of unburned fuel. Flue gas recirculation may be employed to facilitate mixing of natural gas with the flue gas and penetration of natural gas into the furnace.

Parametric tests for natural gas reburning aplied to a 108 MW electric output (MWe) cyclone boiler using 18 percent natural gas injection and FGR showed that NO_x emissions were reduced to approximately 300 ppm (at 3 percent O_2), corresponding to a 58 percent reduction efficiency.[62] However, the reburn system resulted in an unacceptable amount of slag build-up on the near wall of the secondary furnace. The use of a water-cooled natural gas injection system in lieu of the FGR system eliminated the excess slag build up but NO_x reduction efficiencies dropped to 46 to 48 percent, based on preliminary testing.

2.4.2.3 Fluidized Bed Combustion. Fluidized bed combustion is often considered a combustion modification for SO_2 control because FBC can sometimes be retrofit to conventional combustors and boilers. Limestone or dolomite added to the bed is calcined to lime and reacts with SO_2 to form calcium sulfate. Bed materials can also effectively capture trace metals. Bed temperatures are typically maintained between 760 and 870 °C (1400 to 1600 °F) to promote the sulfation reaction and to prevent ash fusion. Particulate matter emitted from the boiler is generally captured in a cyclone and recirculated or sent to disposal. Additional particulate control equipment, such as an ESP or baghouse, may be used after the cyclone to further reduce particulate emissions.

2.4.3 Post-Combustion Control

2.4.3.1 Particulate Matter Control. The post-combustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more of the following particulate control devices:

- Electrostatic precipitator (ESP),
- Fabric filter (or baghouse),
- Wet scrubber,
- Cyclone or muliclone collector, or
- Side stream separator.

Filterable particulate emissions can be controlled to various levels by all of these devices. Cyclones, ESPs, and fabric filters have little effect on measured condensible particulate matter (CPM) because they are generally operated at temperatures above the upper limit of the front-half of EPA Method 5 [135°C (275°F)]. Most CPM would remain vaporized and pass through the control device. Wet scrubbers, however, reduce the gas stream temperature so they could theoretically remove some of the CPM.

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes. Application of an ESP should have no adverse effect on combustion system performance.[49] The operating parameters that influence ESP performance include:

- Fly ash mass loading,
- Particle size distribution,
- Fly ash electrical resistivity, and
- Precipitator voltage and current.

Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 micron) and coarse particles (greater than 10 microns).[50] These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 microns.

Fabric filtration has been widely applied to coal combustion sources since the early 1970's. A fabric filter (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Bag materials, such as fiberglass, Nomex,™ or Teflon™ are selected based on operating temperature, particle abrasiveness, and acid gas content in the flue gases. Woven, non-woven (felted), and texturized filament fabrics are chosen based on collection efficiency and cleanability requirements.

The particulate removal efficiency of fabric filters is dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include:

- Particle size distribution,
- Particle cohesion characteristics, and
- Particle electrical resistivity.

Operational parameters that affect fabric filter collection efficiency include:

- Air-to-cloth ratio (A/C),
- Operating pressure loss,
- Cleaning sequence,

- Interval between cleaning,
- Cleaning method, and
- Cleaning intensity.

In addition, fabric properties affect the particle collection efficiency and size distribution:

- Structure of fabric
- Fiber composition
- Bag properties

In fabric filtration, both the collection efficiency and the pressure drop across the bag surface increase as the dust layer on the bag builds up. The method and frequency of bag cleaning determines the overall collection performance and pressure drop as well as the bag life. Cleaning processes include mechanical shaking, reverse-flow, and pulse-jet. Mechanical shaking and reverse-flow systems require lower air to cloth (A/C) ratios (2 to 3 rather than 6 to 12 for pulse jet) and are typically found in the electric utility industry, whereas pulse-jet types are used across most of the industrial and commercial size spectrum. There is increased interest in pulse-jet baghouses in the very large systems because of the equipment size advantage. Emission tests conducted on an industrial spreader stoker equipped with a reverse-flow fabric filter have shown fractional efficiencies as high as 99.9 percent for particles in the 0.02 to 2 micron size range.[51] Other reported test data for seven industrial boilers equipped with baghouses showed controlled PM emissions ranging from 4.1 to 15 ng/J (0.010 to 0.035 lb/million Btu) and fractional efficiencies of 99.7 to 99.9+ percent.[52]

The above tests indicate that fabric filter performance is not significantly affected by boiler design type or size. It should be noted that most bag materials will develop holes or leak paths due to flex abrasion wear, hot embers ("sparklers"), or failure of attachment points. Very small leaks can substantially diminish the collection efficiency of a baghouse system, particularly in the size range below 10 microns. Therefore, careful design and an established maintenance program are important for continued performance at the specified levels.

Wet scrubbers, including venturi and flooded disc scrubbers, tray or tower units, turbulent contact absorbers, or high pressure spray impingement scrubbers are applicable for PM as well as SO_2 control on coal-fired combustion sources. One disadvantage of using scrubbers for PM control is the disposal requirements of the resulting wet sludge as opposed to the dry product as produced by ESPs, fabric filters, or cyclone collectors. Tray tower units are best suited for SO_2 control and are effective only for particles greater than 1 micron in diameter. Venturi type scrubbers are effective down to the submicron range. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure. Reported fractional efficiencies for a venturi scrubber range between 95.00 and 99.89 percent for a 2 micron particle.[53] Corresponding pressure drops ranged from 2 to 10 kPa (8 to 40 inches of water).

Cyclone separators can be installed singly, in series, or grouped as in a multi-cyclone or multiclone collector. These devices are referred to as mechanical collectors because they do not rely on electrical, liquid, or barrier principles for removal of PM from a gas stream. The collection efficiency of a mechanical collector depends strongly on the effective aerodynamic particle diameter. Although these devices will reduce PM emissions from coal combustion, they are relatively ineffective for collection of PM-10. Mechanical collectors are often used as a precollector upstream of an ESP, fabric filter, or wet scrubber so that these devices can be specified for lower particle loadings to reduce capital and/or operating costs. Mechanical collectors are designed for a specified range of gas flows. Because the available collection efficiencies for a given collector depend on inlet velocity, these devices are not effective for a combustion source which typically operates over wide load ranges. The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multi-cyclone and a small pulse-jet baghouse to more efficiently collect small diameter particles that are difficult to capture by a mechanical collector alone. Most applications to date for side-stream separators have been on small stoker boilers.

Atmospheric fluidized bed combustion (AFBC) boilers may tax conventional particulate control systems. The particulate mass concentration exiting AFBC boilers is typically 2 to 4 times higher than pulverized coal boilers[54]. Atmospheric FBC particles are also, on average, smaller in size, irregularly shaped with higher surface area and porosity relative to pulverized coal ashes. The effect is a higher pressure drop.

The AFBC ash is more difficult to collect in ESPs than pulverized coal ash because AFBC ash has a higher electrical resistivity and the use of multiclones for recycling, inherent with the AFBC process, tends to reduce exit gas stream particulate size[54].

2.4.3.2 SO_2 Control. Commercialized post-combustion flue gas desulfurization (FGD) uses an alkaline reagent to absorb SO_2 in the flue gas and produces a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream particulate control devices as described in Section 2.4.3.1. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable such that the reagent material can be treated and reused, or are non-regenerable in which all waste streams are de-watered and discarded. Table 2-7 summarizes commercially available post-combustion SO_2 control technologies.

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste-water discharges, and produce saleable sulfur product.[36] Some of the current non-regenerable calcium based processes can, however, produce a saleable gypsum product.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables.

The lime and limestone scrubbing process uses a slurry of calcium oxide (CaO) or limestone ($CaCO_3$) to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods have been demonstrated.[53] The process produces a calcium sulfite and calcium sulfate mixture. Calcium sulfite and calcium sulfate crystals precipitate in a hold tank. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slip stream from the hold tank is sent to a solid-liquid separator to remove precipitated solids. The waste solids, typically 35 to 70 weight percent solids, are generally disposed of by ponding or landfill.

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs; however, these systems have been installed on industrial boilers up to 125 MW (430 million Btu/hr) thermal input.[14] SO_2 removal efficiencies of up to 96.2 percent have been demonstrated.[53] Because the SO_2 removal efficiency can vary during load swings and process upsets, a long term mean efficiency of at least 91 percent is necessary to comply with the 90 percent NSPS reduction requirement based on a 30-day rolling average. The operation of the scrubber is characterized by a low liquid-to-gas ratio [1.3 to 3.4 l/m^3 (10 to 25 gal/ft^3)] and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. The scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts.

The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. Most of the effluent from the sodium scrubber is recycled back to the scrubber, but a slipstream is withdrawn and reacts with lime or limestone in a regeneration reactor. The regeneration reactor effluent is sent to a thickener where the solids are concentrated. The overflow is sent back to the system while the underflow is further concentrated in a vacuum filter (or other device) to about 50 percent solids content. The solids are washed to recover soluble sodium compounds which are returned to the scrubber. Performance data indicate average SO_2 removal efficiencies of 90 to 96 percent.[14] However, initial reports of long-term operating histories with dual alkali scrubbing have indicated system reliability averages of only slightly higher than 90 percent.[54]

Spray drying is a dry scrubbing approach to FGD. The technology is best suited for low to medium sulfur coals with sulfur contents up to 3 percent, but may be applied to higher sulfur-content coals. A solution or slurry of alkaline material is sprayed into a reaction vessel as a fine mist and contacted with the flue gas for a relatively long period of time (5 to 10 seconds). The SO_2 reacts with the alkali solution or slurry to form liquid phase salts. The slurry is dried by the hot flue gas to about one percent free moisture. The dried material continues to react with SO_2 in the flue gas to form sulfite and sulfate salts. The spray dryer solids are entrained in the flue gas and carried out of the dryer to a particulate control device such as an ESP or baghouse. Systems using a baghouse for particulate removal report additional SO_2 capture across the baghouse.

Spray drying is a relatively new FGD technology and extensive large-scale commercial experience is limited. Vendors have offered commercial guarantees of up to 90 percent capture on low sulfur (less than 2 percent) coal.[14] Pilot data on calcium-based sorbents have also showed SO_2 reduction efficiencies of 90 percent.[14] Spray drying with sodium-based sorbents should produce greater removal efficiencies due to the greater reactivity of sodium hydroxide or sodium carbonate compared with lime.

A number of dry and wet sorbent injection technologies are under development to capture SO_2 in the furnace, the boiler sections, or ductwork downstream of the boiler. These technologies are generally designed for retrofit applications and are well suited for coal combustion sources requiring moderate SO_2. There are commercial applications of furnace sorbent injection in Europe; however, the technologies are not yet commercialized in the U.S. The objectives for SO_2 removal efficiencies are between 25 and 50 percent.[36]

2.4.3.3 <u>NO_x Control</u>. The injection of ammonia (NH_3)- or urea-based reagents into the furnace or flue gas path for NO_x control is considered to be post- combustion control. This process, known as Selective Non-Catalytic Reduction (SNCR), is seeing some commercial application, primarily for industrial FBC boilers in California. In bubbling bed FBCs, the reagent is injected above the bed in the freeboard space. In circulating bed FBCs, injection occurs just prior to, or sometimes within, the first stage cyclone separator.

The NO_x reduction reactions occur in a relatively narrow temperature window between 920 and 1030 °C (1700 to 1900 °F). Because of the typically limited residence times available in this temperature range, the reagent must be injected at high velocity or with steam or air assist in order to achieve good mixing. Poor quality mixing or excessive reagent use results in emissions of ammonia (slip) in the flue gas. Demonstrated efficiencies for NO_x reduction range from 30 to 50 percent for bubbling bed FBCs, and up to 80 percent for circulating bed FBCs at NO_x/NH_3 molar ratios between 2 and 4.[55] Reduction efficiencies are apparently higher for circulating FBCs because of the residence time and intense mixing available in the cyclone.

TABLE 2-1. U.S. COAL CONSUMPTION BY SECTOR in 1990[2]

Sector	Total Consumption, 10^3 metric tons (10^3 short tons)
Electric Utility	701,759 (773,549)
Industrial (Excluding Coke Plants)	69,246 (76,330)
Residential/Commercial	6,100 (6,724)
Total For All Sectors	777,105 (856,603)

TABLE 2-2. BOILER USAGE BY SECTOR

Sector	Capacity, MW	Boiler type	Application
Utility	>100	Watertube	Electricity Generation
Industrial	10-100	Watertube	Electricity Generation
		Watertube	Process Steam
		Watertube	Space Heating
		Firetube	Process Steam
		Firetube	Space Heating
Commercial	0.5-10	Watertube	Space Heating
		Firetube	Space Heating
		Cast Iron	Space Heating
Residential	<0.5	Cast Iron	Space Heating

TABLE 2-3. TOTAL 1985 EMISSIONS FROM COAL COMBUSTION BY USE SECTOR[13]

Sector	Annual emissions, 10^3 metric tons (10^3 short tons)			
	SO_2	NO_x	TSP[a]	VOC
Residential	27 (30)	1.8 (2)	10 (11)	7 (8)
Commercial/ Institutional	126 (139)	26 (29)	15 (17)	0.9 (1)
Industrial	1,478 (1,629)	513 (565)	102 (112)	5 (6)
Electric Generation	13,427 (14,801)	5,084 (5,604)	432 (476)	26 (29)
Total	20,998 (23,146)	18,635 (20,541)	7,605 (8,383)	20,024 (22,073)

[a] Total suspended particulate.

TABLE 2-4. NSPS SUMMARY FOR FOSSIL FUEL-FIRED BOILERS

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart D	>73 (>250)	Gas	43 (0.10)	NA	86 (0.20)
Industrial- Utility		Oil	43 (0.10)	340 (0.80)	129 (0.30)
Commence construction after 8/17/71		Bit./Subbit. Coal	43 (0.10)	520 (1.20)	300 (0.70)
Subpart Da Utility	>73 (>250)	Gas	13 (0.03 [NA]	340 (0.80) [90][a]	86 (020) [25]
Commence construction after 9/18/78		Oil	13 (0.03) [70]	340 (0.80) [90][a]	130 (0.30) [30]
		Bit./Subbit. Coal	13 (0.03) [99]	520 (1.20) [90][b]	260/210[c] (0.60/0.50) [65/65]
Subpart Db	>29 (>100)	Gas	NA[d]	NA[d]	43[f] (0.10)
Industrial- Commercial- Institutional		Distillate Oil	43 (0.10)	340[i] (0.80) [90]	43[f] (0.10)
Commence construction after[k] 6/19/84		Residual Oil	(Same as for distillate oil)	(Same as for distillate oil)	130[g] (0.30)
		Pulverized Bit./Subbit. Coal	22[e] (0.05)	520[e] (1.20) [90]	300 (0.70)
		Spreader Stoker & FBC	22[e] (0.05)	520[e] (1.20) [90]	260 (0.60)
		Mass-Feed Stoker	22[e] (0.05)	520[e] (1.20) [90]	210 (0.50)
Subpart Dc	2.9 - 29 (10 - 100)	Gas	-[h]	-	-
Small Industrial- Commercial- Institutional		Oil	-[h,i]	215 (0.50)	-
Commence construction after 6/9/89		Bit. & Subbit. Coal	22[i,j] (0.05)	520[j] (1.20 [90]	-

Footnotes For Table 2-4

[a]Zero percent reduction when emissions are less than 86 ng/J (0.20 lb/MMBtu).
[b]70 percent reduction when emissions are less than 260 ng/J (0.60 lb/MMBtu).
[c]The first number applies to bituminous coal and the second to subbituminous coal.
[d]Standard applies when gas is fired in combination with coal, see 40 CFR 60, Subpart Db.
[e]Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Db.
[f]For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 86 ng/J (0.20 lb/MMBtu).
[g]For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 170 ng/J (0.40 lb/MMBtu).
[h]Standard applies when gas or oil is fired in combination with coal, see 40 CFR 60, Subpart Dc.
[i]20 percent capacity limit applies for heat input capacities of 8.7 Mwt (30 MMBtu/hr) or greater.
[j]Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Dc.
[k]Additional requirements apply to facilities which commenced construction, modification, or reconstruction after 6/19/84 but on or before 6/19/86 (see 40 Code of Federal Regulations Part 60, Subpart Db).
[l]215 ng/J (0.50 lb/million Btu) limit (but no percent reduction requirement) applies if facilities combust only very low sulfur oil (< 0.5 wt. % sulfur).

TABLE 2-5. COMMERCIALLY AVAILABLE NO_x CONTROL TECHNIQUES FOR PULVERIZED COAL-FIRED BOILERS

Control technique	Description of technique	Effectiveness of control, % NO_x reduction	Range of application	Commercial availability/R&D status	Comments
Low Excess Air (LEA)	Reduction of combustion air	0-25 (avg. 9)	Excess oxygen reduced to 5.2% on the average.	Available.	Added benefits of technique include increase in boiler efficiency, limited by increase in CO. HC and smoke emissions.
Burners out of service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	27-39 (avg. 33)	Applicable only for boilers with minimum of 4 burners.	Available. However, extensive engineering work necessary before implementation.	Limited by the number of burners available. Load reduction required in most cases. Possible increased slagging, corrosion.
Overfire air injection (OFA)	Secondary air from OFA ports above fuel rich firing burners.	5-30	Burner stoichiometry as low as 100%.	Commercially offered but not demonstrated for industrial size boilers.	Requires installation of OFA ports, etc. Possible increased slagging, corrosion.
Flue gas recirculation (FGR)	Recirculation of flue gas to burner windbox.	0-20	Up to 25% of the flue gas recirculated.	Not offered because relatively ineffective.	Requires installation of FGR ducts, fan, etc. Can cause combustion instability. Burner windbox may need extensive modifications.
Low NO_x burner (LNB)[a]	New burner designed utilizing controlled air-fuel mixing.	45-60	Prototype LNB limited to size ranges above 29 MW (100×10^6 Btu/h)	Still in the development stage. Prototype LNB available from major boiler mfrs.	Active R&D efforts underway.
Ammonia injection (SNCR)	Injection of NH_3 in convective section of boiler.	40-60	Limited by furnace geometry. NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not demonstrated.	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.
Reduced load (RL)	Reduction of fuel and air flow to the boiler.	Varies from 45% reduction to 4% increase in NO_x	Applicable to all boilers. Load can be reduced to 25% of capacity.	Available now but not implemented because of adverse operational impacts.	Load reduction often not effective because of increase in excess O_2. Best implemented with increase in furnace size for new boilers.

[a]Low NO_x burners are the minimum control technology required for NO_x emissions from PC-fired utility boilers.

TABLE 2-6. COMMERCIALLY AVAILABLE NO_x CONTROL TECHNIQUES FOR STOKER COAL-FIRED BOILERS

Control technique	Description of technique	Effectiveness of control, % NO_x reduction	Range of application	Commercial availability/R&D status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed	5-25	Excess oxygen limited to 5-6% minimum.	Available now but need R&D on lower limit of excess air.	Danger of overheating grate, clinker formation, corrosion, and high CO emissions.
Staged combustion (LEA + OFA)	Reduction of undergrate air flow and increase of overfire air flow.	5-25	Excess oxygen limited to 5% minimum.	Most stokers have OFA ports as smoke control devices but may need better air flow control devices.	Need research to determine optimal location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion, and high CO emission can occur if undergrate airflow is reduced below acceptable level as in LEA.
Load reduction (LR)	Reduction of coal and air feed to the stoker.	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease).	Has been used down to 25% load.	Available.	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency.
Reduced air preheat (RAP)	Reduction of combustion air temperature.	8	Combustion air temperature reduced from 473K to 453K.	Available now if boiler has combustion air heater.	Not a desirable technique because of loss in boiler efficiency.
Ammonia injection	Injection of NH_3 in convective section of boiler.	40-60 (from gas- and oil-fired boiler experience).	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not yet demonstrated.	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.

TABLE 2-7. POST COMBUSTION SO_2 CONTROLS FOR COMBUSTION SOURCES

Control technology	Process	Available control efficiencies	Remarks
Wet Scrubber	Lime/Limestone	80 - 95+%	Applicable to high sulfur fuel, Wet sludge product
	Sodium Carbonate	80 - 98%	1.5 - 125 MWt [5 - 430 million Btu/hr (MMBtu/hr) typical application range, High reagent costs
	Magnesium Oxide/ Hydroxide	80 - 95+%	Can be regenerated
	Dual Alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray Drying	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, Produces dry product
Furnace Injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct Injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several R&D and demonstration projects underway, Not yet commercially available in the U.S.

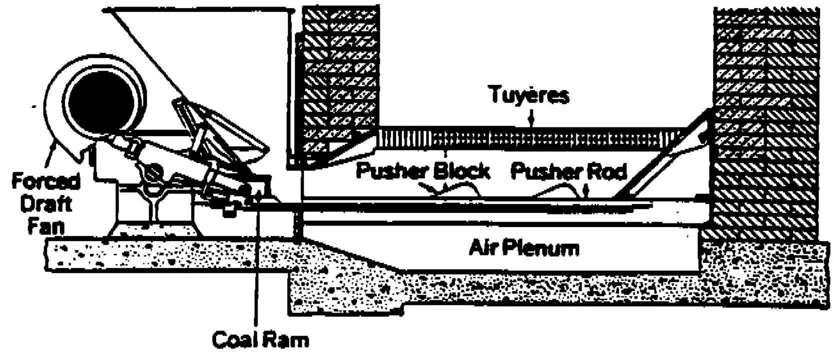

Figure 2-1. Single-retort horizontal-feed underfeed stoker.[1]

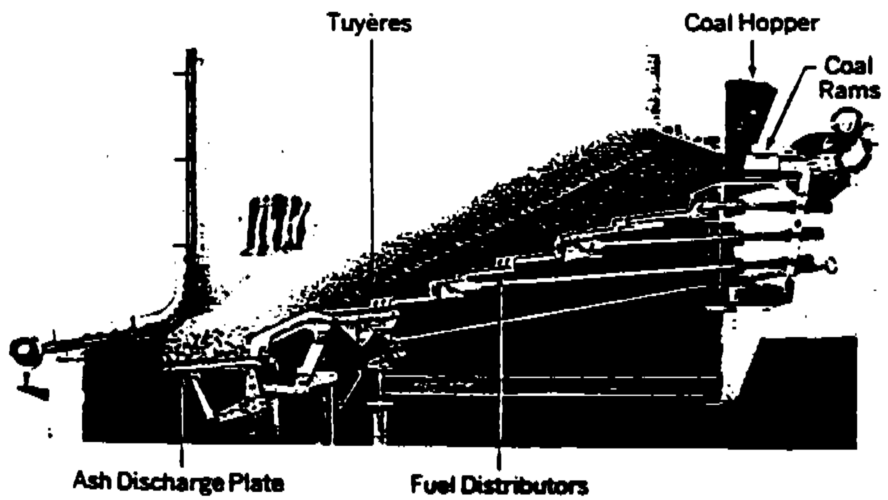

Figure 2-2. Multiple-retort gravity-feed underfeed stoker.[2]

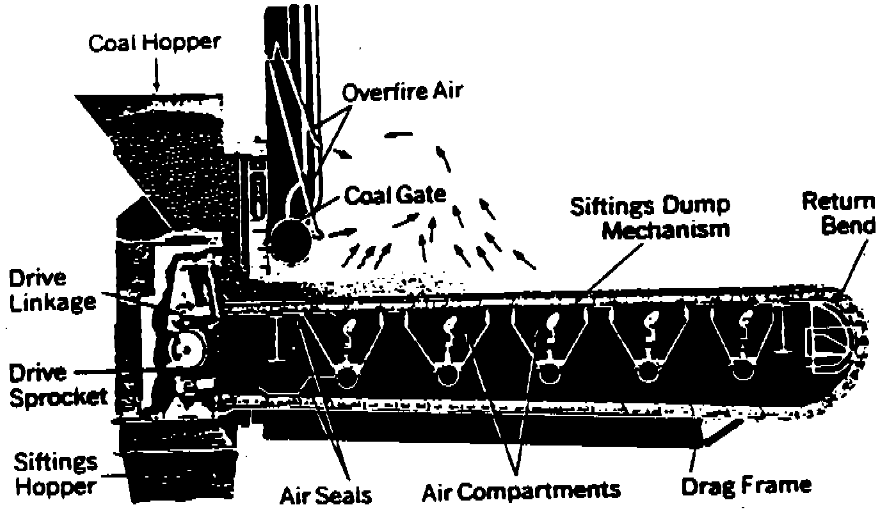

Figure 2-3. Overfeed chain-grate stoker.[1]

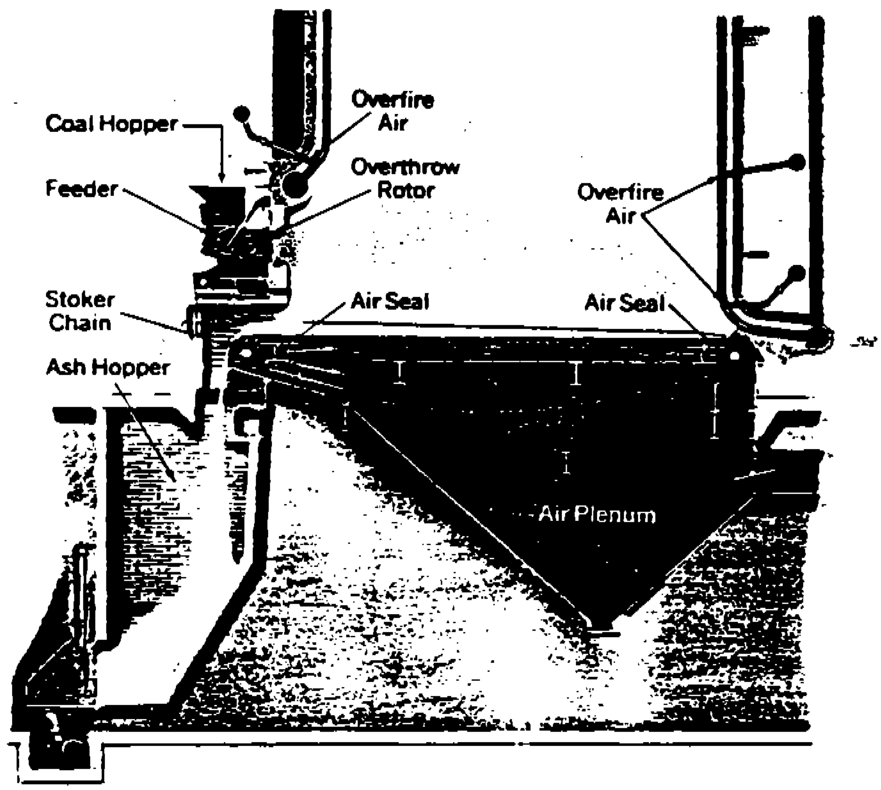

Figure 2-4. Spreader stoker.[1]

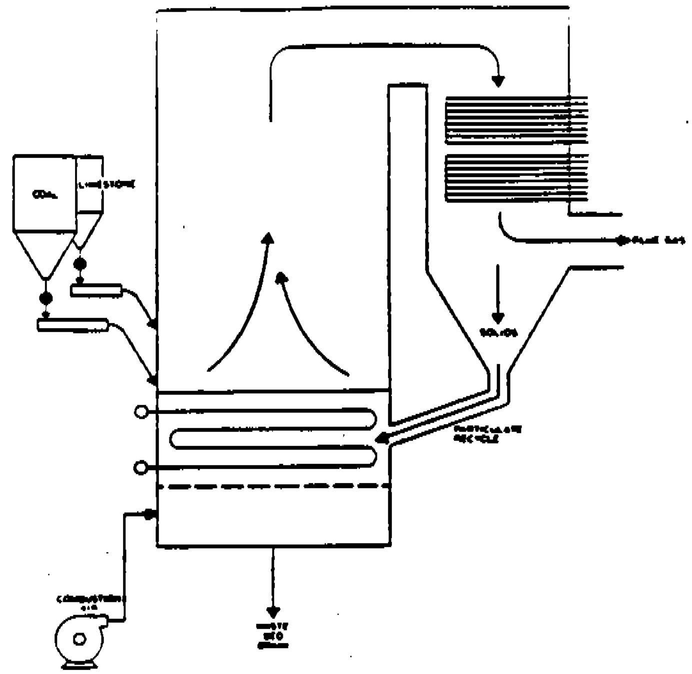

Figure 2-5. Bubbling FBC schematic.[56]

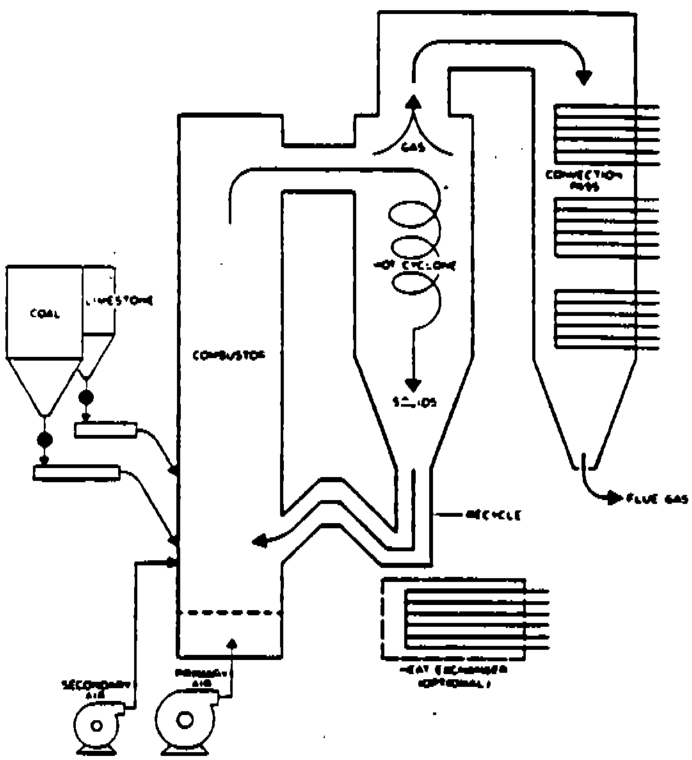

Figure 2-6. Circulating FBC schematic.[56]

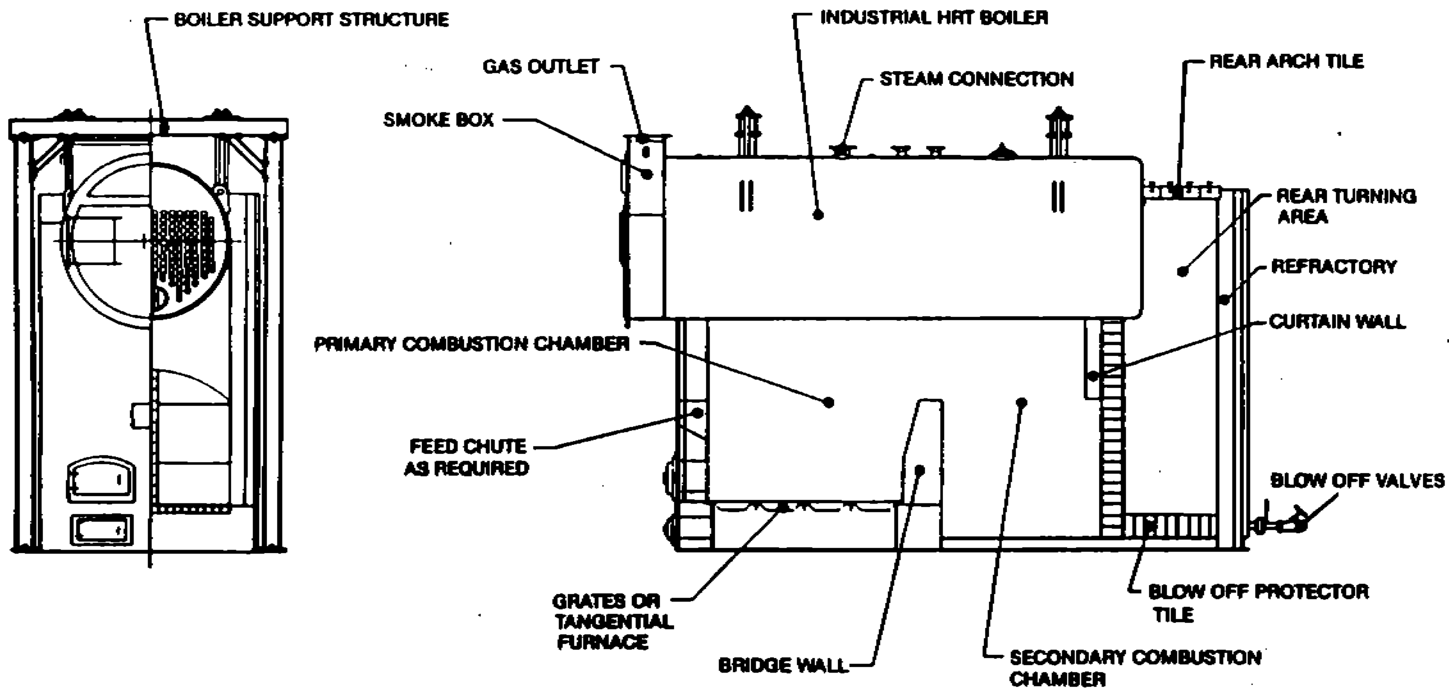

Figure 2-7. Two-pass HRT boiler.[57]

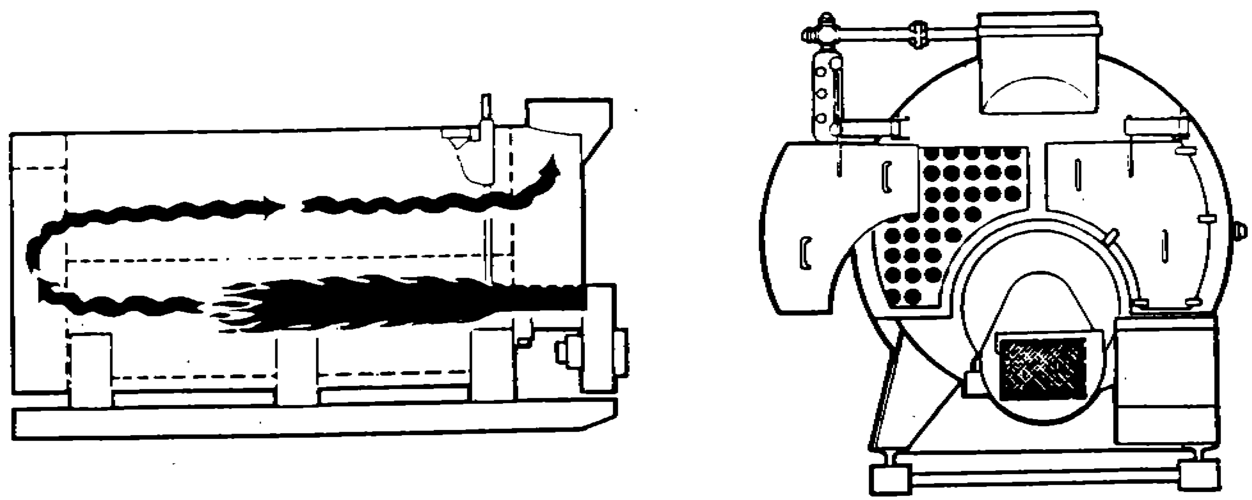

Figure 2-8. Firetube boiler.[58]

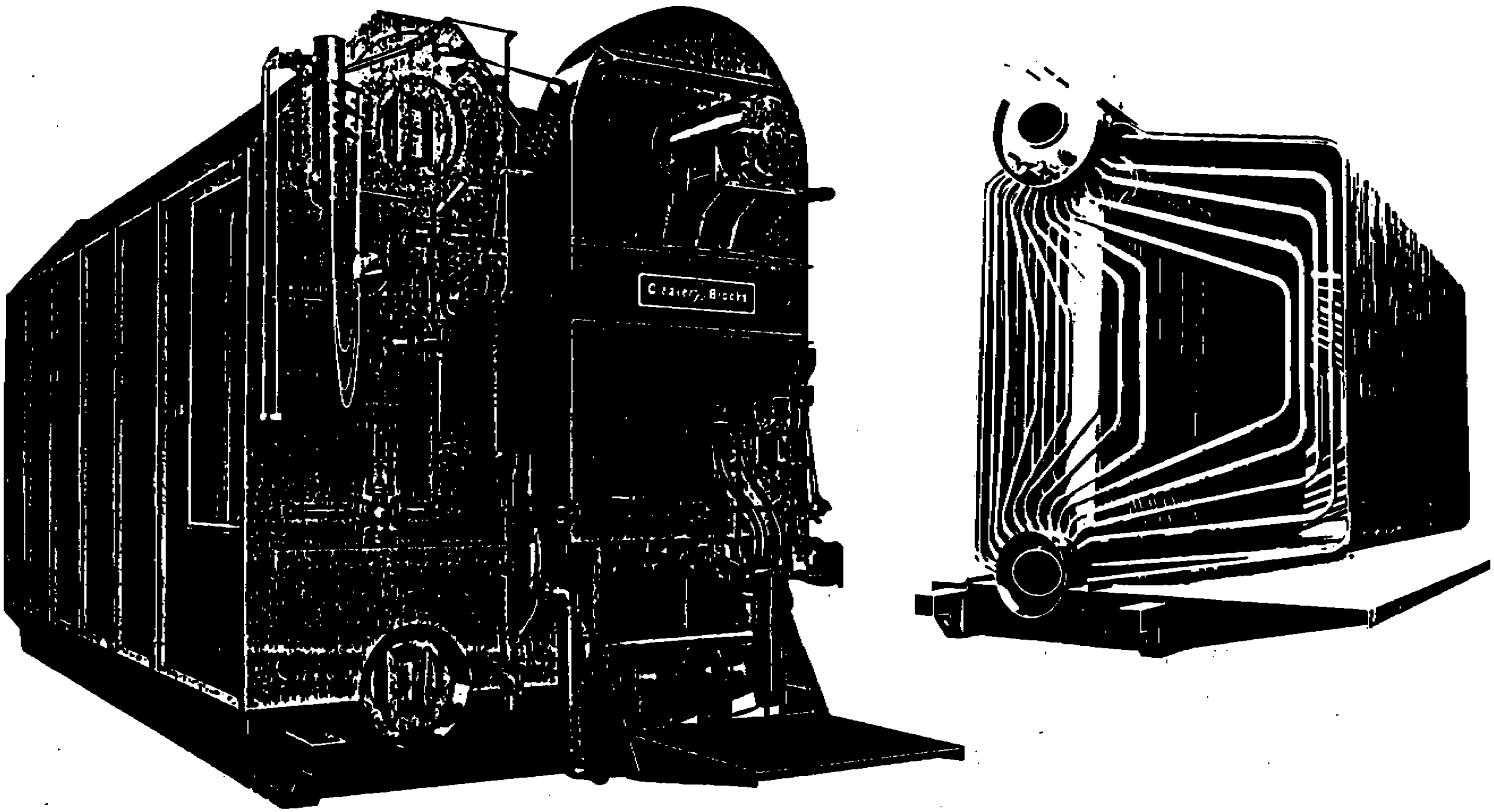

Figure 2-9. D-type packaged boiler and watertubes.[59]

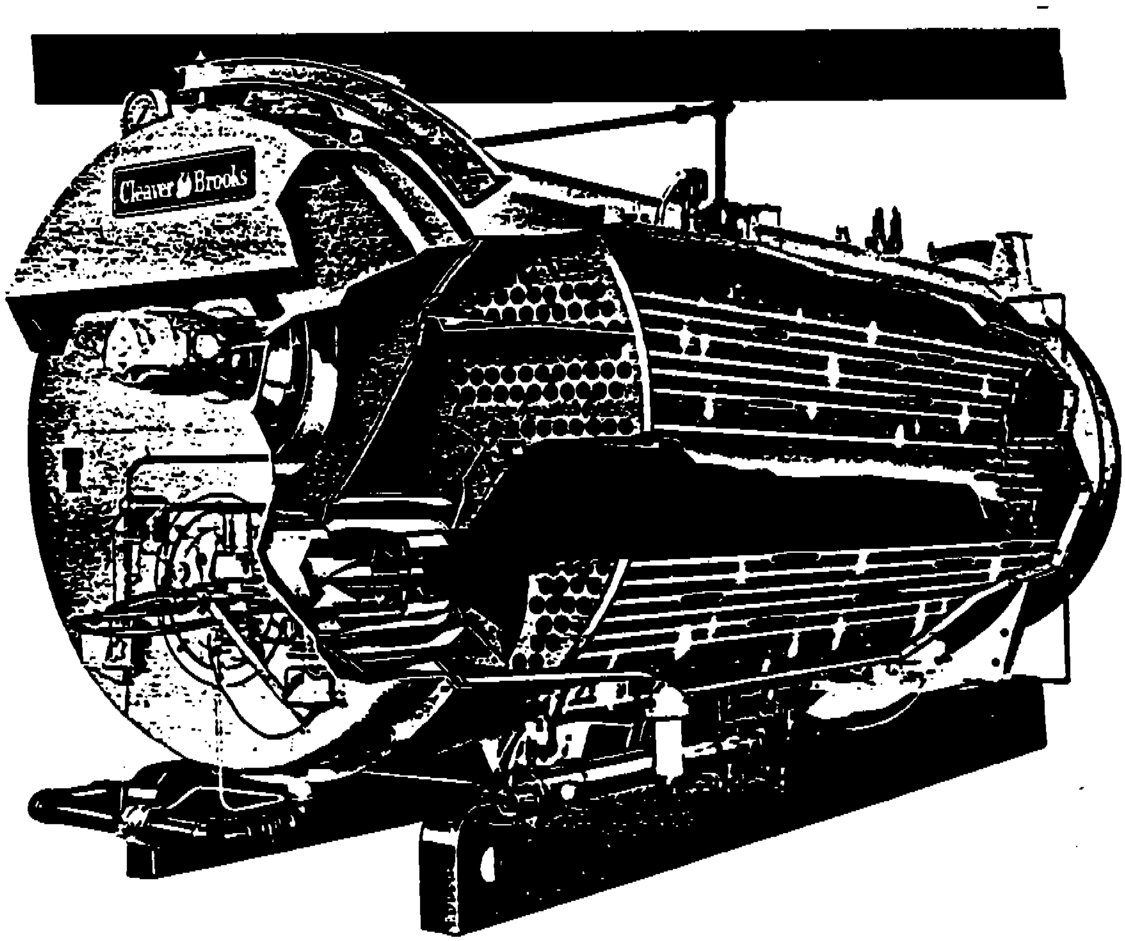

Figure 2-10. Four-pass scotch boiler.[60]

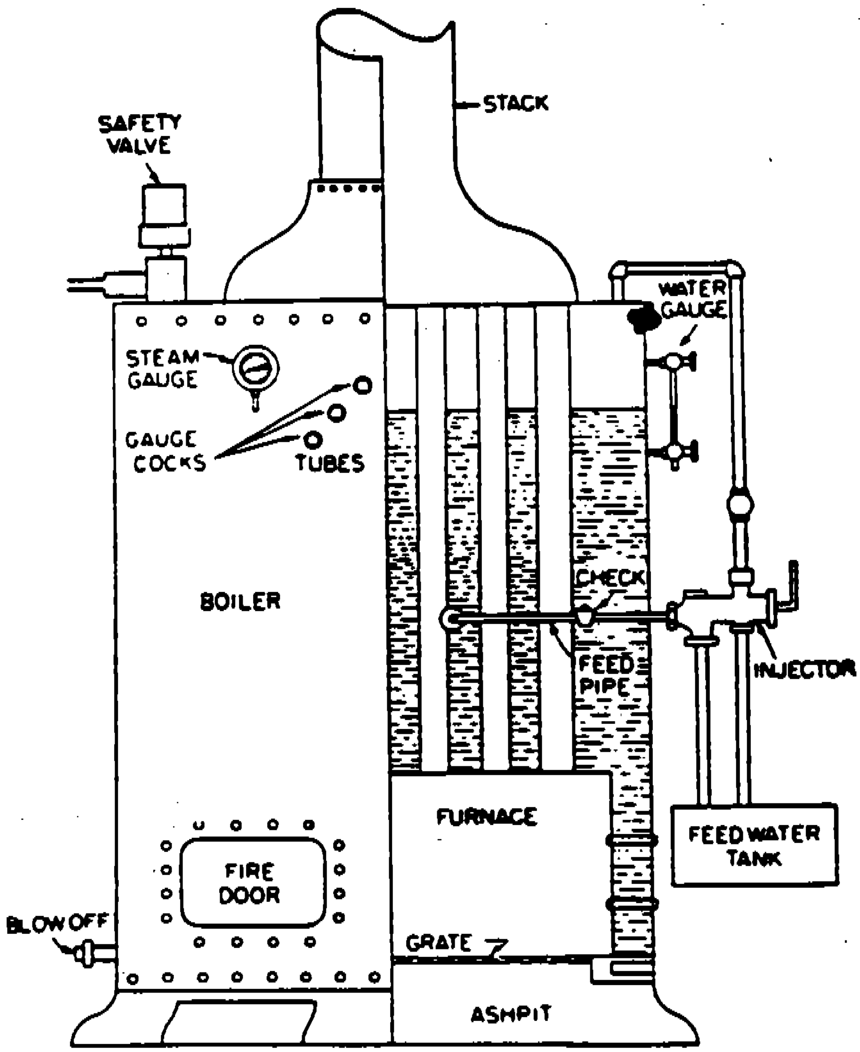

Figure 2-11. Exposed-tube vertical boiler.[3]

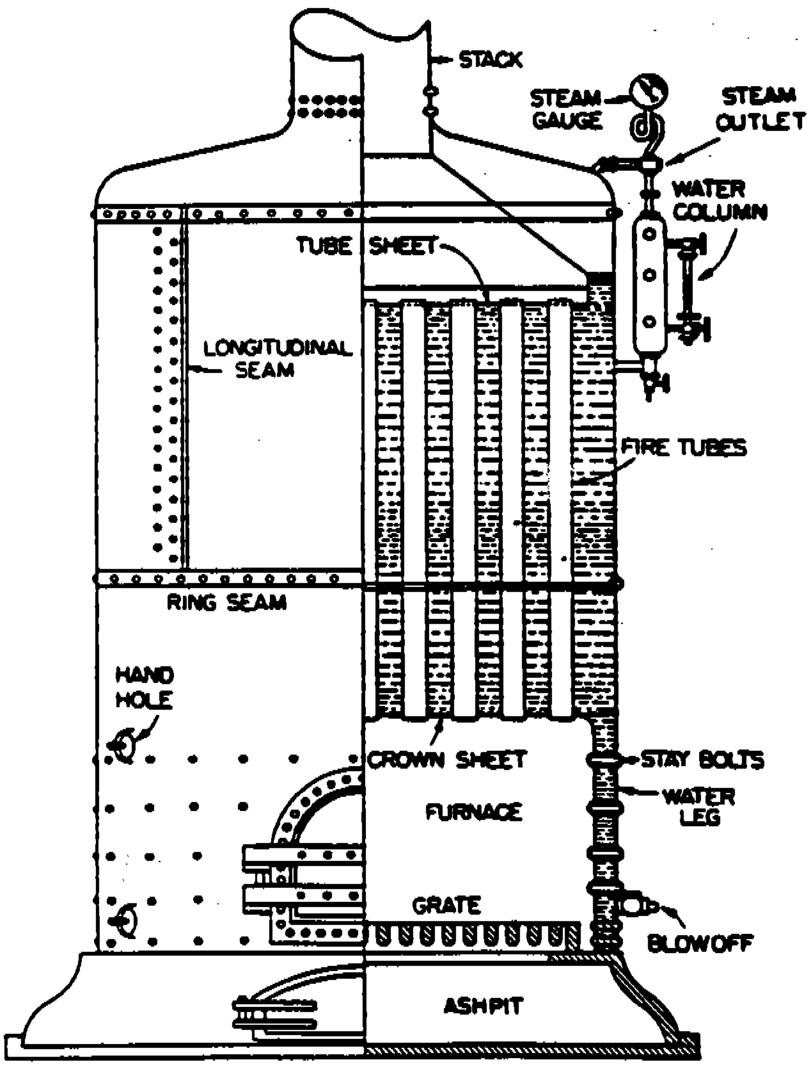

Figure 2-12. Submerged-tube vertical boiler.[3]

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3. GENERAL EMISSION DATA REVIEW AND ANALYSIS PROCEDURE

3.1 CRITERIA POLLUTANTS

3.1.1 Literature Search

The first step in this revision and update involved an extensive literature search to identify sources of criteria (non-criteria) pollutant emissions data associated with bituminous and subbituminous coal combustion. This search included:

- Existing AP-42 background files;
- Files maintained by EPA's Emission Standards Division and Emission Factor and Methodologies Section of the Office of Air Quality Planning and Standards (OAQPS);
- PM-10 documents;
- NSPS Background Information Documents;
- Various EPA emissions assessment and control technology reports;
- National Technical Information Service (NTIS) holdings;
- Reports from industry organizations including the Electric Power Research Institute (EPRI) and API;
- Various on-line computerized data bases and search services;
- EPA contractor reports; and
- Contractor in-house files.

A summary of these information sources is given in Table 3-1.

3.1.2 Literature Evaluation

To reduce the large amount of available literature to a final group of references pertinent to this task, the following general criteria were used:

1. Emissions data must be from a well documented reference;

2. The referenced study must contain results based on more than one test run; and

3. The report must contain sufficient data to evaluate the testing procedures and source operating conditions.

Employing these criteria in a thorough review of the reports, documents, and information, a final set of reference materials was compiled. The data contained in this final set of references were then subjected to a thorough quality and quantity evaluation to determine their suitability for use in emission factor calculations. Checklists were employed to facilitate and document this evaluation. The completed checklists were placed in the background files for this AP-42 update. Data with the following characteristics were excluded from further consideration:

1. Test series averages reported in units that cannot be converted to the selected reporting units;

2. Test series representing incompatible test methods (i.e., comparison of EPA Method 5 front-half with EPA Method 5 front-and back-half);

3. Test series of controlled emissions for which the control device is not specified;

4. Test series in which the source or control process is not clearly identified and described; and

5. Test series in which it is not clear whether the emissions were measured before or after the control device.

Data sets that were not excluded were assigned a quality rating. The rating system used was that specified in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). The data were rated as follows:

A: Multiple tests performed on the same source using sound methodology and reported in enough detail for adequate validation. These tests are not necessarily EPA reference method tests, although such reference methods are preferred and certainly to be used as a guide.

B: Tests that were performed by a generally sound methodology but lack enough detail for adequate validation.

C: Tests that were based on an untested or new methodology or that lacked a significant amount of background data.

D: Tests that were based on a generally unacceptable method but may provide an order-of-magnitude value for the source.

The following criteria were used to evaluate source test reports for sound methodology and adequate detail:

1. Source operation. The manner in which the source was operated is well documented in the report. The source was operating within typical parameters during the test.

2. Sampling procedures. The sampling procedures conformed to generally acceptable methodology. If actual procedures deviated from accepted methods, the deviations are well documented. When this occurred, an evaluation was made of the extent such alternative procedures could influence the test results.

3. Sampling and process data. Adequate sampling and process data are documented in the report. Many variations can occur unnoticed and without warning during testing. Such variations can induce wide deviations in sampling results. If a large spread between test results cannot be explained by information contained in the test report, the data are suspect and given a lower rating.

4. Analysis and calculations. The test reports contain original raw data sheets. The nomenclature and equations used were compared to those (if any) specified by EPA to establish equivalency. The depth of review of the calculations was dictated by the reviewer's confidence in the ability and conscientiousness of the tester, which in turn was based on factors such as consistency of results and completeness of other areas of the test report.

In most cases, emissions data were obtained from original source assessment or source test reports. In addition, there is a large body of data that have been summarized by EPA in background documents, emissions assessment reports, and control technology reports.

These reports were used to support regulatory development efforts, control technology determinations, permitting, and for setting further research priorities.

Because of their intended usage, the data contained in these reports have been produced under rigorous quality assurance/quality control procedures and, before being summarized, have undergone data quality review by EPA. Because of these procedures, emissions data were taken directly from the summary reports for input into the emission factor calculations. The data taken from these reports were assigned a "B" quality rating. This rating was given to reflect the fact that testing followed EPA reference methods or otherwise sound methodology; however, the summary reports do not contain enough raw data to verify the data reduction calculations. To supplement the summary report information, orders were placed for copies of the original test reports cited in the summary reports. These test reports, when received, were placed in the background files.

3.1.3 Emission Factor Quality Rating

In each AP-42 section, tables of emission factors are presented for each pollutant emitted from each of the emission points associated with the source. The reliability or quality of each of these emission factors is indicated in the tables by an overall Emission Factor Quality Rating ranging from A (excellent) to E (poor). These ratings incorporate the results of the above quality and quantity evaluations on the data sets used to calculate the final emission factors. The overall Emission Factor Quality Ratings are described as follows:

A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough so that variability within the source category population may be minimized.

B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are noted in the emissions factor table.

E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of these factors are always noted.

The use of these criteria is somewhat subjective and depends to an extent on the individual reviewer. Details of the rating of each candidate emission factor are provided in Chapter 4 of this report.

3.2 SPECIATED VOCs

3.2.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of speciated VOC emissions data associated with coal fired boilers. Some specific areas of search include Tennessee Valley Authority, Electric Power Research Institute (EPRI)/PISCES, EPA/Air and Waste Mangement Association (AWMA) Air Toxics Symposia, and Toxic Air Pollutants: State and Local Regulatory Strategies 1989. The details of the literature search are summarized in Table 3-2.

3.2.2 Literature Evaluation

Until recently, little concern existed for VOC speciation on stationary external sources. Nearly all organics sampling was focused on semi-volatile compounds. Reliable methods for volatile organics sampling and analysis to low levels have only been developed since the late 1980's. Therefore, available data for VOC speciation were sparse, limiting this data evaluation essentially to the OAQPS databases, the VOC/PM Speciation Data System (SPECIATE) and the Crosswalk/Air Toxic Emission Factor data base (XATEF), and their references.

3.2.3 Data and Emission Factor Quality Rating

The ratings of emission factors in SPECIATE and XATEF should not be used without first reviewing primary sources of numerical data against the criteria presented in Chapter 3.1. The quality of the data is insufficient to satisfy the requirements for

Western States Petroleum Association (WSPA), the Canadian Electrical Association (CEA), the Ontario Ministry of the Environment and KEMA of the Netherlands.

3.3.2 Literature Evaluation for Air Toxics

The references obtained from the literature search were evaluated for their applicability for generating emission factors. Table 3-3 summarizes the data sources and indicates which sources were used in generating the emission factors and which sources were eliminated from use. The table contains a reference number which corresponds to the list of references provided at the end of this section. The references are evaluated and discussed in greater detail in Section 4.3.1. The criteria used to perform this evaluation are discussed in detail in Section 3.3.3.

3.3.3 Data and Emission Factor Quality Rating Criteria

Emissions data used to calculate emission factors are obtained from many sources such as published technical papers and reports, documented emissions test results, and regulatory agencies such as local air quality management districts. The quality of these data must be evaluated in order to determine how well the calculated emission factors represent the emissions of an entire source category. Data sources may vary from single source test runs to ranges of minimum and maximum values for a particular source. Some data must be eliminated all together due to their format or lack of documentation. Factors such as the precision and accuracy of the sampling and analytical methods and the operating and design specifications of the unit being tested are key in the evaluation of data viability.

The first step in evaluating a data report is to determine whether the source is a primary or secondary source. A primary source is that which reports the actual source test results while a secondary source is one that references a data report. Many of the sources referenced by XATEF, SPECIATE, and the CD ROM are secondary or tertiary sources. Preferably only primary sources were used in the development of emission factors. When there was not time in this work effort to obtain or evaluate the primary sources, data were taken from a secondary reference if it appeared that an adequate evaluation of the data was performed.

The primary source reports are evaluated to determine if sufficient information is included on the device of interest and on any abatement equipment associated with

/ironmental Protection Agency, Generalized Particle Size Distributions in Preparing Size Specific Particulate Emission Inventories, EPA-450/4- Research Triangle Park, North Carolina, 1986.

/ironmental Protection Agency, Technical ?rocedures for Developing mission Factors and Preparing AP-42 Sections - Draft, Research Park, North Carolina, March 1992.

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3.4.3 Data and Emission Factor Quality Rating

Data obtained through the literature search, except that derived from on-line N_2O analysis with gas chromotography/electron capture detection (GC/ECD), were rated C or poorer, because the data were based on untested or new methodology that lacked sufficient background data. A problem has been identified in using grab sampling techniques measuring N_2O emissions from coal combustion. Storing combustion products in grab samples containing SO_2, NO_x and water for periods as short as 1 hour can lead to the formation of several hundred parts per million (ppm) of N_2O where none originally existed. Presented below are some improved methodologies for N_2O sampling and analysis and their relative effects on data quality ratings:

- On-line N_2O analysis with GC/ECD (preferred method)
- Grab samples
  - Removing H_2O - drying the sample reduces the most important reactant, but may not entirely eliminate N_2O formation.
  - Removing SO_2 - scrubbing the sample through NaOH solution.
  - A combination of the two (second preference)

The emission factor for pulverized coal-fired boilers was calculated with B rated data. Of the data reported, eighty percent of the values used to calculate the emission factor were below the detection limit of the analytical instrument. Therefore, the emission factor was assigned a D quality rating.

The emission factor for fluidized bed combustors was developed from D rated test data. Because the data were not recorded with an on-line GC/ECD N_2O analysis and the tested facilities are not representative of the industry, the emission factor received an E rating.

3.5 FUGITIVES

A literature search was conducted on fugitive emissions as described in section 3.1.1. A literature evaluation and data rating was not conducted for coal storage and handling operations, because those fugitive emissions are covered in sub-sections of AP-42 Chapter 11. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive particulate matter emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during transfer operations from silos to trucks or rail cars. Particulate matter emission factors resulting from these operations can be developed using the procedures in AP-42 Chapter 11.

3.6 PARTICLE SIZE DISTRIBUTION

3.6.1 Literature Search

The literature search emphasized filling the perceived gaps in the previous updates. Updates to AP-42 are supposed to report PM-10 emissions as the sum of the in-stack filterable particulate and the organic and inorganic CPM. Upon review of the 1988 AP-42 update of particulate sizing emission data, the largest gap appeared to be the lack of CPM data.

The background files for the 1988 AP-42 update were reviewed. A Dialog data base search was conducted, focussing on reports issued since 1980. Based on the results of the Dialog search, NTIS documents, EPA reports, and conference proceedings were ordered and journal articles were collected. Conference symposia that were searched included the Eighth and Ninth Particulate Control Symposia and the Air and Waste Management Association Conferences for 1988 through 1991.

The following PM-10 "gap filling" documents were examined (with results indicated):

- "PM-10 Emission Factor Listing Developed by Technology Transfer" (EPA-450/4-89-022): The factors presented for bituminous coal came from AP-42.

- "Gap Filling PM-10 Emission Factors for Selected Open Area Dust Sources" (EPA-450/88-003): Not applicable to stationary source combustion.

- "Generalized Particle Size Distributions for Use in Preparing Size Specific Particulate Emission Inventories" (EPA-450/4-86-013): Lists the average collection efficiencies of various particulate control devices for different size fractions. This was the source of the overall collection efficiency estimates for the 1986 PM-10 update of AP-42 Chapter 1.

The following regional EPA offices and state and regional air pollution control boards were contacted:

- EPA Region 2
- EPA Region 3
- EPA Region 4
- EPA Region 5
- California Air Resources Board: Stationary Sources Division, Monitoring and Laboratory Division, and the Compliance Division
- Illinois Air Pollution Control
- New York Air Pollution Control
- New Jersey Air Pollution Control
- Bay Area Air Quality Management District (CA)
- Kern County Air Pollution Control District (CA)
- Stanislaus County Air Pollution Control District (CA)
- San Joaquin County Air Pollution Control District (CA)

The primary source of the particulate size distribution data for the previous AP-42 update was the Fine Particulate Emissions Information System (FPEIS). The FPEIS has not been updated since the previous AP-42 update.

The EPA OAQPS Emissions Monitoring Branch was contacted for test data from method development studies for EPA Method 202.

Contacts were also made with Electric Power Research Institute (EPRI), Wheelabrator Air Pollution Control, Southern Research Institute, and Entropy.

3.6.2 Literature Evaluation

The previous update was reviewed and evaluated. The size distribution data were evaluated by spot-checking the tabulated results against the original FPEIS printouts. If during the literature search, the original test report was uncovered that corresponded to a particular FPEIS printout, the data were compared. The objective of the review was to ensure that the data collected in the 1986 update were ranked and used appropriately.

The previous update was also evaluated with respect to the development of emission factors from the particle size distribution data.

The original FPEIS printouts were also examined. There were two objectives in the reevaluation of the FPEIS printouts:

(1) Ensure that only filterable PM was included in the cumulative percent mass results; and

(2) Search for impinger results to provide CPM emission data.

New literature was evaluated based on the use of appropriate sampling methods and documentation of sufficient process information.

3.6.3 Data Quality Ranking

Data were reviewed and ranked according to the criteria described previously (Ref. 31) and the data evaluation criteria presented for the previous update. Data quality was assessed based on the particle sizing and/or PM-10 measurement method used and the availability of sampling and process data.

For particulate sizing and filterable PM-10 data the following criteria were used:

A - Particle sizing tests performed by cascade impactors or PM-10 measurements performed via Method 201 or 201A. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - Particle sizing tests performed via SASS trains if the sampling flowrate isokinetic value was reported and sufficient operating data were used. Cascade impactor data or Method 201 or 201A data if isokinetics not reported or if isokinetics not within the 90 to 110 percent range.

C - SASS train data if the isokinetics were not reported or if the isokinetics did not fall within the 90 to 110 percent range.

D - Test results based on a generally unaccepted particulated sizing method, such as polarized light microscopy.

Although cascade impactors are generally considered the best available method for measuring particulate size distributions, errors in segregating specific sizes of combustion particles arise from the following:

- Particle bounce and re-entrainment
- Diffusive deposition of fine particles
- Deposition of condensible/adsorbable gases
- Losses to the impactor walls

The effects of such errors are described in "Cascade Impactors in the Chemical and Physical Characterization of Coal-Combustion Aerosol Particles", by John M. Ondov, Chapter 25 of Fossil Fuels Utilization: Environmental Concerns, 1986.

The ranking of data for CPM was based primarily on the methodology. Most CPM source tests have been conducted using the back-half of a Method 5, Method 17 or South Coast methods 5.2 or 5.3 trains. However, these test methods do not require a nitrogen (N_2) purge of the impingers. Without the N_2 purge, dissolved SO_2 remains in the impingers and is included in the inorganic CPM results. This type of CPM data is considered very low quality. In contrast, Method 202 includes a one-hour N_2 purge of the impingers immediately after sampling to remove dissolved SO_2. Therefore Method 202 CPM data should be ranked higher than Method 5 or Method 17 CPM data, even though Method 202 is a relatively new method. The following rankings were selected for CPM data:

A - CPM tests performed via Method 202. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - CPM tests performed via Method 202 but isokinetics not reported or isokinetics not within the 90 to 110 percent range. CPM tests performed via Method 5 or Method 17 or another acceptable EPA Method that does not include an impinger N_2 purge, if the isokinetics were within the 90 to 110 percent range.

C - CPM tests performed via Method 5 or Method 17 or another acceptable EPA Method that does not include an impinger N_2 purge, if the isokinetics were not reported or not within the 90 to 110 percent range.

D - Test results based on a generally unaccepted CPM method.

TABLE 3-1. LITERATURE SEARCH RESULTS

Literature Type	New baseline data	NO_x control information	Particulate control information	SO_x control information
1. AP-42 files	✓	✓	✓	✓
2. ESD Files/ NSPS Background Information Documents	None	✓	✓	✓
3. CTC publications	None	✓	None	None
4. ORD reports	✓	✓	✓	✓
5. NTIS	✓	✓	✓	✓
6. EPRI	None	✓	None	None
7. Contractor in-house documents	✓	✓	✓	✓
8. API	✓	None	None	None

ESD = Emission Standard Division (of EPA)
CTC = Control Technology Center (of EPA)
ORD = Office of Research and Development (of EPA)
NTIS = National Technical Information Service
EPRI = Electric Power Research Institute
API = American Petroleum Institute

TABLE 3-2. SPECIATED VOC LITERATURE SEARCH RESULTS

Literature Type	Remarks
EPA/AWMA Air Toxics Symposia (1988-1990)	No Data
TOXIC AIR POLLUTANTS: State and Local Regulatory Strategies (1989)	Called those states and localities listed in air toxics report. Received some data, but all was criteria data
Contractor in-house documents	No useful data.
Journals	No useful data.
COMPENDEX	No references found.
EPRI/PISCES	Available end of 1992.
Papers	No useful data.

TABLE 3-3. EVALUATION OF AIR TOXICS REFERENCES

Section 3 Reference	Used in update?	Reason	Parameter of Interest
8	No	Not a primary reference. Document references other low quality references.	
9	Yes	Not a primary reference, however, data are presented for use for rough estimates.	POM
10	No	Not a primary reference. Document references 3a.	
10a	No	Data of unacceptable quality to generate emission factors.	
11	No	Not a primary reference. Document references 4a and 4b.	
11a	No	Data not of sufficient quality to generate emission factors or enrichment ratios.	
11b	No	Emission factors units can not be converted to desired units.	
12	No	Fuel mixture is not applicable.	
13	No	Fuel mixture is not applicable.	
14	No	Fuel mixture is not applicable.	
15	No	Data from Reference 4a were sited. These data are of unacceptable quality.	
16	No	Document presents criteria data only.	
17	No	Same as Reference 2.	
18	Yes	Not a primary reference. Data are of sufficient quality for emission estimates.	Chromium
19	Yes	Not a primary reference. Data of sufficient quality for emission estimates.	Formaldehyde
20	Yes	Not a primary reference. Data of sufficient quality for emission estimates.	Metals
21	Yes	Source test data are of sufficient quality to calculate enrichment ratios and emission factors.	PAH, radionuclides, metals
22	Yes	Enrichment ratio data are of sufficient quality to present.	Metals
23	Yes	Emission factor data are of sufficient quality for emission estimates.	Manganese
24	Yes	Reference used in discussion of partitioning behavior.	

TABLE 3-4. N_2O LITERATURE SEARCH RESULTS

Literature Type	Remarks
TOXIC AIR POLLUTANTS: State and Local Regulatory Strategies (1989)	No useful data
Contractor in-house documents	One primary reference
University of North Dakota	Data apply to lignite combustion
TVA	No useful data
COMPENDEX	No references identified
EPRI/PISCES	Available end of 1992
FBC International Conferences	Did not get 11th conference proceedings; others not useful
Journals	Used one journal as a primary reference
EPA workshops	Some useful references

TVA = Tennessee Valley Authority

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4. EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for bituminous and subbituminous coal combustion.

4.1 CRITERIA POLLUTANTS

4.1.1 Review of Previous AP-42 Data

The emission factor documentation files from the prior AP-42 updates of Section 1-1 were obtained and reviewed. The criteria emission factors were developed in 1981 and documented in Reference 1. The emission factors for particle sizing and particulate collection efficiencies by particle size were developed in 1984 in Reference 2. Initially, much of the documentation used in developing these prior emission factors were reviewed. The references included:

- The 61 primary references cited in the 1988 Section 1.1.;
- Secondary references from background files;
- Memoranda and emission factor worksheets from the prior updates.

The references used in developing the prior emissions factors were checked in several cases as a first-level quality check on the documentation. Table 4-1 lists several of the cases where the reference trail was spot checked. Several anomalies regarding reference documentation were revealed, but none which invalidated the quality of the results. A review of the 1988 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was done by selecting primary data references from the background files, reviewing data quality sampling and analytical procedures, determining completeness, and verifying that the site emission factors in the background files could be reconstructed and were accurate. Examples of spot-check data are presented in Appendix A.

Spot checks revealed that, in general, ample A-quality rated data points were available for the criteria pollutants or that most poor quality data had little affect on the published AP-42 emission factors. However, questions regarding the quality of the data used to calculate the emission factors were justified and point to a need to properly review references, assigned data quality ratings, and calculations, when developing improved emission factors for well-defined equipment categories.

4.1.2 Review of New Baseline Data

A total of 60 references were identified and reviewed during the literature search. These references are listed in the checklists added to the background files for this update to AP-42. The original group of 60 documents was reduced to a set of rated references utilizing the criteria outlined in Chapter 3. The following is a discussion of the data contained in each of the rated references.

Reference 3

This report covers the emissions of two hand-feed space heaters tested in cooperation with the Vermont Agency of Environmental Conservation. Oxygen, CO_2 and CO were measured by Orsat from a grab sample collected over the test duration. SO_2 and light hydrocarbons were analyzed from a grab sample in a gas chromatograph. Particulate measurement was made from front half catch of a Modified Method 5 (MM5) sampling train. Hazardous air pollutants (HAPs) were also reported. No original data sheets were found. Coal analysis was reported on a dry basis and higher heating value (HHV) was reported on dry ash free basis. Emissions were calculated in the report (p.15) but appear to be reported incorrectly. Particulate emissions were recalculated using the F-factor in 40 Code of Federal Regulations (CFR) Part 60 Appendix A, EPA Method 19. Data were assigned a rating of C.

Reference 4

This report covers the emissions of one 40,000 lb steam/hr (18,000 kg steam/hr) FBC for long term performance. Data were collected to support NSPS for small boilers. Oxygen, CO_2, SO_2, NO_x, and CO were analyzed by certified continuous emission monitors (CEMs). Test data for the thirty day testing period are presented in the report in molar concentration units. Data from February 28, 1986 were averaged to obtain NO_x and CO emission factors. Sulfur dioxide emissions were controlled by limestone addition to the FBC. No uncontrolled particulate data were found. Data were given a quality rating of B.

Reference 5

This is a compliance test report for PM, SO_2, and NO_x on a 100 MWe tangential-fired boiler for the Nebraska Department of Environmental Control in Lincoln, Nebraska. Particulate was sampled after an ESP and was not useful for uncontrolled emissions. Sampling was performed by EPA Methods 6 and 7. Emissions were given in lb/million Btu (MMBTU). Data were given a quality rating of A.

Reference 6

This is a compliance test report for SO_2 on a 145 MWe PC-fired unit manufactured by Riley Stoker Corporation. Sampling was performed by EPA Method 6 after an ESP. Emissions were given in lb/MMBTU. Data were given a quality rating of A.

Reference 7

This is a test report for short-term testing on seven separate boilers with different configurations over a five-day period. Emphasis of the report is on specific organic compounds; however, CEMs were used to monitor O_2, CO, and total hydrocarbons (THC) during test conditions. There was inadequate information in this report to determine reporting units and measurement method for THC. No CEM specifications or calibration procedures were found but method is fairly well established. Some sampling sites were located after ESPs but this was not expected to significantly alter CO emissions. Sulfur dioxide and NO_X data were available for one of the plants tested via plant-installed CEMs after an ESP. Data were given a quality rating of B.

Reference 8

This is a compliance test report for the Kansas Board of Public Utilities for two coal-fired cyclone boilers. Testing was done by EPA Method 6. Raw data were available but titrations were not checked. Sampling was conducted at the stack after a baghouse and ESP, respectively. A summary table listed emissions in lb/MMBTU based on Tabulated F-factor in 40 CFR Part 60 Appendix 19. Data were given a quality rating of A.

Reference 9

This is a compliance test report for the Kansas Board of Public Utilities on a PC-fired boiler. Insufficient detail for the unit was given to specify firing configuration; however, this information is not necessary for emission factor development at this time. Samples were taken both before and after an ESP to show removal efficiency. Unit was operating at nominally 90 percent of nameplate rating (145 MWe). Raw data were available. Emissions were presented in lb/MMBTU based on an F-factor derived from the fuel analysis. Data were given a quality rating of A.

Reference 10

This report is an EPA/Office of Air Quality Planning and Standards (OAQPS)/Emission Measurements Branch (EMB) document describing a test of Tennessee Eastman's Boiler 24 in Kingsport, Tennessee, in support of the industrial boiler NSPS. The tests were conducted to determine the effects of boiler load, O_2 and preheat on NO_x emissions. Continuous monitors were used to measure NO_x, CO and O_2; NO_x was also measured using EPA Method 7. Comparison of the two NO_x methods was acceptable and the average was used for emission factor calculation. Five of the nine runs were conducted at acceptable boiler loads (> 70 percent). The remaining runs at low load (approximately 55 percent) indicated a 20 percent reduction in NO_x emissions with little effect on CO levels. An A rating has been assigned to this data.

Reference 11

This report is an EPA/OAQPS/EMB document describing a test of an industrial boiler with stoker gas recirculation (SGR) at Upjohn Company's Kalamazoo, MI, facility. These tests were also in support of the industrial boiler NSPS. The effects of boiler load, O_2 and SGR on NO_x emissions were measured. Continuous monitors were used to measure NO_x, CO, and O_2. Nine of the ten runs were made at boiler loads of 75 to 100 percent with O_2 levels between 3.2 and 8.0 percent. These data were used in the emission factor calculations. The remaining run at 50-percent load showed no noted effect on NO_x or CO levels. An A rating has been assigned to this data.

Reference 12

T[illegible] report is an EPA/OAQPS/EMB report describing a test of an industrial spreader stoker at the Burlington Industries facility in Clarksville, VA. These tests were conducted in support of the industrial boiler NSPS for PM. Nine runs were performed at various boiler loads using a slight variation of EPA Method 5 for the particulate measurements. The modification to the sampling method was in heating the filter box to 160°C (320°F) . In a previous report comparing results using this variation to standard Method 5 data, this method produced particulate catches of 94 to 100 percent of Method 5 results. Five of the nine runs were used in the emission factor calculations. Three of the remaining runs were at one-third boiler load and one run exceeded the acceptable percent-isokinetic standard. A B rating was assigned to this data because of the method modification and wide variation in results.

Reference 13

Contains SO_2 and NO_x summary data for the Tennessee Valley Authority's (TVA) bubbling bed FBC (with and without fly ash reinjection) and Batelle's circulating bed FBC. Original test reports are referenced in the document and should be obtained in order to upgrade quality rating. Data were assigned a quality rating of D.

4.1.3 Compilation of Baseline Emission Factors

The references described above were used in updating the uncontrolled (baseline) emission factors for criteria pollutants. Computerized spreadsheets were set up to calculate new data points from the information contained in these references. Sections of the spreadsheets, pertaining to specific pollutants are shown as Tables 4-2 through 4-8.

The new data points were combined with the 1988 AP-42 Section 1.1 data points retained from spot checking to develop new emission factors. The various formulae and conversion factors used in the spreadsheet programs and in the calculation of new emission factors are shown in Appendix B.

4.1.3.1 SO_2 Emission Factors. The new SO_2 baseline data are summarized in Table 4-2. The following new data points were added to the emission factor database:

- Cyclone furnace: 3 points
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Pulverized coal, dry bottom, wall fired: 1 point
- Handfeed: 1 point
- Bubbling bed FBC: 6 points
- Circulating bed FBC: 1 point

The spot checks revealed only minor anomalies in the 1988 AP-42 emission factor calculations. One test report[14] appeared to have a discrepancy in the fuel analysis procedures. For the "ALMA" site, the facility data point was developed from the fuel sulfur content measured on a dried and pulverized (as-fired) basis, but with the as-received HHV. However, making this correction only changes the data point from 33S to 33.7S, where S is the percent sulfur in the fuel. Also, for the subbituminous coal testing at the same site, the coal sample averages did not match the emissions average periods. Again, however, making these corrections did not effectively change the site data point. Therefore, all previous SO_2 emission factor background data were retained in the current update effort.

For bituminous coal firing, three new data points were added for cyclone boilers, and one data point each was added for PC wall-fired and tangential-fired boilers. Of the three cyclone boiler tests, data from two tests were rated E because the calculated emission factors were above the theoretical maximum value of 40S; the remaining cyclone boiler test produced a B-rated emission factor of 31.5S. Test data from the two PC-fired boilers were rated A and B. The average of the emission factors from these two tests was 38.1S. These data, when combined with a 1984 review[89] of the 1982 emission factor development effort and data base, justify a revision of the SO_x emission factor from 39S to 38S for PC-fired, cyclone, spreader stoker, and overfeed stoker boilers.

One new data point from Reference 1 was obtained for a small 2.9 KW (10,000 Btu/hr) hand-fired unit. However, this data point was assigned a C rating and, at a value of 52.4S, was significantly different from the existing average emission factor of 31S for underfeed and hand-fired units. Therefore, the existing AP-42 emission factor was retained.

No new data for subbituminous coal firing were identified during this update. Therefore, the existing emission factor of 35S for PC, cyclone, and spreader and overfeed stokers was retained.

New emission factors were developed for FBCs which have been included in this update of AP-42 as a new source category. As discussed in Chapter 2, a correlation was developed with the coal sulfur content and the calcium-to-sulfur ratio in the bed. The data obtained from the FBC test reports are plotted against calcium-to-sulfur ratio (Ca/S) in Figure 4-1.

Four data points were obtained from Reference 4 showing the effect of available Ca/S ratio on SO_2 emissions. Reference 4 data were given an A rating. The FBC in Reference 4 is a bubbling bed FBC incorporating reinjection of fly ash captured in the first stage cyclone. Fly ash reinjection results increase in higher calcium utilization and lower SO_2 emissions.

Reference 13 presented summary data from both bubbling and circulating bed FBCs. These data were given D ratings because the report lacked sufficient background data to fully evaluate the source operation and test methodology. However, when plotted on Figure 4-1, the data point from the bubbling bed unit with fly ash reinjection matched the data from the similar FBC in Reference 2. Because of the limited number of FBC test data reports which were obtained for this update of AP-42, all these data points were used in developing the SO_2 emission factor correlation. The data from the bubbling bed unit without fly ash reinjection do not match the reinjection data and therefore were not considered in the correlation. Also, the data point from the circulating bed FBC plotted on Figure 4-1 follows the same trend as the bubbling bed units with fly ash reinjection. This behavior is not surprising because circulating bed units are essentially an extension of bubbling bed technology but with higher fluidizing velocities and a high ratio of fly ash reinjection.

All data shown in Figure 4-1 from the bubbling bed units with fly ash reinjection and the circulating bed unit were curve-fit to develop a correlation for the emission factor. The best-fit equation reflecting the SO_2 emissions performance of FBCs was:

$$\frac{lb\ SO_2}{ton\ coal} = 39.6(S)\left(\frac{Ca}{S}\right)^{-1.9}$$

where S is the weight percent sulfur in the coal and Ca/S is the molar calcium-to-sulfur ratio in the bed. This correlation was used for the SO_2 emission factor for both bubbling bed and circulating bed FBCs. An emission factor quality rating of D was given for bubbling bed units because of the limited number of facilities used to obtain the test data. An emission factor quality rating of E was given to the circulating bed units.

When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate FBC SO_2 emissions. In this case, the emission factor quality ratings should be E for both bubbling and circulating bed units.

4.1.3.2 <u>NO_x Emission Factors</u>. The new NO_x baseline data are summarized in Table 4-3. The following new data points were added to the emission factor database:

- Cyclone furnace: 1 point
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Handfed: 1 point

- Bubbling bed FBC: 1 point
- Circulating bed FBC: 1 point

One new data point was averaged with prior data to calculate a new emission factor for cyclone boilers. Although the data point value of 7.52 kg/Mg (15.04 lb/ton) was considerably below the previous AP-42 emission factor of 18.2 kg/Mg (36.4 lb/ton), it appears to be of at least equal quality to the previous background data. The new emission factor of 16.9 kg/Mg (33.8 lb/ton) was calculated by averaging the new data with the old data, all of which have a B quality rating. The emission factor rating of C was retained to indicate that a reasonable set of data points were used to develop the emission factor; however, it is not clear that the facilities tested represent a random sample of the population. now have 8 data pts

Data from References 10 and 11 were averaged with the prior data for spreader stokers. The resulting change in emission factor was minor. The existing value of 7 kg/Mg (14 lb/ton) was changed to 6.9 kg/Mg (13.7 lb/ton). The emission factor rating of A was retained. 2 pts

One data point for a tangential-fired boiler was obtained from Reference 5. At 3.5 kg/Mg (6.9 lb/ton), this data point was somewhat below the 1988 AP-42 emission factor of 7.5 kg/Mg (15 lb/ton); however, it was rated as A quality because Reference 5 is a well-documented and complete compliance test report. A new emission factor of 7.2 kg/Mg (14.4 lb/ton) was developed by averaging the new data point with the old A-rated data. The emission factor rating of A was retained. now have 13 data pts

Two data points were obtained for bubbling bed FBCs. The FBC boiler in Reference 4 is a bubbling bed unit installed in Prince Edward Island, Canada. The data quality rating given to the Reference 4 data point was A because it is a complete and well-documented emission assessment report. Because the FBC unit in Reference 13 is the TVA 20 MWe demonstration unit, it may be more representative of NO_x emissions from new bubbling bed units designed to meet the Federal New Source Performance Standards. However, the data quality assigned to Reference 13 was D because of the lack of supporting information in the test report. Therefore, only the A-rated data from Reference 4 were used for the bubbling bed FBC emission factor. The emission factor is 7.6 kg/Mg (15.2 lb/ton) and has been given an emission factor quality rating of D because the data have been obtained from only one facility.

One data point was obtained for a circulating fluidized bed boiler from Reference 13. Because the data quality rating is D from this standard reference, an emission factor rating of E has been assigned to this source category.

One data point was obtained from a small, hand-fed domestic furnace in Reference 3. To determine if this data point should be combined with the existing data used in the 1988 AP-42 emission factor, a detailed spot check was performed. The emission factor could be reproduced from the data contained in the reference; however, with no supporting sampling discussion or data documentation, the data quality for the existing data point would warrant a C or D rating. Therefore, the new emission factor was developed by averaging the two data points [i.e., 7.6 kg/Mg (15.2 lb/ton) from Reference 1 and 1.5 kg/Mg (3 lb/ton) from the single data point in the 1988 AP-42 emission factor] to obtain a value of 4.55 kg/Mg (9.1 lb/ton). An emission factor quality rating of E was assigned for this source category.

No additional data points were obtained for overfeed and underfeed stokers nor for wet bottom wall-fired pulverized coal units. Therefore, the 1988 AP-42 emission factors were retained for these sources categories. The emission factor ratings of A were retained for the overfeed and underfeed stokers based on the quality of the original references.

Based on the existing AP-42 emission factor spot checks discussed in Section 4.1.1, two data points were removed from the emission factor calculation for wall-fired pulverized coal, dry bottom boilers. This resulted in a change in the emission factor from 10.5 kg/Mg (21 lb/ton) to 10.9 kg/Mg (21.7 lb/ton). The emission factor quality rating of A was retained based on the quality of the remaining references.

4.1.3.3 <u>CO Emission Factors</u>

<u>PC Boilers</u>. Four new data points were obtained as shown in Table 4-4. The two wall-fired data points were lower than the 1988 emission factor of 0.3 kg/Mg (0.6 lb/ton), but the individual runs were consistent at each site. The vertical V-fired data point of 0.76 kg/Mg (1.52 lb/ton) was obtained from the average of individual runs that varied from 0.16 kg/Mg (0.37 lb/ton) to 1.85 kg/Mg (2.71 lb/ton). This point was

not used because of its variability and the fact that the resulting number was far outside of the previous data grouping. The tangentially-fired (T-fired) data point of 0.05 kg/Mg (0.10 lb/ton), although unusually low, appears to be high quality data. Two new cyclone boiler points were also found and added to the baseline database. Both were lower than the computed emission factor but were considered reliable data. A new average emission factor of 0.25 kg/Mg (0.52 lb/ton) was computed. This compares to the previously-computed factor of 0.29 kg/Mg (0.58 lb/ton). The current emission factor has been changed from 0.3 kg/Mg (0.6 lb/ton) to 0.25 kg/Mg (0.5 lb/ton).

The new T-fired data point was considered as a candidate for a new, separate T-fired emission factor. After it was averaged with the existing T-fired data, however, a new emission factor was not warranted.

Spreader Stoker. Two new data points were added to the existing 22 data points [i.e., 0.8 kg/Mg (1.60 lb/ton and 0.46 kg/Mg (0.92 lb/ton)]. Both were considerably below the average emission factor of 0.29 kg/Mg (0.58 lb/ton). A new average emission factor of 2.46 kg/Mg (4.92 lb/ton) was computed. It is recommended to retain the existing factor of 2.5 kg/Mg (5 lb/ton).

Overfeed and Underfeed Stoker. No new data were found. It is recommended to retain the current value.

Hand-fed Units. Two new data points were obtained. The data were assessed to be of C quality. A spot check of Reference 15 revealed that the prior data should be discarded in light of the new data. It is recommended to change the emission factor to 215 kg/Mg (430 lb/ton), which is a simple average of the two new data points.

Fluidized Bed Combustors. A new data point was obtained and is shown in Table 4-4. An emission factor of 9 kg/Mg (18 lb/ton) is recommended for both bubbling bed and circulating FBCs.

4.1.3.4 Particulate Emission Factors

PC-fired, Dry Bottom, Wall Fired. A spot check revealed one data point of low quality. This value was removed from the emission factor data base. Because of the large number of data points and the proximity of the rejected point to the average value, this process had little effect on the new average emission factor. A new data point shown in Table 4-5 was added to the data base. Although the new value was 9.16 kg/Mg (18.31 lb/ton), its addition to the data base did not cause the average emission factor to increase beyond 5.22 kg/Mg (10.44 lb/ton).

PC-fired, Dry Bottom, Tangentially Fired. Existing data were reviewed and an average emission factor was computed. The average value of four data points generated by EPA Method 5 measurements was 5.2 kg/Mg (10.3 lb/ton). An emission factor of 5 kg/Mg (10 lb/ton) is recommended. Because only four data points were used, a quality rating of B was assigned.

PC-fired, Wet Bottom. The existing data were reviewed. Because only one data point was used (the only one found using EPA Method 5), the quality rating was confirmed to be D.

Cyclone Furnace. The existing data were reviewed. Because only one data point was available and it was not obtained by an EPA-approved method, the quality rating was downgraded to E.

Spreader Stoker. Based on the findings of the spot checks, the data point based on Reference 16 was discarded from the new emission factor calculation. The remaining seven data points were averaged with the one new data point obtained from Reference 12 to give a new emission factor of 33 kg/Mg (66.0 lb/ton). The B emission factor quality rating was retained.

Spreader Stoker with Multiclones and Reinjection. Six data points were used and all were based on EPA Method 5 measurements.

Spreader Stoker with Multiclones and No Reinjection. Twelve data points were used and all were based on EPA Method 5 measurements. The A quality rating appears to be warranted since these data are from many diverse facilities. This is also an extremely specific source category and the data did not have a high degree of variability.

Overfed Stoker. Eight data points were used and all were based on EPA Method 5 measurements. Considerable data scatter indicates C quality data.

Overfed Stoker with Multiple Cyclones. All five data points were obtained using EPA Method 5 measurements. Reasonable data consistency warrants a B quality rating.

Underfed Stoker. Although nine EPA Method 5 data points were used, considerable variability exits. A quality rating of C is recommended.

Underfed Stoker with Multiple Cyclone. A quality rating of D is recommended because, although the data are consistent, only two data points are available.

Hand-fed Units. Data were reviewed from the two sources (References 17 and 15). Data from Reference 17 were discounted because the unit was from an open fireplace. Data from Reference 15 were secondary data. Two new data points were added, taken from Table 4-5. Because the two new data points have an average emission factor of approximately 7.5 kg/Mg (15 lb/ton), it is recommended that the emission factor remain unchanged.

Fluidized Bed Combustor, Bubbling Bed. No baseline particulate data, either old or new, were available. It is estimated that PM emissions would most closely match those of a spreader stoker with multiple cyclones and no flyash reinjection. The corresponding PM emission factor of 6 kg/Mg (12 lb/ton) is recommended for use. This assumption warrants the lowest quality rating of E.

Fluidized Bed Combustor, Circulating Bed. No data, either old or new, were available. It was estimated that PM emissions would most closely match those of a spreader stoker with multiple cyclones and no fly ash reinjection. Its PM emission factor of 6 kg/Mg (12 lb/ton) is recommended for use. This assumption warrants the lowest quality rating of E.

4.1.3.5 Methane Emission Factors. Reference 15 was spot checked, and it was found that methane (CH_4) emission factors could be computed for individual boiler types. The existing data were grouped into their appropriate boiler types and new individual emission factors were calculated. Although the same data were used, the emission factor data quality was downgraded to B since each boiler type had only three to five data points.

The only new data obtained were for hand-fed boilers. The spot checks of prior data showed these data to be outdated and unusable. A new emission factor was calculated based on two new data points as shown in Table 4-6.

No CH_4 data were available for FBCs. Possibilities of using data from comparable combustion devices were explored. No suitable estimation procedure was identified.

4.1.3.6 <u>Non-CH_4 Emission Factors</u>. As with CH_4, Reference 15 revealed individual emission data for each boiler type. The existing data were grouped into boiler categories and new individual emission factors were calculated. Although the same data were used, the emission factor data were downgraded to B since each boiler type had only three to five data points.

No new data were found for hand-fed units. Spot checks revealed previous data to be outdated and unusable. Because no other data were available, the existing emission factor was retained in this update. Its quality rating was downgraded to E.

4.1.4 <u>Compilation of Controlled Emission Factors</u>

A compilation of controlled emissions and control efficiencies achieved through application of some of the control technologies discussed in Section 2.4 is given in Tables 4-7 through 4-9.

4.2 SPECIATED VOCs

The VOC speciation data base was very sparse, as described in Section 3.2. The data evaluation was limited to the single report referenced in the database. The report contained only two references for VOC speciation data; only one of these references documented the protocols used for collecting and analyzing the samples. In the one case, samples were collected with Tedlar bags using a vacuum pump. Gas chromatography was the analysis technique. There were no data sheets, calibration procedures or quality control (QC) methods mentioned and no source operating conditions listed. Without these details, the data were considered "unratable," and not suitable for use in developing emission factors.

In the absence of developed emission factors for VOC speciation, the SPECIATE and XATEF databases for speciated VOCs can be consulted for qualitative guidance.

4.3 AIR TOXICS

4.3.1 Review of New Data

The data search summarized in Section 3.3 identified several key documents with primary test data or data compilations for air toxics emissions. The evaluation of several of the key references follows:

Reference 24

This article summarizes the emissions of certain trace metals and hazardous pollutants from bituminous coal combustion. The data presented are a summary of a literature review. Emission factors are presented in the units of mass emitted per heat input quantity combusted and are presented for boilers of different sizes and configurations. The article references several primary references which were evaluated but determined to be of insufficient quality.

Reference 25

This document is a compilation of the available information on sources and emission of POM and is not a primary reference. The document cautions the use of these data for development of an exact assessment of emissions from any particular facility, however, the data are useful for providing rough estimates of POM emissions from boilers firing bituminous coal. The emission factors provided are for controlled devices. Data for utility boilers are used in this update because this is the largest and most complete data set for coal combustion.

Reference 26

The data quality in this report is of unacceptable quality to generate enrichment ratios for metals or emission factors for metals, organics, and POM.

Metals: Metals samples were not taken after the boiler and before the multicyclones so enrichment factors for the pieces of equipment could not be calculated. The multicyclones malfunctioned during the coal test rendering the metals data of questionable quality.

Organics: It was stated in the report (on page 6-28) that the organics recovered were not combustion products but were components in the sample collection media and in the analytical lab.

POM: POM data were below detection limit. The malfunctioning multicyclones would also impact the quality of these data.

Reference 29

The data quality and documentation in this report are of unacceptable quality to generate emission factors.

Metals: Level I sampling and analysis program which is semiquantiative (a factor of ± 3) data quality. A source assessment sampling system (SASS) train and spark source mass spectroscopy (SSMS) analyses were used. These data are not suited for calculation of enrichment factors or mass balances as stated in the source on page 269.

POM: The sampling and analytical procedures are also of lower quality [i.e., SASS and gas chromatography/mass spectrometry (GC/MS)].

The documentation for the analytical results is not clear as to why only portions of the samples were analyzed; therefore, one cannot determine if the entire sample is being accounted for.

Reference 28

The purpose of this document is to provide a preliminary emission assessment of conventional stationary combustion sources. The data presented deals with national averages or ranges based on the best available information. Emission factors in mass emitted per heat unit input are not provided.

Reference 29

The emission factors for oil combustion that were summarized in this document came from Reference 29. These data were eliminated from use in this update due to their poor quality.

Reference 30

This report summarizes testing performed on several sizes and types of boilers; however, only criteria pollutant testing was performed.

Reference 31

Measured and calculated emission factors for bituminous coal are presented in this document. The emission factors are rated as low quality because the document is not a primary source and the quality of the data cannot be verified.

Reference 32

This document presents a summary of emission factors for different types of processes which emit formaldehyde. The emission factors are presented in mass per unit heat input. A factor is provided for coal-fired sources; however, the factors are based on one or two tests. Also, the type of coal is not specified. The emission factor is therefore assigned a low rating and represents an approximate emission estimate.

Reference 33

This document provides a summary of the emissions factors for metals, POM, and formaldehyde for bituminous coal-fired boilers. Control efficiencies are reported for some control devices. No data are reported for uncontrolled emissions of POM and radionuclides. The formaldehyde data are from 1964 and are considered to be of unacceptable quality. The emission factors are based on source test data from coal-fired utility and industrial boilers. Data for different boiler configurations are presented in the units of mass emitted per unit of fuel input.

This reference is not a primary source. The document cautions that relatively limited data are available on toxic air pollutants resulting from these types of processes and that emissions data in the document should not be used to develop an exact assessment of emissions from any particular facility. Emission factors for the processes outlined in the document are summarized and provided for use in determining order-of-magnitude emissions. The emission factors are rated low quality because the data acquisition and manipulation could not be verified.

Reference 34

The data quality and documentation in this report are of high enough quality to develop enrichment ratios for metals and radionuclides on boilers and their associated abatement devices. Emission factors expressed as mass emitted per unit heat combusted are calculated for PAH compounds.

Reference 35

This report summarizes the current research effort in the Netherlands to determine the fate of trace elements at coal-fired power plants. A total of sixteen test and mass balance programs were undertaken to determine enrichment ratios for boilers and high-efficiency cold-side ESPs. Enrichment ratios for boilers are presented by classes of metals. Enrichment ratios for the ESPs are also presented. The data are of sufficient quality for use in this update.

Reference 36

This document presents emission factors for sources of chromium. A literature survey was used to compile emission estimates from bituminous coal-fired boilers. The emission data for utility boilers is used to generate the emission factor.

The data from these references were reviewed and ranked according to the quality criteria discussed in Section 3.

4.3.2 Baseline Emission Factors

Emission factors for metals, radionuclides, and other HAPs are quite often presented in units of mass emitted per heat input combusted. These units are adequate for developing emission factors for organic HAPs but are not desirable for developing factors for metals and radionuclides. Ideally, emission factors for trace elements should be developed as a function of the boiler firing configuration, boiler size, trace element content of the fuel, ash content, higher heating value, enrichment ratio (see discussion below), and the collection efficiency of the control device.

The concepts of partitioning and enrichment are needed to describe the fate of trace metals within the boiler and collection devices. The concept of partitioning is used to describe the distribution of trace elements among the boiler system outlet streams. These streams may include the bottom ash collector hoppers, boiler/economizer/preheater hoppers, and flue gas. Enrichment refers to the preferential migration of specific trace metals to a process stream or to a specific particle size range, especially the respirable range and below. The process of enrichment typically involves a control device, where collection efficiency varies by particle size range. When metals are distributed unequally across size ranges, the collection device will then yield disproportionate partitioning from the size enrichment. The physical and chemical properties of a trace metal governs how that metal will be distributed in the outlet streams. For example, mercury is a highly volatile metal and therefore, the majority of the mass of mercury in the coal tends to be emitted from the boiler in the flue gas and not in the bottom ash or in the fly ash.

A method for describing partitioning behavior is to report the fraction of the total elemental mass input that has exited the boiler in an outlet stream. Another method for quantifying the distribution of a metal is to calculate an enrichment ratio by comparing the trace element concentration of an outlet stream to the trace element concentration in the inlet coal stream. The enrichment ratio calculation that is outlined in Reference 33 is performed using the following equation:

$$ER_{ij} = (C_{ij}/C_{Rj})/(C_{ic}/C_{Rc})$$

where: ER_{ij} = enrichment ratio for element i in stream j

C_{ij} = concentration of element i in stream j

C_{Rj} = concentration of reference element R in stream j

C_{ic} = concentration of element i in coal

C_{Rc} = concentration of reference element R in coal

Enrichment ratios greater than 1 indicate that an element is enriched in a given stream, e.g. stream j, or that it partitions to a given stream. The reference element is used because its partitioning and enrichment behavior is often comparable to that for the total ash. In other words, the reference element partitions with consistent concentrations in all ash streams and normalizes the calculation. Typical reference elements are aluminum, iron, scandium, and titanium. The enrichment behavior of elements is relatively consistent in different types of boilers and can be explained by a volatilization-condensation or adsorption mechanisms. A summary of the enrichment behavior for air toxic metals and the reference metals is presented in Table 4-10. Table 4-11 presents a summary of enrichment behaviors including approximate enrichment ratios for particular classes of compounds.

The enrichment ratio can be used in conjunction with additional data from a specific facility to estimate emissions of trace elements. The equation outlined in Reference 35 is used to calculate the emission factor for a trace element as follows:

$$EF = (C/H)*F*(1-E)*ER*10^3$$

where: EF = emission factor for a specific trace element, ng/J

C = concentration of element in coal, μg/g

H = higher heating value of coal, kJ/kg

F = fraction of coal ash as fly ash

E = fractional particulate collection efficiency of control device (zero for uncontrolled emissions)

ER = enrichment factor for the trace element (ratio of concentration of element in emitted fly ash to concentration of element in coal ash, often based on aluminum).

In many cases, the source test programs did not include key parameters such as: ultimate and trace element analyses of coal used for the test, measurements of the boiler effluent for metals and ash, and measurements of metals and ash after the collection device. This made it impossible to calculate partitioning of metals within the bottom and fly ash. When supporting documentation to develop enrichment ratios were not available, emission factors in the units of mass emitted per unit thermal heat input were provided. Although this is not the optimal method of estimating emissions, it provides a means of performing approximate emission estimation.

Table 4-12 summarizes the enrichment ratios for metals and radionuclides for various uncontrolled boilers and for a high efficiency cold-side ESP. The enrichment ratios presented are the ranges for the references obtained. The quality of these enrichment ratios is low (E quality) because of the small number of boilers tested and limited control data used to perform the calculations. Enrichment ratio data are a significant data gap in the air toxic data bases.

Table 4-13 and 4-14 present summaries of emission factors in the units of mass emitted per unit thermal heat input combusted for uncontrolled boilers. Data are presented for metals, POM, and formaldehyde. The tables are presented in English units and metric units, respectively. The quality rating of these data are low because many of the sources of information are of low quality and the number of data points are too small to represent an entire source category. Limited data are available on organic air toxic compounds but could not be obtained for this update. The metals data were most abundant and the data for formaldehyde were very limited. The POM data were also fairly limited. When received, these data will be added to the AP-42 Section 1.1 Background File for consideration in the next update of this section.

4.3.3 Controlled Emission Factors

Table 4-15 and 4-16 present the summary of emission factors for various controlled emissions in the units of mass emitted per unit thermal heat input. The data obtained in the literature review were very limited. The quality rating of these data are low because many of the sources of information are of low quality and the number of data points are too small to represent an entire source category. Table 4-17 summarizes control efficiencies for various parameters of several control devices.

4.4 N_2O

A total of 43 references were documented and reviewed during the literature search. These references are listed at the end of this chapter.

The original group of 43 documents was reduced to a final set of primary references using the criteria outlined in Chapter 3. Many of the references were based on the pre-1988 protocol which resulted in unrelaible N_2O measurements because of reactions in sample containers. For the 40 references documents not used, the reason(s) for rejection are summarized below (the reference number corresponds to the reference list at the end of this chapter):

Reference	Reason for rejection
39	Data were pre-1988
40	Data were pre-1988
41	Pilot-scale boiler
42	Duplicate of test in Reference 2
43	No N_2O data
44	Only information on N_2O emissions from global sources
45	Data were pre-1988
46	Data were pre-1988
47	Test data taken from an airplane
48	Duplicate of test in Reference 12
49	Duplicate of test in Reference 2
50	Insufficient lab, process, analytical data
51	Chemical kinetics calculation
52	Insufficient lab, process, analytical data
53	No N_2O data
54	No N_2O data
55	Insufficient lab, process, analytical data
56	No N_2O data
57	Duplicate of test in Reference 2
58	Insufficient lab, process, analytical data
59	Insufficient lab, process, analytical data
60	Insufficient lab, process, analytical data
61	No N_2O data
62	Data were pre-1988
63	Data were pre-1988
64	Data were pre-1988
65	Data were pre-1988
66	Data were pre-1988

67	Solid waste co-fired in boiler
68	Data were pre-1988
69	Data were pre-1988
70	Data were pre-1988
71	Data were pre-1988
72	Not citable as a primary reference
73	Not citable as a primary reference
74	Pilot-scale boiler
75	Pilot-scale boiler
76	Pilot-scale boiler
77	Pilot-scale boiler

This screening resulted in the selection of three references which could be used to develop N_2O emission factors. The following paragraphs discuss the data contained in each of the primary references used to develop emission factors. Emission factor calculations were made in terms of mass of pollutant per unit mass of coal feed. It should be noted that the terms "controlled" and "uncontrolled" in this discussion are indicative only of the location at which the measurements were made [i.e., after or before control device(s), respectively].

Reference 78

This reference contained N_2O emissions data from eight full-scale tests. All test reports were rejected except for the test report from the Italian power plant. The Italian power plant had two sources. One source combusted fuel oil while the other source combusted bituminous coal. The data from both the boilers were acceptable; only the coal data were used for the update of AP-42 Section 1.1.

In the Italian test report, a B quality rating was assigned to the data from both sources. The report provided adequate detail for validation and the sampling and analysis methodology appeared sound.

Reference 79

This reference contained data from N_2O emissions tests conducted at six boilers. Data were used from four of the sources, because the other two boilers were operated below 70 percent of full load (although the data were comparable). The acceptable N_2O emissions data correspond to coal boiler test conducted with on-line GC. The tests were conducted after the economizer and flue gas cleaning.

An A quality rating would have been applied to the data except that the calibration data showed excessively high values; therefore a B quality rating was assigned.

Reference 80

This reference contained data for N_2O emissions from FBCs. The data are in graphical form and presented in units of milligrams per megajoule. The conversion from milligram per megajoule to ppm is one milligram per megajoule equals 1.7 ppm. The test was performed on a circulating fluidized bed boiler controlled by recirculation of flue gases. The reference case is defined by a bed temperature of 850 °C (1,560 °F), a primary air stoichiometry of 0.75 and excess air ratio of 1.2. The actual emission values can only be estimated from the graphs and, therefore, the data were assigned a rating of D.

The new N_2O emissions data are presented in Table 4-18 and a summary of the emission factor results are shown in Table 4-19.

4.5 PARTICLE SIZE DISTRIBUTION

For the current revision, the scope of AP-42 was extended to include segregation of filterable and condensible PM-10 emission factors along with the particle size distribution data. The prior AP-42 updates include detailed analysis of particulate size distribution data.

4.5.1 Review of 1986 AP-42 Data

The 1986 database[2] was evaluated with respect to sources of data, data analyses, and calculations. Data retrieved and analyzed for that update were all filterable particulate.

Table 4-20 lists the sets of A and B rated data that the 1986 AP-42 emission factors update used. This table shows where high-quality data are lacking. The Fine Particulate Emission Inventory System (FPEIS) data base was the primary source of emissions data for the 1986 update. In some instances, the data were given a low rating because of insufficient data in the FPEIS printouts. During the literature search, original documents with primary test data were uncovered that corresponded to the FPEIS documents.

The original test document for the FPEIS Test Series Number 35 in the 1986 background document is EPA-600/2-75-013-a (Reference 81). The tests were conducted on a bituminous-coal-fired spreader stoker to determine the fractional efficiency of the boiler baghouse. Inlet and outlet data are provided for 22 tests. All 22 data sets were used for the particle size distribution for baghouse controlled spreader stokers and 21 of the 22 data sets were used in the preparation of the size distribution data for uncontrolled spreader stoker boilers. The data were B-rated in the 1986 update because the system operating conditions and sampling flowrate isokinetic results were unknown. Review of the report did not uncover isokinetic results; however, there was considerable discussion of the baghouse operating conditions. Eleven of the 22 tests were conducted under normal baghouse operating conditions while the remaining tests were conducted under experimental conditions. The range of conditions may explain the large variation in the controlled emissions results. For instance, the cumulative mass less than 10 microns ranged from 16 percent to 96 percent. However, little difference was found overall by comparing the average distribution of the "normal" runs with the average distribution of all 22 runs. Because of this finding, it was concluded that the data need not be changed and are indeed representative of baghouse emission distributions. The values in the 1986 background document were also spot-checked against the numbers in the plots of the original test report. The numbers compared favorably.

4.5.2 Review of New Data

A search for additional data was conducted. Of primary interest was CPM data collected via EPA Method 202 because this particulate fraction has not been addressed in previous AP-42 updates. Unfortunately, only methods development source test data were found because this is still a relatively new protocol.

Although a variety of sources were contacted regarding particulate sizing and PM-10 data, very little additional data were located. State and district offices that were contacted either had no PM-10 data available or were unable to process such a request due to other staff commitments. Several groups within the California Air Resources Board were contacted because California considers condensible particulate as a portion of total particulate; however, no data were received.

The New Jersey Air Pollution Control Office likely has particulate sizing data for coal emissions. Their policy is to conduct data searches only when a written request is submitted which includes lists of specific facilities.[82] Because specific facility lists were unavailable, this avenue was not pursued.

One test report[83] was obtained that contained CPM emission data for coal-fired boilers. The tests were conducted by EPA/OAQPS/EMB. The test objectives were to determine the adequacy of and produce documentation to support Draft Method 202; revise the candidate method based on results of laboratory experiments; validate the method in field tests; and revise the method, if necessary.

It was not possible to prepare emission factors from the results. The data wer presented as mg emitted/m^3 and no data were presented regarding the volumetric flue gas flow rate or the size of the boiler. F-factors are provided in 40 CFR Part 60.45 to convert emissions into mass emitted per unit heat input. However, to use an F-factor, one must first be able to correct the flue gas volume to zero percent O_2. No data were available regarding the percent O_2 in the flue gas flow; therefore the calculation was not conducted.

Emission factors from these tests would not be reliable because the sampling was single-point sampling rather than a duct traverse (since the objective was to examine the test method rather than to obtain representative data). Therefore, any emission factors derived from this data would be of D-rating. However, inferences may be drawn regarding the relative size of the organic and inorganic fractions of the CPM. These results are presented in Table 4-21. The results indicate that CPM originating from coal-fired boilers are at least 90 percent inorganic matter.

An EPRI report[84] describes tests of a 22 MW Babcock and Wilcox front wall fired boiler fueled on low-sulfur bituminous coal. The particulate sizing data were collected with a cascade impactor upstream of the fabric filter control system. The results are presented in Table 4-22. Total particulate was measured both upstream and downstream of the fabric filter via EPA Method 5. The overall baghouse efficiency was 99.8 percent. Because sufficient raw data were not provided in the report, the data were rated B quality. Because sufficient A quality data exist for pulverized coal-fired boilers in the 1988 version of AP-42, it was not necessary to incorporate these new data.

For atmospheric fluidized bed boilers, two sets of data are available for the filterable particulate emissions.[87] A pilot AFBC unit was tested while firing both subbituminous coal and lignite. The purpose of these tests was to investigate the corrosive and/or erosive properties of low-rank coal ash on heat transfer surfaces.

As part of the test, the PM exiting a multicyclone system was measured for particule size distribution. A flow sensor multicyclone and laser aerodynamic particle sizer (APS) provided particle size distribution data at the inlet to the scrubber (after the multiclone controls). The APS is a real-time particle sizer that measures sizes in the range of 0.5 to 15 microns.

The data are rated as D quality due to the pilot-scale size, the particulate collection methods, and lack of sufficient background data on protocols and unit operation. For these tests, the cumulative percent mass collection values were inferred via interpolation of log-log graphs of the results. The particulate size distribution data are shown on Table 4-23.

A paper presented at the 51st American Power Conference describes particulate size distribution data from a coal-fired pressurized fluidized bed combustion (PFBC) unit, before and after high-pressure, high-temperature emission control devices.[86] As PFBC is not a common coal-combustion device at this time, these data were not evaluated.

4.6.3 Compilation of Uncontrolled Emission Factors

The 1988 update was reviewed with respect to the procedure used to develop emission factors from the particle size distribution data. The uncontrolled emission factors were calculated for each size fraction by multiplying the total particulate emission factor by the cumulative percent mass for the given size interval. Therefore all uncontrolled emission factors will change as a result of updating the total PM emission factors.

It is apparent that the level of uncertainty increases as one moves from the cumulative percent mass to the uncontrolled emission factors. The uncontrolled emission factors are functions of two numbers estimated generally from different sets of data: the cumulative percent mass, and the total PM emission factor.

The filterable PM-10 emission factors are included in the particulate size distribution tables. There is currently no need to prepare tables devoted only to PM-10. As CPM data become available, a new table should be added to each AP-42 section. The table should include columns for filterable PM-10, inorganic CPM, and organic CPM.

4.6.4 Control Technology Emission Factors

There were two calculation steps used in the development of controlled emission factors in the 1986 particulate sizing update.[2] First, a controlled emission factor was developed for total particulate by multiplying the uncontrolled total particulate emission factor from the criteria pollutant table by one of the following estimated control efficiency factors:

- Multiple cyclone - 80 percent,
- Baghouse - 99.8 percent,
- ESP - 99.2 percent, and
- Scrubber - 94 percent.

Next, a controlled emission factor was developed for each of the cumulative size ranges by multiplying the controlled emission factor for total particulate by the cumulative percent mass for the size range. Thus the quality of the right-hand side of each size distribution table in Section 1.1 of AP-42 is directly related to the quality of three other numbers: (1) the control efficiency factors, (2) the total particulate emission factor (from the criteria pollutant table), and (3) the cumulative percent mass data. This, in part, explains the low data rating generally listed in AP-42 for the controlled particle-specific emission factors.

The disadvantage of this procedure is the loss of emission factor quality. The advantage of the procedure is that it allows the determination of control device-specific controlled emission factors rather than using generalized control efficiency results. Control device-specific controlled emission factors are better than generalized control efficiencies results because control efficiency is dependent on particulate parameters, such as the resistivity, and not just the particle size distribution.

It is useful to note that the procedure does not assume a single control efficiency for each particle size. Rather, it assumes a single overall efficiency and applies this to the total particulate emission factor. The size-based emission factors depend on the total controlled emission factor and the percent of the total controlled mass within a particular size range. For example, collected data indicated that 71 percent of controlled PM from a wet scrubber is less than or equal to 10 microns. Based on this value; on an uncontrolled emission factor of 5A kg/Mg; and on an estimated scrubber control efficiency of 94 percent, the controlled PM-10 emission factor is calculated as 0.21 kg/Mg:

$$0.71 \times 5A \times (1.0-0.94) = 0.21 \text{ kg/Mg}.$$

Although different methods could be used to develop controlled emission estimates, the procedure used in the 1986 document[2] is a logical way to compensate for sparse data. The process appears to create conservatively high values for the controlled emission factors, as there are occasionally controlled emission factors in the tables that are larger than the uncontrolled factors.

The particulate control efficiencies for the four technologies used throughout the previous update are all reasonable and were retained in the current update.

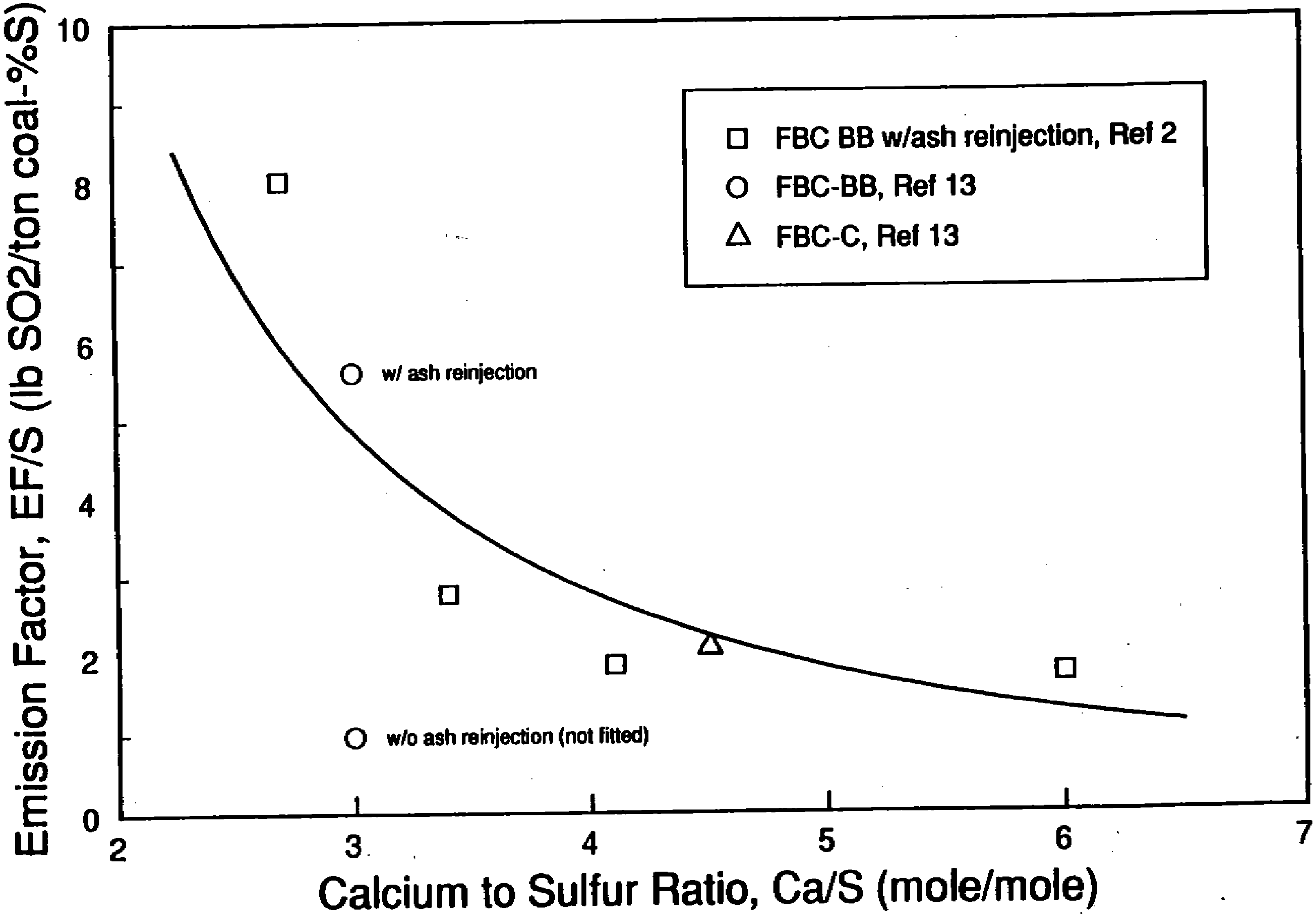

Figure 4-1. FBC SO_2 emissions versus calcium-to-sulfur ratio.

TABLE 4-1. BACKGROUND DOCUMENT CHECK

Pollutant	Configuration	References cited in 1988 AP-42 Section 1.1	Site No.	Emission factor	References spot checked
PM	PC dry bottom	15, 16, 17, 19, 21 EPA-650/7-80-171 (20)	17	10A	15, 17
PM	Handfired units				49, 50
SO_2	Bituminous emission-based	9, 16, 17, 18, 19, 21, 31, 37, 39, 41, 42, 43, 46, 51, 52, 55	49	39S	17, 18
SO_2	Bituminous retention-based	17, 18, 32, 33, 34, 35, 41, 42, 44, 45	11	39S	18
SO_2	Subbituminous	9, 17, 31, 53, 54	15	35S	17
NO_x	PC dry bottom	11, 14, 16, 17, 21, 56	28	21	17
NO_x	Handfired units				50
CO	Handfired units				50
VOC	PC dry bottom	58	17	.07	58
VOC	PC wet bottom				58
VOC	Cyclone, spreader stoker, overfeed stoker				58
VOC	Underfeed stoker				58
VOC	Handfired units				58, 50
CH_4	PC, Cyclone, Spreader Stoker, Overfeed Stoker	58	16	.03	58
CH_4	Underfeed Stoker				58
CH_4	Handfired Units				58, 50

A = weight percent ash in fuel
S = weight percent sulfur in fuel

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel: HHV, Btu/lb	Fuel: S, wt%	Operation: Capacity	Operation: Units	Operation: Load Factor	SO_2 Emissions: ppm	SO_2 Emissions: lb/MMBtu	SO_2 Emissions: (lb/ton)/S	FBC control efficiency: Ca/S, mole/mole	FBC control efficiency: SO2, %
8	E	Cyclone	KAW Unit 1	3B	11496	2.68	400000	lb/hr	0.96		5.0700	43.60		
8	E	Cyclone	KAW Unit 1	1B	11629	2.63	400000	lb/hr	0.96		4.9700	43.95		
8	E	Cyclone	KAW Unit 1	3A	11496	2.68	400000	lb/hr	0.96		5.0700	43.50		
8	E	Cyclone	KAW Unit 1	2B	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
8	E	Cyclone	KAW Unit 1	1A	11629	2.63	400000	lb/hr	0.96		5.2100	46.07		
8	E	Cyclone	KAW Unit 1	2A	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
												44.65		
7	B	Cyclone	Plant 5	3	12121	1.81	584	MW	1.01	980.0	2.4880	33.32		
7	B	Cyclone	Plant 5	1	12121	1.81	584	MW	1.01	840.0	2.2153	29.67		
7	B	Cyclone	Plant 5	2	12121	1.81	584	MW	1.00	950.0	2.5054	33.56		
7	B	Cyclone	Plant 5	4	12121	1.81	584	MW	0.79	900.0	2.1263	28.48		
7	B	Cyclone	Plant 5	5	12121	1.81	584	MW	0.63	950.0	2.4119	32.30		
												31.47		
8	E	Cyclone	Quindaro #1	2A	11375	2.81	625000	lb/hr	0.74		5.7000	46.15		
8	E	Cyclone	Quindaro #1	2B	11375	2.81	625000	lb/hr	0.74		5.6800	45.99		
8	E	Cyclone	Quindaro #1	3A	11387	1.93	625000	lb/hr	0.75		5.6500	66.67		
8	E	Cyclone	Quindaro #1	1B	11309	2.76	625000	lb/hr	0.74		5.7200	46.87		
8	E	Cyclone	Quindaro #1	3B	11387	1.93	625000	lb/hr	0.75		5.7400	67.73		
8	E	Cyclone	Quindaro #1	1A	11309	2.76	625000	lb/hr	0.74		5.5400	45.40		
												53.14		
4	A	FBC-BB	Summerside	AVE	11770	5.96	50	MMBTU/hr	0.72		2.0300	8.02ᵃ	2.70	0.73
4	A	FBC-BB	Summerside	AVE	11510	5.82	50	MMBTU/hr	0.73		0.4800	1.87ᵃ	4.10	0.95
4	A	FBC-BB	Summerside	AVE	11760	5.90	50	MMBTU/hr	0.73	212.3	0.6981	2.78ᵃ	3.40	0.93

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel: HHV, Btu/lb	Fuel: S, wt%	Operation: Capacity	Operation: Units	Operation: Load Factor	SO_2 Emissions: ppm	SO_2 Emissions: lb/MMBtu	SO_2 Emissions: (lb/ton)/S	FBC control efficiency: Ca/S, mole/mole	FBC control efficiency: SO2, %
4	A	FBC-BB	Summerside	AVE	11430	5.20	50	MMBTU/hr	0.65		0.4000	1.76[a]	6.00	0.98
13	D	FBC-BB	TVA 20MWe	2	13000	3.84	228	MMBTU/hr	0.68		0.1400	0.95[a]	3.00	0.98
13	D	FBC-BB	TVA 20MWe	1	13000	4.46	228	MMBTU/hr	0.68		0.9600	5.61[a]	3.00	0.87
13	D	FBC-C	BATTELLE	1	13000	1.50	50	MMBTU/hr			0.1200	2.08	4.50	0.95
3	C	Hand-Fed		Coal Stove	14118	0.77	0.01	MMBTU/hr		208.0	0.8957	32.69		
3	E	Hand-Fed		Modified Wood Stove	13421	0.79	0.01	MMBTU/hr		430.0	2.1201	72.07		
6	A	PC-fired	Quindaro #2	2B	11201	1.70	145	MW	0.83		2.9700	39.14		
6	A	PC-fired	Quindaro #2	2A	11201	1.70	145	MW	0.83		2.8800	37.69		
6	A	PC-fired	Quindaro #2	4A	11304	1.72	145	MW	0.83		2.8500	37.46		
6	A	PC-fired	Quindaro #2	4B	11304	1.72	145	MW	0.83		2.8900	37.99		
6	A	PC-fired	Quindaro #2	3A	11185	1.77	145	MW	0.83		2.9700	37.54		
6	A	PC-fired	Quindaro #2	1A	11230	1.80	145	MW	0.83		2.8100	36.06		
6	A	PC-fired	Quindaro #2	3B	11185	1.77	145	MW	0.83		2.8400	37.16		
												37.43		
5	A	PC-TFired		3	8104	0.44	100	MW	1.02		1.1000	40.52		
5	A	PC-TFired		2	8104	0.44	100	MW	1.02		1.0390	38.27		
5	A	PC-TFired		1	8104	0.44	100	MW	1.02		1.0200	37.57		
												38.79		

[a] SO_2 emissions controlled by the addition of sorbents (e.g., limestone) to the FBC.
S = weight percent sulfur in fuel

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel: HHV, Btu/lb	Fuel: S, wt%	Fuel: N, wt%	Fuel: Ash, wt%	Operation: Capacity	Operation: Units	Operation: Load factor	NO_x emissions, lb/MMBtu	NO_x emissions, lb/ton
7	B	Cyclone	Plant 5	4	12121	1.81		13.81	584	MW	0.79	0.5773	14.00
7	B	Cyclone	Plant 5	1	12121	1.81		13.81	584	MW	1.01	0.5307	12.87
7	B	Cyclone	Plant 5	3	12121	1.81		13.81	584	MW	1.01	0.7117	17.25
7	B	Cyclone	Plant 5	2	12121	1.81		13.81	584	MW	1.00	0.6445	15.62
7	B	Cyclone	Plant 5	5	12121	1.81		13.81	584	MW	0.83	0.6387	15.48
													15.04
4	A	FBC-BB	Summerside	Avg.	11430	5.20	1.05	11.20	50	MMBtu/hr	0.65	0.6800	15.54
4	A	FBC-BB	Summerside	Avg.	11750	5.90	1.06	9.58	50	MMBtu/hr	0.73	0.6195	14.56
4	A	FBC-BB	Summerside	Avg.	11510	5.92	1.08	11.40	50	MMBtu/hr	0.73	0.6500	14.96
4	A	FBC-BB	Summerside	Avg.	11770	5.86	1.03	9.73	50	MMBtu/hr	0.72	0.6700	15.77
													15.21
13	D	FBC-BB	TVA 20MWe	1	13000	4.45			228	MMBtu/hr	0.68	0.3400	8.84
13	D	FBC-BB	TVA 20MWe	2	13000	3.84			228	MMBtu/hr	0.68	0.2300	5.98
													7.41
13	D	FBC-C	BATTELLE	1	13000	1.50			50	MMBtu/hr		0.1500	3.90

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel: HHV, Btu/lb	Fuel: S, wt%	Fuel: N, wt%	Fuel: Ash, wt%	Operation: Capacity	Operation: Units	Operation: Load factor	NO_x emissions, lb/MMBtu	NO_x emissions, lb/ton
3	C	Hand-Fed		Modified wood stove	13421	0.79		5.43	0.01	MMBtu/hr		0.5670	15.22
5	A	PC:T-Fired		1	8104	0.44		5.42	100	MW	1.02	0.4310	6.99
5	A	PC:T-Fired		3	8104	0.44		5.42	100	MW	1.02	0.4140	6.71
5	A	PC:T-Fired		2	8104	0.44		5.42	100	MW	1.02	0.4390	7.12
													6.94
10	A	Stoker-spreader	Boiler 24	2	12906				320000	lb/hr	0.82	0.7500	19.36
10	A	Stoker-spreader	Boiler 24	6	13581				320000	lb/hr	0.82	0.5750	15.62
10	A	Stoker-spreader	Boiler 24	7	13761				320000	lb/hr	0.81	0.6900	18.99
10	A	Stoker-spreader	Boiler 24	5	13674				320000	lb/hr	1.00	0.6550	17.91
10	A	Stoker-spreader	Boiler 24	1	13203				320000	lb/hr	0.81	0.6000	15.84
													17.54
11	A	Stoker-spreader	Kalamazoo	2	13645				90000	lb/hr	1.00	0.4347	11.86
11	A	Stoker-spreader	Kalamazoo	6	13592				90000	lb/hr	0.75	0.3567	9.70

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

					Fuel				Operation			NO_x emissions,	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	N, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
11	A	Stoker-spreader	Kalamazoo	3	13617				90000	lb/hr	0.75	0.4626	12.60
11	A	Stoker-spreader	Kalamazoo	8	13827				90000	lb/hr	0.75	0.5066	14.01
11	A	Stoker-spreader	Kalamazoo	5	13059				90000	lb/hr	0.75	0.5345	13.96
11	A	Stoker-spreader	Kalamazoo	4	13676				90000	lb/hr	1.00	0.3702	10.06
11	A	Stoker-spreader	Kalamazoo	1	13727				90000	lb/hr	1.00	0.4032	11.07
11	A	Stoker-spreader	Kalamazoo	9	13559				90000	lb/hr	0.75	0.3840	10.41
11	A	Stoker-spreader	Kalamazoo	10	13628				90000	lb/hr	0.75	0.3546	9.67
													11.48

TABLE 4-4. NEW CO BASELINE DATA

						Fuel			Operation			CO Emissions		
Ref.	Data quality	Boiler type	Fuel	Site	Run	HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	Cyclone	Bituminous	Plant 5	3	12121		13.81	584	MW	1.01	7.3	0.0068	0.16
7	B	Cyclone	Bituminous	Plant 5	1	12121		13.81	584	MW	1.01	12.9	0.0129	0.31
7	B	Cyclone	Bituminous	Plant 5	4	12121		13.81	584	MW	0.79	9.4	0.0090	0.22
7	B	Cyclone	Bituminous	Plant 5	2	12121		13.81	584	MW	1.00	8.0	0.0076	0.18
														0.22
7	B	Cyclone	Bituminous	Plant 6	4	8895		11.06	180	MW	0.94	36.4	0.0354	0.63
7	B	Cyclone	Bituminous	Plant 6	3	8895		11.06	180	MW	1.03	17.9	0.0168	0.30
7	B	Cyclone	Bituminous	Plant 6	5	8895		11.06	180	MW	0.98	15.1	0.0146	0.26
7	B	Cyclone	Bituminous	Plant 6	1	8895		11.06	180	MW	1.00	28.3	0.0277	0.49
7	B	Cyclone	Bituminous	Plant 6	2	8895		11.06	180	MW	1.02	12.1	0.0120	0.21
														0.38
4	A	FBC-BB	Bituminous	Summerside	Avg.	11750	1.06	9.58	50	MMBtu/hr	0.73	419.2	0.6032	14.17
4	A	FBC-BB	Bituminous	Summerside	Avg.	11510	1.08	11.40	50	MMBtu/hr	0.73	452.8	0.6418	14.78
4	A	FBC-BB	Bituminous	Summerside	Avg.	11430	1.05	11.20	50	MMBtu/hr	0.65	800.7	1.1788	26.86
4	A	FBC-BB	Bituminous	Summerside	Avg.	11770	1.03	9.73	50	MMBtu/hr	0.72	432.4	0.6560	15.44
														17.83
3	C	Hand-Fed	Bituminous		Modified wood stove	13421		5.43	0.01	MBtu/hr		4000.0	8.6283	231.60
3	C	Hand-Fed	Bituminous		Coal stove	14119		3.09	0.01	MBtu/hr		6000.0	11.3042	319.20
														275.40
7	B	PC-TFired	Subbituminous	Plant 1	4B	7842		13.91	660	MW	0.84	6.5	0.0063	0.10
7	B	PC-TFired	Subbituminous	Plant 1	4A	7842		13.91	660	MW	0.84	6.5	0.0063	0.10

TABLE 4-4. NEW CO BASELINE DATA

						Fuel			Operation			CO Emissions,		
Ref.	Data quality	Boiler type	Fuel	Site	Run	HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	PC-TFired	Subbituminous	Plant 1	3B	7842		13.91	660	MW	0.93	6.9	0.0066	0.10
7	B	PC-TFired	Subbituminous	Plant 1	3A	7842		13.91	660	MW	0.93	6.9	0.0066	0.10
7	B	PC-TFired	Subbituminous	Plant 1	5B	7842		13.91	660	MW	0.92	7.4	0.0072	0.11
														0.10
7	B	PC:V-Fired	Bituminous	Plant 2	4B	11576		13.55	250	MW	1.06	31.7	0.0270	0.62
7	B	PC:V-Fired	Bituminous	Plant 2	5A	11576		13.55	250	MW	1.04	71.7	0.0596	1.38
7	B	PC:V-Fired	Bituminous	Plant 2	1A	11576		13.55	250	MW	1.07	119.9	0.1088	2.52
7	B	PC:V-Fired	Bituminous	Plant 2	2A	11576		13.55	250	MW	1.07	143.8	0.1170	2.71
7	B	PC:V-Fired	Bituminous	Plant 2	3B	11576		13.55	250	MW	1.04	19.4	0.0168	0.39
7	B	PC:V-Fired	Bituminous	Plant 2	4A	11576		13.55	250	MW	1.06	31.7	0.0270	0.62
7	B	PC:V-Fired	Bituminous	Plant 2	2B	11576		13.55	250	MW	1.07	143.8	0.1170	2.71
7	B	PC:V-Fired	Bituminous	Plant 2	3A	11576		13.55	250	MW	1.04	19.4	0.0168	0.39
7	B	PC:V-Fired	Bituminous	Plant 2	5B	11576		13.55	250	MW	1.04	71.7	0.0596	1.38
7	B	PC:V-Fired	Bituminous	Plant 2	1B	11576		13.55	250	MW	1.07	119.9	0.1088	2.52
														1.52
7	B	PC:W-Fired	Bituminous	Plant 3	2	11660		13.40	125	MW	0.98	14.6	0.0138	0.32
7	B	PC:W-Fired	Bituminous	Plant 3	5	11660		13.40	125	MW	0.97	10.3	0.0096	0.22
7	B	PC:W-Fired	Bituminous	Plant 3	1	11660		13.40	125	MW	0.97	17.7	0.0166	0.38
7	B	PC:W-Fired	Bituminous	Plant 3	3	11660		13.40	125	MW	0.97	11.7	0.0110	0.26
7	B	PC:W-Fired	Bituminous	Plant 3	4	11660		13.40	125	MW	0.97	8.8	0.0082	0.19
														0.28
7	B	PC:W-Fired	Bituminous	Plant 4	1	11920		11.78	217	MW	0.96	9.2	0.0098	0.23
7	B	PC:W-Fired	Bituminous	Plant 4	2	11920		11.78	217	MW	0.98	17.0	0.0178	0.42

TABLE 4-4. NEW CO BASELINE DATA

						Fuel			Operation			CO Emissions,		
Ref.	Data quality	Boiler type	Fuel	Site	Run	HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	PC:W-Fired	Bituminous	Plant 4	3	11920		11.78	217	MW	0.99	20.1	0.0208	0.50
7	B	PC:W-Fired	Bituminous	Plant 4	4	11920		11.78	217	MW	0.98	24.4	0.0250	0.60
														0.43
10	A	Sprdr Stkr	Bituminous	Boiler 24	1	13203			320000	lb/hr	0.81	28.0	0.0271	0.72
10	A	Sprdr Stkr	Bituminous	Boiler 24	6	13581			320000	lb/hr	0.82	60.0	0.0572	1.55
10	A	Sprdr Stkr	Bituminous	Boiler 24	7	13761			320000	lb/hr	0.81	40.0	0.0431	1.19
10	A	Sprdr Stkr	Bituminous	Boiler 24	5	13674			320000	lb/hr	1.00	96.0	0.0928	2.54
10	A	Sprdr Stkr	Bituminous	Boiler 24	2	12906			320000	lb/hr	0.82	72.0	0.0782	2.02
														1.60
11	A	Sprdr Stkr	Bituminous	Kalamazoo	2	13645			90000	lb/hr	1.00	42.0	0.0434	1.18
11	A	Sprdr Stkr	Bituminous	Kalamazoo	6	13592			90000	lb/hr	0.75	36.0	0.0315	0.86
11	A	Sprdr Stkr	Bituminous	Kalamazoo	3	13617			90000	lb/hr	0.75	24.0	0.0241	0.66
11	A	Sprdr Stkr	Bituminous	Kalamazoo	8	13627			90000	lb/hr	0.75	22.0	0.0236	0.65
11	A	Sprdr Stkr	Bituminous	Kalamazoo	5	13059			90000	lb/hr	0.75	26.0	0.0300	0.78
11	A	Sprdr Stkr	Bituminous	Kalamazoo	4	13576			90000	lb/hr	1.00	42.0	0.0353	0.96
11	A	Sprdr Stkr	Bituminous	Kalamazoo	1	13727			90000	lb/hr	1.00	63.0	0.0548	1.51
11	A	Sprdr Stkr	Bituminous	Kalamazoo	9	13569			90000	lb/hr	0.75	28.0	0.0256	0.69
11	A	Sprdr Stkr	Bituminous	Kalamazoo	10	13628			90000	lb/hr	0.75	43.0	0.0374	1.02
														0.92

TABLE 4-5. NEW PM BASELINE DATA FOR BITUMINOUS COAL

					Fuel			Operation			PM Emissions,	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
3	C	Hand-Fed		Coal Stove	14119	0.77	3.09	0.01	MMBtu/hr			20.94
3	C	Hand-Fed		Modified Wood Stove	13421	0.79	5.43	0.01	MMBtu/hr			10.14
												15.54
9	A	PC-	Quindaro #2	1	11460	2.69	12.43	145	MW	0.91	9.9130	227.21
9	A	PC-	Quindaro #2	2	11460	2.69	12.43	145	MW	0.92	10.4090	238.57
9	A	PC-	Quindaro #2	3	11061	2.71	14.06	145	MW	0.89	12.3170	272.48
9	A	PC-	Quindaro #2	5	11161	2.63	13.23	145	MW	0.89	9.7040	216.61
												238.72
12	B	Stoker-Spreader	Clarksville	2	13885	0.69	6.10	150000	lb/hr	1.00	6.7000	186.06
12	B	Stoker-Spreader	Clarksville	3	13771	0.68	6.50	150000	lb/hr	1.00	5.2200	143.77
12	B	Stoker-Spreader	Clarksville	4	13729	0.62	7.50	150000	lb/hr	0.66	4.7900	131.51
12	B	Stoker-Spreader	Clarksville	5	13846	0.68	6.00	150000	lb/hr	0.66	5.1600	142.89
12	B	Stoker-Spreader	Clarksville	6	13808	0.65	5.40	150000	lb/hr	0.66	9.8200	271.19
												175.08

TABLE 4-6. NEW CH_4 BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data quality	Boiler type	Fuel	Run	Fuel			Operation		CH_4 Emissions,		
					HHV, Btu/lb	S, wt%	Ash, wt%	Capacity	Units	ppm	lb/MMbtu	lb/ton
3	C	Hand-Fed	Bituminous	Coal Stove	14118	0.77	3.09	0.01	MMBtu/hr	210.0	0.2261	6.38
3	C	Hand-Fed	Bituminous	Modified Wood Stove	13421	0.78	5.43	0.01	MMBtu/hr	95.0	0.1171	3.14
												4.76

Table 4-7. CONTROLLED PM EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel			Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency (%)	Ref.
		S, wt %	Ash, wt %	HHV, Btu/lb				
36 MW	Coal/industrial				Wet scrubber	(311 kg/hr/2.0 kg/hr)	99.4	20
10.2/15 MW 34/50 MMBtu/hr	Coal fired/ spreader stoker	0.8	9.7	12,900	Side stream separator	(23.3[a]/0.12)	99.5[a]	21
12.6-14/15 MW 39-47/50 MMBtu/hr	Coal fired/ spreader stoker	1.8	9.0	12,400	Side stream separator	(24.2[a]/0.12)	99.5[a]	21
15.6-16/20 MW 55-56/70 MMBtu/hr	Coal fired/ spreader stoker	0.9	4.3	13,700	Side stream separator	(21.9[a]/0.12)	99.4[a]	21
16.3-18.4/23 MW 56.8-64/80 MMBtu/hr	Coal fired/ spreader stoker	0.8	10.1	11,400	Side stream separator	(26.3[a]/0.13)	99.6[a]	21
17.8-18.9/18 MW 59.4-63/60 MMBtu/hr	Coal fired/ spreader stoker	2.1	8.8	12,400	Side stream separator	(24.2[a]/0.14)	99.4[a]	21
17.5-19.4/18 MW 53.8-65/60 MMBtu/hr	Coal fired/ spreader stoker	0.8	7.8	13,100	Side stream separator	(22.9[a]/0.17)	99.3[a]	21
24.7-28.1/29 MW 85-91/100 MMBtu/hr	Coal fired/ spreader stoker	1.7	6.1	13,100	Side stream separator	(22.9[a]/0.16)	99.3[a]	21
9/9 MW31/31 MMBtu/hr	Coal fired/ spreader stoker	1.3	7.8	13,200	Side stream separator	(22.7[a]/0.12)	99.6[a]	21
50.4/69 MW 172.3/236 MMBtu/hr	Coal fired	2.6	11.4	NR	Wet scrubber/ venturi	(NR/0.10)	N/A	21
58.7-62.9/69 MW 200-215/236 MMBtu/hr	Coal fired	2.5	10.4	NR	Wet scrubber/ venturi	(NR/0.07)	N/A	21
34/37 MW 115/125 MMBtu/hr	Coal fired	1.3	4.4	NR	Wet scrubber/ venturi	(NR/0.08)	N/A	21
18.6-19/19 MW 62.7-64/64 MMBtu/hr	Coal fired spreader stoker	2.8	6.9	13,600	Fabric filter	([a]22.1 /0.015)	99.7[a]	21
16-18.2/19 MW 56.3-61.4/64 MMBtu/hr	Coal fired spreader stoker	0.8	6.9	NR	Fabric filter	(NR/0.033)	N/A	21
28.5/37 MW 96/125 MMBtu/hr	Coal fired spreader stoker	2.6	7.0	13,500	Fabric filter	([a]22.2/0.01)	100.0[a]	21
43.2/46 MW 173.9/18 MMBtu/hr	Coal fired spreader stoker	2.9	6.5	13,800	Fabric filter	([a]21.7/0.028)	99.9[a]	21
23.4/33 MW 81.7/115 MMBtu/hr	Coal fired/FBC	3.6	12.3	11,800	Fabric filter	(NR/0.019 lb/MMBtu)	N/A	21

Table 4-7. CONTROLLED PM EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel			Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency (%)	Ref.
		S, wt %	Ash, wt %	HHV, Btu/lb				
9.6/13 MW 35.5/48 MMBtu/hr	Coal fired/ spreader stoker	0.6	8.3	13,700	Fabric filter	([a]21.9 lb/MMBtu/ 0.016 lb/MMBtu)	99.9[a]	21
58.4/59 MW 206/208 MMBtu/hr	Circulating FBC	0.4	8.8	12,200	Fabric filter	([a]24.6 lb/MMBtu/ 0.035 lb/MMBtu)	99.8[a]	21
27.8-28.6/27 MW 95-98/92 MMBtu/hr	Coal fired/ spreader stoker	NR	12.0	12,500	ESP	([a]24.0 lb/MMBtu/ 0.007 lb/MMBtu)	99.9[a]	21
32.8-34.3/35 MW 112-118/120 MMBtu/hr	Coal fired/ spreader stoker	1.0	11.2	12,500	ESP	([a]24.0 lb/MMBtu/ 0.006 lb/MMBtu)	99.9[a]	21
45.5-46.9/46 MW 154-159/156 MMBtu/hr	Coal fired/ spreader stoker	0.57	11.4	11,400	ESP	([a]26.3 lb/MMBtu/ 0.012 lb/MMBtu)	100.0[a]	21
63.5-65/73 MW 218-223/250 MMBtu/hr	Coal fired/ spreader stoker	0.73	6.6	13,100	ESP	([a]22.9 lb/MMBtu/ 0.021 lb/MMBtu)	99.9[a]	21
83.6/110 MW 285/375 MMBtu/hr	Coal fired/ spreader stoker	0.54	8.3	10,200	ESP	([a]28.4 lb/MMBtu/ 0.044 lb/MMBtu)	99.8[a]	21
57.2-64.9/110 MW 195/221 MMBtu/hr	Coal fired/ spreader stoker	0.63	5.4	10,600	ESP	([a]28.3 lb/MMBtu/ 0.018 lb/MMBtu)	99.9[a]	21

[a]Calculated
NR = not reported

TABLE 4-8. CONTROLLED SO_x EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel S[a], %	Control technology	Emissions (uncontrolled/controlled), lb/MMBtu[a]	Removal efficiency, %	Ref.
NR/36 MW	Coal/industrial		Wet scrubber	(115 kg/h/3.7 kg/h)	96.8	20
NR/400 MW NR/1360 MMBtu/hr	Coal	2.5-2.8	Dual alkali/wet scrubber	(5.4/0.65 lb/MMBTU)	88.0	22
NR/163 MW NR/570 MMBtu/hr	Coal	2.5	Dual alkali/wet scrubber	(3.85/0.31 lb/MMBTU)	92.2	22
NR/40 MW NR/140 MMBtu/hr	Coal	3-3.5	Dual alkali/wet scrubber	(5.6/0.47 lb/MMBTU)	91.2	22
82/82 MW 280/280 MMBtu/hr	Pulverized coal	13.33 lb SO_2/MMBtu	Dual alkali/wet scrubber	N/A	74.5	22
26/34 MW 86.3/116 MMBtu/hr	Pulverized coal	.96 lb SO_2/MMBtu	Lime spray dry FGD	N/A	92.4	22
24/69 MW 82.1/235 MMBtu/hr	Coal spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	79.7	22
46/69 MW 1645/235 MMBtu/hr	Spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	89.9	22
57/69 MW 193/236 MMBtu/hr	Spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	95.6	22
35-52/69 MW 118-174/235 MMBtu/hr	Spreader stoker	6.6 lb SO_2/ MMBtu	Lime spray dry FGD	N/A	64-96	22
69/69 MW 235/235 MMBtu/hr	Pulverized coal	.96 lb SO_2/ MMBtu	Lime spray dry FGD	N/A	96.6	22
305,000 SCFM	Industrial coal	3.0	Double Alkali System	(18,000 ppm/ 1,800 ppm)	90	23
210,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
67,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
236,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
38,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
140,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
8,070 SCFM	Industrial coal	2.5-3.0	Double Alkali System	(10,000 ppm/ 1,000 ppm)	90.5	23
128,400 SCFM	Industrial coal	2.5	Double Alkali System	(8,000 ppm/ 800 ppm)	90	23

[a]Unless otherwise noted
N/A = Not available

TABLE 4-9. CONTROLLED NO_x EMISSIONS

Boiler load level	Boiler type	Fuel N, wt %	Control technology	Emissions (uncontrolled/controlled), lb/MMBtu	Removal efficiency, %	Ref.
14.6/18 MW 51/63 MMBtu/hr	Coal/spreader stoker	1.5	LEA	(0.635/0.452)	29	24
23.5/28 MW 79/94 MMBtu/hr	Coal/spreader stoker	1.4	LEA	(0.634/0.491)	23	24
28.7/29 MW 98/99 MMBtu/hr	Coal/spreader stoker	1.0	LEA	(0.540/0.412)	24	24
28.7/29 MW 98/99 MMBtu/hr	Coal/spreader stoker	1.0	LEA	(0.572/0.401)	30	24
21.8/28 MW 73.5/96 MMBtu/hr	Coal/spreader stoker	1.2	LEA	(0.468/0.443)	5	24
21.8/29 MW 73.5/98 MMBtu/hr	Coal/spreader stoker	1.1	LEA	(0.454/0.312)	31	24
21.8/29 MW 75/h/100 MMBtu/hr	Coal/spreader stoker	1.1	LEA	(0.506/0.405)	20	24
22/29 MW 76/100 MMBtu/hr	Coal/spreader stoker	0.5	LEA	(0.483/0.418)	13	24
16.9/22 MW 57.6/75 MMBtu/hr	Coal/underfed stoker	1.4	LEA	(0.364/0.263)	28	24
16.9/22 MW 57.6/75 MMBtu/hr	Coal/underfed stoker	1.4	LEA	(0.433/0.361)	17	24
29.1/28 MW 98.6/95 MMBtu/hr	Coal/overfed stoker	1.8	LEA	(0.400/0.283)	29	24
28.6/28 MW 96.9/95 MMBtu/hr	Coal/overfed stoker	1.4	LEA	(0.229/0.211)	8	24
23/23 MW 77/77 MMBtu/hr	Coal/overfed stoker	1.7	LEA	(0.353/0.316)	10	24
19.2/18 MW 63.6/63 MMBtu/hr	Coal/overfed stoker	1.6	LEA	(0.324/0.310)	4	24
9.1/8 MW 31.9/56 MMBtu/hr	Coal/vibrating grate stoker	0.9	LEA	(0.277/0.209)	25	24
40-82%-150 MWe	PC: tangentially fired	N/A	OFA	(0.59/0.48)	19	25
40-82%-150 MWe	PC: wall fired	N/A	OFA	(0.77/0.06)	22	25

TABLE 4-9. CONTROLLED NO_X EMISSIONS

Boiler load level	Boiler type	Fuel N, wt %	Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency, %	Ref.
40-82%-150 MWe	PC: wall fired	N/A	LNB + OFA	(0.77/0.33)	57	25
40-82%-150 MWe	PC: wall fired	N/A	LNB	(0.77/0.45)	42	25
40-82%-150 MWe	PC: tangentially fired	N/A	LBN + OFA + FGR	(0.58/0.28)	52	25
40-82%-150 MWe	PC: tangentially fired	N/A	SNCR	(0.70/0.35)	50	25
40-82%-150 MWe	PC: wall fired	N/A	SNCR	(0.28/0.18)	36	25
40-82%-150 MWe	PC: wall fired	N/A	SCR	(0.28/0.08)	71	25
40-82%-150 MWe	PC: tangentially fired	N/A	SCR	(0.70/0.15)	79	25
40-82%-190 MWe	Cyclone	N/A	NGR	(1.28/0.56)	56	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	OFA	(0.77/0.60)	22	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	LNB	(0.77/0.45)	41	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	LNB + OFA	(0.77/0.33)	57	25
60-123 MWe/150 MWe	Coal/tangential	N/A	LNB + OFA + FGR	(0.58/0.28)	52	25
60-123 MWe/150 MWe	Coal/cyclone	N/A	reburn	(1.28/0.56)	57	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SCR	(0.28/0.08)	71	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SCR	(0.70/0.15)	78	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SNCR	(0.28/0.18)	36	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SNCR	(0.70/0.35)	50	25
60-123 MWe/150 MWe	PC: tangentially fired	N/A	OFA	(0.59/0.48)	19	25

LEA = Low excess air
OFA = Overfired air ports
LNB = Low NO_X burner
FGR = Flue gas recirculation
NGR = Natural gas reburn
N/A = Not available

TABLE 4-10 METAL ENRICHMENT BEHAVIORS

Class	Description	Reference 35	Reference 28	Reference 39
I	Equal distribution between fly ash and bottom ash		Aluminum (Al), Cobalt (Co), Iron (Fe), Manganese (Mn), Scandium (Sc), Titanium (Ti)	Al, Co, Chromium (Cr), Fe Mn, Sc, Ti
II	Enriched in fly ash relative to bottom ash	Arsenic (As), Cadmium (Cd)	As, Cd, Lead (Pb), Antimony (Sb)	As, Cd, Pb, Sb
III	Somewhere in between Class I and II, multiple behavior	Beryllium (Be), Cr, Nickel (Ni), Mn	Cr, Ni	Ni
IV	Emitted in gas phase	Mercury (Hg)	Hg	Hg

TABLE 4-11. ENRICHMENT RATIOS FOR CLASSES OF ELEMENTS

Class	Description	Metals	Fly ash enrichment ratio
I	Nonvolatile	Cr, Sc, Ti, Fe	ER = 1
IIa	Volatile with varying condensation on ash particles	As, Cd, Pb, Sb	ER > 4
IIb		Be, Co, Ni	2 < ER < 4
IIC		Mn	1.3 < ER ≤ 2
III	Very volatile, almost no condensation	Hg, Se	

ER = Enrichment ratio

TABLE 4-12. ENRICHMENT RATIOS FOR BOILERS AND ESP

Boiler type (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	Th 232	Th 228	U 238	Th 230	Ra 226	Pb 210
Pulverized Coal Dry Bottom (10100202)	1.07	1.26	0.66	0.56	0.98	1.02	1.46	1.07	0.72	0.97	1.01	1.43	0.96	1.19		0.98	1.33
Pulverized Coal Dry Bottom Tangential (10100212)	0.97 to 1.33	1.08 to 1.27	0.78 to 1.12	0.49 to 0.88	0.42 to 0.97	0.90 to 0.97	1.28 to 1.42	0.86 to 1.02	0.71	0.94 to 1.54	0.76 to 0.82	1.04 to 1.16	0.82 to 1.16	1.06 to 1.24	1.19	0.95 to 1.19	1.36
High efficiency Cold-side ESP	5.4 to 26	5 to 29.6	2.1	8	1 to 21.7	1.1 to 9.9	3.0 to 18.3	1.4 to 13.8	1.0 to 19.3	1.8 to 10.1	7 to 86.2	0.04 to 0.88	1.19	1.15 to 1.36		1.68	0.94

TABLE 4-13. HAP EMISSION FACTORS (ENGLISH UNITS) FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized Coal Configuration Unknown (No SCC)	N/A	N/A	N/A	1922	N/A	N/A	N/A	N/A	N/A	112[b]
Pulverized Coal Wet Bottom (10100201)	538	81	44-70	1020-1570	507[c]	808-2980	16	840-1290	N/A	N/A
Pulverized Coal Dry Bottom (10100202)	684	81	44.4	1250-1570	507[c]	228-2980	16	1030-1290	2.08	N/A
Pulverized coal Dry Bottom, Tangential (10100212)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.4	N/A
Cyclone Furnace (10100203)	115	<81	28	212-1502	507[c]	228-1300	16	174-1290	N/A	N/A
Stoker Configuration Unknown (No SCC)	N/A	73	N/A	19-300	N/A	2170	16	775-1290	N/A	N/A
Spreader Stoker (10100204)	264-542	N/A	21-43	942-1570	507[c]	N/A	N/A	N/A	N/A	221[d]
Traveling Grate, Overfed Stoker (10100205)	542-1030	N/A	43-82	N/A	507[c]	N/A	N/A	N/A	N/A	140[e]

[a] All emission factors in lb/10^{16} Btu; all emission factors rated E.
[b] Based on 2 units; 456 MWe and 133 MMBtu/hr.
[c] Lead emission factors were taken directly from an EPA background document for support of the NAAQS.
[d] Based on 1 unit; 59 MMBtu/hr.
[e] Based on 1 unit; 52 MMBtu/hr.

TABLE 4-14. HAP EMISSION FACTORS (METRIC UNITS) FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized Coal Configuration Unknown (No SCC)	N/A	N/A	N/A	825	N/A	N/A	N/A	N/A	N/A	48[b]
Pulverized Coal Wet Bottom (10100201)	231	35	18-30	439-676	218[c]	348-1282	7	361-555	N/A	N/A
Pulverized Coal Dry Bottom (10100202)	294	35	19	538-676	218[c]	98-1282	7	443-555	0.894	N/A
Pulverized coal Dry Bottom, Tangential (10100212)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.03	N/A
Cyclone Furnace (10100203)	49.5-133	<34.9	12	91.2-676	218[c]	98-559	6.9	74.9-555	N/A	N/A
Stoker Configuration Unknown (No SCC)	N/A	31.4	N/A	8.1-675	N/A	934	6.9	334-555	N/A	N/A
Spreader Stoker (10100204)	114-233	N/A	9.0-18.5	N/A	218[c]	N/A	N/A	N/A	N/A	95[d]
Traveling Grate, Overfed Stoker (10100205)	233-443	N/A	19-35	N/A	218[c]	N/A	N/A	N/A	N/A	60[e]

[a] All emission factors in pg/J; all emission factors rated E.
[b] Based on 2 units; 456 MWe and 39 MW.
[c] Lead emission factors were taken directly from an EPA background document for support of the NAAQS.
[d] Based on 1 unit; 17 MW.
[e] Based on 1 unit; 15 MW.

TABLE 4-15. HAP EMISSION FACTORS (ENGLISH UNITS) FOR CONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Boiler configuration (SCC)	Control device	Cr	Mn	POM
Pulverized coal Configuration unknown (no SCC)	Multicyclones	12		
	ESP	5.8-7990		
	Wet scrubber	0.61-12		
	Multicyclones/wet scrubber	18		
Pulverized coal Wet bottom (10100201)	ESP		78	18.6
	Wet scrubber			565
Cyclone Furnace (10100203)	ESP	19-22	60.8	0.46
	Wet scrubber	107	126	57.2
Stoker Configuration unknown	Multicyclones	62-2423	110	16.2
(no SCC)	ESP	135		
Pulverized coal Dry bottom (10100202)	ESP		96.2	8.55
	Wet scrubber		112	0.033-18.6
	Multicyclones/ ESP			

[a] All emission factors in lb/MMBtu; all emission factors rated E.

TABLE 4-16. HAP EMISSION FACTORS (METRIC UNITS) FOR CONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Boiler configuration (SCC)	Control device	Cr	Mn	POM
Pulverized coal Configuration unknown (No SCC)	Multicyclones	5.3		
	ESP	2.5-3430		
	Wet scrubber	0.26-5.3		
	Multicyclones/wet scrubber	7.8		
Pulverized coal Wet bottom (10100201)	ESP		33.5	8.0
	Wet scrubber			2.43
Cyclone furnace (10100203)	ESP	8.4-9.7	27	0.20
	Wet scrubber	47.3	55.8	25.3
Stoker Configuration unknown (No SCC)	Multicyclones	27.4-1072	48.7	7.2
	ESP	59.7		
Pulverized coal Dry bottom (10100202)	ESP		41.3	3.68
	Wet scrubber		48.2	0.014-8
	Multicyclones/ESP			

[a] All emission factors in pg/J; all emission factors rated E.

TABLE 4-17. AVERAGE TRACE ELEMENT REMOVAL EFFICIENCY FOR CONTROL DEVICES[a]

Compound	Mechanical precipitation	ESP	FGD scrubber	Two ESPs in series	ESP/ scrubber	Two multicyclones
Arsenic	51	87.5		99.6	98.9	
Beryllium	37	91.9	94.3	99.94		
Cadmium	28.9	74.6	94.4[b]	90.5		
Chromium[d]	42.3	71.5	91.8[b]	93.7	92.9	50[c]
Manganese	54.3	78.1	89.1[b]	96.4	97.7	
Nickel	49.4	79.1	96.4[b]	96.6	97.2	

[a] These average control efficiencies represent measured control levels reported in the literature. They may or may not be indicative of the long-term performance of these types of controls on emissions from coal combustion sources. The average values should not be construed to represent an EPA-recommended efficiency level for these devices. Only limited data are available for lead and mercury removal efficiencies. Each emission test was weighted equally.

[b] The type of scrubber was not specified.

[c] These control efficiencies are for hexavalent chromium; the remaining values are for total chromium.

[d] The chromium control efficiencies may be biased low due to contamination from sampling equipment. Emission factors calculated using these efficiencies probably represent, in most cases, upper bound estimates.

TABLE 4-18. N_2O EMISSIONS DATA

Ref.	Data quality	Boiler type	Fuel type	Boiler capacity	Boiler load	Uncontrolled N_2O emissions, ppm	N_2O emission factor, lb/ton
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.96	2.1	7.56E-02
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.82	2.5	9.00E-02
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.76	5.1	1.84E-01
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.96	3.3	1.19E-01
							1.17E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	2	7.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.9	6.55E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	4.6	1.64E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.7	2.55E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.1	4.01E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.9	3.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.8	2.91E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.9	3.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3	1.07E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	2.1	7.65E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	0.7	2.49E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.4	5.10E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.1	7.47E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
							8.74E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
							1.06E-01
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02

TABLE 4-18. N_2O EMISSIONS DATA

Ref.	Data quality	Boiler type	Fuel type	Boiler capacity	Boiler load	Uncontrolled N_2O emissions, ppm	N_2O emission factor, lb/ton
79	B	TANGENTIAL	BIT.	700 MW	0.8	2.3	8.18E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
							2.96E-02
80	C	FLUIDIZED BED COMBUSTION CIRC	BIT.	8 MW		136	5.65E+00

TABLE 4-19. SUMMARY OF N_2O EMISSION FACTORS FOR BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Firing configuration	Rating	N_2O emission factor, lb/ton	N_2O emission factor, kg/Mg
Pulverized coal fired			
Dry bottom - wall fired	D	0.09	0.045
Dry bottom - tangential	D	0.03	0.015
Wet bottom	E	0.09[a]	0.045[a]
Cyclone furnace	E	0.09[a]	0.045[a]
Spreader stoker	E	0.09[a]	0.045[a]
Overfeed stoker	E	0.09[a]	0.045[a]
Underfeed stoker	E	0.09[a]	0.045[a]
Handfired units	E	0.09[a]	0.045[a]
Fluidized beds			
Bubbling	E	5.5[b]	2.7[b]
Circulating	E	5.5	2.7

[a] No data; value for pulverized coal dry bottom - wall fired was assigned.
[b] No data; value for circulating fluidized bed was assigned.

TABLE 4-20. PARTICULATE SIZING DATA FOR THE 1986 AP-42 DATABASE: NUMBER OF A & B RANKED DATA SETS[a]

Source category	Emission control device				
	None	Multiple cyclones	Scrubber	ESP	Baghouse
Bituminous/subbituminous coal					
combustion	>30	3	>30	>30	2
- Dry bottom, pulv. coal	3	0	0	0	0
- Wet bottom, pulv. coal	0	0	1	2	0
- Cyclone furnace	>30	11[b]	0	0	>30
- Spreader stoker	3	2	0	0	0
- Overfeed stoker	6		0	0	0
- Underfeed stoker					

[a] Data from Reference 2
[b] All data correspond to no fly ash reinjection

TABLE 4-21. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A COAL-FIRED BOILER[a]

Run Number[b]	Organic CPM emissions,		Inorganic CPM emissions[c],	
	mg/m^3	% of total	mg/m^3	% of total
1	0.5	1.2	40.1	98.8
2	0.5	1.3	37.4	98.7
3	1.6	4.5	33.9	95.5
4	1.6	3.7	42.0	96.3
5	0.6	1.5	38.9	98.5

[a] Based on Reference 83.
[b] Run 1 results consist of one train with an N_2 purge. Run 2 is an average of two simultaneous trains purged with N_2. Runs 3 and 5 are averages of three simultaneous trains purged with N_2. Run 4 is an average of four simultaneous trains purged with N_2.
[c] Corrected for chlorides.

TABLE 4-22. FILTERABLE PARTICULATE FOR A FRONT WALL FIRED BOILER FUELED ON A LOW SULFUR WESTERN BITUMINOUS COAL

	Filterable particulate, Cumulative mass percent less than stated size (in microns)								
Side of duct	0.625	1.00	1.25	2.50	6.00	10	15	Data quality rating	Ref.
West side	< 4	< 4	4	5	8	13	18	B	86
East side	< 2	< 2	2	4	9	15	24	B	86

TABLE 4-23. FILTERABLE PARTICULATE FOR SUBBITUMINOUS COAL FIRED FLUIDIZED BED COMBUSTORS WITH MULTICLONE CONTROLS

	Filterable particulate, Cumulative mass percent less than stated size (in microns)								
Fuel	0.625	1.00	1.25	2.50	6.00	10	15	Data quality rating	Ref.
Navajo subbituminous	< 2	12	22	56	82	88	90	D	85
Sarpy Creek subbituminous	< 2	9	17	55	74	85	90	D	85

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APPENDIX A

BACKGROUND FILE DATA SPOT CHECK SUMMARY

A review of the 1988 AP-42 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was sone by selecting primary data references from the background file, reviewing data quality sampling and analytical procedures, determining completeness, and verifyuing that the site emission factors in the background files could be reconstructed and were accurate. The results of these spot checks are summarized below; the reference numbers correspond to the 1988 AP-42 Section 1.1 reference list. Example spot check data are presented in Table A-1.

Reference 15

Contains six data points. States in the paper that a sampling was only for comparative purposes and emission shouldn't be taken as absolute. Couldn't get all representative sampling locations due to obstruction or bends. Able to recreate "background" data values in histogram.

Reference 17

Checked "ALMA" site. Particulate tests done with bituminous and subbituminous coal. Appears two values were averaged and entered in histogram twice.

Sulfur dioxide data are questionable because sulfur analysis was taken from samples after the blower but HHV is baseed on "as received" coal. Need to eliminate some anomalous data points. Requires minor adjustment to SO_2 histograms. Chedked "ALMA" site. Appears that emission factor was calculated from parametric test midifying combustion air. Normal operation should be used for emission factor indicating a revision of the histogram and emission factor.

Reference 18

Sample train was an unproven Method 5 midified to collect HAPs from utility boilers. Sulfur dioxide based on sulfur retention in bottom ash was acceptable. Carbon monoxide data were not of good quality but hadd not been used in the previous AP-42 update. Particulate data (uncontrolled) were colleced in an improper sampling location with poor flow distribution and significant swirl because it was only two diameters from the inlet breaching. Data should be rated as poor quality but calculated emission factor (96A) is very close to the AP-42 published average. therefore, inclusion or exclusion is not significant.

Reference 23

Particulate measurements were nade using currently unapproved APCO and ASME methods. Correlation between tow methods was not good; test conditions, methodologies, and data collected were not well-documented (no raw data sheets). Data quality should be reated no better than C. Calculations were correct.

Reference 34

Appeared to be a well-codumented test report with good quality measurement methodology. the source operation, however, appeared to be somewhat variable with paramenter swings and intermittent periods of fly ash reinjection.

Reference 49

All dat for fireplaces. Several points burning coal in fireplaces. Discard data. New data available for hand-fed particulate.

Reference 50

No CH_4 data. Emission factor given as "estimate", but references 1966 data not representative of current protocols. Recommend not using current published emission factor.

Reference 58

No CH_4 data for handfed units. All data in this report are for larger utility boilers. Volatile organic compound data were acceptable.

TABLE A-1. SO_x EMISSIONS FROM PULVERIZED COAL, DRY BOTOM BOILERS

Boiler[a] Type	Fuel[b]	Ref.[a]	Site	Data Date	Run No.	Fuel HHV Btu/lb, Btu/g	Fuel S%	Fuel N%	Fuel Ash%	Operation Load/Capacity	Controls Description	Sampling Method	Sampling O_2	Emission UC, C #/10^6 Btu	Remarks
FW	B	17	ALMA	75	6	10776	3.66	1.00	13.47	196/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	35	5.957 34.9 (S) N/A	Uses S analysis from blower catch in report. This sample has been ground and dried substantially. HHV is taken from 1 as received ultimate analysis. Recalculate EF data point with ulimate analysis Nos. Previous average appears to be 335. New average would be 33.7(S) but 12.2% O_2 is very high and at low load, probably should drop. No sampling data sheets in this reference; they are contained in EPA60017-78-1-55b.
FW	B	17	ALMA	75	9	10776	3.66	1.00	13.47	57/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	40	6.396 37.5 (S) N/A	
FW	B	17	ALMA	75	16	10776	3.66	1.00	13.47	60/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	12 2	4.905 28.7 (S) N/A	
FW	S	17	ALMA	75	63	9336	0.81	0.73	17.26	131/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	28	2.888 66.6 (S)	
FW	S	17	ALMA	75	64	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	29	1.440 33.2 (S)	
FW	S	17	ALMA	75	72	9336	0.81	0.73	17.26	101/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	67	2.387 55 (S)	
FW	S	17	ALMA	75	73	9336	0.81	0.73	17.26	94/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	50	1.799 41.5 (S)	
FW	S	17	ALMA	75	74	9336	0.81	0.73	17.26	90/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	68	1.407 32.4 (S)	
FW	S	17	ALMA	75	75	9336	0.81	0.73	17.26	160/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	58	1.367 31.5	

[a]FW-Front wall-fired pulverized coal boiler.
[b]B-Bituminous coal, S-Subbituminous coal.
[c]Reference numbers as cited in 1988 AP-42 Section 1.1.

TABLE A-2. NO_x EMISSIONS FROM PULVERIZED COAL, DRY BOTTOM BOILERS

Boiler Type	Fuel	Reference	Site	Data Date	Run No.	Fuel: HHV Btu/lb, Btu/g	Fuel: S%	Fuel: N%	Fuel: Ash%	Operation: Load/ Capacity	Sampling: Method	Sampling: O_2 %	Emission: UC, C # NO_2 / 10^3 Btu	Remarks
FW	B	17	ALMA	75	50	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr	Teco 10	5.2	0.935	Presented in summary table = 20.15 + 15.5. Burner diffuser varied from normal, high O_2.
FW	B	17	ALMA	75	25	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		3.8	0.834	EF-17.97 Air Reg. as found.
FW	B	17	ALMA	75	42	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		2.9	0.785	EF-16.9 as found.
FW	B	17	ALMA	75	47	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		3.7	0.860	EF-18.54 Air Reg. as found.
FW	B	17	ALMA	75	49	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		1.8	0.481	EF-10.36 Burners varied, Low O^2 appears EF based on parametric O_2 tests No. 47, 49, 50-yielding 15.2 normal operation would be better described by "as found" No. 25, 42, 47-yielding EF-17.8.
FW	S	17	ALMA	75	57A	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr		5.7	0.958	Chosen for summary table EF-17.89 old EFD value - 12 only high load test w/o modifying air.
FW	S	17	ALMA	75	57A	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr	avgs in table 5.1-10		25.1% of fuel N	EF-12.04 but includes averages from all parametric tests including 25% and 50% loads.
FW	S	17	ALMA	75	68	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr		2.7	0.469	CO high, 750 ppm, ignore EF-8.76.

[a]FW-front wall-fired pulverized coal boiler.
[b]B-Bituminous coal, S-Subbituminous coal.
[c]Reference numbers as cited in 1988 AP-42 Section 1.1.

TABLE A-3. PM EMISSIONS FROM PULVERIZED COAL, DRY BOTTOM BOILERS

Boiler Type	Fuel	Reference	Site	Data Date	Run No.	Fuel HHV Btu/lb, Btu/g	Operation Load/ Capacity	Sampling Method	Sampling O_2 %	Emission UC, C $\frac{\# NO_2}{10^3 Btu}$	Emission Factor
HO	B	15	Hartlee #3	72	1	12310	490/480	5	3.0	3.03	12.05A
HO	B	15	Hartlee #3	72	2	12589	488/480	5	3.7	3.20	9.72A
HO	B	15	Hartlee #3	72	3	12121	483/480	5	3.0	3.84	8.58A
HO	S	15	Four Corners #4	72	1	8821	755/800	5	3.4	7.65	21.92A
HO	S	15	Four Corners #4	72	2	8811	755/800	5	3.1	8.91	21.96A
FW	B	15	Widows Creek #6	72	1	11452	125/125	5	3.3	4.65	15.87A
FW	B	15	Widows Creek #6	72	2	11477	128/125	5	3.6	7.89	18.39A
T	B	15	Barry #3	73	1	12706	293/360	5	5.0	2.0	4.89A
T	B	15	Barry #3	73	2	12641	283/360	5	4.5	5.14	4.86A

FW = Front Wall.
HO = Horizontally opposed pulverized coal boiler.
T = tangentially fired pulverized coal boiler.
B = Bituminous coal, S- Subbituminous coal.
Reference numbers as cited in 1988 AP-42 Section 1.1.

APPENDIX B

CONVERSION FACTORS

TABLE B-1. CONVERSION FACTORS

Given	To Obtain	Multiply By
ppm	lb/MBtu	2.59 X 10^{-9} (MW)Fd (20.9/20.9-O_2) Where Fd from 40 CFR Part 60 Appendix A M19 - usually 9820
lb/MBtu	lb/ton	HHV (as rec'd) = 2,000/10^6
lb/ton	kg/Mg	0.5
HHV dry, mineral matter free	HHV (as rec'd)	(100-M-A)/100

MW = Molecular weight of pollutant.
O_2 = Oxygen concentration at sampling point in percent.
M = Moisture in as received coal sample in percent.
A = Ash in as received coal sample in percent.

APPENDIX C

MARKED-UP 1988 AP-42 SECTION 1.1

REPORT ON REVISIONS TO
5TH EDITION AP-42
SECTION 1.1
Bituminous and Subbituminous
Coal Combustion

Prepared for:

Contract No. 68-D2-0160, Work Assignment 92
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October 1996

Table of Contents

1.0 INTRODUCTION

This report supplements the Emission Factor (EMF) Documentation for AP-42 Section 1.1, Bituminous and Subbituminous Coal Combustion, dated April, 1993. The EMF describes the source and rationale for the material in the most recent updates to the 4th Edition, while this report provides documentation for the updates written in both Supplements A and B to the 5th Edition.

Section 1.1 of AP-42 was reviewed by internal peer reviewers to identify technical inadequacies and areas where state-of-the-art technological advances need to be incorporated. Based on this review, text has been updated or modified to address any technical inadequacies or provide clarification.

Emission factors for criteria pollutants were checked for accuracy with information in the EMF Document and new emission factors generated if recent test data were available. If discrepancies were found when checking the factors with the information in the EMF Document, the appropriate reference materials were then checked. In some cases, the factors could not be verified with the information in the EMF Document or from the reference materials, in which case the factors were not changed.

The emission factors for toxic air pollutants in Section 1.1 were not examined; however, emissions data from several sources were evaluated for toxic emission factors of sufficient quality that could replace existing factors of relatively lower quality or that would be added to the section as new factors. None of the existing toxic emission factors were replaced, but many new factors were added as a result of the evaluation.

Four sections follow this introduction. Section 2 of this report documents the revisions and the basis for the changes. Section 3 presents the references for the changes documented in this report. Section 4 presents the revised AP-42 Section 1.1, and Section 5 contains the EMF documentation dated April, 1993.

2.0 REVISIONS

This section documents the revisions made to Section 1.1 of the 5th Edition of AP-42.

2.1 General Text Changes

Text was clarified or added concerning coal rank, firing practices, emissions, and controls. The table presenting NO_x controls for stoker coal-fired boilers was modified to include NO_x controls for all types of coal-fired boilers. Also, at the request of EPA, metric units were removed.

2.2 Sulfur Oxides, SO_x

The SO_x emission factors were checked against information in Table 4-2 of the EMF Document and no changes were required.

2.3 Nitrogen Oxides, NO_x

The NO_x emission factors were checked against information in Table 4-3 of the EMF Document and no changes were required. However, data were available to create an emission factor for a new firing configuration—cell burner fired boilers. The cell burner boiler is a special type of an opposed wall-fired boiler that has two or three closely (vertically) spaced burners (referred to as a "cell"). Cell burner boilers can emit up to twice as much NO_x as typical wall-fired boilers due to higher heat release rates, higher combustion temperatures, and more turbulence in the primary combustion zone. All of these factors contribute to higher NO_x levels.

Data for six cell burner units from four references were reviewed.[1-4] The data ranged from 18.5 lb/ton to 44.4 lb/ton, with an average of 31 lb/ton. The data are summarized in Table 1.2.4.

Table 1. Summary of Cell Burner Data

Reference[a]	Data Rating	Unit	Capacity (MW)	Coal Type	Heating Value, Btu/lb	Tested Load, %	NO_x lb/mmBtu	NO_x lb/ton
1	B	Cumberland 1	1300	Bit (1)	13064	78	1.7	44.42
1	B	Cumberland 2	1300	Bit (1)	13016	95	1.5	39.05
1	B	Cumberland 2	1300	Bit (1)	13016	100	1.4	36.44
1	B	Four Corners 4	800	Subbit (2)	13016	75	1.08	28.08
1	B	Four Corners 4	800	Subbit (2)	13000	95	1.09	28.34
2	C	Four Corners 4	800	Subbit (3)	13000	100	1.27	35.17
1	B	Harlee Branch 3	480	Bit (2)	13848	83	0.71	18.46
1	B	Harlee Branch 3	480	Bit (2)	13000	100	0.95	24.70
3	C	Four Corners 5	800	Subbit (4)	13848	93	1.15	31.85
4	B	J.M. Stuart 4	610	Bit (2)	13000	75	0.92	23.92
4	B	J.M. Stuart 4	610	Bit (2)	13000	100	1.22	31.72
Overall Rating: Average	C						1.18	31.10

Heating Value Notes:
(1) From reference, p. 102
(2) Typical value, AP-42, 5th Edition, Appendix A
(3) Estimated from Four Corners 5 data in Reference 5
(4) From Reference 4

[a]REFERENCES:

from 18.5 lb/ton to 44.4 lb/ton, with an average of 31 lb/ton. The data are summarized in Table 1.

2.4 Carbon Monoxide, CO

The CO emission factors were checked against information in Table 4-4 of the EMF Document and no changes were required.

2.5 Filterable Particulate Matter (PM) and PM Less Than 10 Microns (PM-10)

The filterable PM and PM-10 emission factors were checked against Table 4-2 of the EMF Document and remain the same as in the 7/93 version of AP-42.

2.6 Particle Size Distribution, PSD

The PSD emission factors for dry bottom boilers, wet bottom boilers, cyclone furnaces, spreader stokers, overfeed stokers, and underfeed stokers were checked against information in the EMF Document and the 9/88 version of AP-42. There were no changes required.

2.7 Total Non-Methane Organic Compounds, TNMOC

The TNMOC emission factors were checked against information in the EMF Document and no changes were necessary.

2.8 Greenhouse Gases

2.8.1 Carbon Dioxide, CO_2

The CO_2 emission factors provided in the footnotes to Tables 1.1-1 and 1.1-2 were based on 100% conversion of fuel carbon content to CO_2. References 5-8 suggest that 99% is a more accurate conversion factor for solid fuel combustion. Therefore, the conversion factor in the footnotes of Table 1.1-1 was changed from 73.3C to 72.6C.

In case an ultimate analysis is not available, default CO_2 emission factors for U.S. coals were computed based on the conversion factor presented above and average carbon content (dry basis) for each class of coal. Several references were located that listed carbon content of U.S. coals. These reference sources were then compared and default emission factors were computed based on the average of all reference sources for the bituminous and subbituminous coals in Table 2. Because of the geographical variance of carbon content within each subtype, these default factors were assigned a "C" rating.

Table 2. Default CO_2 Emission Factors for U.S. Coals
Emission Factor Rating: C

Coal Type	Average %C[a]	Conversion Factor[b]	Emission Factor (lb CO_2/ton coal)
Subbituminous	66.3	72.6	4810
High-Volatile Bituminous	75.9	72.6	5510
Medium-Volatile Bituminous	83.2	72.6	6040
Low-Volatile Bituminous	86.1	72.6	6250

[a] An average of the values given in References 9-12. Each of these references listed average carbon contents for each coal type (dry basis) based on extensive sampling of U.S. coals.

[b] Based on the following equation:

$$\frac{44 \text{ ton } CO_2}{12 \text{ ton C}} \times 0.99 \times 2000 \frac{\text{lb } CO_2}{\text{ton } CO_2} \times \frac{1}{100\%} = 72.6 \frac{\text{lb } CO_2}{\text{ton} - \%C}$$

Where: 44 = molecular weight of CO_2;
12 = molecular weight of carbon; and
0.99 = fraction of fuel oxidized during combustion (Reference 6).

2.8.2 Methane, CH_4

No data were found to improve the current “B” rated CH_4 emission factors for bituminous and subbituminous coal combustion in Tables 1.1-11 and 1.1-12.

2.8.3 Nitrous Oxide, N_2O

The existing N_2O emission factors for coal combustion in Table 1.1-11 were “E” rated and may possibly be based on test data obtained before the discovery of a testing artifact that caused erratic readings in test samples.[(13)] The following emission factors are based on source test data obtained since the discovery of the N_2O testing artifact and were obtained using proper testing protocols.

Table 3. Emission Factors for Coal Combustion in Section 1.1
(lb N_2O/ton coal)

Combustion Category	New	New	Previous	Previous AP-42
Fluidized bed - utility	B	3.5[a]	5.5	E
Pulverized coal - utility	D	0.04[b]	0.09	E
Spreader-stoker - utility	D	0.04[b]	0.09	E
Tangentially fired - utility / industrial	B	0.08[a]	0.03	D
Wall fired - utility / industrial	B	0.3[a]	0.09	D

[a] References 14, 15.
[b] References 16, 17.

The fluidized bed emissions data are based on 17 source tests at 5 different facilities collected by Nelson.[(14)] This data were regressed and emission factors were developed by Peer.[(15)] The pulverized coal and spreader-stoker factor is based on data taken at six coal-fired power plants collected by Montgomery[(16)] and analysis of this data conducted by Piccot.[(17)] The tangentially-fired data are based on 24 source tests at 10 different facilities collected by Nelson.

The wall-fired data are based on 15 source tests conducted at 7 different facilities collected by Nelson.

The data sets were converted to pounds per million BTU (lb/MMBtu) according to the procedures given in 40 CFR 60, Appendix A. To obtain lbs/MMBtu, the emissions (in ppm) were first multiplied by 1.141 x 10^{-7} (lb/scf)/ppm. These values were then converted to lb/MMBtu using the following formula:

$$E = C_d F_d \left(\frac{20.9}{20.9 - \%O_2} \right)$$

Where: C_d = N_2O concentration (lb/scf);
F_d = Fuel factor (F-factor) for coal; and
$\%O_2$ = oxygen concentration in the exhaust gas.

An F-factor of 9,780 scf/MMBtu was used for bituminous coal. Lb/MMBtu values were then converted to mass-based emission factors using a heating value of 13,000 Btu/lb for bituminous coal (AP-42 Appendix A).

2.9 Toxic Air Pollutants

The existing toxic emission factors in Section 1.1 were not replaced but an evaluation of toxic emissions data resulted in the development of new factors that were added to the section. Most of the emissions data were stack test reports that presented emission factors, or reports that presented emissions and process data from which emission factors were developed. The following sections describe the documents evaluated and the methods used to develop the toxic emission factors.

2.9.1 General Document Evaluation and Emission Factor Development

Section 1.1, Bituminous And Subbituminous Coal Combustion and Section 1.7, Lignite Combustion were updated simultaneously and, therefore, emissions data from both types of combustion were of interest during the emissions data evaluation.

The focus of the emissions data evaluation was on toxic air pollutants, especially metals. Several documents provided emissions data for compounds that are not considered hazardous air pollutants and these data were not used to develop emission factors. Because of the limited scope of the emission factor development project, some data for toxic air pollutants were not used. Emissions data for radionuclides were encountered but were not used because the list of potential radionuclide emission factors is quite extensive. Emissions data for dioxins/furans were not used unless data for the tetra— through octa— homologue groups were provided.

Because of budget constraints, the document evaluation concentrated on air emissions, or final stack emissions, only. Emissions data obtained from sampling at control device inlets, or outlets of intermediate control devices, were not used to develop emission factors.

Following EPA guidance, the emission factors developed for Section 1.1 of AP-42 are expressed in units of pound of pollutant emitted per ton of coal fired (lb/ton). Thus, the emissions documents were evaluated in order to identify emission factors, or information from which emission factors could be developed, in units of lb/ton. Many of the documents presented emission factors, but they were in units of pound of pollutant emitted per million British thermal units of heat input (lb/MMBtu). In such cases, a higher heating value (HHV) for coal in units of Btu/lb was used to convert the factor to units of lb/ton. Several of the documents provided emissions and process information, such as emission rates and coal feed rates, that were used to develop emission factors. Some of the documents provided coal data, such as the HHV and coal feed rate, on a dry-basis. When the moisture content of the coal was provided, the dry-basis data were converted to as-fired, or as-received, data. The methods used for each document to develop the emission factors are described in Section 2.9.2 Description Of Documents Evaluated.

The majority of the documents evaluated were emissions test reports obtained from various sources. One source of emissions information was test reports provided by the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE). EPRI and DOE conducted an extensive emissions test program at several coal-fired power plants in order to characterize their emissions. Most of the individual facility test reports and the summary report of the test program were provided to EPA for use in emission factor development.

Another source of information was several emissions test reports from coal-fired power plants provided to EPA by the Northern States Power Company (NSP). In addition, several test reports obtained by EPA from other sources were evaluated.

A computer spreadsheet was constructed for each document where calculations were required to develop and characterize emission factors from information presented in the document. A spreadsheet was created for every reference except Reference 18. Reference 18 is a summary of an emissions test program conducted by EPRI and DOE. The spreadsheets were used as mathematical tools and as a means of documenting all calculations and assumptions. Also, information from each document that was used to characterize the emission factors was included in the spreadsheets. For example, information provided about the boiler(s) tested was used to assign a source classification code (SCC). In addition, any control devices in use by the emission source were noted. The spreadsheets are included in Appendix A.

When assigning SCCs to an emission source described in a reference, the boiler was assumed to be dry bottom unless the document specified that the boiler was wet bottom or mentioned an ash removal method that would be indicative of a wet bottom boiler. All emission controls described by the reference as being in use at the time the emissions data were collected were noted and no attempt was made to judge the effect of a control device on any of the sampled pollutants. Emissions data were characterized as "uncontrolled" unless there was no type of pollution control device at all in use when the emissions data were collected.

2.9.2 Description of Documents Evaluated

The following paragraphs provide a summary of the information presented in each document that was evaluated for emission factors. Also, the methods used to develop emission factors from the information provided in each document are described. The computer spreadsheets that were constructed for each document (except Reference 18) are contained in Appendix A. The text descriptions are provided as a supplement to the spreadsheets in order to ensure that the development of all emission factors is fully explained.

Reference 18

This document summarizes the results of the emissions test program conducted by EPRI and DOE. This document presents emission factor equations for nine trace metals and emission factors for five organic pollutants that were developed from emissions data collected during the test program. The emission factor equations were judged to be of sufficient quality for inclusion in AP-42 and are presented there "as is," i.e., no adjustments or conversions were made. The organic emission factors were not used for AP-42 because they are a geometric, instead of arithmetic, mean. The reference was assigned a data quality rating of "A." The emission factor equations are discussed in detail in Section 2.9.3 Emission Factor Development.

Reference 19

This reference presents the results of an emissions test at the NSP Sherco Plant located in Becker, Minnesota. The boiler tested was Unit Three, which is an 860 megawatt (MW) Babcock and Wilcox (B&W) unit which came on line in 1987. The boiler was firing pulverized subbituminous coal from Montana during the emissions test. Emission controls utilized during the emissions test were a spray dryer absorber and a baghouse.

Three sampling runs were conducted for dioxins/furans, and the emissions test results are reported as emission rates in units of grams per second (g/sec). The reference indicates that all sampling results were above the detection limits. Emission rates in units of g/sec were converted to pounds per hour (lb/hr).

The report did not provide coal feed rates or the HHV of the coal fired during the emissions tests. A fuel factor (F-factor) for coal of 9,780 dry standard cubic feet per MMBtu (dscf/MMBtu), provided in 40 Code of Federal Regulations (CFR) Part 60 Appendix A Method 19, and the stack gas volumetric flow rate, dry standard cubic feet per hour (dscf/hr) were used to develop an energy input rate in MMBtu/hr. An HHV of 8,547 Btu/lb, provided in another stack test report (Reference 25) from the same facility was used to convert the energy input rate to a coal feed rate in units of ton/hr. The dioxin/furan emission rates (lb/hr) were then divided by the coal feed rate to arrive at emission factors in lb/ton.

A data quality rating of "C" was assigned to the reference because the coal feed rate during the emissions tests and the HHV of the coal were not provided.

Reference 20

This document presents the results of two emissions tests conducted at the NSP Sherco plant in Becker Minnesota. One emission test was conducted on Unit Three, which is a B&W 860 MW boiler firing pulverized subbituminous coal from Montana. Unit Three came on line in 1987. Emissions controls utilized during the test were a spray dryer absorber and a baghouse.

The second emissions test was performed simultaneously on Units One and Two, which are identical Combustion Engineering 750 MW boilers which came on line in 1976. During the tests, both boilers were firing 70% Wyoming and 30% Montana pulverized subbituminous coal. Emissions from Units One and Two were controlled by a venturi scrubber spray tower during the emissions tests.

Both emissions tests consisted of three sampling runs for mercury and the results are presented as emission rates in units of lb/hr. The reference indicates that all sampling results were above the detection limits. In addition, the document presents the coal feed rates in ton/hr during both tests. Mercury emission factors in units of lb/ton were developed by dividing the emission rates by the coal feed rates.

The document was assigned a data quality rating of "A."

Reference 21

This reference presents the results of an emissions test conducted simultaneously on the Number One, Number Three, and Number Four boilers at the NSP Black Dog Plant located in Burnsville, Minnesota. The boilers are water tube boilers and were fired with pulverized subbituminous coal from the Antelope and North Antelope mines during the test. Emissions controls utilized during the test were two electrostatic precipitators (ESPs) in series.

The emissions test consisted of three sampling runs for metals and the results are presented as emission rates in units of lb/hr. Full detection limit values were used to develop emission rates for pollutants that were not detected in any sampling run. Stack gas volumetric flow rates presented in the report (dscf/hr) and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in units of MMBtu/hr. The reference provides an HHV for the coal fired during the emissions test of 8,707 Btu/lb on an as-received basis. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rate to arrive at emission factors in units of lb/ton.

The document was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 22

The results of an emissions test conducted on the Number Two boiler at the NSP Black Dog plant in Burnsville, Minnesota, are presented in this report. The Number Two boiler is a 137 MW Foster-Wheeler atmospheric fluidized bed combustor (AFBC). At the time of the emissions test, Unit Two was firing 100% Western coal (blend of Antelope and Northern Antelope), which is subbituminous coal. Emission control devices in use during the test were a mechanical dust collector and two ESPs in series.

Three sampling runs were conducted for metals and the results are presented as emission rates in units of lb/hr. Full detection limit values were used to develop emission rates for pollutants that were not detected in any sampling run. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in units of MMBtu/hr. The reference provides an HHV for the coal fired during the emissions test of 8,553 Btu/lb on an as-received basis. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

The reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 23

This reference presents the results of an emissions test conducted simultaneously on the Number Three, Number Four, Number Five, and Number Six boilers at the NSP High Bridge plant in St. Paul, Minnesota. All of these boilers are B & W boilers and are equipped to fire pulverized coal. During the test, the boilers were fired with subbituminous coal from the Rochelle mine. A coldside ESP was in use during the emissions test.

Three sampling runs were conducted for metals, benzene, toluene, ethylbenzene, and xylene and the results are presented as emission rates in units of lb/hr. All sampling results for metals were above the detection limits. Benzene, toluene, ethylbenzene, and xylene were not detected in any sampling run and no emission factors for these pollutants were developed. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in MMBtu/hr. The reference presents an HHV for the coal fired during the emissions test of 8,498 Btu/lb on an as-received basis. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

This reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 24

This document presents the results of emissions tests conducted on the Units Six and Seven at the NSP Riverside plant in Minneapolis, Minnesota. These boilers are pulverized coal-fired boilers and were firing subbituminous coal from the Rochelle mine during the emissions tests. Emission controls in use during the test consisted of a baghouse.

Three sampling runs were conducted for metals, benzene, toluene, ethylbenzene and xylene. For metals, the emissions data from both units were combined and presented as emission rates in units of lb/hr. The benzene, toluene, ethylbenzene and xylene emissions data are presented separately for each unit as emission rates in lb/hr. All sampling results for metals were above the detection limits. Toluene, ethylbenzene, and xylene were not detected in any sampling run and no emission factors for these pollutants were developed. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in MMBtu/hr. The reference provides an HHV for the coal fired during the emissions test of 8,602 Btu/lb on an as-received basis. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

The reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 25

The results of an emissions test conducted simultaneously on Units One and Two at the NSP Sherburne County Generating Station located in Becker, Minnesota, are presented in this reference. The units are identical Combustion Engineering 750 MW boilers which came on line in 1976 and were fired with 80% Rochelle and 20% Coalstrip pulverized subbituminous coal during the test. The boilers were controlled by a wet limestone scrubbing system consisting of twelve individual rod venturi scrubber spray towers during the test.

Three sampling runs were conducted for metals and the results are presented as emission rates in units of lb/hr. Full detection limit values were used to calculate emission rates for pollutants that were not detected in any sampling run. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in MMBtu/hr. The reference provides an HHV for the coal fired during the emissions test of 8,547 Btu/lb on an as-received basis. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

The reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 26

This document presents the results of an emissions test conducted simultaneously on Units One and Two at the NSP Sherburne County Generating Station located in Becker, Minnesota. The units are identical Combustion Engineering 750 MW boilers which came on line in 1976. The document does not specify the type of coal being fired during the tests. Two other test reports from this facility are included in this documentation (References 25 and 19) and the boilers were firing pulverized subbituminous coal during those tests. Thus, it was assumed that the boilers were firing pulverized subbituminous coal during the tests described in this reference. Emissions were controlled by a wet limestone scrubbing system consisting of twelve individual rod venturi scrubber spray towers during the emissions test.

Three sampling runs were conducted for metals and the results are presented as emission rates in units of lb/hr. Full detection limit values were used to develop emission rates for pollutants that were not detected in any sampling run. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in MMBtu/hr. The reference does not provide an HHV for the coal fired during the emissions test and, therefore, an HHV for coal of 8,547 Btu/lb presented in Reference 25 (test report from the same facility) was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

The reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 27

The results of an emissions test conducted on Unit Three at the NSP Sherburne County Generating Station located in Becker, Minnesota, are presented in this document. Unit Three is a B & W 860 MW boiler which came on line in 1987 and was fired with pulverized subbituminous coal from Montana during the emissions test. The boiler was controlled by a spray dryer absorber and a baghouse during the emissions test.

Three sampling runs were conducted for metals and the results are presented as emission rates in units of lb/hr. Full detection limit values were used to develop emission rates for pollutants that were not detected in any sampling run. Stack gas volumetric flow rates (dscf/hr) provided in the document and an average F-factor for coal of 9,780 dscf/MMBtu were used to develop an energy input rate in MMBtu/hr. The document does not provide an HHV for the coal fired during the test and, therefore, an HHV for coal of 8,547 Btu/lb presented in Reference 25 (test report from the same facility) was used to convert the energy input rate to a coal feed rate in ton/hr. The emission rates were divided by the coal feed rates to arrive at emission factors in units of lb/ton.

The reference was assigned a data quality rating of "B" because the coal feed rates during the emissions test were not provided.

Reference 28

This reference presents the results of emission testing at a facility designated as EPRI Site 10. The boiler at this site is a fluidized bed combustor capable of producing approximately 100 MW of power at full load. According to the EPRI Synthesis Report (Reference 18), the boiler is a circulating bed AFBC and was firing subbituminous coal during the tests. Emissions controls utilized during the tests were flue gas desulfurization (FGD) by limestone injection into the boiler combustion chamber and a fabric filter.

Test sampling runs were conducted for metals and organics. Because of a forced boiler outage, only one sampling run was conducted for all compounds except benzene. Five samples for benzene were collected at a later date. Full detection limit values were used to develop emission factors for pollutants that were not detected in any sampling run.

Emissions test results for dibutyl phthalate, bis(2-ethylhexyl), and N-nitrosodimethylamine are presented as concentrations in units of microgram per Normal cubic meter ($\mu g/Nm^3$). The reference indicates that all sampling results for these pollutants were above the detection limits. The concentrations were converted to units of pounds per dry standard cubic feet (lb/dscf) and multiplied by the stack gas volumetric flow rate (dscf/hr) to arrive at an emission rate in lb/hr. The reference presents a dry-basis coal feed rate of 108,626 lb/hr during the test and a coal moisture percent of 7.3. The dry coal feed rate was divided by 100% minus 7.3% (92.7%) to obtain a coal feed rate, as fired, of 117,180 lb/hr. The emission rates for the three pollutants were divided by the coal feed rate, as fired, to obtain emission factors in units of lb/ton.

The emissions results for the other compounds are presented as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on sampling results that were below detection limits. The reference presents an HHV for the coal of 11,000 Btu/lb on a dry basis. The dry-basis HHV was divided by 100% plus 7.3% (107.3%) to obtain a HHV of 10,252 Btu/lb for the coal, as fired. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 29

This document presents the results of emissions testing at a facility designated as EPRI Site 11. The boiler tested is a 700 MW Combustion Engineering dry bottom, tangentially fired unit with pulverized subbituminous coal from the Power River basin. Emission controls utilized during the test were over-fire air, an ESP, and a wet limestone scrubber/absorber.

Three sampling runs were conducted for metals, formaldehyde, and naphthalene and the results are presented as emission factors in units of lb/MMBtu. However, Run Three was invalid because of suspected contamination. For Run One, the vapor phase samples were lost and, therefore, were not analyzed. Emissions results for the solid phase of Run One and the Run Two solid and vapor phase results were used to calculate the average emission factors presented in the report. Rather than convert the emission factors presented in the reference from lb/10^{12} Btu to lb/ton, the data from Run Two were used to develop emission factors. Pollutant concentrations in μg/Nm^3 provided in the report for Run Two were converted to lb/dscf and then multiplied by the stack gas volumetric flow rate (dscf/hr) provided in the report to obtain emission rates in lb/hr. Full detection limit values were used to develop emission rates for pollutants that were not detected. An F-factor for coal of 9,780 dscf/MMBtu and the stack gas volumetric flow rate (dscf/hr) were used to calculate an energy input rate in MMBtu/hr. The reference presents an HHV for the coal fired during the emissions test of 8,300 Btu/lb, as received. This value was used to convert the energy input rate to a coal feed rate in ton/hr. The pollutant emission rates were divided by the coal feed rate to obtain emission factors in units of lb/ton.

This reference was assigned a data quality rating of "B" because the coal feed rate was not provided.

Reference 30

The results of emissions testing at a facility designated as EPRI Site 12 are presented in this report. The boiler at Site 12 is an approximately 700 MW which commenced commercial operation in the mid-1980's. The boiler is a B & W balanced draft, opposed-wall, natural circulation, pulverized coal-fired, dry bottom boiler. The boiler was firing western Pennsylvania bituminous coal and was controlled by a wet limestone scrubber and ESP during the emissions test.

Three sampling runs were conducted for metals and organics, however, one of the metals runs was declared invalid because of a sample processing error. The emissions results are presented as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on results that were below detection limits. The reference provides an average HHV for the coal fired during the emissions test of 13,733 Btu/lb on a dry basis and a coal moisture content of 4.12% The dry-basis HHV was converted to an as-fired basis by dividing 13,733 Btu/lb by 104.12%, resulting in an HHV of 13,190 Btu/lb. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 31

This reference presents the results of emissions testing at a facility designated as EPRI Site 15. Site 15 has a boiler with a capacity of approximately 600 MW which began commercial operation in 1970. The boiler is a tangentially fired furnace manufactured by

Combustion Engineering and was firing pulverized Eastern bituminous coal during the emissions test. The pollution control system in use during the test consisted of an ESP.

Three sampling runs were conducted for metals and organics and the results are presented as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on results that were below detection limits. The reference provides an HHV for the coal fired during the test of 13,000 Btu/lb, which was assumed to be on an as-fired basis. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

A data quality rating of "A" was assigned to this reference.

Reference 32

The results of emissions testing at a facility designated as EPRI Site 19 are presented in this report. The boiler tested at Site 19 is a B & W opposed, wall-fired unit and was burning bituminous coal from western Virginia and Kentucky during the emissions test. An ESP was in use during the test.

Three sampling runs were conducted for various metals. The results for antimony, beryllium, and cobalt are presented as concentrations in units of microgram per Normal cubic meter. The results for the three compounds were above detection limits for all sampling runs. The concentrations were converted to lb/dscf and multiplied by the stack gas volumetric flow rate (dscf/hr) to obtain emission rates in units of lb/hr. The reference provides an average coal feed rate during the test of 694,000 lb/hr on a dry-basis and a coal moisture content of 6.1%. The dry-basis coal feed rate was converted to an as-fired basis by dividing 694,000 by 93.9% (100% - 6.1%), resulting in a value of 739,084. The pollutant emission rates were divided by the coal feed rate to obtain emission factors in units of lb/ton.

The results for the other metals are expressed as emission factors in units of lb/10^{12} Btu. The reference indicates that sampling results for all compounds were above the detection limits. The reference provides an average HHV of the coal fired during the test of 13,467 Btu/lb on a dry basis. This HHV was converted to an as-fired HHV of 12,693 Btu/lb by dividing 13,467 by 106.1%. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

<u>Reference 33</u>

This reference presents the results of emissions testing at a facility designated as EPRI Site 20. The boiler tested at Site 20 is a B & W wall-fired, drum type boiler with a normal full-load value of 680 MW. The boiler was firing pulverized lignite from Wilcox, Texas during the emissions test. Emissions controls in use during the test include two parallel cold-side ESPs and a FGD system that uses limestone slurry for reagent.

Four sampling runs were conducted for various metals. The results for antimony are presented as concentrations in units of microgram per Normal cubic meter. Antimony was not detected in any of the sampling runs the concentrations are based on full detection limits. The concentrations were converted to lb/dscf and multiplied by the stack gas volumetric flow rate (dscf/hr) to obtain emission rates in units of lb/hr. The reference provides a coal feed rate during the test of 618,000 lb/hr on a dry-basis and a coal moisture content of 34.4%. The dry-basis coal feed rate was converted to an as-fired basis by dividing 618,000 by 66.4% (100% - 34.4%), resulting in a value of 942,073. The average antimony emission rate was divided by the coal feed rate to obtain an emission factor in units of lb/ton.

The results for the other metals are expressed as emission factors in units of lb/10^{12} Btu. The reference indicates that all pollutants were detected in all sampling runs. The reference provides an HHV of the coal fired during the test of 6,760 Btu/lb on an as-received basis. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 34

The results of emissions testing at a facility designated as EPRI Site 21 are presented in this reference. The boiler at Site 21 is rated at 667 MW, gross load, and was firing bituminous coal from Pennsylvania and West Virginia during the emissions test. Emission controls utilized during the emissions test were a pilot ESP and FGD system. The FGD system is a spray tower absorber using an alkaline slurry. The pilot system has demonstrated the capability to produce the same results as a full-scale FGD system.

Eight sampling runs were conducted for metals and seven for polycyclic aromatic hydrocarbons (PAHs). The results of the sampling runs are presented as emission factors in unit of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on sampling results that were below the detection limits. The reference presents an average HHV for the coal fired during the test of 14,032 Btu/lb on a dry basis and a coal moisture content of 7%. The dry-basis HHV was converted to an HHV on an as-fired basis by dividing 14,032 by 107%, resulting in a value of 13,114. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

A data quality rating of "A" was assigned to this reference.

Reference 35

This reference presents the results of emissions testing at a facility designated as EPRI Site 22. The boiler tested at Site 22 is a B & W 700 MW, wall-fired, radiant boiler. The boiler was burning pulverized subbituminous coal from the Powder River region during the emissions test. Emission controls used during the test were two parallel cold-side ESPs.

Three sampling runs were conducted for metals, dioxins/furans, and PAHs and the results are presented as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on results that were below the detection limits. The reference provides an average HHV for the coal fired during the emissions test of 11,981 Btu/lb on a dry-basis and a coal moisture content of 29.5%. The dry-basis HHV was converted to an as-fired HHV of 9,252 Btu/lb by dividing 11,981 by 129.5%. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This report was assigned a data quality rating of "A."

Reference 36

This reference presents the results of emissions testing at a facility designated as EPRI Site 101. The boiler tested at this site is a B & W, 800 MW, wall-fired unit and was burning pulverized subbituminous coal from New Mexico during the emissions test. Emission controls in use during the test include low NO_x burners, a fabric filter, and FGD system consisting of a wet lime scrubber.

Three sampling runs were conducted for metals and organics. The solid phase sample for metals test Run Two was destroyed prior to analysis and, therefore, except for mercury, the metals emissions results are based on two sampling runs. Because mercury is present primarily in the vapor phase, the solid phase average of Runs One and Three was used to represent the solid phase results for mercury for Run Two.

The test runs results are presented as emission factors in units of lb/10^{12} Btu. The reference presents an average HHV for the coal fired during the test of 10,190 Btu/lb on a dry basis and a coal moisture content of 14%. The dry-basis HHV was converted to an as-fired HHV by dividing 10,190 by 114%, resulting in a value of 8,939. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

A data quality rating of "A" was assigned to this reference.

Reference 37

The results of emissions testing at a facility designated as EPRI Site 111 are presented in this reference. The boiler at this site is 267 MW, two-flow, single-reheat, balanced draft, drum type boiler. The boiler was burning a Western subbituminous coal during the tests. The pollution control system in use during the test consists of a fabric filter and spray dryers for FGD.

Two sampling runs were conducted for metals, PAHs, and various other organics. The results are expressed as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on sampling results that were below detection limits. The reference provides an average HHV for the coal fired during the test of 10,020 Btu/lb on an as-received basis. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This report was assigned a data quality rating of "A."

Reference 38

This reference presents the results of emissions testing at a facility designated as Site 114. The unit at Site 114 is a B & W, cyclone-fired reheat boiler rated at 100 MW. Bituminous coal from Indiana was fired during the emissions tests. Emissions sampling was conducted under two boiler operating conditions, baseline and reburn. Emissions controls used under the baseline operating condition consisted of an ESP. Controls used during the reburn operating condition were an ESP along with wall-fired burners located at a higher elevation in the boiler and overfire air to reduce NO_x emissions.

Three sampling runs for metals, PAHs, and various other organics were conducted under each operating condition and the results for each condition are reported separately and are expressed as emission factors in units of lb/10^{12} Btu. PAHs are reported as "not detected" and no emission factors were developed. For the other "not detected" pollutants, full detection limit values were used to develop emission factors.

The reference reports an average HHV for the coal fired during the baseline condition of 13,490 Btu/lb on a dry-basis and a coal moisture content of 15.6%. The dry-basis HHV was converted to an as-fired basis by dividing 13,490 by 115.6%, resulting in an as-fired HHV of 11,670 Btu/lb. The reported average HHV for the coal fired during the reburn condition was 13,280 Btu/lb, dry-basis, and the average content was 12.5%. The dry-basis HHV was converted to an as-fired HHV by dividing 13,280 by 112.5%, resulting in an as-fired HHV of 11,804 Btu/lb. The as-fired coal HHVs were used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a quality rating of "A."

Reference 39

The results of emissions testing at a facility designated as EPRI Site 115 are presented in this report. The unit tested at this site is a 117 MW B & W roof-fired boiler commissioned in 1955. The boiler was firing pulverized Western bituminous coal during the emissions tests. Emissions tests were conducted in two phases. Emissions controls in use during both phases included low NO_x burners, overfire air, and a fabric filter. Additional controls used in Phase II included a urea injection system for selective non-catalytic NO_x reduction.

Three sampling runs were conducted for metals and organics during both operating conditions, and the results are presented separately and are expressed as emission factors in lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on sampling results that were below detection limits.

The report presents an average HHV for the coal of 12,565 Btu/lb and 12,638 Btu/lb fired during Phase I and Phase II, respectively. The reported HHV for the coal is on a dry basis and the reference does not provide the moisture content of the coal, as received. A test report from the facility designated as EPRI Site 111 (Reference 37) where the boiler was firing a Western bituminous coal reports a moisture content of 9.8%. This value was used to convert the dry-basis coal HHV at Site 115 to an as-fired basis by dividing 12,565 and 12,638 by 109.8%, resulting in an as-fired HHV for the coal fired during Phase I testing of 11,444 Btu/lb and 11,510 Btu/lb for the coal fired during Phase II. The as-fired coal HHVs were used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "C" because an as-fired coal HHV or information that could be used to calculate it were not provided.

Reference 40

This reference presents the results of DOE emissions testing at Springerville Generating Station Unit No. 2. This facility is owned and operated by the Tucson Electric Power Company and is located near Springerville, Arizona. Unit No. 2 was manufactured by Combustion Engineering and is a 397 MW, corner-fired, balanced-draft design. According to the EPRI Synthesis Report (Reference 18), this boiler is tangentially-fired. The unit was burning pulverized subbituminous coal from the Lee Ranch Mine in New Mexico during the emissions tests. Emissions controls in use during the emissions test included overfire air and spray dryer absorbers.

Three sampling runs were conducted for metals and the results are expressed as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that were not detected in any sampling run. The report presents an average as-received HHV for the coal fired during the emissions test of 9,446 Btu/lb. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 41

The results of DOE emissions testing at the Niles Station Unit No. 2 of Ohio Edison are presented in this reference. Unit No. 2 is a B & W, 108 MW, cyclone boiler and was burning pulverized bituminous coal during the emissions test. The coal is a blend of eastern Ohio and western Pennsylvania coals and is received in the respective proportions of 70/30. Emissions controls in use during the test consisted of an ESP.

Three sampling runs were conducted for metals and various organics and the results are presented as emission factors expressed in units of lb/10^{12} Btu. Emission factors for pollutants that were not detected in any sampling run were developed using one-half of the detection limit value. The average as-received HHV of the coal fired during the emissions test was 12,184

Btu/lb. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 42

This reference presents the results of DOE emissions testing at the Coal Creek Station which is operated by Cooperative Power and is located about 50 miles north of Bismarck, North Dakota. The unit tested is a 550 MW, tangentially-fired, water walled, dry bottom furnace, with a Combustion Engineering controlled circulation boiler. The furnace is fueled by lignite from the Falkirk mine located adjacent to the plant. Emissions controls used during the test were an ESP and wet limestone scrubber.

Three sampling runs were conducted for metals and various organics and the results are presented as emission factors expressed in units of lb/10^{12} Btu. Emission factors for pollutants that were not detected in any sampling run were developed using one-half of the detection limit value. The average as-received HHV for the lignite fired during the emissions test was 6,230 Btu/lb. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 43

The results of DOE emissions testing at Baldwin Power Station Unit 2 are presented in this reference. Unit 2, located in Baldwin, Illinois, is a B & W cyclone furnace rated at 568 MW and was built in 1973. The furnace was firing Illinois bituminous coal during the emissions test. Emissions controls used during the test were an ESP.

Three sampling runs were conducted for metals and various organics, including PAHs and dioxins/furans. Test results are reported as emission factors expressed in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors for pollutants that were not detected in any sampling run. The average of the HHV values reported in the reference for the coal fired during the emissions test was 10,633 Btu/lb, as received. The as-received coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 44

This reference presents the results of DOE emissions testing at the Boswell Energy Center Unit 2 located in Cohasset, Minnesota. This unit is a Riley Stoker front-fired boiler built in 1957 and rated at 69 MW. The boiler was burning pulverized western subbituminous coal from the Powder River Basin area of Wyoming and Montana during the emissions tests. Emissions controls in use during the test were a baghouse.

Three sampling runs were conducted for metals and various organics, including PAHs and dioxins/furans. Emissions results are reported as emission factors expressed in units of lb/10^{12} Btu. When a pollutant was not detected in any sampling run, full detection limit values were used to calculate an emission factor. The average of the HHV values reported in the reference for the coal fired during the emissions test was 8,798 Btu/lb, as received. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 45

The results of DOE emissions testing at Cardinal Plant Unit 1 located in Brilliant, Ohio, are presented in this reference. Unit 1 is a wall-fired boiler rated at 615 MW and was burning pulverized Pittsburgh No. 8 bituminous coal during the emissions test. The unit is equipped with two ESPs arranged in parallel.

Three sampling runs for metals and various organics were conducted during sootblowing operations and three were conducted during non-sootblowing conditions. Emissions results are presented for both conditions, but only the results for non-sootblowing conditions were used to develop AP-42 emission factors. The emissions test results are reported as emission factors expressed in units of lb/10^{12} Btu. For pollutants where the results for all sampling runs were below the detection limit, the average of the run detection limits was used to develop an emission factor. The reference does not report a coal feed rate or the HHV of the coal fired during the emissions test and, therefore, a value of 13,000 Btu/lb listed in Appendix A of AP-42 was used to convert the reported emission factors to emission factors in units of lb/ton.

A data quality rating of "C" was assigned to this reference because the coal feed rate and the coal HHV were not reported.

Reference 46

This reference presents the results of DOE emissions testing at a facility designated as Site 16. The unit tested is a Foster Wheeler wall-fired boiler rated at 500 MW. The EPRI Synthesis Report (Reference 18) indicates that the boiler was burning pulverized bituminous coal from Virginia and Kentucky during the emissions test. Emissions controls in use during the test were low NO_x burners with overfire air and an ESP.

Three sampling runs were conducted for metals and various organics and the emissions results are presented as emission factors in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on results that were below the detection limit. The reference reports an average HHV for the coal fired during the emissions test of 13,800 Btu/lb, dry-basis, and a coal moisture content of 3.8%. The average dry-basis HHV was divided by 103.8% to obtain an average as-fired HHV of 13,295 Btu/lb. The as-fired coal HHV was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

<u>Reference 47</u>

The results of emissions testing at a facility designated as EPRI Site 122 are presented in this reference. The unit tested is a cyclone boiler constructed during the 1950s and has a nominal power production capacity of 275 MW. The boiler was burning bituminous coal from the Illinois No. 5 Seam in Saline County, Illinois. An ESP was in use during the emissions test.

Three sampling runs were conducted for metals and organics and the emissions results are reported as emission factors that are expressed in units of lb/10^{12} Btu. Full detection limit values were used to develop emission factors that are based only on results that were below the detection limit. The average HHV of the coal fired during the emissions test was 12,327 Btu/lb, as fired. This value was used to convert the emission factors in units of lb/10^{12} Btu to factors in units of lb/ton.

This reference was assigned a data quality rating of "A."

Reference 48

This reference presents hydrogen chloride (HCl) and hydrogen fluoride (HF) emission factors that were developed from the results of a literature search. The literature search was conducted under the National Acid Precipitation Assessment Program (NAPAP).

The reference lists four emission factors each, or four pairs of factors, for HCl and HF. The factors are in units of lb/ton and represent both controlled and uncontrolled boilers. One pair of emission factors is for electric generation (utility) and industrial boilers firing bituminous or subbituminous coal. The second pair of factors is for utility and industrial boilers firing lignite. The third pair of emission factors is for commercial/institutional boilers firing bituminous or subbituminous coal. The fourth pair of factors is for commercial/institutional boilers firing lignite.

The reference states that AP-42 procedures for assigning quality ratings were used to assign ratings to the factors. The emission factor quality ratings were retained and it was not necessary to assign a data quality rating to this reference.

References Examined But Not Used For Emission Factor Development

Several documents were examined and the emissions data they contained were not used to develop emission factors because the data were not considered representative of the general population of coal or lignite-fired boilers. For example, data from boilers that were not burning 100% coal or lignite were excluded. Data from boilers that were not operating normally or were using experimental control devices were not used. Also, data whose use would result in relatively low quality emission factors were not used. The following paragraphs describe the documents that were examined but not used and an explanation of why they were not used.

Results of the May 28 - 31, 1991 Trace Metal Characterization Study and Dioxin Emission Test on Unit 1 at the A.S. King Plant in Bayport, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. November 6, 1991. The boiler was firing a mixture of coal (90%) and petroleum coke (10%) at the time of the emissions tests.

Results of the July 1992 Air Toxic Emission Study on Unit 8 at the NSP Riverside Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. September 29, 1992. The boiler was firing a mixture of coal (94%) and coke (6%) at the time of the emissions tests.

Measurement of Chemical Emissions Under the Influence of Low-Nox Combustion Modifications. Submitted To Southern Company Services, Inc. Final Report. October 8, 1993. This facility was included in the emissions sampling program sponsored by EPRI and was designated Site 110. The reference states, "Site 110 provides control over the emissions of NO_X, however, it does so with modified combustion conditions having the potential of producing unwanted increases in the emissions of toxic organic compounds and conceivably undesirable changes in the emissions of inorganic substances."

A Study of Toxic Emissions From a Coal-fired Power Plant Utilizing an ESP While Demonstrating the ICCT CT-121 FGD Project. Radian Corporation, Austin, Texas. 28 December, 1993. This facility was included in the emissions sampling program sponsored by EPRI and was designated DOE Site 4. The boiler was utilizing an experimental, or "demonstration", type of flue gas desulfurization technology during the emissions tests.

Preliminary Draft. Field Chemical Emissions Monitoring Project: Site 14 Emissions Monitoring. Radian Corporation, Austin, Texas. November, 1992. This facility was included in the emissions sampling program sponsored by EPRI and was designated Site 14. The facility was utilizing a pilot-scale dry FGD system at the time of the test. The pilot system consisted of a spray dryer followed by a pulse-jet fabric filter. A portion of the flue gas exiting the boiler was treated by the FGD system and then recombined with the gas entering the outlet stack.

Preliminary Draft. Field Chemical Emissions Monitoring Project: Site 18 Emissions Monitoring. Radian Corporation, Austin, Texas. April, 1993. This facility was included in the emission sampling program sponsored by EPRI and was designated Site 18. At the time of the emissions test, the unit was not operating under optimal conditions. One of the five coal pulverizing mills was out of service and adjustments were made to the other four in order to maintain a steady operating load. Due to the adjustments, operating conditions for the unit were not normal. In addition, one of the control devices utilized by the boiler was experiencing problems and had to be repaired after the emissions test.

Field Chemical Emissions Monitoring Project: Site 116 Emissions Report. Radian Corporation, Austin, Texas. Preliminary Draft Report, October, 1994. This facility was included in the emission sampling program sponsored by EPRI and was designated Site 116. The facility was utilizing a "demonstration" pollution control system at the time of the emissions tests. A portion of the flue gas was treated by the system and then rejoined with the flue gas exiting the boiler prior to entering another control device.

2.9.3 Emission Factor Development

Once the evaluation of all documents was completed and spreadsheets were created to contain the emissions information extracted from each reference, the emission factors from the individual spreadsheets were combined into groups of factors according to pollutant type. This grouping was performed in order to more easily identify patterns in the emission factor values that could be attributed to coal type, boiler configuration (SCC), and/or control devices employed. Emission factors making up a pattern would be averaged together in order to develop an AP-42 emission factor that represents the boilers and emission controls included in the pattern. The groups are: (1) metals emission factor equations; (2) hydrogen chloride and hydrogen fluoride emission factors; (3) dioxin/furan emission factors; (4) metals emission factors; (5) PAH emission factors; and, (6) emission factors for various organics. A spreadsheet was constructed for each group of emission factors, except for the metals emission factor equations. These spreadsheets are hereafter referred to as "main" spreadsheets.

The metals emission factor equations in Reference 18 were not revised or converted. Because no calculations were necessary, a main spreadsheet for the emission factor equations was not constructed. The main spreadsheet containing the HCl and HF emission factors has only four factors for each pollutant and no extensive data manipulation was necessary. The main spreadsheets for dioxins/furans, metals, PAHs, and organics contain factors from numerous sources, and some processing of the data was necessary in order to develop AP-42 emission factors. The following paragraphs describe how these data were processed.

Each main spreadsheet for dioxins/furans, metals, PAHs, and organics was constructed with all emission factors from a single reference arranged on one row, except in the case of multiple emission factors representing different operating conditions. In such cases, the factors for each operating condition were arranged on one row. In addition to the emission factors, other data obtained from the reference were included on the appropriate spreadsheet row. These data included the reference number, number of boilers tested, coal type, boiler type, boiler MW rating, boiler SCC, control devices used, reference data quality, and number of test runs. These data were included in order to document and characterize the emission factors. Each type of data was entered in a single column of the spreadsheet. For example, all SCCs are in a single column, all coal types are in a single column, all emission factors for arsenic are in a single column, etc. With this arrangement, the data can be sorted by SCC, coal type, and control device in order to identify patterns in the emission factor values.

According to EPA guidance, emission factors that are based completely on detection limits should be calculated using one half of the detection limit. When the emission factors were extracted from the references, those factors based completely on detection limits were identified and it was noted if full value or one-half value detection limits were used to calculate them. All such factors were calculated using full detection limit values except for factors from Reference 41 and Reference 42, which were based on one-half detection limit values. All emission factors in the main spreadsheets that are based completely on detection limits were divided by two except for factors from Reference 41 and Reference 42. The factors from all references that are based completely on detection limits are identified by a "DL/2" in the column to the right of the emission factor.

EPA guidance also prescribes that when averaging emission factors together in order to obtain an AP-42 factor, the average should be an arithmetic mean. In addition, values representing factors based completely on detection limits that are larger than values representing factors that are based on detectable sample quantities (the pollutant was detected in at least one sampling run) should not be included in the overall averaging. In the main spreadsheets, after a group of emission factors for a pollutant were selected to be averaged together, the factors based only on detection limits were examined to determine if they should be included in the overall average. The "non-detected" factors that were higher in value than "detected" factors were not included in the overall average. In each column of pollutant emission factors, the factors (detected and non-detected) that are included in the overall average are marked with an asterisk in the column to the left of the factors. The average of the selected factors is at the bottom of the column. The quality rating of the average factor is included in the column to the right of the average factor.

When a pollutant was not detected at any facility, no AP-42 emission factor was developed for that pollutant. These pollutants appear in the main spreadsheets with a "DL/2" to the right of every factor for the pollutant. Although no emission factor was developed for these pollutants, they are identified in the footnotes of the AP-42 table that they would appear in if a factor had been developed.

The metals emission factor equations and the development of the HCl/HF emission factors are discussed below. The factors in the dioxin/furan, metals, PAHs, and organic main spreadsheets were sorted by SCC and control devices in order to identify patterns in the factor values that could be attributed to one or more of these parameters. The result of this sorting is also discussed below.

Metals Emission Factor Equations

The emission factor equations provided in Reference 18 are included in AP-42 "as is," i.e., no conversions or revisions were made to the equations. There are equations for nine metals and they may be used to generate emission factors for both controlled and uncontrolled boilers. In addition, the equations may be used to generate emission factors for all typical firing configurations for utility, industrial, and commercial/industrial boilers. The emission factor equations are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate matter emission factors. Because these are the major parameters affecting trace metals emissions from coal combustion, it is recommended that the emission factor equations be used to generate emission factors when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant and there is an emission factor for the provided in Section 1.1, then the factor should be used. The emission factor equations are provided in Table 4.

Hydrogen Chloride and Hydrogen Fluoride Emission Factors

All HCl and HF emission factors were obtained from Reference 48. These factors are shown in Table 5. The factors for utility/industrial boilers firing bituminous/subbituminous coal, commercial/industrial boilers firing bituminous/subbituminous coal, and commercial/industrial boilers firing lignite were averaged together to obtain an overall factor (one for HCl and one for HF) that represents all three categories. The emission factors for utility/industrial boilers firing lignite were not used in developing the AP-42 emission factors because of the relatively low value of the emission factors.

Dioxin/Furan, Metals, PAHs, and Various Organic Emission Factors

As described above, the emission factors for these pollutants were sorted by SCC and control device in order to identify patterns. No patterns became apparent in any of the four spreadsheets except in the spreadsheet containing the dioxin/furan emission factors. One pattern includes factors for a boiler controlled by a spray dryer absorber and a fabric filter and a second pattern is for boilers controlled by an ESP (2 boilers) or fabric filter (1). What makes the patterns apparent is that the factors for the first pattern are consistently higher in value for all dioxins/furans than the factors for the second pattern. Thus, the dioxin/furan emission factors added to Section 1.1 are for two control device scenarios. The factors for the other groups were averaged together to arrive at one AP-42 factor for each pollutant. The SCCs and controls attributed to the AP-42 factor are a combination of the SCCs and controls represented by the individual factors.

Copies of the spreadsheets used to develop the dioxin/furan, metals, PAHs, and various organic emission factors are shown in Tables 6, 7, 8, and 9, respectively.

Table 4. Metals Emission Factor Equations for Section 1.1 of AP-42[a,b]

Pollutant	Emissions Equation[c] (lb/10^{12} Btu)
Antimony	$0.92 \times (C/A \times PM)^{0.63}$
Arsenic	$3.1 \times (C/A \times PM)^{0.85}$
Beryllium	$1.2 \times (C/A \times PM)^{1.1}$
Cadmium	$3.3 \times (C/A \times PM)^{0.5}$
Chromium	$3.7 \times (C/A \times PM)^{0.58}$
Cobalt	$1.7 \times (C/A \times PM)^{0.69}$
Lead	$3.4 \times (C/A \times PM)^{0.80}$
Manganese	$3.8 \times (C/A \times PM)^{0.60}$
Nickel	$4.4 \times (C/A \times PM)^{0.48}$

[a]Reference 18

[b]All equations are rated "A." The emission factor equations are applicable to all typical firing configurations (SCCs) for electric generation (utility) boilers, industrial boilers, and commercial/industrial boilers firing bituminous coal, subbituminous coal, or lignite. Also, the equations apply to boilers using typical control devices, including no controls.

[c]C = concentration of trace metal in the coal, parts per million by weight (ppm wt)
A = weight fraction of ash in coal, (dimensionless)
PM = site-specific emission factor for total particulate matter, (lb/10^6 Btu)

Table 5. Data Used to Develop Hydrogen Chloride and Hydrogen Fluoride Emission Factors for Section 1.1 of AP-42[a,b]

BOILER SCC DESCRIPTIONS	Source Classification Codes[c]	Hydrogen Chloride (lb/ton)[c]	Hydrogen Fluoride (lb/ton)
Commerical/Industrial Boilers			
Bituminous and Subbituminous Coal			
Firing Types			
Pulverized Coal Wet Bottom	1-03-002-05/21*	1.48*	0.17
Pulverized Coal Dry Bottom	1-03-002-06/22		
Overfeed Stoker	1-03-002-07		
Underfeed Stoker	1-03-002-08		
Spreader Stoker	1-03-002-09/24		
Hand-fired	1-03-002-14		
Pulverized Coal Dry Bottom Tangential	1-03-002-16/26		
Atmospheric Fluidized Bed Combustor	1-03-002-17/18		
Cyclone Furnace	1-03-002-23		
Traveling Grate Overfeed Stoker	1-03-002-25		
Electric Generation & Industrial Boilers			
Bituminous and Subbituminous Coal			
Firing Types			
Pulverized Coal Wet Bottom	1-01-002-01/21*	1.9*	0.23
	1-02-002-01/21		
Pulverized Coal Dry Bottom	1-01-002-02/22		
	1-02-002-02/22		
Cyclone Furnace	1-01-002-03/23		
	1-02-002-03/23		
Spreader Stoker	1-01-002-04/24		
	1-02-002-04/24		
Traveling Grate Overfeed Stoker	1-01-002-05/25		
	1-02-002-25		
Overfeed Stoker	1-02-002-05		
Pulverized Coal Dry Bottom, Tangential Firing	1-01-002-12/26		
	1-02-002-12		

Table 5. Continued

BOILER SCC DESCRIPTIONS	Source Classification Codes[c]	Hydrogen Chloride (lb/ton)[c]	Hydrogen Fluoride (lb/ton)
Atmospheric Fluidized Bed	1-01-002-17		
	1-01-002-18		
	1-02-002-17		
	1-02-002-18		
Underfeed Stoker	1-02-002-06		
Commerical/Industrial Boilers			
Lignite			
Firing Types			
Pulverized Coal	1-03-003-05*	0.351*	0.063
Pulverized Coal Tangential Firing	1-03-003-06		
Traveling Grate Overfeed Stoker	1-03-003-07		
Spreader Stoker	1-03-003-09		
Electric Generation & Industrial Boilers			
Lignite			
Firing Types			
Pulverized Coal	1-01-003-01	0.01	0.01
	1-02-003-01		
Pulverized Coal Tangential Firing	1-01-003-02		
	1-02-003-02		
Cyclone Furnace	1-01-003-03		
	1-02-003-03		
Traveling Grate Overfeed Stoker	1-01-003-04		
	1-02-003-04		
Spreader Stoker	1-01-003-06		
	1-02-003-06		
	Overall Average	1.2	0.15
	Quality Rating	B	B

[a]All factors are from Reference 48.
[b]Factors are for both uncontrolled and controlled boilers.
[c]An asterisk to the left of a factor indicates that it was used in calculating the overall emission factor.

Table 6. Data Used to Develop Dioxin/furan Emission Factors for Section 1.1 of AP-42

Ref. No.	Coal Type	Boiler Type[a]	MW	SCCs	CONTROL DEVICE 1[b]	CONTROL DEVICE 2[b]	DATA QUALITY	No. of Test Runs[c]
19	Subituminous	PC,DB	860	10100222	FGD-SDA	FF	C	3
Quality rating								
35	Subituminous	PC,DB	700	10100222	ESP	none	A	3
43	Bituminous	Cyclone	568	10100203	ESP	none	A	3
44	Subituminous	PC,DB	69	10100222	FF	none	A	3 *
Average Factor								
Quality rating								

Table 6. Continued

Ref. No.	2.3.7.8-TCDD[dc]	TOTAL TCDD[dc]	TOTAL PeCDD[dc]	TOTAL HxCDD[dc]	TOTAL HpCDD[dc]	TOTAL OCDD[dc]
19	---	3.93e-10	7.06e-10	3.00e-09	1.00e-08	2.87e-08
Quality rating		E	E	E	E	E
35	3.1e-11 DL/2*	8.7e-11	No dataDL/2	No dataDL*	1.80e-10 *	9.60e-10 *
43	2.70e-11 DL/2*	2.85e-11 *	7.85e-12 DL/2*	2.04e-11 *	5.38e-11 *	9.45e-11 DL/2*
44	1.43e-11 *	1.63e-10 *	8.16e-11 *	3.70e-11 *	1.64e-11 DL/2*	1.94e-10 *
Average Factor	1.43e-11	9.28e-11	4.47e-11	2.87e-11	8.34e-11	4.16e-10
Quality rating	E	D	D	D	D	D

Table 6. Continued

Ref. No.	2.3.7.8-TCDF[dc]	TOTAL TCDF[dc]	TOTAL PeCDF[dc]	TOTAL HxCDF[dc]	TOTAL HpCDF[dc]	TOTAL OCDFd
19	---	2.49e-09	4.84e-09	1.27e-08	4.39e-08	1.37e-07
Quality rating		E	E	E	E	E
35	3.35e-11 DL/2*	1.10e-10 *	1.4e-10 *	6.5e-11 *	4.1e-11 *	7.8e-11
43	1.35e-11 DL/2*	4.06e-11 DL/2*	8.49e-11 *	1.18e-10 *	6.74e-11 *	8.83e-11
44	1.06e-10 *	1.06e-09 *	8.34e-10 *	3.92e-10 *	1.22e-10 *	3.27e-11
Average Factor	5.10e-11	4.04e-10	3.53e-10	1.92e-10	7.68e-11	6.63e-11
Quality rating	D	D	D	D	D	D

Table 6. Continued

Ref. No.	TOTAL CDD[e]	TOTAL CDF[e]	TOTAL CDD/CDF[e]
19	4.28e-08	2.01e-07	2.44e-07
Quality rating	E	E	E
35	---	---	---
43	---	---	---
44	---	---	---
Average Factor	6.66e-10	1.09e-09	1.76e-09
Quality rating	D	D	D

a PC = Pulverized Coal; DB = Dry Bottom.
b FGD-SDA = Flue Gas Desulfurization, Spray Dryer Absorber, ESP = Electrostatic Precipitator, FF = Fabric Filter
c An "*" to the left of a factor indicates that it was used in calculating the average factor.
d A "DL/2" to the right of a factor indicates that the factor is based only on sampling results that were below the detection limits. The value shown here represents a factor based on one half of the detection limit.
e Total CDD is the sum of Tetra- through Octa- CDD. Likewise for CDF. Total CDD/CDF is the sum of Total CDD and Total CDF.

Table 7. Data Used to Develop Controlled Metals Emission Factors for Section 1.1 of AP-42

Ref. No.	No. of Boilers	Fuel Type	Boiler Type[a]	MW	SCC	Control Device 1[b]	Control Device 2[b]	Control Device 3[b]	Data Quality	No. of Test Runs[c]
20	1	Subbituminous	PC, DB	860	10100222	FGD-SDA	FF	none	A	3
20	2	Subbituminous	PC, DB	750 ea.	10100222	FGD-VSST	none	none	A	3
21	3	Subbituminous	PC, DB	---	10100222	ESP	ESP	none	B	3
22	1	Subbituminous	AFBC, CB	137	10100238	Cyclone	ESP	ESP	B	3
23	4	Subbituminous	PC, DB	---	10100222	ESPC	none	none	B	3 *
24	2	Subbituminous	PC, DB	---	10100222	FF	none	none	B	3 *
25	2	Subbituminous	PC, DB	750 ea.	10100222	FGD-VSST	none	none	B	3 *
26	2	Subbituminous	PC, DB	750 ea.	10100222	FGD-VSST	none	none	B	3 *
27	1	Subbituminous	PC, DB	860	10100222	FGD-SDA	FF	none	B	3 *
28	1	Subbituminous	AFBC, CB	110	10100238	FGD-FIL	FF	none	A	1
29	1	Subbituminous	PC, DB, T	700	10100226	OFA	FGD-WLS	ESP	B	1
30	1	Bituminous	PC, DB, O	700	10100202	ESP	FGD-WLS	none	A	2
31	1	Bituminous	PC, DB, T	600	10100212	ESP	none	none	A	3
32	1	Bituminous	PC, DB, O	1,160	10100202	ESP	none	none	A	3 *
33	1	Lignite	PC	680	10100301	ESP	FGD-WLS	none	A	4
34	1	Bituminous	PC, DB, O	667	10100202	ESP	FGD-WLS	none	A	8
35	1	Subbituminous	PC, DB, O	700	10100222	ESP	none	none	A	3
36	1	Subbituminous	PC, DB, W	800	10100222	LNB	FF	FGD-WLS	A	2
37	1	Subbituminous	PC, DB	267	10100222	LNB	FGD-SD	FF	A	2

Table 7. Continued

Ref. No.	No. of Boilers	Fuel Type	Boiler Type[a]	MW	SCC	Control Device 1[b]	Control Device 2[b]	Control Device 3[b]	Data Quality	No. of Test Runs[c]
38	1	Bituminous	Cyclone	100	10100203	ESP	none	none	A	3
38	1	Bituminous	Cyclone	100	10100203	Reburn/OFA	ESP	none	A	3
39	1	Bituminous	PC, DB	117	10100202	LNB/OFA	FF	none	B	3
39	1	Bituminous	PC, DB	117	10100202	LNB/OFA	SNCR	FF	B	3
40	1	Subbituminous	PC, DB, T	422	10100226	LNB/OFA	FGD-SDA	FF	A	3 *
41	1	Bituminous	Cyclone	108	10100203	ESP	none	none	A	3
42	1	Lignite	PC, DB, T	550	10100302	ESP	FGD-WLS	none	A	3 *
43	1	Bituminous	Cyclone	568	10100203	ESP	none	none	A	3 *
44	1	Subbituminous	PC, DB	69	10100222	FF	none	none	A	3
45	1	Bituminous	PC, DB	615	10100202	ESP	none	none	C	3 *
46	1	Bituminous	PC, DB	500	10100202	LNB/OFA	ESP	none	A	3
47	1	Bituminous	Cyclone	275	10100203	ESP	none	none	A	3
Average Factor										
Quality Rating										

Table 7. Continued

Ref. No.	Antimony[dc]	Arsenic[dc]	Beryllium[dc]	Cadmium[dc]	Chromium[dc]	Chromium VI[dc]
20	---	---	---	---	---	---
20	---	---	---	---	---	---
21	4.80e-05 DL/2*	1.06e-05	1.16e-06 DL/2*	5.31e-05 *	4.89e-05	---
22	4.66e-06 DL/2*	9.03e-06	2.33e-07 DL/2*	1.11e-04 *	1.08e-04	---
23	1.23e-05 *	5.63e-06 *	1.33e-06 *	1.11e-05 *	1.18e-04	---
24	5.78e-06 *	1.89e-05 *	8.09e-06 *	4.83e-04 *	2.35e-04	---
25	9.12e-06 *	4.42e-05 *	4.34e-06 *	1.80e-05 *	1.95e-04	---
26	1.48e-05 *	4.26e-05 *	4.80e-06 *	4.78e-05 *	1.34e-04	---
27	7.06e-06 *	4.14e-07 DL/2*	1.11e-07	---*	1.59e-04 *	1.49e-05
28	---	1.03e-05 DL/2	2.05e-06 DL/2	4.10e-06 DL/2*	3.28e-05	---
29	---*	1.41e-05	1.41e-06 DL/2*	1.83e-05 *	9.87e-05	---*
30	---*	1.19e-05	2.11e-06 DL/2*	3.17e-05 *	9.23e-05	---
31	---*	3.38e-04 *	1.04e-05 *	8.06e-05 *	3.12e-04	---*
32	3.83e-05 *	2.01e-04 *	3.08e-05 *	3.30e-06 *	3.30e-04	---*
33	8.70e-06 DL/2*	8.52e-06 *	4.73e-06 *	9.46e-06 *	3.79e-05	---*
34	---*	1.62e-04 *	3.41e-06 *	1.49e-05 *	7.19e-05	---*
35	3.52e-05 DL/2*	1.61e-06	2.87e-07 DL/2*	2.96e-06 *	9.81e-06	---
36	---*	6.08e-06 *	6.44e-07 *	7.15e-06 *	3.93e-05	---*
37	---	2.11e-06 DL/2	---	2.11e-05 DL/2	4.31e-05 DL/2	---

Table 7. Continued

Ref. No.	Antimony[dc]	Arsenic[dc]	Beryllium[dc]	Cadmium[dc]	Chromium[dc]	Chromium VI[dc]
38	---*	1.63e-04 *	5.60e-05 *	4.20e-05 *	3.27e-04	---
38	---*	1.89e-04 *	1.89e-05 *	9.44e-06 *	1.09e-04	---
39	---*	1.72e-05	2.29e-07 DL/2*	2.75e-06 *	1.51e-05	---
39	---*	3.45e-06	2.30e-07 DL/2*	8.05e-07 DL/2*	6.91e-06	---
40	7.75e-07 *	2.83e-06	3.78e-07 DL/2*	4.91e-07 *	1.89e-06	---
41	4.39e-06 DL/2*	1.02e-03 *	4.63e-06 *	1.71e-06 *	7.31e-05	---*
42	2.24e-06 *	1.50e-05	1.06e-05 DL/2	1.99e-05 DL/2	---	---*
43	3.23e-05 *	2.85e-04 *	3.00e-05 *	6.42e-05 *	1.08e-03	---*
44	5.95e-06 DL/2*	5.70e-06	1.14e-06 DL/2	5.70e-06 DL/2*	3.59e-05	---*
45	6.14e-05 *	9.07e-05 *	1.82e-06 *	2.20e-05 *	1.95e-04	---*
46	---*	2.92e-03 *	8.24e-05 *	9.57e-05 *	5.58e-04 *	1.44e-04 *
47	---*	5.42e-03 *	9.86e-05 *	8.88e-05 *	2.47e-03	---*
Average Factor	1.84e-05	4.08e-04	2.12e-05	5.08e-05	2.55e-04	7.95e-05
Quality Rating	A	A	A	A	A	D

Table 7. Continued

Ref. No.	Cobalt[dc]	Lead[dc]	Magnesium[dc]	Manganese[dc]	Mercury[dc]	Nickel[dc]	Selenium[d]
20	---	---	---	---*	8.40e-05	---	---
20	---	---	---	---*	6.82e-05	---	---
21	---*	3.59e-04 *	1.60e-02 *	1.04e-04 *	8.05e-05 *	1.23e-04 *	2.12e-05
22	---*	8.59e-04 *	1.22e-02 *	1.05e-04 *	4.41e-05 *	4.91e-04 *	6.97e-06
23	---*	6.06e-05 *	5.44e-03 *	1.38e-04	3.28e-05 DL/2*	5.84e-05 *	1.31e-05
24	---*	1.15e-04 *	5.63e-02 *	3.32e-04 *	8.36e-05 *	5.76e-04 *	4.14e-05
25	---*	1.26e-04 *	1.33e-02 *	5.24e-04 *	1.79e-05 *	2.36e-05 *	1.33e-04
26	---*	1.41e-04 *	7.75e-03 *	3.91e-04 *	9.56e-05 *	7.53e-05 *	1.49e-04
27	---*	1.34e-04 *	4.30e-04 *	3.21e-04 *	6.26e-05 *	1.01e-04	2.07e-05 DL/2
28	8.20e-06 DL/2*	1.23e-05	---*	6.36e-04	---	2.05e-05 DL/2	1.64e-04 DL/2
29	2.40e-05 *	1.97e-04	---*	1.61e-03 *	5.24e-05 *	6.63e-05	2.12e-05 DL/2
30	1.32e-05 DL/2*	1.50e-04	---*	4.22e-05 *	4.22e-06 *	1.16e-04 *	3.43e-04
31	5.20e-05 *	1.12e-04	---*	2.24e-04	---*	1.53e-04 *	2.00e-03
32	1.32e-04	---	---*	1.37e-04 *	1.57e-04 *	2.01e-04 *	6.60e-03
33	9.33e-06 *	5.14e-05	---*	1.15e-04 *	1.62e-04 *	5.81e-05 *	2.16e-03
34	1.08e-04 *	1.66e-04	---*	3.93e-04 *	2.20e-05 *	4.41e-05 *	2.60e-04
35	6.50e-06 DL/2*	2.04e-06 *	8.70e-04 *	2.04e-05 *	7.03e-05 *	1.18e-05 *	9.81e-07
36	2.32e-06 *	1.29e-05	---*	1.79e-04 *	3.40e-05 *	5.01e-05 *	2.50e-05
37	---	---	---	---	6.70e-04 DL/2*	1.06e-04	---

Table 7. Continued

Ref. No.	Cobalt[dc]	Lead[dc]	Magnesium[dc]	Manganese[dc]	Mercury[dc]	Nickel[dc]	Selenium[d]
38	---*	2.01e-03	---*	4.67e-04 *	1.05e-04 *	1.82e-03 *	5.60e-03
38	---*	1.35e-03	---*	3.54e-04 *	8.97e-05 *	8.03e-04 *	3.54e-03
39	2.52e-06 DL/2*	1.01e-05	---*	2.29e-05 *	4.01e-06 DL/2*	3.43e-05 *	8.24e-06
39	2.65e-06 DL/2*	9.21e-06	---*	2.05e-05 *	9.44e-06 *	1.04e-05 *	6.90e-07 DL/2
40	2.84e-06 DL/2*	1.32e-05	---*	2.13e-04 *	7.90e-05 *	2.84e-06 DL/2*	3.59e-07 DL/2
41	1.46e-06 DL/2*	3.90e-05	---*	8.29e-05 *	3.41e-04 *	1.34e-05 *	1.51e-03
42	1.87e-05 *	8.60e-06	---*	3.74e-04 *	1.18e-04 *	6.35e-05 *	1.03e-04
43	1.45e-04 *	6.08e-04 *	6.17e-03 *	4.74e-04 *	8.14e-05 *	4.70e-04 *	2.76e-03
44	1.23e-05 *	4.29e-05 *	3.61e-03 *	3.24e-04 *	3.40e-05 *	3.47e-05 *	5.68e-05
45	1.64e-05 *	9.96e-05 *	4.26e-04 *	3.90e-04 *	1.16e-05 *	1.23e-04 *	2.41e-03
46	1.73e-04 *	2.92e-04	---*	5.58e-04 *	1.28e-04 *	4.52e-04 *	3.72e-03
47	6.41e-04 *	4.44e-03	---*	5.05e-03 *	2.02e-04 *	1.75e-03 *	1.65e-03
Average Factor	1.03e-04	4.23e-04	1.11e-02	4.86e-04	8.30e-05	2.80e-04	1.32e-03
Quality Rating	A	A	A	A	A	A	A

Table 7. Continued

[a]PC = Pulverized Coal, DB = Dry Bottom, T = Tangential, O = Opposed, W = Wall, AFBC = Atmospheric Fluidized Bed Combustor, CB = Circulating Bed

[b]ESP = Electrostatic Precipitator, FGD = Flue Gas Desulfurization, FIL = Furnace Injection of Limestone, FF = Fabric Filter, LNB = Low Nox Burners, OFA = Overfire Air, SDA = Spray Dryer Absorber, SNCR = Selective Non-catalytic Reduction, WLS = Wet Limestone Scrubber, VSST = Venturi Scrubber Spray Tower
These are the controls that were in place during the emissions tests.

[c]An asterisk before a factor indicates that the factor was used in calculating the overall average.

[d]A "DL/2" after a number indicates that the pollutant was not detected in any of the sampling runs used to develop the factor. The value shown here represents a factor based on one half of the detection limit.

Table 8. Data Used to Develop Controlled PAH Emission Factors for Section 1.1 of AP-42

Ref. No.	No. of Boilers	Type of Coal	Boiler Type	MW	SCC	Control Device 1[b]	Control Device 2[b]	Control Device 3[b]	Data Quality	No. of Test Runs[c]
29	1	Subbituminous	PC,DB,T	700	10100226	OFA	FGD-WLS	ESP	B	1
34	1	Bituminous	PC,DB,O	667	10100202	ESP	FGD-WLS	none	A	7
35	1	Subbituminous	PC,DB,O	700	10100222	ESP	none	none	A	3
37	1	Subbituminous	PC,DB	267	10100222	LNB	FGD-SD	FF	A	2
39	1	Bituminous	PC,DB	117	10100202	LNB/OFA	FF	none	B	3
41	1	Bituminous	Cyclone	108	10100203	ESP	none	none	A	3 *
42	1	Lignite	PC,DB,T	550	10100302	ESP	FGD-WLS	none	A	3 *
43	1	Bituminous	Cyclone	568	10100203	ESP	none	none	A	3
44	1	Subbituminous	PC,DB	69	10100222	FF	none	none	A	3
45	1	Bituminous	PC,DB	615	10100202	ESP	none	none	C	3
46	1	Bituminous	PC,DB	500	10100202	LNB/OFA	ESP	none	A	3
Average Factor										
Quality Rating										

Table 8. Continued

Ref. No.	Biphenyl[dc]	Acenaph-thene[dc]	Acenaph-thylene[dc]	Anthracene[dc]	Benz(a)an-thracene[dc]	Benzo(a)-pyrene[dc]
29	---	---	---	---	---	---
34	---*	4.72e-07 *	1.97e-07 *	2.60e-07 *	3.41e-08 *	4.72e-08 *
35	---*	1.11e-07 *	6.29e-08 *	8.51e-08 *	1.85e-08 *	2.04e-08 *
37	---*	1.60e-06 *	6.01e-07 *	4.01e-07 *	1.80e-07	4.01e-08 DL/2*
39	---	---	---	---	---	---
41	3.06e-06 *	6.46e-07 *	1.66e-07 *	5.04e-07 *	9.02e-08	2.92e-08 DL/2*
42	2.87e-07 *	2.16e-07 *	1.31e-07 *	1.83e-07 *	2.62e-08 *	1.12e-08 *
43	9.35e-06 DL/2*	6.70e-08 DL/2*	6.78e-07 *	5.61e-08 *	2.49e-08	5.80e-09 DL/2*
44	1.57e-06 DL/2*	7.18e-07 *	9.34e-08 *	1.09e-07 *	8.23e-08 *	3.68e-09 *
45	---	---	---	---	---	---
46	---*	2.15e-07 *	7.98e-08 *	9.84e-08 *	1.86e-07 *	1.09e-07 *
Average Factor	1.67e-06	5.06e-07	2.51e-07	2.12e-07	8.03e-08	3.83e-08
Quality Rating	D	B	B	B	B	D

Table 8. Continued

Ref. No.	Benzo(b,j,k)-fluoranthene[dc]	Benzo(g,h,i)-perylene[dc]	Chrysene[dc]	Fluoran-thene[dc]	Fluorene[dc]	Indeno(1,2,3-cd)pyrene[dc]
29	---	---	---	---	---	---
34	1.73e-07 *	3.15e-08 *	1.81e-07 *	1.39e-06 *	1.68e-06 *	3.93e-08
35	5.00e-08 *	4.07e-08 *	4.63e-08 *	4.44e-07 *	2.22e-07 *	1.59e-07
37	2.40e-07 *	8.02e-08 *	4.01e-08 DL/2*	6.01e-07 *	3.61e-06 *	8.02e-08 *
39	---	---	---	---	---	---*
41	1.71e-07	2.92e-08 DL/2*	2.17e-07 *	6.58e-07 *	7.63e-07	2.92e-08 DL/2*
42	5.61e-08 *	7.48e-09 *	6.60e-08 *	5.26e-07 *	5.17e-07 *	7.48e-09 *
43	8.32e-08	1.20e-08 DL/2	---*	3.70e-07 *	1.04e-07	1.18e-08 DL/2*
44	5.37e-08 *	4.55e-09 DL/2	---*	1.45e-06 *	1.56e-07 *	6.07e-09 *
45	---	---	---	---	---	---*
46	3.99e-08 *	8.24E-08*	4.79e-08 *	2.66e-07 *	2.63e-07 *	7.18e-08
Average Factor	1.08e-07	2.74e-08	9.97e-08	7.13e-07	9.14e-07	6.06e-08
Quality Rating	B	D	C	B	B	C

Table 8. Continued

Ref. No.	Naphthalene[dc]	Phenanthrene[dc]	Pyrene[dc]	5-methyl chrysene[d]
29	2.82e-05 DL/2	---	---	---
34	---*	5.51e-06 *	6.29e-07 *	3.93e-08
35	---*	1.28e-06 *	2.96e-07 *	4.35e-09 DL/2
37	1.52e-05 *	2.61e-06 *	2.00e-07	---
39	5.95e-06	---	---	---
41	5.25e-06 *	1.89e-06 *	3.39e-07	---
42	3.18e-06 *	3.91e-06 *	2.02e-07	---
43	8.38e-06 *	1.21e-06 *	6.00e-08	---
44	4.45e-06 *	3.70e-06 *	6.56e-07	---
45	5.04e-05	---	---	---
46	---*	1.17e-06 *	2.92e-07	---
Average Factor	1.33e-05	2.66e-06	3.34e-07	2.18e-08
Quality Rating	C	B	B	D

[a]PC = Pulverized Coal, DB = Dry Bottom, T = Tangential, O = Opposed
[b]ESP = Electrostatic Precipitator, FF = Fabric Filter, FGD = Flue Gas Desulfurization LNB = Low Nox Burners, OFA = Overfire Air, SD = Spray Dryer, WLS = Wet Limestone Scrubber
These controls were in use during emissions tests.
[c]An asterisk before a factor indicates that it was used in calculating the overall average.
[d]A DL/2 after a factor indicates that the pollutant was not detected in any of the sampling runs used to develop factor. The value shown here represents a factor based on one half of the detection limit.

Table 9. Data Used to Develop Organic Emission Factors for Section 1.1 of AP-42

Ref. No.	No. of Boilers	Coal Type	Boiler Type[a]	MW	SCC	Control Device 1[b]	Control Device 2[b]	Control Device 3[b]	Data Quality	No. of Test Runs
23	4	Subbituminous	PC,DB	---	10100222	ESP	None	None	B	3
24	1	Subbituminous	PC,DB	---	10100222	FF	None	None	B	3
24	1	Subbituminous	PC,DB	---	10100222	FF	None	None	B	3
28	1	Subbituminous	AFBC,CB	110	10100238	FGD-FIL	FF	None	A	1
29	1	Subbituminous	PC,DB,T	700	10100226	OFA	FGD-WLS	ESP	B	1
30	1	Bituminous	PC,DB,O	700	10100202	ESP	FGD-WLS	None	A	2
31	1	Bituminous	PC,DB,T	600	10100212	ESP	None	None	A	3
34	1	Bituminous	PC,DB,O	667	10100202	ESP	FGD-WLS	None	A	7
35	1	Subbituminous	PC,DB,O	700	10100222	ESP	None	None	A	3
36	1	Subbituminous	PC,DB,W	800	10100222	LNB	FF	FGD-WLS	A	2
37	1	Subbituminous	PC,DB	267	10100222	LNB	FGD-SD	FF	A	2
38	1	Bituminous	Cyclone	100	10100203	ESP	None	None	A	3
38	1	Bituminous	Cyclone	100	10100203	Reburn/OFA	ESP	None	A	3
39	1	Bituminous	PC,DB	117	10100202	LNB/OFA	FF	None	B	3
41	1	Bituminous	Cyclone	108	10100203	ESP	None	None	A	3
42	1	Lignite	PC,DB,T	550	10100302	ESP	FGD-WLS	None	A	3
43	1	Bituminous	Cyclone	568	10100203	ESP	None	None	A	3
44	1	Subbituminous	PC,DB	69	10100222	FF	None	None	A	3
45	1	Bituminous	PC,DB	615	10100202	ESP	None	None	C	3
46	1	Bituminous	PC,DB	500	10100202	LNB/OFA	ESP	None	A	3
47	1	Bituminous	Cyclone	275	10100203	ESP	None	None	A	3
Average Factor										
Quality Rating										

Table 9. Continued

Ref. No.[c]	Acetaldehyde[d,c]	Acetophenone[d,c]	Acrolein[d,c]	Benzene[d,c]	Benzyl-chloride[d,c]	bis(2-ethyl-hexyl-phthalate[d]
23	---	---	---	*5.45E-07 DL/2	---	---
24	---	---	---	*1.66E-02	---	---
24	---	---	---	6.30E-04 DL/2	---	---
28	---	---	---	*4.10E-05	---	*9.24E-05
29	---	---	---	---	---	---
30	---	---	---	*1.82E-05	---	---
31	---	---	---	*2.08E-05	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	*1.02E-05	---	---
37	---	---	---	*4.23E-04	---	---
38	*6.07E-05	---	---	*5.37E-05	---	---
38	*3.07E-05 DL/2	---	---	*2.46E-05	---	---
39	---	---	---	*5.95E-05	---	---
41	*2.17E-03	*1.55E-05	*9.99E-04	*1.93E-04	1.44E-07 DL/2	---
42	*8.35E-04	*6.76E-06	*1.37E-05 DL/2	*5.11E-04	*7.10E-08	---
43	*2.91E-04	*2.62E-05	*7.55E-05	*2.57E-03	---	*9.78E-05
44	*9.60E-06 DL/2	*1.25E-05	*5.98E-05	*1.81E-03	---	*2.96E-05
45	---	---	---	*8.84E-05	*1.40E-03	---
46	---	---	---	*1.36E-05	---	---
47	---	---	---	*1.92E-04	---	---
Average Factor	5.66E-04	1.52E-05	2.87E-04	1.33E-03	7.00E-04	7.33E-05
Quality Rating	C	D	D	A	D	D

Table 9. Continued

Ref. No.[c]	Bromoform[d,c]	Carbon Disulfide[d,c]	Carbon Tetrachloride[d,c]	2-Chloro-acetophenone[d,c]	Chlorobenzene[d,c]	Chloroform[d]
23	---	---	---	---	---	---
24	---	---	---	---	---	---
24	---	---	---	---	---	---
28	---	---	---	---	---	---
29	---	---	---	---	---	---
30	---	---	---	---	---	---
31	---	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	---	---	---	---	---	---
38	---	---	---	---	---	---
39	---	---	---	---	---	---
41	5.85E-05 DL/2	*1.44E-04	*6.09E-05 DL/2	7.02E-06	6.09E-05 DL/2*	*6.09E-05 DL/2
42	*3.86E-05	*4.24E-05	*3.99E-05 DL/2	---	*4.11E-05	*3.99E-05 DL/2
43	---	*2.91E-06	---	---	---	---
44	---	*3.11E-04	---	---	*2.87E-06	---
45	---	---	---	---	---	*7.59E-05
46	---	---	---	---	---	---
47	---	---	---	---	---	---
Average Factor	3.86E-05	1.25E-04	5.04E-05 DL/2	7.02E-06	2.20E-05	5.89E-05
Quality Rating	E	D		E	D	D

Table 9. Continued

Table 9. Continued

Ref. No.[c]	Cumene[d,c]	Cyanide[d,c]	1,3-Dichloro-propylene[d,c]	Dibutyl Phthalate[d,c]	N-nitroso Dimethylamine[d,c]	2,4-Dinitro-toluene[d]
23	---	---	---	---	---	---
24	---	---	---	---	---	---
24	---	---	---	---	---	---
28	---	---	---	*4.77E-05	---	---
29	---	---	---	---	---	---
30	---	---	---	---	---	---
31	---	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	---	---	---	---	---	---
38	---	---	---	---	---	---
39	---	---	---	---	---	---
41	---	*4.39E-03	*6.09E-05 DL/2	---	---	*4.80E-07
42	---	6.35E-04	*3.99E-05 DL/2	---	---	*8.10E-08
43	---	---	---	*6.38E-05	---	---
44	*5.31E-06	---	---	*1.71E-05 DL/2	*7.80E-06 DL/2	---
45	---	---	---	---	---	---
46	---	---	---	---	---	---
47	---	---	---	---	---	---
Average Factor	5.31E-06	2.51E-03	5.04E-05 DL/2	4.29E-05 DL/2	7.80E-06 DL/2	2.81E-07
Quality Rating	E	D				D

Table 9. Continued

Table 9. Continued

Ref. No.[c]	Dimethyl Sulfate[d,c]	Ethyl Benzene[d,c]	Ethyl Chloride[d,c]	Ethylene Dichloride[d,c]	Ethylene Dibromide[d,c]	Ethylidene Dichloride[d]
23	---	*5.45E-07 DL/2	---	---	---	---
24	---	6.30E-04 DL/2	---	---	---	---
24	---	6.30E-04 DL/2	---	---	---	---
28	---	---	---	---	---	---
29	---	---	---	---	---	---
30	---	---	---	---	---	---
31	---	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	---	---	---	---	---	---
38	---	---	---	---	---	---
39	---	---	---	---	---	---
41	---	6.09E-05 DL/2	6.09E-05 DL/2	6.09E-05 DL/2	---	6.09E-05 DL/2
42	---	3.99E-05 DL/2	*3.99E-05 DL/2	*3.99E-05	---	3.99E-05 DL/2
43	---	*2.68E-06	---	---	---	---
44	---	*7.51E-06	*4.40E-05	---	*1.15E-06	---
45	*4.76E-05	---	---	---	---	---
46	---	---	---	---	---	---
47	---	---	---	---	---	---
Average Factor	4.76E-05	9.38E-05	4.20E-05	3.99E-05	1.15E-06	5.04E-05 DL/2
Quality Rating	E	D	D	E	E	

Table 9. Continued

Table 9. Continued

Ref. No.[c]	Formaldehyde[d,c]	Hexachloro-butadiene[d,c]	Hexachloro-ethane[d,c]	Hexane[d,c]	Isophorone[d,c]	Methyl Bromide[d]
23	---	---	---	---	---	---
24	---	---	---	---	---	---
24	---	---	---	---	---	---
28	1.54E-04 DL/2	---	---	---	---	---
29	7.05E-05 DL/2	---	---	---	---	---
30	*2.22E-04	---	---	---	---	---
31	6.50E-05 DL/2	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	*6.07E-05	---	---	---	---	---
38	3.07E-05 DL/2	---	---	---	---	---
39	*3.78E-04	---	---	---	---	---
41	*9.50E-05	*1.44E-07 DL/2	*1.44E-07 DL/2	---	---	7.80E-05 DL/2
42	*2.24E-05	---	---	---	---	*5.36E-05
43	*3.57E-05	---	---	*3.49E-06	*5.57E-04	*2.06E-05
44	*1.49E-05 DL/2	---	---	*2.71E-05	---	---
45	*1.56E-03	---	---	*1.70E-04	*6.06E-04	*3.93E-04
46	*3.46E-05	---	---	---	---	---
47	*1.73E-05	---	---	---	---	---
Average Factor	2.44E-04	1.44E-07 DL/2	1.44E-07 DL/2	6.69E-05	5.81E-04	1.56E-04
Quality Rating	A			D	D	D

Table 9. Continued

Ref. No.[c]	Methyl Chloride[d,c]	Methyl Hydrazine[d,c]	Methyl Ethyl Ketone[d,c]	Methyl Methacrylate[d,c]	Methyl Tert Butyl Ether[d,c]	Methylene Chloride[d]
23	---	---	---	---	---	---
24	---	---	---	---	---	---
24	---	---	---	---	---	---
28	---	---	---	---	---	---
29	---	---	---	---	---	---
30	---	---	---	---	---	---
31	---	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	---	---	---	---	---	---
38	---	---	---	---	---	---
39	---	---	---	---	---	---
41	*1.19E-04	---	*1.24E-04	---	---	---
42	*1.32E-03	---	*1.22E-04	---	---	---
43	---	---	*7.87E-05	---	---	*3.89E-04
44	---	---	8.78E-05 DL/2	*2.01E-05	---	*1.88E-04
45	*1.66E-04	*1.71E-04	*1.52E-03	---	*3.54E-05	---
46	---	---	---	---	---	---
47	---	---	---	---	---	---
Average Factor	5.35E-04	1.71E-04	3.94E-04	2.01E-05	3.54E-05	2.89E-04
Quality Rating	D	E	D	E	E	D

Table 9. Continued

Ref. No.[c]	Phenol[d,c]	Propion-aldehyde[d,c]	Propylene Dichloride[d,c]	1,1,2,2-Tetrachloro-ethane[d,c]	Tetrachloro-ethene[d,c]	Styrene[d]
23	---	---	---	---	---	---
24	---	---	---	---	---	---
24	---	---	---	---	---	---
28	---	---	---	---	---	---
29	---	---	---	---	---	---
30	---	---	---	---	---	---
31	---	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	---	---	---	---	---	---
37	---	---	---	---	---	---
38	---	---	---	---	---	---
38	---	---	---	---	---	---
39	---	---	---	---	---	---
41	---	*6.09E-04	*6.09E-05 DL/2	*6.09E-05 DL/2	*7.55E-05	6.09E-05 DL/2
42	---	*1.50E-04	*3.99E-05 DL/2	*3.99E-05 DL/2	3.99E-05 DL/2	*4.11E-05
43	*2.45E-05	---	---	---	---	*4.23E-06
44	*7.55E-06	---	---	---	*9.87E-06	*3.08E-05
45	---	---	---	---	---	---
46	---	---	---	---	---	---
47	---	---	---	---	---	---
Average Factor	1.60E-05	3.79E-04	5.04E-05 DL/2	5.04E-05 DL/2	4.27E-05	2.54E-05
Quality Rating	D	D			D	D

Table 9. Continued

Ref. No.[c]	Toluene[d,c]	1,1,1-Trichloro-ethane[d,c]	1,1,2-Trichloro-ethane[d,c]	Trichloroethene[d,c]	Xylenes[d,c]	Vinyl Acetate[d]
23	*5.45E-07 DL/2	---	---	---	*5.45E-07 DL/2	---
24	6.30E-04 DL/2	---	---	---	6.30E-04 DL/2	---
24	6.30E-04 DL/2	---	---	---	6.30E-04 DL/2	---
28	---	---	---	---	---	---
29	---	---	---	---	---	---
30	*2.74E-05	*1.98E-05	---	---	*1.90E-05	---
31	*1.35E-04	---	---	---	---	---
34	---	---	---	---	---	---
35	---	---	---	---	---	---
36	*1.02E-05	---	---	---	---	---
37	---	---	---	---	---	---
38	*2.38E-05	---	---	---	---	---
38	*1.65E-05	---	---	---	---	---
39	*2.40E-03	---	---	---	---	---
41	*8.53E-05	6.09E-05 DL/2	*5.85E-05 DL/2	*6.09E-05 DL/2	6.09E-05 DL/2	6.09E-05 DL/2
42	*2.99E-04	3.99E-05 DL/2	*3.99E-05 DL/2	*3.99E-05 DL/2	*4.36E-05	3.99E-05 DL/2
43	*4.25E-05	---	---	---	*3.97E-05	---
44	*9.59E-05	---	---	---	*4.27E-05	*7.55E-06
45	*1.34E-04	---	---	---	*7.75E-05	---
46	*1.86E-05	---	---	---	---	---
47	*4.68E-05	---	---	---	---	---
Average Factor	2.38E-04	1.98E-05	4.92E-05 DL/2	5.04E-05 DL/2	3.72E-05	7.55E-06
Quality Rating	A	E			C	E

Table 9. Continued

Ref. No.[c]	Vinyl Chloride[d,c]	Hexachlorobenzene[d]
23	---	---
24	---	---
24	---	---
28	---	---
29	---	---
30	---	---
31	---	---
34	---	---
35	---	---
36	---	---
37	---	---
38	---	---
38	---	---
39	---	---
41	*6.09E-05 DL/2	*1.44E-07 DL/2
42	*3.99E-05 DL/2	*1.12E-08 DL/2
43	---	---
44	---	---
45	---	---
46	---	---
47	---	---
Average Factor	5.04E-05 DL/2	7.76E-08 DL/2
Quality Rating		

Table 9. Continued

[a] PC = Pulverized Coal, DB = Dry Bottom, AFBC = Atmospheric Fluidized Bed Combustion, CB = Circulating Bed, T = Tangential, O = Opposed, W = Wall.

[b] Controls in use during emissions tests: ESP = Electrostatic Precipitator, FF = Fabric Filter, FGD = Flue Gas Desulfurization, FIL = Furnace Injection of Limestone, LNB = Low No_x Burners, SD = Spray Dryer, WLS = Wet Limestone Scrubber.

[c] An asterisk before a factor indicates that it was used in calculating the overall emission factor.

[d] A DL/2 after a factor indicates that the pollutant was not detected in any of the sampling runs used to develop the factor. The value shown here represents a factor based on one-half of the detection limit.

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4.0 REVISED SECTION 1.1

This section contains the revised Section 1.1 of AP-42, 5th Edition. The electronic version can be located on the EPA TTN CHIEF Web site at http://www.epa.gov/ttn/chief/ap42c1.html

5.0 EMISSION FACTOR DOCUMENTATION, APRIL 1993

This section contains the Emission Factor Documentation for Section 1.1, Bituminous and Subbituminous Coal Combustion, dated April 1993. The electronic version can be located on the EPA TTN at http:\\134.67.104.12\html\chief\fbgdocs.htm.

Appendix A

TEST REPORT TITLE: RESULTS OF THE MARCH 28, 1990 DIOXIN EMISSION PERFORMANCE TEST ON UNIT 3 AT THE NSP SHERCO PLANT IN BECKER, MINNESOTA

FACILITY: NSP SHERCO
UNIT NO.: 3
LOCATION: Becker, Minnesota
FILENAME SHERCO3.tbl

PROCESS DATA

	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	6.30	5.80	5.80
Vol. Flow Rate (dscf/m)[b]	1,971,603	1,939,776	1,952,851
Vol. Flow Rate (dscf/hr)	118,296,180	116,386,560	117,171,060
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	8,450	8,598	8,656
HHV Bituminous Coal (Btu/lb)[d]	8,547	8,547	8,547
HHV Bituminous Coal (Btu/ton)	17,094,000	17,094,000	17,094,000
Coal Feed (ton/hr)	494	503	506
Coal type[e]	Subbituminous		
Boiler configuration[e]	Pulverized, dry bottom		
Coal source[e]	Montana		
SCC	10100222		
Control device 1[e]	Flue Gas Desulfurization, Spray Dryer absorber		
Control device 2[e]	Baghouse		
Data Quality	C- Coal heating value and feed rate not provided.		
Process Parameters[e]	860 megawatts, on line in 1987.		
Test methods[f]	MM5		
Number of test runs[g]	3		

[a]Page 8.
[b]Page 9.
[c]40 CFR Pt 60, App A, Meth. 19, Bituminous coal
[d]From report "Results of the May 29, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station in Becker, Minnesota", page G-1. (Reference No. 25).
[e]Page 1. Assumed dry bottom.
[f]Page 1.
[g]Page 5.

DIOXIN/FURAN EMISSION FACTORS

EMISSION RATES (g/sec)[a]	Run 1	Run 2	Run 3	AVG
TCDD	4.0e-08	2.0e-08	1.4e-08	
PeCDD	7.8e-08	3.8e-08	1.7e-08	
HxCDD	3.2e-07	1.6e-07	8.6e-08	
HpCDD	1.19e-06	4.6e-07	2.4e-07	
OCDD	3.51e-06	1.16e-06	7.2e-07	
TCDF	3.2e-07	1.0e-07	4.8e-08	
PeCDF	5.7e-07	2.2e-07	1.2e-07	
HxCDF	1.43e-06	6.5e-07	3.2e-07	
HpCDF	5.12e-06	1.97e-06	1.18e-06	
OCDF	1.670e-05	5.12e-06	4.02e-06	

EMISSION RATES (lb/hr)[b]	Run 1	Run 2	Run 3	AVG
TCDD	3.18e-07	1.59e-07	1.11e-07	
PeCDD	6.19e-07	3.02e-07	1.35e-07	
HxCDD	2.54e-06	1.27e-06	6.83e-07	
HpCDD	9.45e-06	3.65e-06	1.91e-06	
OCDD	2.79e-05	9.21e-06	5.72e-06	
TCDF	2.54e-06	7.94e-07	3.81e-07	
PeCDF	4.52e-06	1.75e-06	9.53e-07	
HxCDF	1.14e-05	5.16e-06	2.54e-06	
HpCDF	4.06e-05	1.56e-05	9.37e-06	
OCDF	1.33e-04	4.06e-05	3.19e-05	

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
TCDD	6.42e-10	3.16e-10	2.19e-10	3.93e-10
PeCDD	1.25e-09	6.00e-10	2.67e-10	7.06e-10
HxCDD	5.14e-09	2.53e-09	1.35e-09	3.00e-09
HpCDD	1.91e-08	7.26e-09	3.76e-09	1.00e-08
OCDD	5.64e-08	1.83e-08	1.13e-08	2.87e-08
TCDF	5.14e-09	1.58e-09	7.52e-10	2.49e-09
PeCDF	9.15e-09	3.47e-09	1.88e-09	4.84e-09
HxCDF	2.30e-08	1.03e-08	5.02e-09	1.27e-08
HpCDF	8.22e-08	3.11e-08	1.85e-08	4.39e-08
OCDF	2.68e-07	8.08e-08	6.30e-08	1.37e-07

[a]Page 4
[b]Convert g/sec to lb/hr.
[c]Divide emission rate by coal feed rate.

REFERENCE 20 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 10 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE SEPTEMBER 10 AND 11, 1991 MERCURY REMOVAL TESTS ON THE UNITS 1 & 2, AND UNIT 3 SCRUBBER SYSTEMS AT THE NSP SHERCO PLANT IN BECKER, MINNESOTA

FACILITY: NSP SHERCO
UNIT NO.: 3
LOCATION: Becker, Minnesota
FILENAME: SHRCO123.tbl

PROCESS DATA UNIT 3			
	Run 1	Run 2	Run 3
Vol. Flow Rate (dscf/m)[a]	1,909,745	1,908,275	1,850,934
Vol. Flow Rate (dscf/hr)	114,584,700	114,496,500	111,056,040
Coal Feed (ton/hr)[b]	490	494	503
Coal type[c]	Subbituminous		
Boiler configuration[c]	Pulverized, dry bottom		
Coal source[c]	Montana		
SCC	10100222		
Control device 1[c]	Flue Gas Desulfurization, Spray Dryer absorber		
Control device 2[c]	Baghouse		
Data Quality	A		
Process Parameters[c]	860 megawatts, on line in 1987.		
Test methods[c]	EPA 101A for mercury		
Number of test runs[d]	3		

[a]Page 18.
[b]Page 7.
[c]Page 1. Assumed to be dry bottom.
[d]Page 5.

MERCURY EMISSION FACTORS UNIT 3				
	Run 1	Run 2	Run 3	AVG
EMISSION RATES (lb/hr)[a]	0.038	0.043	0.044	
EMISSION FACTOR (lb/ton)[b]	7.76e-05	8.70e-05	8.75e-05	8.40e-05

[a]Page 5.
[b]Divide emission rate by coal feed rate.

REFERENCE 20 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 10 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

PROCESS DATA UNITS 1 & 2			
	Run 1	Run 2	Run 3
Vol. Flow Rate (dscf/m)[a]	3,334,932	3,376,641	3,313,486
Vol. Flow Rate (dscf/hr)	200,095,920	202,598,460	198,809,160
Coal Feed (ton/hr)[b]	764	775	766
Coal type[c]	Subbituminous		
Boiler configuration[c]	Pulverized, assume dry bottom		
Coal source[c]	70% Wyoming/30% Montana		
SCC	10100222		
Control device 1[c]	Flue Gas Desulfurization, Venturi Scrubber Spray Tower		
Control device 2[c]			
Data Quality	A		
Process Parameters[c]	750 MW each, on line in 1976		
Test methods[c]	EPA 101A for mercury		
Number of test runs[d]	3		

[a]Page 16.
[b]Page 7.
[c]Page 1.
[d]Page 5.

MERCURY EMISSION FACTORS UNIT 1 & 2				
	Run 1	Run 2	Run 3	AVG
EMISSION RATES (lb/hr)[a]	0.042	0.025	0.090	
EMISSION FACTOR (lb/ton)[b]	5.50e-05	3.23e-05	1.17e-04	6.82e-05

[a]Page 5.
[b]Divide emission rate by coal feed rate.

REFERENCE 21 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 11 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE NOVEMBER 5, 1991 AIR TOXIC EMISSION STUDY ON THE NO. 1, 3 & 4 BOILERS AT THE NSP BLACK DOG PLANT

FACILITY: NSP BLACK DOG
UNIT NO.: 1, 3 & 4
LOCATION: Burnsville, Minnesota
FILENAME BLKDG134.tbl

PROCESS DATA	METALS			
	Run 1	Run 2	Run 3	
Oxygen (% v/v)[a]	7.10	6.80	6.60	
Vol. Flow Rate (dscf/m)[b]	836,298	842,891	824,638	
Vol. Flow Rate (dscf/hr)	50,177,880	50,573,460	49,478,280	
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780	
Heat input (MMBtu/hr)	3,388	3,489	3,462	
HHV Bituminous Coal (Btu/lb)[d]	8,707	8,707	8,707	
HHV Bituminous Coal (Btu/ton)	17,414,000	17,414,000	17,414,000	
Coal Feed (ton/hr)	195	200	199	
Coal type[e]	Subbituminous			
Boiler configuration[e]	Pulverized, dry bottom			
Coal source[e]	Antelope/North Antelope			
SCC	10100222			
Control device 1[e]	ESP			
Control device 2[e]	ESP			
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate, ton/hr.		
Process Parameters[e]	Three watertube boilers at 720,000, 775,000 and 1,250,000 lb/hr steam.			
Test methods[f]	MM 5 metals			
Number of test runs[g]	3			

[a]Page 22.
[b]Page 29.
[c]Page 29.
[d]Section 4 Results of Fuel Analyses.
[e]Page 1. Assumed dry bottom.
[f]Page 1.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	8.8	9.7	10.9	
Antimony[b]	0.019	0.019	0.019	
Arsenic	0.0021	0.0021	0.0021	
Barium	0.67	0.51	0.22	
Beryllium	0.00036	0.00047	0.00055	
Boron	0.11	0.099	0.12	
Cadmium	0.0017	0.013	0.017	
Calcium	12.6	15.2	13.2	
Chromium	0.0071	0.013	0.009	
Copper	0.037	0.14	0.034	
Iron	3.1	3.8	4.1	
Lead	0.017	0.19	0.0084	
Magnesium	2.7	3.2	3.6	
Manganese	0.019	0.021	0.022	
Mercury	0.017	0.0087	0.022	
Molybdenum[b]	0.0063	0.0063	0.0063	
Nickel	0.012	0.052	0.0092	
Potassium	0.52	0.93	0.65	
Selenium	0.0042	0.0042	0.0042	
Silver	0.0038	0.0032	0.0078	
SO2	1490	1630	1460	
Sodium	1.5	2.5	1.9	
Strontium	0.23	0.23	0.19	
Vanadium	0.023	0.025	0.026	
Zinc	0.059	0.46	0.091	

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	4.52e-02	4.84e-02	5.48e-02	4.95e-02
Antimony[b]	9.77e-05	9.48e-05	9.56e-05	9.60e-05
Arsenic	1.08e-05	1.05e-05	1.06e-05	1.06e-05
Barium	3.44e-03	2.55e-03	1.11e-03	2.37e-03
Beryllium	1.85e-06	2.35e-06	2.77e-06	2.32e-06
Boron	5.65e-04	4.94e-04	6.04e-04	5.54e-04
Cadmium	8.74e-06	6.49e-05	8.55e-05	5.31e-05
Calcium	6.48e-02	7.59e-02	6.64e-02	6.90e-02
Chromium	3.65e-05	6.49e-05	4.53e-05	4.89e-05
Copper	1.90e-04	6.99e-04	1.71e-04	3.53e-04
Iron	1.59e-02	1.90e-02	2.06e-02	1.85e-02
Lead	8.74e-05	9.48e-04	4.23e-05	3.59e-04
Magnesium	1.39e-02	1.60e-02	1.81e-02	1.60e-02
Manganese	9.77e-05	1.05e-04	1.11e-04	1.04e-04
Mercury	8.74e-05	4.34e-05	1.11e-04	8.05e-05
Molybdenum[b]	3.24e-05	3.14e-05	3.17e-05	3.18e-05
Nickel	6.17e-05	2.60e-04	4.63e-05	1.23e-04
Potassium	2.67e-03	4.64e-03	3.27e-03	3.53e-03
Selenium	2.16e-05	2.10e-05	2.11e-05	2.12e-05
Silver	1.95e-05	1.60e-05	3.92e-05	2.49e-05
SO2	7.66e+00	8.14e+00	7.34e+00	7.71e+0
Sodium	7.71e-03	1.25e-02	9.56e-03	9.92e-03
Strontium	1.18e-03	1.15e-03	9.56e-04	1.10e-03
Vanadium	1.18e-04	1.25e-04	1.31e-04	1.25e-04
Zinc	3.03e-04	2.30e-03	4.58e-04	1.02e-03

[a]Table 3 (page 13?).

[b]Not detected in any of the sampling runs, emission factor is based on detection limits.

[c]Divide emission rate by coal feed rate.

REFERENCE 22 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 12 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE JANUARY 1992 AIR TOXIC EMISSION STUDY ON THE NO. 2 BOILER AT THE NSP BLACK DOG PLANT

FACILITY: NSP BLACK DOG
UNIT NO.: 2
LOCATION: Burnsville, Minnesota
FILENAME BLKDOG2.tbl

PROCESS DATA	METALS		
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	10.40	10.20	10.20
Vol. Flow Rate (dscf/m)[b]	354,118	351,097	354,635
Vol. Flow Rate (dscf/hr)	21,247,080	21,065,820	21,278,100
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	1,091	1,103	1,114
HHV Bituminous Coal (Btu/lb)[d]	8,553	8,553	8,553
HHV Bituminous Coal (Btu/ton)	17,106,000	17,106,000	17,106,000
Coal Feed (ton/hr)	64	64	65
Coal type[e]	Subbituminous		
Boiler configuration[e]	Atmospheric Fluidized bed Combustor (AFBC), circulating bed		
Coal source[e]	Antelope/North Antelope		
SCC	10100238		
Control Device 1[e]	Cyclone (mechanical dust collector)		
Control device 2[e]	ESP		
Control device 3[e]	ESP		
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate (ton/hr).	
Process Parameters[e]	137 MW		
Test methods[f]	MM 5 metalS.		
Number of test runs[g]	2 for lead, 3 for all others		

[a]Page 20.
[b]Page 25.
[c]Page 25.
[d]Page 31
[e]Page 1. Coal from Antelope/Northern Antelope is subbituminous, according to another report.
[f]Page 1.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	1.05	1.29	1.33	
Antimony[b]	0.0006	0.0006	0.0006	
Arsenic	0.000584	0.000603	0.000559	
Barium	0.0541	0.0639	0.0691	
Beryllium[b]	0.00003	0.00003	0.00003	
Boron	0.0927	0.101	0.0847	
Cadmium	0.00403	0.0117	0.00575	
Calcium	4.05	4.59	4.76	
Chromium	0.00573	0.0112	0.00386	
Copper	0.0139	0.0177	0.0113	
Iron	0.969	1.04	1.15	
Lead	0.0496		0.0613	
Magnesium	0.704	0.812	0.835	
Manganese	0.00529	0.00615	0.00895	
Mercury	0.0029	0.00265	0.00297	
Molybdenum	0.0064	0.0135	0.0051	
Nickel	0.0376	0.0471	0.01	
Potassium	0.07	0.107	0.0901	
Selenium	0.000602	0.000299	0.000445	
Silver[b]	0.0006	0.0006	0.0006	
SO2	362	356	334	
Sodium	0.837	0.983	0.829	
Strontium	0.056	0.0651	0.0733	
Vanadium	0.00437	0.00434	0.00436	
Zinc	0.122	0.092	0.0479	

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	1.65e-02	2.00e-02	2.04e-02	1.90e-02
Antimony[b]	9.40e-06	9.31e-06	9.21e-06	9.31e-06
Arsenic	9.15e-06	9.35e-06	8.58e-06	9.03e-06
Barium	8.48e-04	9.91e-04	1.06e-03	9.67e-04
Beryllium[b]	4.70e-07	4.65e-07	4.61e-07	4.65e-07
Boron	1.45e-03	1.57e-03	1.30e-03	1.44e-03
Cadmium	6.32e-05	1.81e-04	8.83e-05	1.11e-04
Calcium	6.35e-02	7.12e-02	7.31e-02	6.93e-02
Chromium	8.98e-05	1.74e-04	5.93e-05	1.08e-04
Copper	2.18e-04	2.75e-04	1.74e-04	2.22e-04
Iron	1.52e-02	1.61e-02	1.77e-02	1.63e-02
Lead	7.77e-04		9.41e-04	8.59e-04
Magnesium	1.10e-02	1.26e-02	1.28e-02	1.22e-02
Manganese	8.29e-05	9.54e-05	1.37e-04	1.05e-04
Mercury	4.55e-05	4.11e-05	4.56e-05	4.41e-05
Molybdenum	1.00e-04	2.09e-04	7.83e-05	1.29e-04
Nickel	5.89e-04	7.31e-04	1.54e-04	4.91e-04
Potassium	1.10e-03	1.66e-03	1.38e-03	1.38e-03
Selenium	9.43e-06	4.64e-06	6.83e-06	6.97e-06
Silver[b]	9.40e-06	9.31e-06	9.21e-06	9.31e-06
SO2	5.67e+00	5.52e+00	5.13e+00	5.44e+00
Sodium	1.31e-02	1.52e-02	1.27e-02	1.37e-02
Strontium	8.78e-04	1.01e-03	1.13e-03	1.00e-03
Vanadium	6.85e-05	6.73e-05	6.70e-05	6.76e-05
Zinc	1.91e-03	1.43e-03	7.36e-04	1.36e-03

[a]Page 11
[b]Pollutant was not detected in any of the sampling runs, detection limits used to develop rates.
[c]Divide emission rate by coal feed rate.

REFERENCE 23 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 13 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE NOVEMBER 7, 1991 AIR TOXIC EMISSION STUDY ON THE NOS. 3, 4, 5 & 6 BOILERS AT THE NSP HIGH BRIDGE PLANT

FACILITY: NSP High Bridge
UNIT NO.: 3, 4, 5 & 6
LOCATION: St. Paul, Minnesota
FILENAME HIBRIDGE.tbl

PROCESS DATA	METALS		
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	7.70	7.60	7.80
Vol. Flow Rate (dscf/m)[b]	804,786	788,668	815,076
Vol. Flow Rate (dscf/hr)	48,287,160	47,320,080	48,904,560
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	3,118	3,079	3,134
HHV Bituminous Coal (Btu/lb)[d]	8,498	8,498	8,498
HHV Bituminous Coal (Btu/ton)	16,996,000	16,996,000	16,996,000
Coal Feed (ton/hr)	183	181	184
Coal type[e]	Subbituminous		
Boiler configuration[e]	Pulverized, dry bottom		
Coal source[e]	Rochelle		
SCC	10100222		
Control device 1[e]	ESPC		
Control device 2[e]	None		
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate, ton/hr.	
Process Parameters[e]	Watertube boilers with economizers and air preheaters		
Test methods[f]	MM 5 metals, Method 18 for BTEX		
Number of test runs[g]	3		

[a]Page 29.
[b]Page 37.
[c]40 CFR Pt 60, App A, Meth. 19
[d]Page 42
[e]Page 1. Assumed dry bottom.
[f]Page 1 for metals, page 3 for BTEX.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	4.17	3.24	4.63	
Antimony	0.00126	0.00456	0.00092	
Arsenic	0.00126	0.00091	0.00092	
Barium	0.406	0.350	0.433	
Beryllium	0.00018	0.00018	0.00037	
Boron	0.127	0.105	0.118	
Cadmium	0.0023	0.0018	0.002	
Calcium	5.25	4.12	6.45	
Chromium	0.023	0.018	0.024	
Copper	0.036	0.024	0.028	
Iron	1.66	1.42	1.55	
Lead	0.015	0.0091	0.0092	
Magnesium	1.03	0.82	1.14	
Manganese	0.033	0.015	0.028	
Mercury[b]	0.013	0.010	0.013	
Molybdenum	0.059	0.046	0.061	
Nickel	0.012	0.0091	0.011	
Potassium	0.54	0.38	0.49	
Selenium	0.0036	0.0018	0.0018	
Silver	0.072	0.051	0.037	
SO2	1,319	1,290	1,247	
Sodium	1.22	1.02	1.40	
Strontium	0.17	0.12	0.15	
Vanadium	0.0066	0.0067	0.0068	
Zinc	0.074	0.049	0.050	

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	2.27e-02	1.79e-02	2.51e-02	2.19e-02
Antimony	6.87e-06	2.52e-05	4.99e-06	1.23e-05
Arsenic	6.87e-06	5.02e-06	4.99e-06	5.63e-06
Barium	2.21e-03	1.93e-03	2.35e-03	2.16e-03
Beryllium	9.81e-07	9.94e-07	2.01e-06	1.33e-06
Boron	6.92e-04	5.80e-04	6.40e-04	6.37e-04
Cadmium	1.25e-05	9.94e-06	1.08e-05	1.11e-05
Calcium	2.86e-02	2.27e-02	3.50e-02	2.88e-02
Chromium	1.25e-04	9.94e-05	1.30e-04	1.18e-04
Copper	1.96e-04	1.32e-04	1.52e-04	1.60e-04
Iron	9.05e-03	7.84e-03	8.41e-03	8.43e-03
Lead	8.18e-05	5.02e-05	4.99e-05	6.06e-05
Magnesium	5.61e-03	4.53e-03	6.18e-03	5.44e-03
Manganese	1.80e-04	8.28e-05	1.52e-04	1.38e-04
Mercury[b]	7.09e-05	5.52e-05	7.05e-05	6.55e-05
Molybdenum	3.22e-04	2.54e-04	3.31e-04	3.02e-04
Nickel	6.54e-05	5.02e-05	5.96e-05	5.84e-05
Potassium	2.94e-03	2.10e-03	2.66e-03	2.57e-03
Selenium	1.96e-05	9.94e-06	9.76e-06	1.31e-05
Silver	3.92e-04	2.82e-04	2.01e-04	2.92e-04
SO2	7.19e+00	7.12e+00	6.76e+00	7.02e+00
Sodium	6.65e-03	5.63e-03	7.59e-03	6.62e-03
Strontium	9.27e-04	6.62e-04	8.13e-04	8.01e-04
Vanadium	3.60e-05	3.70e-05	3.69e-05	3.66e-05
Zinc	4.03e-04	2.70e-04	2.71e-04	3.15e-04

[a]Table 4, page 16.
[b]Pollutant not detected in any of the sampling runs, detection limit used to develop emission factor.
[c]Divide emission rate by coal feed rate.

REFERENCE 23 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 13 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

BTEX EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3
Benzene[b]	0.2	0.2	0.2
Toluene[b]	0.2	0.2	0.2
Ethyl Benzene[b]	0.2	0.2	0.2
Xylene[b]	0.2	0.2	0.2

[a]page 22

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Benzene[b]	1.09e-03	1.10e-03	1.08e-03	1.09e-03
Toluene[b]	1.09e-03	1.10e-03	1.08e-03	1.09e-03
Ethyl Benzene[b]	1.09e-03	1.10e-03	1.08e-03	1.09e-03
Xylene[b]	1.09e-03	1.10e-03	1.08e-03	1.09e-03

[a]page 22
[b]Pollutant was not detected in any of the sampling runs, detection limits used to develop emission factor.
[c]Divide emission rate by coal feed rate.

REFERENCE 24 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 14 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE DECEMBER 1991 AIR TOXIC EMISSION STUDY ON UNITS 6 & 7 AT THE NSP RIVERSIDE PLANT

FACILITY: NSP Riverside
UNIT NO.: 6, 7
LOCATION: Minneapolis, Mn
FILENAME RIVERSID.tbl

PROCESS DATA		
Coal type[a]	Subbituminous	
Boiler configuration[a]	Pulverized, dry bottom	
Coal source[a]	Rochelle	
SCC	10100222	
Control device 1[b]	Baghouse	
Control device 2[b]	None	
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate (ton/hr)
Process Parameters[a]	575,000 lb/hr steam each; equipped with economizers and air preheaters.	
Test methods[c]	MM5 for PM/Metals, Method 18 for BTEX.	
Number of test runs[d]	3	

FLOW RATES, COAL FEED RATES		Unit 6	
	Run 1	Run 2	Run 3
Volumentric flow rate (dscf/m)[e]	193,851	189,541	187,122
Volumentric flow rate (dscf/hr)	11,631,060	11,372,460	11,227,320
F-Factor (dscf/MMBtu)[f]	9,780	9,780	9,780
O2 %v/v[g]	6.00	6.00	6.60
Heat input (MMBtu/hr)	848	829	785
Coal HHV (Btu/lb)[h]	8,602	8,602	8,602
Coal HHV (Btu/ton)	17,204,000	17,204,000	17,204,000
Coal feed rate (ton/hr)	49.28	48.19	45.66

	Unit 7			
	Run 1	Run 2	Run 3	
Volumentric flow rate (dscf/m)[e]	188,847	188,814	194,376	
Volumentric flow rate (dscf/hr)	11,330,820	11,328,840	11,662,560	
F-Factor (dscf/MMBtu)[f]	9,780	9,780	9,780	
O2 %v/v[g]	6.30	6.20	6.30	
Heat input (MMBtu/hr)	809	815	833	
Coal HHV (Btu/lb)[h]	8,602	8,602	8,602	
Coal HHV (Btu/ton)	17,204,000	17,204,000	17,204,000	
Coal feed rate (ton/hr)	47.04	47.36	48.42	

[a]Page 1. Assumed dry bottom.
[b]Page 2.
[c]Page 1, 3, 24.
[d]Various pages.
[e]Page 29 for Unit 6 metals, Page 30 for Unit 7 metals.
[f]Page 28.
[g]Page 23 for Unit 6 metals, Page 24 for Unit 7 metals.
[h]Page 36.

METALS EMISSION FACTORS UNITS 6 & 7

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	13.9	16.7	15.5	
Antimony	0.00075	0.00067	0.00024	
Arsenic	0.00174	0.00183	0.00183	
Barium	0.073	0.005	0.002	
Beryllium	0.00073	0.0007	0.00088	
Boron	0.132	0.022	0.007	
Cadmium	0.115	0.0141	0.0101	
Calcium	23.4	27.7	19.0	
Chromium	0.0228	0.0209	0.0234	
Copper	0.060	0.065	0.053	
Iron	5.5	6.7	5.9	
Lead	0.0134	0.0100	0.0096	
Magnesium	4.9	5.9	5.3	
Manganese	0.0298	0.0400	0.0252	

METALS EMISSION FACTORS UNITS 6 & 7

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Mercury	0.013	0.006	0.005	
Molybdenum	0.00198	0.00409	0.00434	
Nickel	0.0285	0.113	0.0234	
Potassium	0.55	0.78	0.61	
Selenium	0.00706	0.00289	0.00193	
Silver	0.005	0.002	0.002	
SO2	875	788	762	
Sodium	2.03	2.85	2.49	
Strontium	0.328	0.372	0.256	
Vanadium	0.0289	0.0390	0.0347	
Zinc	0.071	0.278	0.006	
EMISSION FACTORS (lb/ton)[b]	**Run 1**	**Run 2**	**Run 3**	**AVG**
Aluminum	1.44e-01	1.75e-01	1.65e-01	1.61e-01
Antimony	7.79e-06	7.01e-06	2.55e-06	5.78e-06
Arsenic	1.81e-05	1.92e-05	1.95e-05	1.89e-05
Barium	7.58e-04	5.23e-05	2.13e-05	2.77e-04
Beryllium	7.58e-06	7.33e-06	9.35e-06	8.09e-06
Boron	1.37e-03	2.30e-04	7.44e-05	5.58e-04
Cadmium	1.19e-03	1.48e-04	1.07e-04	4.83e-04
Calcium	2.43e-01	2.90e-01	2.02e-01	2.45e-01
Chromium	2.37e-04	2.19e-04	2.49e-04	2.35e-04
Copper	6.23e-04	6.80e-04	5.63e-04	6.22e-04
Iron	5.71e-02	7.01e-02	6.27e-02	6.33e-02
Lead	1.39e-04	1.05e-04	1.02e-04	1.15e-04
Magnesium	5.09e-02	6.18e-02	5.63e-02	5.63e-02
Manganese	3.09e-04	4.19e-04	2.68e-04	3.32e-04
Mercury	1.35e-04	6.28e-05	5.31e-05	8.36e-05
Molybdenum	2.06e-05	4.28e-05	4.61e-05	3.65e-05
Nickel	2.96e-04	1.18e-03	2.49e-04	5.76e-04

EMISSION FACTORS (lb/ton)[b]	Run 1	Run 2	Run 3	AVG
Potassium	5.71e-03	8.16e-03	6.48e-03	6.79e-03
Selenium	7.33e-05	3.02e-05	2.05e-05	4.14e-05
Silver	5.19e-05	2.09e-05	2.13e-05	3.14e-05
SO2	9.08e+00	8.25e+00	8.10e+00	8.48e+00
Sodium	2.11e-02	2.98e-02	2.65e-02	2.58e-02
Strontium	3.41e-03	3.89e-03	2.72e-03	3.34e-03
Vanadium	3.00e-04	4.08e-04	3.69e-04	3.59e-04
Zinc	7.37e-04	2.91e-03	6.38e-05	1.24e-03

[a]Table 8, page 16.
[b]Divide emission rate by coal feed rate.

BTEX EMISSION FACTORS UNIT 6

Emission Rates (lb/hr)[a]	Run 1	Run 2	Run 3	
Benzene	1.02	1.05	0.33	
Toluene[b]	0.06	0.06	0.06	
Ethylbenzene[b]	0.06	0.06	0.06	
Xylene[b]	0.06	0.06	0.06	
Emission Factors (lb/ton)[c]				avg
Benzene	2.07e-02	2.18e-02	7.23e-03	1.66e-02
Toluene[b]	1.22e-03	1.25e-03	1.31e-03	1.26e-03
Ethylbenzene[b]	1.22e-03	1.25e-03	1.31e-03	1.26e-03
Xylene[b]	1.22e-03	1.25e-03	1.31e-03	1.26e-03

[a]page 19.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits.
[c]Divide emission rate by coal feed rate.

BTEX EMISSION FACTORS UNIT 7

Emission Rates (lb/hr)[a]	Run 1	Run 2	Run 3
Benzene[b]	0.06	0.06	0.06
Toluene[b]	0.06	0.06	0.06
Ethylbenzene[b]	0.06	0.06	0.06
Xylene[b]	0.06	0.06	0.06

Emission Factors (lb/ton)[c]				
Benzene[b]	1.28e-03	1.27e-03	1.24e-03	1.26e-03
Toluene[b]	1.28e-03	1.27e-03	1.24e-03	1.26e-03
Ethylbenzene[b]	1.28e-03	1.27e-03	1.24e-03	1.26e-03
Xylene[b]	1.28e-03	1.27e-03	1.24e-03	1.26e-03

[a]page 19.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits.
[c]Divide emission rate by coal feed rate.

REFERENCE 25 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 15 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE MAY 29, 1990 TRACE METAL CHARACTERIZATION STUDY ON UNITS 1 AND 2 AT THE SHERBURNE COUNTY GENERATING STATION IN BECKER, MINNESOTA

FACILITY: NSP Sherco
UNIT NO.: 1, 2
LOCATION: Becker, Minnesota
FILENAME SHERCO12.tbl

PROCESS DATA	PM/METALS		
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	6.60	6.50	6.60
Vol. Flow Rate (dscf/m)[b]	3,305,953	3,340,203	3,106,503
Vol. Flow Rate (dscf/hr)	198,357,180	200,412,180	186,390,180
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	13,877	14,119	13,040
HHV Bituminous Coal (Btu/lb)[d]	8,547	8,547	8,547
HHV Bituminous Coal (Btu/ton)	17,094,000	17,094,000	17,094,000
Coal Feed (ton/hr)	812	826	763
Coal type[e]	Subbituminous		
Boiler configuration[e]	Pulverized, dry bottom		
Coal source[e]	80% Rochelle/20% Coalstrip		
SCC	10100222		
Control device 1[e]	Flue Gas Desulfurization, Venturi Scrubber Spray Tower		
Control device 2[e]	None		
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate, ton/hr.	
Process Parameters[e]	750 MW each, on line in 1976.		
Test methods[f]	MM 5		
Number of test runs[g]	2 for nickel, 3 for all others		

[a]Page 7.
[b]Page 8.
[c]40 CFR Pt 60, App A.
[d]Page G-1.
[e]Page 1.
[f]Page 1.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	8.9725	23.3877	7.7052	
Antimony	0.0084	0.0041	0.0092	
Arsenic	0.0304	0.0433	0.0326	
Barium	3.3101	6.4375	2.6330	
Beryllium	0.0033	0.0036	0.0035	
Boron	4.1097	86.2852	43.3077	
Cadmium	0.0205	0.0132	0.0097	
Calcium	67.2241	141.6439	72.3851	
Chromium	0.2046	0.1788	0.0881	
Copper	0.1302	0.1694	0.1321	
Iron	10.3672	13.7879	9.5545	
Lead	0.1116	0.0941	0.0969	
Magnesium	7.0757	18.5219	6.6221	
Manganese	0.3068	0.3294	0.6076	
Mercury	0.0093	0.0196	0.0141	
Molybdenum	0.0279	0.0471	0.0264	
Nickel	0.0186	----	0.0185	
Potassium	1.5806	2.0705	1.8493	
Selenium	0.0818	0.1129	0.1233	
Silver[b]	0.0112	0.0113	0.0114	
Sodium	4.7419	6.8704	5.4597	
Strontium	2.5197	4.5928	2.4657	
Vanadium	0.2603	0.3294	0.2906	
Zinc	0.2696	0.3106	0.2378	

[a] Page 5.
[b] Pollutant was not detected in any of the sampling runs. EF is based on detection limits.

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	1.11e-02	2.83e-02	1.01e-02	1.65e-02
Antimony	1.03e-05	4.96e-06	1.21e-05	9.12e-06
Arsenic	3.74e-05	5.24e-05	4.27e-05	4.42e-05
Barium	4.08e-03	7.79e-03	3.45e-03	5.11e-03
Beryllium	4.06e-06	4.36e-06	4.59e-06	4.34e-06
Boron	5.06e-03	1.04e-01	5.68e-02	5.54e-02
Cadmium	2.53e-05	1.60e-05	1.27e-05	1.80e-05
Calcium	8.28e-02	1.71e-01	9.49e-02	1.16e-01
Chromium	2.52e-04	2.16e-04	1.15e-04	1.95e-04
Copper	1.60e-04	2.05e-04	1.73e-04	1.80e-04
Iron	1.28e-02	1.67e-02	1.25e-02	1.40e-02
Lead	1.37e-04	1.14e-04	1.27e-04	1.26e-04
Magnesium	8.72e-03	2.24e-02	8.68e-03	1.33e-02
Manganese	3.78e-04	3.99e-04	7.97e-04	5.24e-04
Mercury	1.15e-05	2.37e-05	1.85e-05	1.79e-05
Molybdenum	3.44e-05	5.70e-05	3.46e-05	4.20e-05
Nickel	2.29e-05		2.43e-05	2.36e-05
Potassium	1.95e-03	2.51e-03	2.42e-03	2.29e-03
Selenium	1.01e-04	1.37e-04	1.62e-04	1.33e-04
Silver[b]	1.38e-05	1.37e-05	1.49e-05	1.41e-05
Sodium	5.84e-03	8.32e-03	7.16e-03	7.11e-03
Strontium	3.10e-03	5.56e-03	3.23e-03	3.97e-03
Vanadium	3.21e-04	3.99e-04	3.81e-04	3.67e-04
Zinc	3.32e-04	3.76e-04	3.12e-04	3.40e-04

[a]Page 5.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits.
[c]Divide emission rate by coal feed rate.

REFERENCE 26 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 16 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE MAY 1, 1990 TRACE METAL CHARACTERIZATION STUDY ON UNITS 1 AND 2 AT THE SHERBURNE COUNTY GENERATING STATION

FACILITY: NSP Sherco
UNIT NO.: 1, 2
LOCATION: Becker, Minnesota
FILENAME SHRCO12A.TBL

PROCESS DATA	METALS		
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	6.60	6.60	6.70
Vol. Flow Rate (dscf/m)[b]	3,284,153	3,326,471	3,347,367
Vol. Flow Rate (dscf/hr)	197,049,180	199,588,260	200,842,020
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	13,786	13,963	13,953
HHV Bituminous Coal (Btu/lb)[d]	8,547	8,547	8,547
HHV Bituminous Coal (Btu/ton)	17,094,000	17,094,000	17,094,000
Coal Feed (ton/hr)	806	817	816
Coal type[e]	Subbituminous		
Boiler configuration[e]	Pulverized, dry bottom		
Coal source	no data		
SCC	10100222		
Control device 1[e]	Flue Gas Desulfurization, Venturi Scrubber Spray Tower		
Control device 2[e]	None		
Data Quality	B	Had to use F-factor and average HHV to get coal feed rate, ton/hr.	
Process Parameters[e]	750 MW each, on line in 1976.		
Test methods[f]	MM 5 metals.		
Number of test runs[g]	2 for cadmium, nickel, copper and zinc; 3 for all others		

[a]Page 14.
[b]Page 19.
[c]40 CFR Pt 60, App A.
[d]From report "Results of the May 29, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station in Becker, Minnesota", page G-1. (Reference No. 25)
[e]Page 1 of "Results of the September 10 and 11, 1991 Mercury Removal Tests on the Units 1 & 2, and Unit 3 Scrubber Systems at the NSP Sherco Plant in Becker, Minnesota" (Reference 19). Dry bottom assumed.
[f]Page 2.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	9.58	11.06	8.86	
Antimony	0.016	0.011	0.009	
Arsenic	0.035	0.039	0.030	
Barium	3.59	5.81	2.25	
Beryllium	0.0037	0.0042	0.0038	
Boron	98.0	18.1	38.1	
Cadmium	---	0.029	0.049	
Calcium	126	141	129	
Chromium	0.133	0.101	0.092	
Copper	---	0.200	0.227	
Iron	14.6	14.6	12.9	
Lead	0.127	0.118	0.100	
Magnesium	5.36	7.65	5.91	
Manganese	0.281	0.401	0.273	
Mercury	0.092	0.078	0.063	
Molybdenum [b]	0.027	0.027	0.027	
Nickel	---	0.071	0.052	
Potassium	2.00	1.88	1.74	
Selenium	0.109	0.137	0.118	
Silver	0.009	0.010	0.030	
Sodium	7.67	6.42	5.13	
Strontium	3.26	3.82	3.09	
Vanadium	0.300	0.291	0.282	
Zinc	---	0.70	0.45	

EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	1.19e-02	1.35e-02	1.09e-02	1.21e-02
Antimony	1.98e-05	1.35e-05	1.10e-05	1.48e-05
Arsenic	4.34e-05	4.77e-05	3.68e-05	4.26e-05
Barium	4.45e-03	7.11e-03	2.76e-03	4.77e-03
Beryllium	4.59e-06	5.14e-06	4.66e-06	4.80e-06
Boron	1.22e-01	2.22e-02	4.67e-02	6.35e-02
Cadmium		3.55e-05	6.00e-05	4.78e-05
Calcium	1.56e-01	1.73e-01	1.58e-01	1.62e-01
Chromium	1.65e-04	1.24e-04	1.13e-04	1.34e-04
Copper		2.45e-04	2.78e-04	2.61e-04
Iron	1.81e-02	1.79e-02	1.58e-02	1.73e-02
Lead	1.57e-04	1.44e-04	1.23e-04	1.41e-04
Magnesium	6.65e-03	9.37e-03	7.24e-03	7.75e-03
Manganese	3.48e-04	4.91e-04	3.34e-04	3.91e-04
Mercury	1.14e-04	9.55e-05	7.72e-05	9.56e-05
Molybdenum[b]	3.35e-05	3.31e-05	3.31e-05	3.32e-05
Nickel		8.69e-05	6.37e-05	7.53e-05
Potassium	2.48e-03	2.30e-03	2.13e-03	2.30e-03
Selenium	1.35e-04	1.68e-04	1.45e-04	1.49e-04
Silver	1.12e-05	1.22e-05	3.68e-05	2.01e-05
Sodium	9.51e-03	7.86e-03	6.28e-03	7.89e-03
Strontium	4.04e-03	4.68e-03	3.79e-03	4.17e-03
Vanadium	3.72e-04	3.56e-04	3.45e-04	3.58e-04
Zinc		8.57e-04	5.51e-04	7.04e-04

[a]Pages 5 and 7.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits.
[c]Divide emission rate by coal feed rate.

REFERENCE 27 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 17 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: RESULTS OF THE MARCH 1990 TRACE METAL CHARACTERIZATION STUDY ON UNIT 3 AT THE SHERBURNE COUNTY GENERATING STATION

FACILITY: NSP SHERCO
UNIT NO.: 3
LOCATION: Becker, Minnesota
FILENAME SHERCO3A.tbl

PROCESS DATA		METALS	
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	6.50	6.20	6.10
Vol. Flow Rate (dscf/m)[b]	1,950,168	1,965,867	1,962,255
Vol. Flow Rate (dscf/hr)	117,010,080	117,952,020	117,735,300
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	8,243	8,483	8,525
HHV Bituminous Coal (Btu/lb)[d]	8,547	8,547	8,547
HHV Bituminous Coal (Btu/ton)	17,094,000	17,094,000	17,094,000
Coal Feed (ton/hr)	482	496	499
		CHROME VI	
	Run 1	Run 2	Run 3
Oxygen (% v/v)[a]	6.10	6.10	6.00
Vol. Flow Rate (dscf/m)[b]	1,957,528	1,950,487	1,944,863
Vol. Flow Rate (dscf/hr)	117,029,220	116,691,780	
F-factor (dscf/MMBtu)[c]	9,780	9,780	9,780
Heat input (MMBtu/hr)	8,504	8,474	8,506
HHV Bituminous Coal (Btu/lb)[d]	8,547	8,547	8,547
HHV Bituminous Coal (Btu/ton)	17,094,000	17,094,000	17,094,000
Coal Feed (ton/hr)	497	496	498
Coal type[e]	Subbituminous		
Boiler configuration[e]	Pulverized, dry bottom		
Coal source[e]	Montana		
SCC	10100222		
Control device 1[e]	Flue Gas Desulfurization, Spray Dryer absorber		
Control device 2[e]	Baghouse		

Data Quality	B	Had to use F-factor and average HHV to get coal feed rate (ton/hr)
Process Parameters[e]	860 megawatts, on line in 1987.	
Test methods[f]	MM5 for metals, MM13 for chrome VI.	
Number of test runs[g]	2 for calcium, nickel, sodium and zinc. 3 for all others.	

[a]Page 12 for metals runs; page 13 for chrome VI runs.
[b]Page 16 for metals runs, page 18 for chrome VI runs.
[c]40 CFR Pt 60, App A, Meth. 19, Bituminous coal.
[d]From report "Results of the May 29, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station in Becker, Minnesota", page G-1. (Reference No. 25).
[e]Page 1. Assumed dry bottom.
[f]Page 1 for MM5, page 2 for MM 13.
[g]Various pages.

METALS EMISSION FACTORS

EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Aluminum	1.91	0.493	0.742	
Antimony	7.09e-03	1.62e-03	1.6e-03	
Arsenic[b]	---	4.12e-04	4.12e-04	
Barium[b]	0.048	0.049	0.050	
Beryllium	1.61e-05	4.93e-05	9.92e-05	
Boron	19.1	3.28	13.9	
Calcium	---	1.91	1.85	
Chromium	0.114	0.0682	0.0520	
Copper	0.789	0.384	0.188	
Iron	1.04	0.759	0.248	
Lead	0.123	0.0394	0.033	
Magnesium	0.294	0.123	0.215	
Manganese	0.0565	0.382	0.0379	
Mercury	0.0411	0.0172	0.0338	
Molybdenum[b]	0.032	0.033	0.033	
Nickel	---	0.0736	0.0264	
Potassium	1.83	0.624	0.602	
Selenium[b]	0.0199	0.0205	0.0207	
Silver[b]	2.41e-03	2.43e-03	2.50e-03	

METALS EMISSION FACTORS				
EMISSION RATES (lb/hr)[a]	Run 1	Run 2	Run 3	AVG
Sodium	---	4.62	4.80	
Strontium	0.0119	0.0411	0.0412	
Vanadium[b]	8.04e-04	8.10e-04	8.09e-04	
Zinc	---	0.262	0.172	
EMISSION FACTORS (lb/ton)[c]	Run 1	Run 2	Run 3	AVG
Aluminum	3.96e-03	9.93e-04	1.49e-03	2.15e-03
Antimony	1.47e-05	3.26e-06	3.21e-06	7.06e-06
Arsenic[b]		8.30e-07	8.26e-07	8.28e-07
Barium[b]	9.95e-05	9.87e-05	1.00e-04	9.95e-05
Beryllium	3.34e-08	9.93e-08	1.99e-07	1.11e-07
Boron	3.96e-02	6.61e-03	2.79e-02	2.47e-02
Calcium		3.85e-03	3.71e-03	3.78e-03
Chromium	2.36e-04	1.37e-04	1.04e-04	1.59e-04
Copper	1.64e-03	7.74e-04	3.77e-04	9.29e-04
Iron	2.16e-03	1.53e-03	4.97e-04	1.39e-03
Lead	2.55e-04	7.94e-05	6.62e-05	1.34e-04
Magnesium	6.10e-04	2.48e-04	4.31e-04	4.30e-04
Manganese	1.17e-04	7.70e-04	7.60e-05	3.21e-04
Mercury	8.52e-05	3.47e-05	6.78e-05	6.26e-05
Molybdenum[b]	6.64e-05	6.65e-05	6.62e-05	6.63e-05
Nickel		1.48e-04	5.29e-05	1.01e-04
Potassium	3.79e-03	1.26e-03	1.21e-03	2.09e-03
Selenium[b]	4.13e-05	4.13e-05	4.15e-05	4.14e-05
Silver[b]	5.00e-06	4.90e-06	5.01e-06	4.97e-06
Sodium		9.31e-03	9.63e-03	9.47e-03
Strontium	2.47e-05	8.28e-05	8.26e-05	6.34e-05
Vanadium[b]	1.67e-06	1.63e-06	1.62e-06	1.64e-06
Zinc		5.28e-04	3.45e-04	4.36e-04

[a]Pages 5 and 7.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits.
[c]Divide emission rate by coal feed rate.

REFERENCE 27 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 17 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

CHROME VI EMISSION FACTORS				
	Run 1	Run 2	Run 3	AVG
Emission Rates (lb/hr)[a]	0.0095	0.0028	0.0100	
Emission Factors (lb/ton)[b]	1.91e-05	5.65e-06	2.01e-05	1.49e-05

[a]Page 8.
[b]Divide emission rate by coal feed rate.

REFERENCE 28 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 18 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 10 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. OCTOBER, 1992.

FACILITY: EPRI SITE 10
FILENAME SITE10.tbl

PROCESS DATA			
Coal feed rate, dry (lb/hr)[a]	108,626	Coal HHV, dry (Btu/lb)[b]	11,000
Coal moisture percent by weight[b]	7.3%	Coal HHV, as received (Btu/lb)	10,252
Coal feed rate, as received (lb/hr)	117,180	Coal HHV, as received (MMBtu/lb)	0.01
Coal feed rate, as received (ton/hr)	58.59	Coal HHV, as received (MMBtu/ton)	20.50
Stack gas flow rate (dscf/hr)[a]	15,500,000		
Coal type[c]	Subbituminous		
Boiler configuration[d]	Circulating Fluidized Bed Combustor (CFBC)		
Coal source[c]	Salt River		
SCC	10100238		
Control device 1[e]	Flue gas desulfurization by limestone injection into the combustion chamber (FGD-FIL)		
Control device 2[e]	Fabric Filter		
Data Quality	A		
Process Parameters[d]	110 megawatts		
Test methods[f]	EPA, or EPA-approved, test methods		
Number of test runs[g]	5 for benzene, 1 for all others.		

[a]Page C-3
[b]Page B-3
[c]Appendix B of EPRI Synthesis Report, page B-3.
[d]Appendix B of EPRI Synthesis Report, page B-6.
[e]Page 1-1
[f]Pages A-3 through A-13
[g]Page 3-1 and B-15 for benzene, page 3-1 for others.

REFERENCE 28 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 18 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

METALS, VOC EMISSION FACTORS[a]

Pollutant	(lb/10^12 Btu)	(lb/MMBtu)	(lb/ton)[c]
Arsenic[b]	1	1.00e-06	2.05e-05
Barium	12.1	1.21e-05	2.48e-04
Beryllium[b]	0.2	2.00e-07	4.10e-06
Cadmium[b]	0.4	4.00e-07	8.20e-06
Chloride	958	9.58e-04	1.96e-02
Chromium	1.6	1.60e-06	3.28e-05
Cobalt[b]	0.8	8.00e-07	1.64e-05
Copper[b]	2	2.00e-06	4.10e-05
Fluoride[b]	18	1.80e-05	3.69e-04
Lead	0.6	6.00e-07	1.23e-05
Manganese	31	3.10e-05	6.36e-04
Molybdenum[b]	4	4.00e-06	8.20e-05
Nickel[b]	2	2.00e-06	4.10e-05
Phosphorous[b]	24	2.40e-05	4.92e-04
Selenium[b]	16	1.60e-05	3.28e-04
Vanadium[b]	2	2.00e-06	4.10e-05
Formaldehyde[b]	15	1.50e-05	3.08e-04
Benzene	2	2.00e-06	4.10e-05

[a]Page 3-12
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

MISC. EMISSION FACTORS

Pollutant	Stack Gas Conc. (ug/Nm3)[a]	Stack Gas Conc. (ug/dscm)[b]	Stack Gas Conc. (lb/dscf)[c]	Emission Rate (lb/hr)[d]	Emission Factor (lb/ton)[e]
Dibutyl Phthalate	3.1	2.89	1.80e-10	2.80e-03	4.77e-05
bis(2-Ethylhexyl) phthalate	6.0	5.59	3.49e-10	5.41e-03	9.24e-05
N-Nitrosodiethylamine	15	13.98	8.73e-10	1.35e-02	2.31e-04

[a]Page 3-14
[b]Convert Normal meter to standard meter, i.e., multiply by 273/293.
[c]Convert ug/dscm to lb/dscf.
[d]Multiply concentration by stack gas flow rate.
[e]Divide emission rate by coal feed rate.

REFERENCE 29 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 19 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 11 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. OCTOBER, 1992.

FACILITY: EPRI SITE 11
FILENAME SITE11.tbl

PROCESS DATA	
Coal type[a]	Subbituminous
Boiler configuration[b]	Pulverized, dry, tangential
Coal source[a]	Powder River Basin
SCC	10100226
Control device 1[a]	Over Fire Air
Control device 2[a]	ESP
Control device 3[a]	Flue Gas Desulfurization, Wet Limestone Scrubber (Absorber)
Data Quality	B
Process Parameters[a]	700 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	1
Stack gas flow rate (dscf/m)[e]	1,598,400
Stack gas flow rate (dscf/hr)	95,904,000
Stack Gas O2 %[e]	6.9
F-factor (dscf/MMBtu)[f]	9,780
Heat input (MMBtu/hr)	6568.7
Coal HHV, as recieved (Btu/lb)[a]	8,300
Coal HHV, as received (MMBtu/lb)	0.008
Coal HHV, as received (MMBtu/ton)	16.60

Coal feed rate as received (ton/hr)	395.70

[a]Page 2-1.
[b]Page 2-1. Assumed dry bottom.
[c]Appendix A.
[d]Page 3-18.
[e]Page D-7.
[f]40 CFR Pt 60, App. A, Meth. 19, bituminous coal.

METALS, VOC EMISSION FACTORS

Pollutant	Particulate Phase (ug/Nm3)[a]	Vapor Phase (ug/Nm3)[a]	Total (ug/Nm3)	Total (ug/dscm)	Total (lb/dscf)	Emission Rate (lb/hr)[c]	Emission Factor (lb/ton)[d]
Arsenic	1.0	NR(3)	1.0	0.93	5.82e-11	5.58e-03	1.41e-05
Barium	97	NR(6)	97.0	90.38	5.64e-09	5.41e-01	1.37e-03
Beryllium[b]	NR(0.2)	NR(1)	0.20	0.19	1.16e-11	1.12e-03	2.82e-06
Cadmium		1.3	1.3	1.21	7.56e-11	7.25e-03	1.83e-05
Chlorine		2200	2,200	2049.83	1.28e-07	1.23e+01	3.10e-02
Chromium	7.0	NR(6)	7.0	6.52	4.07e-10	3.91e-02	9.87e-05
Cobalt	1.7	NR(6)	1.7	1.58	9.89e-11	9.49e-03	2.40e-05
Copper	2.1	NR(10)	2.1	1.96	1.22e-10	1.17e-02	2.96e-05
Fluorine		130	130.00	121.13	7.56e-09	7.25e-01	1.83e-03
Lead		14	14.00	13.04	8.15e-10	7.81e-02	1.97e-04
Manganese	3.9	110	113.90	106.13	6.63e-09	6.36e-01	1.61e-03
Mercury	0.016	3.7	3.72	3.46	2.16e-10	2.07e-02	5.24e-05
Molybdenum[b]	NR(5)	NR(30)	5	4.66	2.91e-10	2.79e-02	7.05e-05
Nickel	4.7	NR(10)	4.7	4.38	2.73e-10	2.62e-02	6.63e-05

Phosphorous[b]	NR(20)	20	18.63	1.16e-09	1.12e-01	2.82e-04

METALS, VOC EMISSION FACTORS

Pollutant	Particulate Phase (ug/Nm3)[a]	Vapor Phase (ug/Nm3)[a]	Total (ug/Nm3)	Total (ug/dscm)	Total (lb/dscf)	Emission Rate (lb/hr)[c]	Emission Factor (lb/ton)[d]
Selenium[b]		NR(3)	3	2.80	1.75e-10	1.67e-02	4.23e-05
Vanadium	2.6	NR(10)	2.6	2.42	1.51e-10	1.45e-02	3.67e-05
Formaldehyde[b]		NR(10)	10	9.32	5.82e-10	5.58e-02	1.41e-04
Naphthalene[b]	NR(4)		4	3.73	2.33e-10	2.23e-02	5.64e-05

[a]Page 3-18, Run 2 data only (other runs invalid).
[b]Page 3-18. Detection limit value for one run used in calculating EF.
[c]Multiply concentration by stack gas flow rate.
[d]Divide emission rate by coal feed rate.

REFERENCE 30 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 20 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 12 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. NOVEMBER, 1992.

FACILITY: EPRI SITE 12
FILENAME SITE12.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[b]	Pulverized, dry, opposed
Coal source[a]	West Pa.
SCC	10100202
Control device 1[c]	ESP
Control device 2[c]	Flue Gas Desulfurization, Wet Limestone Scrubber (Absorber)
Control device 3	None
Data Quality	A
Process Parameters[c]	700 MW
Test methods[d]	EPA, or EPA-approved, test methods
Number of test runs[e]	2 for Metals, 3 for VOCs.
Coal HHV, dry (Btu/lb)[f]	13,733
Coal moisture %[f]	4.12%
Coal HHV, as received (Btu/lb)	13,190
Coal HHV, as received (Btu/ton)	26,379,178
Coal HHV, as received (MMBtu/ton)	26.4

[a]Page 3-5.
[b]Page 2-1. Assumed dry bottom.
[c]Page 2-1.
[d]Appendix A.
[e]Page 3-11 for PM/metals, Page 3-14 for VOC.
[f]Page 3-6.

METALS, VOC EMISSION FACTORS[a]

Pollutant	Emission Factor (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[c]
Arsenic	0.45	4.50e-07	1.19e-05
Barium	6.3	6.30e-06	1.66e-04
Beryllium[b]	0.16	1.60e-07	4.22e-06
Cadmium	1.2	1.20e-06	3.17e-05
Chloride	2500	2.50e-03	6.59e-02
Chromium	3.5	3.50e-06	9.23e-05
Cobalt[b]	1.0	1.00e-06	2.64e-05
Copper	4.4	4.40e-06	1.16e-04
Fluoride	27	2.70e-05	7.12e-04
Lead	5.7	5.70e-06	1.50e-04
Manganese	1.6	1.60e-06	4.22e-05
Mercury	0.16	1.60e-07	4.22e-06
Molybdenum	4	4.00e-06	1.06e-04
Nickel	4.4	4.40e-06	1.16e-04
Selenium	13	1.30e-05	3.43e-04
Vanadium[b]	1.6	1.60e-06	4.22e-05
Formaldehyde[b]	8.4	8.40e-06	2.22e-04
Bromomethane[b]	0.43	4.30e-07	1.13e-05
1,1,1-trichloroethane	0.75	7.50e-07	1.98e-05
Benzene	0.69	6.90e-07	1.82e-05
Toluene	1.04	1.04e-06	2.74e-05
m,p-xylene	0.72	7.20e-07	1.90e-05

[a]Page 3-12 for metals, page 3-14 for VOC. See page 3-11 for number of non-detect runs for pm/metals.
[b]Detection limit value for two runs used in calculating EF.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 31 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 21 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 15 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. OCTOBER, 1992.

FACILITY: EPRI SITE 15
FILENAME SITE15.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[b]	Pulverized, dry, tangential
Coal source[a]	Eastern US
SCC	10100212
Control device 1[a]	ESP cold side
Control device 2	None
Control device 3	None
Data Quality	A
Process Parameters[a]	600 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	2 for lead, 3 for all others
Coal HHV, dry (Btu/lb)[e]	13,000
Coal HHV, as received (Btu/ton)	26,000,000
Coal HHV, as received (MMBtu/ton)	26.0

[a]Page 2-1.
[b]Page 2-1. Assumed dry bottom.
[c]Appendix A.
[d]Page 3-9.
[e]Page 3-4, assumed to be as fired.

EMISSION FACTORS[a]

Pollutant	Emission Factor (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[c]
Arsenic	13	1.30e-05	3.38e-04
Barium	34	3.40e-05	8.84e-04
Beryllium	0.4	4.00e-07	1.04e-05
Cadmium	3.1	3.10e-06	8.06e-05
Chloride	46,700	4.67e-02	1.21e+00
Chromium	12	1.20e-05	3.12e-04
Cobalt	2.0	2.00e-06	5.20e-05
Copper	5.5	5.50e-06	1.43e-04
Fluoride	3,850	3.85e-03	1.00e-01
Lead	4.3	4.30e-06	1.12e-04
Manganese	8.6	8.60e-06	2.24e-04
Molybdenum	5.3	5.30e-06	1.38e-04
Nickel	5.9	5.90e-06	1.53e-04
Selenium	77	7.70e-05	2.00e-03
Vanadium	14	1.40e-05	3.64e-04
Benzene	0.8	8.00e-07	2.08e-05
Formaldehyde[b]	5	5.00e-06	1.30e-04
Toluene	5.2	5.20e-06	1.35e-04

[a]Page 3-10.
[b]Emission factors is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 32 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 22 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 19 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. NOVEMBER, 1992.

FACILITY: EPRI SITE 19
FILENAME SITE19.tbl

PROCESS DATA			
Coal type[a]	Bituminous	Coal HHV, dry (Btu/lb)[g]	13,467
Boiler configuration[b]	Pulverized, dry, opposed	Coal moisture %[g]	6.1%
Coal source	Virginia, Kentucky	Coal HHV, as received (Btu/lb)	12,693
SCC	10100202	Coal HHV, as received (Btu/ton)	25,385,485
Control device 1[c]	ESP cold side	Coal HHV, as received (MMBtu/ton)	25.4
Control device 2	None	Coal feed rate, dry (lb/hr)[h]	694,000
Control device 3	None	Coal moisture percent by weight[g]	6.1%
Data Quality	A	Coal feed rate, as received (lb/hr)	739,084
Process Parameters[d]	1160 MW	Coal feed rate, as received (ton/hr)	369.54
Test methods[e]	EPA, or EPA-approved, test methods	Stack gas flow rate (Nm3/hr)[h]	4,000,000
Number of test runs[f]	3		

[a]Page 2-1.
[b]Page 2-1. Assumed dry bottom.
[c]Page 2-1.
[d]Page 2-2.
[e]Appendix A.
[f]Page 3-7.
[g]Page 3-5.
[h]Page 3-8.

METALS

Pollutant	Emission Factor[a] ($lb/10^{12}$ Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[b]
Arsenic	7.9	7.90e-06	2.01e-04
Cadmium	0.13	1.30e-07	3.30e-06
Chloride	75,000	7.50e-02	1.90e+0
Chromium	13	1.30e-05	3.30e-04
Copper	12	1.20e-05	3.05e-04
Fluoride	5,800	5.80e-03	1.47e-01
Manganese	5.4	5.40e-06	1.37e-04
Mercury	6.2	6.20e-06	1.57e-04
Nickel	7.9	7.90e-06	2.01e-04
Selenium	260	2.60e-04	6.60e-03

[a]Page 3-8.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

MISCELLANEOUS EMISSION FACTORS

Pollutant Concentration (ug/Nm3)[a]	Solid Phase Conc.			Vapor Phase Conc.			Total conc.			
	Run 2	Run 3	Run 4	Run 2	Run 3	Run 4	Run 2	Run 3	Run 4	avg
Antimony	0.47	0.39	0.35	0.76	1.9	1.7	0.47	2.29	2.05	1.60
Beryllium	1.1	1.0	0.72	0.49	0.55	0.50	1.1	1.55	1.22	1.29
Cobalt	4.3	4.2	2.8	2.5	2.8	2.5	4.3	7	5.3	5.53

Pollutant emissions	emission rate (ug/hr)[b]	emission rate (lb/hr)	emission factor (lb/ton)[c]
Antimony	6,413,333	1.41e-02	3.83e-05
Beryllium	5,160,000	1.14e-02	3.08e-05
Cobalt	22,133,333	4.88e-02	1.32e-04

[a]Page 3-9.
[b]Multiply concnetration by stack gas flow rate.
[d]Divide emission rate by coal feed rate.

REFERENCE 33 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 23 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 20 EMISSIONS MONITORING RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1994.

FACILITY: EPRI SITE 20
FILENAME SITE20.tbl

PROCESS DATA	
Coal type[a]	Lignite
Boiler configuration[b]	Pulverized
Coal source[f]	Wilcox, Texas
SCC	10100301
Control device 1[a]	ESP cold side
Control device 2[a]	Flue Gas Desulfurization- Wet Limestone Scrubber (absorber)
Control device 3	None
Data Quality	A
Process Parameters[a]	680 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	4
Coal HHV, as received (Btu/lb)[e]	6,760
Coal HHV, as received (Btu/ton)	13,520,000
Coal HHV, as received (MMBtu/ton)	13.5

[a]Page 2-1.
[b]Page 2-5.
[c]Appendix A.
[d]Page 3-9.
[e]Page 2-2.
[f]Appendix B of EPRI Synthesis Report, page B-3.

REFERENCE 33 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 23 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

EMISSION FACTORS	Emission Factor[a]	Emission Factor	Emission Factor
Pollutant	(lb/10^12 Btu)	(lb/MMBtu)	(lb/ton)[b]
Arsenic	0.63	6.30e-07	8.52e-06
Barium	42	4.20e-05	5.68e-04
Beryllium	0.35	3.50e-07	4.73e-06
Cadmium	0.70	7.00e-07	9.46e-06
Chloride	390	3.90e-04	5.27e-03
Chromium	2.8	2.80e-06	3.79e-05

EMISSION FACTORS	Emission Factor[a]	Emission Factor	Emission Factor
Pollutant	(lb/10^12 Btu)	(lb/MMBtu)	(lb/ton)[b]
Cobalt	0.69	6.90e-07	9.33e-06
Fluoride	430	4.30e-04	5.81e-03
Lead	3.8	3.80e-06	5.14e-05
Manganese	8.5	8.50e-06	1.15e-04
Mercury	12	1.20e-05	1.62e-04
Nickel	4.3	4.30e-06	5.81e-05
Phosphorous	21	2.10e-05	2.84e-04
Selenium	160	1.60e-04	2.16e-03
Vanadium	3.08	3.08e-06	4.16e-05

[a]Page 3-11, Stack data.
[b]Multiply emission factor,lb/MMBtu, by coal HHV, MMBtu/ton.

Antimony EMISSION FACTOR: Note that antimony was not detected in any of the sampling runs.

	Run 1	Run 2	Run 3	Run 4
Coal feed rate (lb/hr, dry)[a]	630,000	614,000	619,000	618,000
Coal moisture (%)[a]	33.5%	34.2%	33.6%	34.4%
Coal feed rate (lb/hr, wet) (as fired)	947,368	933,131	932,229	942,073
Coal feed rate (ton/hr)	474	467	466	471
Stack gas flow rate (Nm3/hr)[b]	3,100,000	3,140,000	3,100,000	3,040,000
Antimony concentration (ug/Nm3)[b,c]	1.31	1.07	1.13	1.29
Antimony emission rate (ug/hr)[d]	4,061,000	3,359,800	3,503,000	3,921,600
Antimony emission rate (lb/hr)[e]	8.95e-03	7.41e-03	7.72e-03	8.65e-03
Antimony emission factor (lb/ton)[f]	1.89e-05	1.59e-05	1.66e-05	1.84e-05
				avg
				1.74e-05

[a]Page 3-6.
[b]Page 3-9.
[c]Pollutant was not detected in any sampling runs. EF based on detection limits.
[d]Multiply concentration by stack gas flow rate.
[e]Convert ug/hr to lb/hr.
[f]Divide emission rate by coal feed rate.

REFERENCE 34 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 24 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 21 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. AUGUST, 1993.

FACILITY: EPRI SITE 21
FILENAME SITE21.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[b]	Pulverized, dry, opposed
Coal source[a]	Pa., W. Va.
SCC	10100202
Control device 1[c]	ESP
Control device 2[c]	Flue Gas Desulfurization, Wet Limestone Scrubber (Absorber)
Control device 3	None
Data Quality	A
Process Parameters[c]	667 MW
Test methods[d]	EPA, or EPA-approved, test methods
Number of test runs[e]	8 for PM/metals, 7 for semi-volatiles
Coal HHV, dry (Btu/lb)[f]	14,032
Coal moisture %[g]	7%
Coal HHV, as received (Btu/lb)	13,114
Coal HHV, as received (Btu/ton)	26,228,037
Coal HHV, as received (MMBtu/ton)	26.2

[a]Page 3-6.
[b]Assumed to be pulverized, dry bottom.
[c]Page 2-3.
[d]Appendix A.
[e]Page 3-10 for metals, page 3-14 for semi-volatiles.
[f]Page 3-5.
[g]Page 7-2.

EMISSION FACTORS	Emission Factor[a]	Emission Factor	Emission Factor[b]
Pollutant	(lb/10^12 Btu)	(lb/MMBtu)	(lb/ton)
Acenapthene	0.018	1.80e-08	4.72e-07
Acenapthylene	0.0075	7.50e-09	1.97e-07
Anthracene	0.0099	9.90e-09	2.60e-07
Arsenic	6.17	6.17e-06	1.62e-04

EMISSION FACTORS Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Barium	3.21	3.21e-06	8.42e-05
Benz(a)anthracene	0.0013	1.30e-09	3.41e-08
Benzo(a)pyrene	0.0018	1.80e-09	4.72e-08
Benzo(b,j,k)fluoranthenes	0.0066	6.60e-09	1.73e-07
Benzo(g,h,i)perylene	0.0012	1.20e-09	3.15e-08
Beryllium	0.13	1.30e-07	3.41e-06
Cadmium	0.57	5.70e-07	1.49e-05
Chloride	1,980	1.98e-03	5.19e-02
Chromium	2.74	2.74e-06	7.19e-05
Chrysene	0.0069	6.90e-09	1.81e-07
Cobalt	4.1	4.10e-06	1.08e-04
Copper	1.57	1.57e-06	4.12e-05
Fluoranthene	0.053	5.30e-08	1.39e-06
Fluorene	0.064	6.40e-08	1.68e-06
Fluoride	31.9	3.19e-05	8.37e-04
Indeno(1,2,3-cd)pyrene	0.0015	1.50e-09	3.93e-08
Lead	6.32	6.32e-06	1.66e-04
Manganese	15	1.50e-05	3.93e-04
Mercury	0.84	8.40e-07	2.20e-05
Molybdenum	0.61	6.10e-07	1.60e-05
Nickel	1.68	1.68e-06	4.41e-05
Phenanthrene	0.21	2.10e-07	5.51e-06
Pyrene	0.024	2.40e-08	6.29e-07
Selenium	9.9	9.90e-06	2.60e-04
Vanadium	5.50	5.50e-06	1.44e-04
5-Methyl Chrysene	0.0015	1.50e-09	3.93e-08

[a]Page 3-15.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 35 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 25 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 22 EMISSIONS REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. FEBRUARY, 1994.

FACILITY: EPRI SITE 22
FILENAME SITE22.tbl

PROCESS DATA	
Coal type[a]	Subbituminous
Boiler configuration[b]	Pulverized, dry, opposed
Coal source[a]	Powder River
SCC	10100222
Control device 1[a]	ESP Cold Side
Control device 2	None
Control device 3	None
Data Quality	A
Process Parameters[c]	700 MW
Test methods[d]	EPA, or EPA-approved, test methods
Number of test runs[e]	3
Coal HHV, dry (Btu/lb)[f]	11,981
Coal moisture %[f]	29.5%
Coal HHV, as received (Btu/lb)	9,252
Coal HHV, as received (Btu/ton)	18,503,475
Coal HHV, as received (MMBtu/ton)	18.5

[a]Page 2-1
[b]Assumed pulverized, dry bottom.
[c]Page 2-2.
[d]Appendix A
[e]Pages 3-7 through 3-11
[f]Page 3-6

METALS, ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Arsenic	0.087	8.70e-08	1.61e-06
Barium	16	1.60e-05	2.96e-04
Beryllium[b]	0.031	3.10e-08	5.74e-07
Cadmium	0.16	1.60e-07	2.96e-06
Chloride	726	7.26e-04	1.34e-02
Chromium	0.53	5.30e-07	9.81e-06
Cobalt[b]	0.70	7.00e-07	1.30e-05
Copper	1.0	1.00e-06	1.85e-05
Fluoride	855	8.55e-04	1.58e-02
Lead	0.11	1.10e-07	2.04e-06
Manganese	1.1	1.10e-06	2.04e-05
Mercury	3.8	3.80e-06	7.03e-05
Molybdenum	1.9	1.90e-06	3.52e-05
Nickel	0.64	6.40e-07	1.18e-05
Phosphorous	11	1.10e-05	2.04e-04
Selenium	0.053	5.30e-08	9.81e-07
Vanadium	0.78	7.80e-07	1.44e-05
Aluminum	136	1.36e-04	2.52e-03
Antimony[b]	3.8	3.80e-06	7.03e-05
Calcium	325	3.25e-04	6.01e-03
Iron	52	5.20e-05	9.62e-04
Magnesium	47	4.70e-05	8.70e-04
Potassium[b]	82	8.20e-05	1.52e-03
Sodium	86	8.60e-05	1.59e-03
Titanium	12	1.20e-05	2.22e-04

[a]Page 3-12.
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

PAH EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Acenaphthalene	0.0034	3.40e-09	6.29e-08
Acenaphthene	0.0060	6.00e-09	1.11e-07
Anthracene	0.0046	4.60e-09	8.51e-08
Benzo(a)pyrene	0.0011	1.10e-09	2.04e-08
Benzo(b,j,k)fluoranthenes	0.0027	2.70e-09	5.00e-08
Benzo(g,h,i)perylene	0.0022	2.20e-09	4.07e-08
Benz(a)anthracene	0.0010	1.00e-09	1.85e-08
Chrysene	0.0025	2.50e-09	4.63e-08
Fluoranthene	0.024	2.40e-08	4.44e-07
Fluorene	0.012	1.20e-08	2.22e-07
Indeno(1,2,3-cd)pyrene	0.0086	8.60e-09	1.59e-07
5-Methyl Chrysene[b]	0.00047	4.70e-10	8.70e-09
Phenanthrene	0.069	6.90e-08	1.28e-06
Pyrene	0.016	1.60e-08	2.96e-07

[a]Page 3-14..
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu, ton.

DIOXIN/FURAN EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
2,3,7,8-TCDD[b]	3.3e-06	3.3e-12	6.1e-11
Total TCDD	4.7e-06	4.7e-12	8.7e-11
Total PeCDD	ND	ND	ND
Total HxCDD	ND	ND	ND
Total HpCDD	9.8e-06	9.8e-12	1.8e-10
OCDD	5.2e-05	5.2e-11	9.6e-10

REFERENCE 35 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 25 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

DIOXIN/FURAN EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
2,3,7,8-TCDF[b]	3.6e-06	3.6e-12	6.7e-11
Total TCDF	6.2e-06	6.2e-12	1.1e-10
Total PeCDF	7.3e-06	7.3e-12	1.4e-10
Total HxCDF	3.5e-06	3.5e-12	6.5e-11
Total HpCDF	2.2e-06	2.2e-12	4.1e-11
OCDF	4.2e-06	4.2e-12	7.8e-11

[a]Page 3-15.
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu, ton.

REFERENCE 36 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 26 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 101 EMISSIONS REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. OCTOBER, 1994.

FACILITY: EPRI SITE 101
FILENAME SITE101.tbl

PROCESS DATA	
Coal type[a]	Subbituminous
Boiler configuration[b]	Pulverized, dry, wall-fired
Coal source[c]	New Mexico
SCC	10100222
Control device 1[a]	Low Nox Burners (LNB)
Control device 2[a]	Fabric Filter
Control device 3[a]	Flue Gas Desulfurization- Wet Limestone Scrubber
Data Quality	A
Process Parameters[a]	800 MW
Test methods[d]	EPA, or EPA-approved, test methods
Number of test runs[e]	3 for benzene, toluene, chloride and fluoride; 2 for all others.
Coal HHV, dry (Btu/lb)[f]	10,190
Coal moisture %[f]	14%
Coal HHV, as received (Btu/lb)	8,939
Coal HHV, as received (Btu/ton)	17,877,193
Coal HHV, as received (MMBtu/ton)	17.9

[a]Page 2-1.
[b]Page 2-1, assumed dry bottom.
[c]Appendix B of the EPRI Synthesis Report, page B-3.
[d]Appendix A.
[e]Page 3-10 for benzene and toluene, page 3-6 for others.
[f]Page 3-5.

REFERENCE 36 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 26 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

METALS, ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Arsenic	0.34	3.40e-07	6.08e-06
Barium	18	1.80e-05	3.22e-04
Beryllium	0.036	3.60e-08	6.44e-07
Cadmium	0.40	4.00e-07	7.15e-06
Chloride	2,500	2.50e-03	4.47e-02
Chromium	2.2	2.20e-06	3.93e-05
Cobalt	0.13	1.30e-07	2.32e-06
Copper	2.2	2.20e-06	3.93e-05
Fluoride	3,600	3.60e-03	6.44e-02
Lead	0.72	7.20e-07	1.29e-05
Manganese	10	1.00e-05	1.79e-04
Mercury	1.9	1.90e-06	3.40e-05
Molybdenum	2.6	2.60e-06	4.65e-05
Nickel	2.8	2.80e-06	5.01e-05
Phosphorous	9.2	9.20e-06	1.64e-04
Selenium	1.4	1.40e-06	2.50e-05
Vanadium	0.93	9.30e-07	1.66e-05
Benzene	0.57	5.70e-07	1.02e-05
Toluene	0.57	5.70e-07	1.02e-05

[a]Page 3-13.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 37 OF AP-42 SECTION 1.1 BACGROUND DOCUMENTATION
REFERENCE 27 OF AP-42 SECTION 1.7 BACGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 111 EMISSIONS REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MAY, 1993.

FACILITY: EPRI SITE 111
FILENAME SITE111.tbl

PROCESS DATA	
Coal type[a]	Subbituminous
Boiler configuration[b]	Pulverized, dry bottom
Coal source[c]	Western
SCC	10100222
Control device 1[c]	Low Nox Burners (LNB)
Control device 2[c]	Flue Gas Desulfurization- Spray Dryer (FGD-SD)
Control device 3[c]	Fabric Filter (FF)
Data Quality	A
Process Parameters[c]	267 MW
Test methods[d]	EPA, or EPA-approved, test methods
Number of test runs[e]	2
Coal HHV, as fired (received) (Btu/lb)[f]	10,020
Coal HHV, as fired (received) (Btu/ton)	20,040,000
Coal HHV, as fired (received) (MMBtu/ton)	20.0

[a]Page 2-2.
[b]Assumed dry bottom.
[c]Page 2-1.
d Page 1-4.
e Page 3-12.
f Page 2-2.

EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[c]
Arsenic[b]	0.21	2.10e-07	4.21e-06
Cadmium[b]	2.1	2.10e-06	4.21e-05
Chromium[b]	4.3	4.30e-06	8.62e-05
Mercury[b]	67	6.70e-05	1.34e-03
Nickel	5.3	5.30e-06	1.06e-04
Chloride	1,250	1.25e-03	2.51e-02
Benzene	21.1	2.11e-05	4.23e-04
Naphthalene	0.76	7.60e-07	1.52e-05
Acenaphthalene	0.03	3.00e-08	6.01e-07
Acenaphthene	0.08	8.00e-08	1.60e-06
Fluorene	0.18	1.80e-07	3.61e-06
Phenanthrene	0.13	1.30e-07	2.61e-06
Anthracene	0.02	2.00e-08	4.01e-07
Fluoranthene	0.03	3.00e-08	6.01e-07
Pyrene	0.01	1.00e-08	2.00e-07
Chrysene[b]	0.004	4.00e-09	8.02e-08
Benz(a)anthracene	0.009	9.00e-09	1.80e-07
Benzo(b)fluoranthene	0.008	8.00e-09	1.60e-07
Benzo(k)fluoranthene	0.004	4.00e-09	8.02e-08
Benzo(a)pyrene[b]	0.004	4.00e-09	8.02e-08
Indeno(1,2,3-cd)pyrene	0.004	4.00e-09	8.02e-08
Benzo(g,h,i)perylene	0.004	4.00e-09	8.02e-08

[a]Page 3-15.
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 38 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 28 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 114 REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MAY, 1994.

FACILITY: EPRI SITE 114
FILENAME SITE114.tbl

PROCESS DATA		
Coal type[a]	Bituminous	
Boiler configuration[a]	Cyclone	
Coal source[a]	Indiana Lamar	
SCC	10100203	
Control device 1[a]	ESP for baseline condition, Reburn/Overfire Air for condition two	
Control device 2[a]	None for baseline, ESP for condition two	
Control device 3	none	
Data Quality	A	
Process Parameters[a]	100 MW	
Test methods[b]	EPA, or EPA-approved, test methods	
Number of test runs[c]	3	
	Baseline	Reburn
Coal HHV, dry (Btu/lb)[d]	13,490	13,280
Coal moisture %[d]	15.6%	12.5%
Coal HHV, as received (Btu/lb)	11,670	11,804
Coal HHV, as received (Btu/ton)	23,339,100	23,608,889
Coal HHV, as received (MMBtu/ton)	23.3	23.6

[a]Page 2-1.
[b]Page 1-4.
[c]Pages 3-8 and 3-9.
[d]Pages 3-4 & 3-5.

EMISSION FACTORS- BASELINE CONDITION

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Arsenic	7	7.00e-06	1.63e-04
Beryllium	2.4	2.40e-06	5.60e-05
Cadmium	1.8	1.80e-06	4.20e-05
Chromium	14	1.40e-05	3.27e-04
Manganese	20	2.00e-05	4.67e-04
Nickel	78	7.80e-05	1.82e-03
Lead	86	8.60e-05	2.01e-03
Selenium	240	2.40e-04	5.60e-03
Mercury	4.5	4.50e-06	1.05e-04
Chloride	4,310	4.31e-03	1.01e-01
Fluoride	64	6.40e-05	1.49e-03
Benzene	2.3	2.30e-06	5.37e-05
Toluene	1.02	1.02e-06	2.38e-05
PAHs[b]	ND	ND	ND
Formaldehyde	2.6	2.60e-06	6.07e-05
Acetaldehyde	2.6	2.60e-06	6.07e-05

[a]Page 3-10.
[b]ND = not detected in three runs, no EF calculated. See page 3-8.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

EMISSION FACTORS- REBURN CONDITION

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[d]
Arsenic	8.0	8.00e-06	1.89e-04
Beryllium	0.8	8.00e-07	1.89e-05
Cadmium	0.4	4.00e-07	9.44e-06
Chromium	4.6	4.60e-06	1.09e-04
Manganese	15	1.50e-05	3.54e-04
Nickel	34	3.40e-05	8.03e-04
Lead	57	5.70e-05	1.35e-03
Selenium	150	1.50e-04	3.54e-03
Mercury	3.8	3.80e-06	8.97e-05
Chloride	6,000	6.00e-03	1.42e-01
Fluoride	89.9	8.99e-05	2.12e-03
Benzene	1.04	1.04e-06	2.46e-05
Toluene	0.70	7.00e-07	1.65e-05
PAHs[b]	ND	ND	ND
Formaldehyde[c]	2.6	2.60e-06	6.14e-05
Acetaldehyde[c]	2.6	2.60e-06	6.14e-05

[a]Page 3-9.
[b]ND = not detected in three runs, no EF calculated. See page 3-9.
[c]Emission factors based completely on detection limits.
[d]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 39 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 29 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 115 EMISSIONS REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. NOVEMBER, 1994.

FACILITY: EPRI SITE 115
FILENAME SITE115.tbl

PROCESS DATA		
Coal type[a]	Bituminous	
Boiler configuration[b]	Pulverized, Dry bottom	
Coal source[a]	Western	
SCC	10100202	
	PHASE I	PHASE II
Control device 1[c]	LNB/OFA	LNB/OFA
Control device 2[c]	Fabric Filter	SNCR
Control device 3[c]	none	Fabric Filter
Data Quality	B	(coal moisture percent not provided)
Process Parameters[a]	117 MW	
Test methods[d]	EPA, or EPA-approved, test methods	
Number of test runs[e]	2 for nickel during Phase I, 3 for all others	
	PHASE I	PHASE II
Coal HHV, dry (Btu/lb)[f]	12,565	12,638
Coal moisture %[g]	9.8%	9.8%
Coal HHV, as received (Btu/lb)	11,444	11,510
Coal HHV, as received (Btu/ton)	22,887,067	23,020,036
Coal HHV, as received (MMBtu/ton)	22.9	23.0

[a]Page 6.
[b]Page 6. Assumed dry bottom.
[c]Page 6. LNB= Low Nox Burners; OFA = Overfire Air; SNCR = Selective non-catalytic reduction.
[d]Appendix A, Table A-1.
[e]Page 26 for Phase I, page 35 for Phase II. Also, see footnote to nickel EF in Table 3-4.
[f]Page 20 for Phase I; Page 32 for Phase II.
[g]The test report does not provide a moisture content for the coal. EPRI Site 111 (Reference 19) also uses a "western bituminous" coal and the value used here is from that reference.

EMISSION FACTORS- PHASE I

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[d] (lb/ton)
Arsenic	0.75	7.50e-07	1.72e-05
Barium	1.1	1.10e-06	2.52e-05
Beryllium[c]	0.02	2.00e-08	4.58e-07
Cadmium	0.12	1.20e-07	2.75e-06
Chromium	0.66	6.60e-07	1.51e-05
Cobalt[c]	0.22	2.20e-07	5.04e-06
Copper	1.1	1.10e-06	2.52e-05
Lead	0.44	4.40e-07	1.01e-05
Manganese	1.0	1.00e-06	2.29e-05
Mercury[c]	0.35	3.50e-07	8.01e-06
Molybdenum	0.17	1.70e-07	3.89e-06
Nickel[b]	1.5	1.50e-06	3.43e-05
Phosphorus	6.7	6.70e-06	1.53e-04
Selenium	0.36	3.60e-07	8.24e-06
Vanadium	0.24	2.40e-07	5.49e-06
Chloride	630	6.30e-04	1.44e-02
Fluoride	4,300	4.30e-03	9.84e-02
Benzene	2.6	2.60e-06	5.95e-05
Toluene	105	1.05e-04	2.40e-03
Formaldehyde	16.5	1.65e-05	3.78e-04
Cyanide	8	8.00e-06	1.83e-04
Naphthalene	0.26	2.60e-07	5.95e-06

[a]page 28, 29. ND = not detected in 3 runs, no EF developed. See page 26 for run data.
[b]One run invalid, data from two runs used to develop EF.
[c]Emission factor is based only on detection limits.
[d]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 39 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 29 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION

EMISSION FACTORS- PHASE II

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Arsenic	0.15	1.50e-07	3.45e-06
Barium	1.1	1.10e-06	2.53e-05
Beryllium[b]	0.02	2.00e-08	4.60e-07
Cadmium[b]	0.07	7.00e-08	1.61e-06
Chromium	0.30	3.00e-07	6.91e-06
Cobalt[b]	0.23	2.30e-07	5.29e-06
Copper	1.3	1.30e-06	2.99e-05
Lead	0.40	4.00e-07	9.21e-06
Manganese	0.89	8.90e-07	2.05e-05
Mercury	0.41	4.10e-07	9.44e-06
Molybdenum	0.27	2.70e-07	6.22e-06
Nickel	0.45	4.50e-07	1.04e-05
Phosphorus	4.6	4.60e-06	1.06e-04
Selenium[b]	0.06	6.00e-08	1.38e-06
Vanadium	0.29	2.90e-07	6.68e-06
Chloride	720	7.20e-04	1.66e-02
Fluoride	4,800	4.80e-03	1.10e-01
Cyanide	9	9.00e-06	2.07e-04

[a]Page 37.
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 40 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 30 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: CHARACTERIZING TOXIC EMISSIONS FROM A COAL-FIRED POWER PLANT DEMONSTRATING THE AFGD ICCT PROJECT AND A PLANT UTILIZING A DRY SCRUBBER/BAGHOUSE SYSTEM. SPRINGERVILLE GENERATING STATION UNIT NO. 2. SOUTHERN RESEARCH INSTITUTE, BIRMINGHAM, AL. DECEMBER, 1993.

FACILITY: Springerville, Arizona
FILENAME DOE7.tbl

PROCESS DATA	
Coal type[a]	Subbituminous
Boiler configuration[b]	Pulverized, dry bottom, tangential
Coal source[a]	New Mexico
SCC	10100226
Control device 1[a]	Low Nox Burners- Overfire Air (LNB/OFA)
Control device 2[a]	Flue Gas Desulfurization- Spray Dryer (FGD-SD)
Control device 3[a]	Baghouse
Data Quality	A
Process Parameters[a]	422 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	2 for selenium, cadmium and manganese, 3 for others.
Coal HHV, as received (Btu/lb)[e]	9,446
Coal HHV, as received (Btu/ton)	18,892,000
Coal HHV, as received (MMBtu/ton)	18.9

[a]Page 3-1.
[b]"Pulverized" from page 3-1, assumed dry bottom,
"Tangential" from Appendix B of EPRI Synthesis Report. Page B-7.
[c]Page 4-2.
[d]Pages 6-53, 6-54, and 6-55.
[e]Page 6-2, average for conveyor.

EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Antimony	0.041	4.10e-08	7.75e-07
Arsenic	0.15	1.50e-07	2.83e-06
Barium	14.1	1.41e-05	2.66e-04
Beryllium[b]	0.04	4.00e-08	7.56e-07
Boron	609	6.09e-04	1.15e-02
Cadmium	0.026	2.60e-08	4.91e-07
Chromium	0.10	1.00e-07	1.89e-06
Cobalt[b]	0.3	3.00e-07	5.67e-06
Copper	0.98	9.80e-07	1.85e-05
Lead	0.70	7.00e-07	1.32e-05
Manganese	11.36	1.14e-05	2.15e-04
Mercury	4.18	4.18e-06	7.90e-05
Molybdenum	1.4	1.40e-06	2.64e-05
Nickel[b]	0.3	3.00e-07	5.67e-06
Selenium[b]	0.038	3.80e-08	7.18e-07
Vanadium	1.0	1.00e-06	1.89e-05

[a]Page 1-11.
[b]Emission factor is based only on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 41 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 31 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: A STUDY OF TOXIC EMISSIONS FROM A COAL-FIRED POWER PLANT- NILES STATION BOILER NO. 2. BATTELLE, COLUMBUS, OHIO. DECEMBER 29, 1993.

FACILITY: Niles, Ohio
FILENAME DOE2.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[a]	Cyclone
Coal source[a]	Ohio/W. Pa.
SCC	10100203
Control device 1[a]	ESP
Control device 2	None
Control device 3	None
Data Quality	A
Process Parameters[a]	108 MW
Test methods	Assumed EPA, or EPA-approved, test methods
Number of test runs[b]	3
Coal HHV, as received (Btu/lb)[c]	12,184
Coal HHV, as received (Btu/ton)	24,368,000
Coal HHV, as received (MMBtu/ton)	24.4

[a]Page 2-1.
[b]Pages 6-24, 6-26, 6-27, 6-28, 6-30, 6-32, 6-33, 6-35.
[c]Page 2-18. Average of 11964, 12504, 12397, 12139, 12031, and 12068 Btu/lb.

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Aluminum	1114	1.11e-03	2.71e-02
Antimony[b]	0.18	1.80e-07	4.39e-06
Arsenic	42	4.20e-05	1.02e-03
Barium	5.4	5.40e-06	1.32e-04
Beryllium	0.19	1.90e-07	4.63e-06
Cadmium	0.07	7.00e-08	1.71e-06

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Chromium	3.0	3.00e-06	7.31e-05
Cobalt[b]	0.06	6.00e-08	1.46e-06
Copper	4.0	4.00e-06	9.75e-05
Lead	1.6	1.60e-06	3.90e-05
Manganese	3.4	3.40e-06	8.29e-05
Mercury	14	1.40e-05	3.41e-04
Molybdenum	2.3	2.30e-06	5.60e-05
Nickel	0.55	5.50e-07	1.34e-05
Potassium	705	7.05e-04	1.72e-02
Selenium	62.0	6.20e-05	1.51e-03
Sodium	1767	1.77e-03	4.31e-02
Titanium	23	2.30e-05	5.60e-04
Vanadium	2.5	2.50e-06	6.09e-05

[a]Page 6-24, "Average" values.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

AMMONIA/CYANIDE EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[c]
Ammonia[b]	70	7.00e-05	1.71e-03
Cyanide	180	1.80e-04	4.39e-03

[a]Page 6-26, Table 6-8, "Average" values.
[b]Detection limit values (1/2) for two runs used in developing EF.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

HCl, HFl EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[b]
Hydrogen Chloride	132,049	1.32e-01	3.22e+00
Hydrogen Fluoride	8,921	8.92e-03	2.17e-01

[a]Page 6-27, Table 6-10, "Average" values.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Chloromethane (Methyl Chloride)	4.9	4.90e-06	1.19e-04
Bromomethane (Methyl Bromide)[b]	3.2	3.20e-06	7.80e-05
Vinyl Chloride[b]	2.5	2.50e-06	6.09e-05
Chloroethane (Ethyl Chloride)[b]	2.5	2.50e-06	6.09e-05
Carbon Disulfide	5.9	5.90e-06	1.44e-04
1,1-Dichloroethane (Ethylidene Dichloride)[b]	2.5	2.50e-06	6.09e-05
Chloroform [b]	2.5	2.50e-06	6.09e-05
1,2-Dichloroethane (Ethylene Dichloride)[b]	2.5	2.50e-06	6.09e-05
2-Butanone (Methyl Ethyl Ketone)	5.1	5.10e-06	1.24e-04
1,1,1-Trichloroethane[b]	2.5	2.50e-06	6.09e-05
Carbon Tetrachloride[b]	2.5	2.50e-06	6.09e-05
Vinyl Acetate[b]	2.5	2.50e-06	6.09e-05
1,2-Dichloropropane (Propylene Dichloride)[b]	2.5	2.50e-06	6.09e-05
Trichloroethene[b]	2.5	2.50e-06	6.09e-05
1,1,2-Trichloroethane[b]	2.4	2.40e-06	5.85e-05
Benzene	7.9	7.90e-06	1.93e-04
1,3-Dichloropropylene[b]	2.5	2.50e-06	6.09e-05
Bromoform[b]	2.4	2.40e-06	5.85e-05
Tetrachloroethene	3.1	3.10e-06	7.55e-05
1,1,2,2-Tetrachloroethane[b]	2.5	2.50e-06	6.09e-05
Toluene	3.5	3.50e-06	8.53e-05
Chlorobenzene[b]	2.5	2.50e-06	6.09e-05
Ethylbenzene[b]	2.5	2.50e-06	6.09e-05
Styrene[b]	2.5	2.50e-06	6.09e-05
Xylenes[b]	2.5	2.50e-06	6.09e-05

[a]Page 6-28 (189 HAPs, only).
[b]Pollutant not detected in any sampling runs. EF is based on detection limits (1/2).
c Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

PAH/ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Benzyl chloride[b]	0.0059	5.90e-09	1.44e-07
Acetophenone	0.6360	6.36e-07	1.55e-05
Hexachloroethane[b]	0.0059	5.90e-09	1.44e-07
Naphthalene	0.2153	2.15e-07	5.25e-06
Hexachlorobutadiene[b]	0.0059	5.90e-09	1.44e-07
2-Chloroacetophenone	0.2879	2.88e-07	7.02e-06
Biphenyl	0.1257	1.26e-07	3.06e-06
Acenaphthylene	0.0068	6.80e-09	1.66e-07
Acenaphthene	0.0265	2.65e-08	6.46e-07
Dibenzofurans	0.0654	6.54e-08	1.59e-06
2,4-Dinitrotoluene	0.0197	1.97e-08	4.80e-07
Fluorene	0.0313	3.13e-08	7.63e-07
Hexachlorobenzene[b]	0.0059	5.90e-09	1.44e-07
Phenanthrene	0.0776	7.76e-08	1.89e-06
Anthracene	0.0207	2.07e-08	5.04e-07
Fluoranthene	0.0270	2.70e-08	6.58e-07
Pyrene	0.0139	1.39e-08	3.39e-07
Benz(a)anthracene	0.0037	3.70e-09	9.02e-08
Chrysene	0.0089	8.90e-09	2.17e-07
Benzo(b,k)fluoranthene	0.0070	7.00e-09	1.71e-07
Benzo(a)pyrene[b]	0.0012	1.20e-09	2.92e-08
Indeno(1,2,3-c,d)pyrene[b]	0.0012	1.20e-09	2.92e-08
Benzo(g,h,i)perylene[b]	0.0012	1.20e-09	2.92e-08

[a]Page 6-30 (most common PAHs, 189 HAPs).
[b]Pollutant not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

DIOXINS/FURANS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
2,3,7,8-TCDD[b]	1.05e-06	1.05e-12	2.56e-11
OCDD	1.89e-05	1.89e-11	4.61e-10
2,3,7,8-TCDF	4.76e-06	4.76e-12	1.16e-10
OCDF	1.95e-05	1.95e-11	4.75e-10

[a]Page 6-32.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ALDEHYDES EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Formaldehyde	3.9	3.90e-06	9.50e-05
Acetaldehyde	89	8.90e-05	2.17e-03
Acrolein	41	4.10e-05	9.99e-04
Propionaldehyde	25	2.50e-05	6.09e-04

[a]Page 6-33.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 42 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 32 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: A STUDY OF TOXIC EMISSIONS FROM A COAL-FIRED POWER PLANT UTILIZING AN ESP/WET FGD SYSTEM. BATTELLE, COLUMBUS, OHIO. DECEMBER 29, 1993.

FACILITY: Underwood, North Dakota
FILENAME DOE6.tbl

PROCESS DATA	
Coal type[a]	Lignite
Boiler configuration[a]	Pulverized, Dry bottom, tangential
Coal source[a]	North Dakota
SCC	10100302
Control device 1[a]	ESP
Control device 2[b]	Flue Gas Desulfurization- Wet Limestone Scrubber (FGD-WLS)
Control device 3	None
Data Quality	A
Process Parameters[c]	550 MW
Test methods[d]	Assumed EPA, or EPA-approved, test methods
Number of test runs[e]	2,3
Coal HHV, as received (Btu/lb)[f]	6,230
Coal HHV, as received (Btu/ton)	12,460,000
Coal HHV, as received (MMBtu/ton)	12.5

[a]Page 2-1.
[b]Pages 2-1, 2-4, and 2-5.
[c]Page 2-1. 2 identical units @ 1,100 MW- one unit = 550 MW.
[d]Page 3-26.
[e]See pages referenced below by groups of EFs.
[f]Page 2-33, average of "As received" values.

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[d] (lb/ton)
Aluminum	578	5.78e-04	7.20e-03
Antimony	0.18	1.80e-07	2.24e-06
Arsenic	1.2	1.20e-06	1.50e-05
Barium	162	1.62e-04	2.02e-03
Beryllium[b]	0.85	8.50e-07	1.06e-05
Boron	19	1.90e-05	2.37e-04
Cadmium[b]	1.6	1.60e-06	1.99e-05
Calcium	1308	1.31e-03	1.63e-02
Chromium[c]	10.0	1.00e-05	1.25e-04
Cobalt	1.5	1.50e-06	1.87e-05
Copper	4.9	4.90e-06	6.11e-05
Lead	0.69	6.90e-07	8.60e-06
Manganese	30	3.00e-05	3.74e-04
Mercury	9.5	9.50e-06	1.18e-04
Molybdenum[c]	0.51	5.10e-07	6.35e-06
Nickel[c]	5.1	5.10e-06	6.35e-05
Potassium	109	1.09e-04	1.36e-03
Selenium	8.3	8.30e-06	1.03e-04
Sodium	218	2.18e-04	2.72e-03
Titanium	42	4.20e-05	5.23e-04
Vanadium	4.4	4.40e-06	5.48e-05

[a]Page 6-76, "Average" values.
[b]Pollutant was not detected in any of the sampling runs. EF is based on detection limits (1/2).
[c]Data from one run not used, EF based on data from two runs.
[d]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

AMMONIA/CYANIDE EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Ammonia[b]	1.9	1.90e-06	2.37e-05
Cyanide	51	5.10e-05	6.35e-04

[a]Page 6-78.
[b]Pollutant was not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

HCl, HFl EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[b]
Hydrogen Chloride	1,339	1.34e-03	1.67e-02
Hydrogen Fluoride	3,976	3.98e-03	4.95e-02

[a]Page 6-80.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Chloromethane (Methyl Chloride)	106	1.06e-04	1.32e-03
Bromomethane (Methyl Bromide)	4.3	4.30e-06	5.36e-05
Vinyl Chloride[b]	3.2	3.20e-06	3.99e-05
Chloroethane (Ethyl Chloride)[b]	3.2	3.20e-06	3.99e-05
Carbon Disulfide	3.4	3.40e-06	4.24e-05
1,1-Dichloroethane (Ethylidene Dichloride)[b]	3.2	3.20e-06	3.99e-05
Chloroform [b]	3.2	3.20e-06	3.99e-05
1,2-Dichloroethane (Ethylene Dichloride)	3.2	3.20e-06	3.99e-05
2-Butanone (Methyl Ethyl Ketone)	9.8	9.80e-06	1.22e-04
1,1,1-Trichloroethane[b]	3.2	3.20e-06	3.99e-05
Carbon Tetrachloride[b]	3.2	3.20e-06	3.99e-05
Vinyl Acetate[b]	3.2	3.20e-06	3.99e-05

ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
1,2-Dichloropropane (Propylene Dichloride)[b]	3.2	3.20e-06	3.99e-05
Trichloroethene[b]	3.2	3.20e-06	3.99e-05
1,1,2-Trichloroethane[b]	3.2	3.20e-06	3.99e-05
Benzene	41	4.10e-05	5.11e-04
1,3-Dichloropropylene[b]	3.2	3.20e-06	3.99e-05
Bromoform	3.1	3.10e-06	3.86e-05
Tetrachloroethene[b]	3.2	3.20e-06	3.99e-05
1,1,2,2-Tetrachloroethane[b]	3.2	3.20e-06	3.99e-05
Toluene	24	2.40e-05	2.99e-04
Chlorobenzene	3.3	3.30e-06	4.11e-05
Ethylbenzene[b]	3.2	3.20e-06	3.99e-05
Styrene	3.3	3.30e-06	4.11e-05
Xylenes	3.5	3.50e-06	4.36e-05

[a]Page 6-82 (only 189 HAPs).
[b]Pollutant was not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

PAH/SVOC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Naphthalene	0.2549	2.55e-07	3.18e-06
Acenaphthene	0.0173	1.73e-08	2.16e-07
Dibenzofurans	0.0516	5.16e-08	6.43e-07
2,4-Dinitrotoluene	0.0065	6.50e-09	8.10e-08
Fluorene	0.0415	4.15e-08	5.17e-07
Hexachlorobenzene[b]	0.0009	9.00e-10	1.12e-08
Phenanthrene	0.3142	3.14e-07	3.91e-06
Anthracene	0.0147	1.47e-08	1.83e-07
Fluoranthene	0.0422	4.22e-08	5.26e-07

PAH/SVOC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Pyrene	0.0162	1.62e-08	2.02e-07
Benz(a)anthracene	0.0021	2.10e-09	2.62e-08
Chrysene	0.0053	5.30e-09	6.60e-08
Benzo(b,k)fluoranthene	0.0045	4.50e-09	5.61e-08
Benzo(a)pyrene	0.0009	9.00e-10	1.12e-08
Indeno(1,2,3-c,d)pyrene	0.0006	6.00e-10	7.48e-09
Benzo(g,h,i)perylene	0.0006	6.00e-10	7.48e-09
Biphenyl	0.0230	2.30e-08	2.87e-07
Acetophenone	0.5425	5.43e-07	6.76e-06
Acenaphthylene	0.0105	1.05e-08	1.31e-07
Benzyl Chloride	0.0057	5.70e-09	7.10e-08

[a]Page 6-84 (most common PAHs, 189 HAPs).
[b]Pollutant was not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

DIOXINS/FURANS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[c]
2,3,7,8-TCDD[b]	9.90e-07	9.90e-13	1.23e-11
OCDD	1.51e-05	1.51e-11	1.88e-10
2,3,7,8-TCDF	9.89e-06	9.89e-12	1.23e-10
OCDF	6.29e-06	6.29e-12	7.84e-11

[a]Page 6-86.
[b]Pollutant was not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ALDEHYDES EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Formaldehyde[b]	1.8	1.80e-06	2.24e-05
Acetaldehyde	67	6.70e-05	8.35e-04
Acrolein	1.1	1.10e-06	1.37e-05
Propionaldehyde	12	1.20e-05	1.50e-04

[a]Page 6-88.
[b]Pollutant was not detected in any sampling runs. EF is based on detection limits (1/2).
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 43 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 33 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: TOXICS ASSESSMENT REPORT. ILLINOIS POWER COMPANY. BALDWIN POWER STATION-UNIT 2. VOLUMES I THROUGH IV. ROY F. WESTON, INC. DECEMBER, 1993

FACILITY: Baldwin, Illinois
FILENAME DOE3.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[a]	Cyclone
Coal source[a]	Illinois
SCC	10100203
Control device 1[b]	ESP
Control device 2	None
Control device 3	None
Data Quality	A
Process Parameters[a]	568 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	6 for filterable PM, 3 for other pollutants
Coal HHV, as received (Btu/lb)[e]	10,633
Coal HHV, as received (Btu/ton)	21,266,000
Coal HHV, as received (MMBtu/ton)	21.3

[a]Page 2-1.
[b]Page 2-4.
[c]Page 1-12.
[d]See pages referenced below by groups of EFs.
[e]Page 2-23. Average of 10765, 10681, 10722, 10412, 10426 and 10794 Btu/lb, as received, non-soot blowing periods.

METALS EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[b]
Aluminum	5.55e+03	5.55e-03	1.18e-01
Antimony	1.52e+00	1.52e-06	3.23e-05
Arsenic	1.34e+01	1.34e-05	2.85e-04
Barium	5.32e+00	5.32e-06	1.13e-04
Beryllium	1.41e+00	1.41e-06	3.00e-05

METALS EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/ton)[b]
Boron	7.67e+03	7.67e-03	1.63e-01
Cadmium	3.02e+00	3.02e-06	6.42e-05
Calcium	3.25e+02	3.25e-04	6.91e-03
Chromium	5.06e+01	5.06e-05	1.08e-03
Cobalt	6.80e+00	6.80e-06	1.45e-04
Copper	1.89e+01	1.89e-05	4.02e-04
Iron	8.39e+03	8.39e-03	1.78e-01
Lead	2.86e+01	2.86e-05	6.08e-04
Magnesium	2.90e+02	2.90e-04	6.17e-03
Manganese	2.23e+01	2.23e-05	4.74e-04
Mercury	3.83e+00	3.83e-06	8.14e-05
Molybdenum	3.37e+01	3.37e-05	7.17e-04
Nickel	2.21e+01	2.21e-05	4.70e-04
Potassium	9.33e+02	9.33e-04	1.98e-02
Phosphorous	1.98e+02	1.98e-04	4.21e-03
Selenium	1.30e+02	1.30e-04	2.76e-03
Sodium	1.17e+03	1.17e-03	2.49e-02
Titanium	3.82e+02	3.82e-04	8.12e-03
Vanadium	1.00e+02	1.00e-04	2.13e-03

[a]Page 4-18, "Average" values.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANICS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Phenol	1.15e+00	1.15e-06	2.45e-05
Acetophenone	1.23e+00	1.23e-06	2.62e-05
Isophorone	2.62e+01	2.62e-05	5.57e-04
Biphenyl[b]	8.78e-01	8.78e-07	1.87e-05
Di-n-butylphthalate	3.00e+00	3.00e-06	6.38e-05
bis(2-Ethylhexyl)phthalate	4.60e+00	4.60e-06	9.78e-05

[a]Page 4-74.
[b]Emission factor based on only non-detects.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

PAH EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor [c] (lb/ton)
Naphthalene	3.94e-01	3.94e-07	8.38e-06
Acenaphthylene	3.19e-02	3.19e-08	6.78e-07
Acenaphthene[b]	6.32e-03	6.32e-09	1.34e-07
Fluorene	4.87e-03	4.87e-09	1.04e-07
Phenanthrene	5.69e-02	5.69e-08	1.21e-06
Anthracene	2.64e-03	2.64e-09	5.61e-08
Fluoranthene	1.74e-02	1.74e-08	3.70e-07
Pyrene	2.82e-03	2.82e-09	6.00e-08
Benz(a)anthracene[b]	1.17e-03	1.17e-09	2.49e-08
Benzo(b,k)fluoranthene	3.91e-03	3.91e-09	8.32e-08
Benzo(a)pyrene[b]	5.44e-04	5.44e-10	1.16e-08
Indeno(1,2,3-c,d)pyrene[b]	1.11e-03	1.11e-09	2.36e-08
Benzo(g,h,i)perylene[b]	1.13e-03	1.13e-09	2.40e-08

[a]Page 4-74.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

DIOXINS/FURANS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
2,3,7,8-TCDD[b]	2.54e-06	2.54e-12	5.40e-11
Total TCDD	1.34e-06	1.34e-12	2.85e-11
Total PeCDD[b]	7.37e-07	7.37e-13	1.57e-11
Total HxCDD	9.59e-07	9.59e-13	2.04e-11
Total HpCDD	2.53e-06	2.53e-12	5.38e-11
Total OCDD[b]	8.91e-06	8.91e-12	1.89e-10
2,3,7,8-TCDF[b]	1.27e-06	1.27e-12	2.70e-11
Total TCDF[b]	3.82e-06	3.82e-12	8.12e-11
Total PeCDF	3.99e-06	3.99e-12	8.49e-11
Total HxCDF	5.57e-06	5.57e-12	1.18e-10
Total HpCDF	3.17e-06	3.17e-12	6.74e-11
Total OCDF	4.15e-06	4.15e-12	8.83e-11

[a]Page 4-76.
[b]Pollutant not detected in any sampling runs.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ALDEHYDES/KETONES EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Formaldehyde	1.68e+00	1.68e-06	3.57e-05
Acetaldehyde	1.37e+01	1.37e-05	2.91e-04
Acrolein	3.55e+00	3.55e-06	7.55e-05
Methyl Ethyl Ketone	3.70e+00	3.70e-06	7.87e-05

[a]Page 4-78, ESP Outlet data, only 189 HAPs.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANICS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Bromomethane (Methyl Bromide)	9.70e-01	9.70e-07	2.06e-05
Carbon Disulfide	1.37e-01	1.37e-07	2.91e-06
Methylene Chloride[b]	1.83e+01	1.83e-05	3.89e-04
Hexane	1.64e-01	1.64e-07	3.49e-06
Benzene	1.21e+02	1.21e-04	2.57e-03
Toluene[b]	2.00e+00	2.00e-06	4.25e-05
Ethylbenzene	1.26e-01	1.26e-07	2.68e-06
Xylenes(m/p + o)	1.87e+00	1.87e-06	3.97e-05
Styrene	1.99e-01	1.99e-07	4.23e-06

[a]Page 4-80.
[b]Results suspected to be biased by lab solvents, do not use.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 44 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 34 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: TOXICS ASSESSMENT REPORT. MINNESOTA POWER COMPANY BOSWELL ENERGY CENTER UNIT 2. COHASSET, MINNESOTA. VOLUME 1- MAIN REPORT. ROY F. WESTON, INC. WEST CHESTER, PENNSYLVANIA. DECEMBER, 1993.

FACILITY: Cohasset, Minnesota
FILENAME DOE8.tbl

PROCESS DATA			
Coal type[a]	Subbituminous		
Boiler configuration[b]	Pulverized, Dry bottom		
Coal source[a]	Montana/Wyoming		
SCC	10100222		
Control device 1[c]	Baghouse		
Control device 2	None		
Control device 3	None		
Data Quality	A		
Process Parameters[a]	69 MW		
Test methods[d]	EPA, or EPA-approved, test methods		
Number of test runs[e]	3		8,692
			8,749
Coal HHV, as received (Btu/lb)[f]	8,798		8,839
Coal HHV, as received (Btu/ton)	17,596,000		8,815
Coal HHV, as received (MMBtu/ton)	17.6		8,871
			8,820
			--------------------
		avg	8,798

[a]Page 2-1.
[b]Page 2-1 for "pulverized", assumed dry bottom.
[c]Page 2-4.
[d]Page 1-12.
[e]See pages listing emission factors.
[f]Page 2-23, average of 8692, 8749, 8839, 8815, 8871, 8820 Btu/lb.

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Aluminum	1.93e+03	1.93e-03	3.40e-02
Antimony[b]	6.77e-01	6.77e-07	1.19e-05
Arsenic	3.24e-01	3.24e-07	5.70e-06
Barium	8.16e+01	8.16e-05	1.44e-03
Beryllium[b]	1.29e-01	1.29e-07	2.27e-06
Boron	6.09e+02	6.09e-04	1.07e-02
Cadmium[b]	6.48e-01	6.48e-07	1.14e-05
Calcium	4.76e+02	4.76e-04	8.38e-03
Chromium	2.04e+00	2.04e-06	3.59e-05
Cobalt	7.01e-01	7.01e-07	1.23e-05
Copper	2.40e+00	2.40e-06	4.22e-05
Iron	4.12e+02	4.12e-04	7.25e-03
Lead	2.44e+00	2.44e-06	4.29e-05
Magnesium	2.05e+02	2.05e-04	3.61e-03
Manganese	1.84e+01	1.84e-05	3.24e-04
Mercury	1.93e+00	1.93e-06	3.40e-05
Molybdenum	1.29e+00	1.29e-06	2.27e-05
Nickel	1.97e+00	1.97e-06	3.47e-05
Potassium	5.71e+01	5.71e-05	1.00e-03
Phosphorous	2.67e+01	2.67e-05	4.70e-04
Selenium	3.23e+00	3.23e-06	5.68e-05
Sodium	1.97e+02	1.97e-04	3.47e-03
Titanium	5.78e+01	5.78e-05	1.02e-03
Vanadium	1.53e+00	1.53e-06	2.69e-05

[a]Page 4-14, "Average" values.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANICS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
n-Nitrosodimethylamine[b]	8.87e-01	8.87e-07	1.56e-05
Phenol	4.29e-01	4.29e-07	7.55e-06
Acetophenone	7.13e-01	7.13e-07	1.25e-05
Biphenyl[b]	1.78e-01	1.78e-07	3.13e-06
Di-n-butylphthalate[b]	1.94e+00	1.94e-06	3.41e-05
bis(2-Ethylhexyl)phthalate	1.68e+00	1.68e-06	2.96e-05

[a]Page 4-43.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

PAH EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Naphthalene	2.53e-01	2.53e-07	4.45e-06
Acenaphthylene	5.31e-03	5.31e-09	9.34e-08
Acenaphthene	4.08e-02	4.08e-08	7.18e-07
Fluorene	8.84e-03	8.84e-09	1.56e-07
Phenanthrene	2.10e-01	2.10e-07	3.70e-06
Anthracene	6.17e-03	6.17e-09	1.09e-07
Fluoranthene	8.25e-02	8.25e-08	1.45e-06
Pyrene	3.73e-02	3.73e-08	6.56e-07
Benz(a)anthracene	4.68e-03	4.68e-09	8.23e-08
Benzo(b,j,k)fluoranthene	3.05e-03	3.05e-09	5.37e-08
Benzo(a)pyrene	2.09e-04	2.09e-10	3.68e-09
Indeno(1,2,3-c,d)pyrene	3.45e-04	3.45e-10	6.07e-09
Benzo(g,h,i)perylene[b]	5.19e-04	5.19e-10	9.13e-09

[a]Page 4-43.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

DIOXINS/FURANS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
2,3,7,8-TCDD	8.14e-07	8.14e-13	1.43e-11
Total TCDD	9.29e-06	9.29e-12	1.63e-10
Total PeCDD	4.64e-06	4.64e-12	8.16e-11
Total HxCDD	2.10e-06	2.10e-12	3.70e-11
Total HpCDD[b]	1.86e-06	1.86e-12	3.27e-11
Total OCDD	1.10e-05	1.10e-11	1.94e-10
2,3,7,8-TCDF	6.03e-06	6.03e-12	1.06e-10
Total TCDF	6.04e-05	6.04e-11	1.06e-09
Total PeCDF	4.74e-05	4.74e-11	8.34e-10
Total HxCDF	2.23e-05	2.23e-11	3.92e-10
Total HpCDF	6.95e-06	6.95e-12	1.22e-10
Total OCDF	1.86e-06	1.86e-12	3.27e-11

[a]Page 4-45.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ALDEHYDES/KETONES EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Formaldehyde[b]	1.70e+00	1.70e-06	2.99e-05
Acetaldehyde[b]	1.09e+00	1.09e-06	1.92e-05
Acrolein	3.40e+00	3.40e-06	5.98e-05
Methyl Ethyl Ketone[b]	4.99e+00	4.99e-06	8.78e-05

[a]Page 4-47, ESP Outlet data, only 189 HAPs.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

VOC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Chloroethane (ethyl chloride)	2.50e+00	2.50e-06	4.40e-05
Carbon Disulfide	1.77e+01	1.77e-05	3.11e-04
Methylene Chloride	1.07e+01	1.07e-05	1.88e-04
Hexane	1.54e+00	1.54e-06	2.71e-05
Vinyl acetate[b]	4.29e-01	4.29e-07	7.55e-06
2-Butanone (Methyl Ethyl Ketone)	1.64e+01	1.64e-05	2.89e-04
Benzene	1.03e-02	1.03e-08	1.81e-07
Methyl Methacrylate	1.14e+00	1.14e-06	2.01e-05
Ethylene Dibromide[c]	6.56e-02	6.56e-08	1.15e-06
Toluene	5.45e+00	5.45e-06	9.59e-05
Tetrachloroethene (PCE)	5.61e-01	5.61e-07	9.87e-06
Chlorobenzene	1.63e-01	1.63e-07	2.87e-06
Ethylbenzene	4.27e-01	4.27e-07	7.51e-06
Xylenes(m/p + o)	2.43e+00	2.43e-06	4.27e-05
Styrene	1.75e+00	1.75e-06	3.08e-05
Cumene	3.02e-01	3.02e-07	5.31e-06

[a]Page 4-49.
[b]Pollutant not detected in any sampling runs. EF is based on detection limits.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 45 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 35 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: ASSESSMENT OF TOXIC EMISSIONS FROM A COAL FIRED POWER PLANT UTILIZING AN ESP. FINAL REPORT-REVISION 1. ENERGY AND ENVIRONMENTAL RESEARCH CORPORATION. IRVINE, CALIFORNIA. DECEMBER 23, 1993.

FACILITY: Brilliant, Ohio, Cardinal Unit 1
FILENAME DOE5.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[b]	Pulverized, Dry bottom
Coal source[a]	Pennysylvania
SCC	10100202
Control device 1[a]	ESP
Control device 2	None
Control device 3	None
Data Quality	C (no HHV for the coal, had to use average from AP-42)
Process Parameters[a]	615
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	3
Coal HHV (Btu/lb)[e]	13,000
Coal HHV (Btu/ton)	26,000,000
Coal HHV (MMBtu/ton)	26.0

[a]Page 1-1.
[b]Page 1-1 for "pulverized", assumed dry bottom.
[c]Page 1-4.
[d]Page 1-5.
[e]Appendix A of AP-42, "Typical Parameters of Various Fuels".

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Aluminum	235	2.35e-04	6.11e-03
Calcium	283	2.83e-04	7.36e-03
Iron	568	5.68e-04	1.48e-02
Magnesium	16.4	1.64e-05	4.26e-04

METALS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Phosphorous	141	1.41e-04	3.67e-03
Potassium	88.7	8.87e-05	2.31e-03
Silicon	60.9	6.09e-05	1.58e-03
Sodium	249	2.49e-04	6.47e-03
Titanium	16.6	1.66e-05	4.32e-04
Zinc	18.3	1.83e-05	4.76e-04
Antimony	2.36	2.36e-06	6.14e-05
Arsenic	3.49	3.49e-06	9.07e-05
Barium	0.872	8.72e-07	2.27e-05
Beryllium	0.070	7.00e-08	1.82e-06
Boron	1,912	1.91e-03	4.97e-02
Cadmium	0.846	8.46e-07	2.20e-05
Chromium	7.51	7.51e-06	1.95e-04
Cobalt	0.631	6.31e-07	1.64e-05
Copper	1.39	1.39e-06	3.61e-05
Lead	3.83	3.83e-06	9.96e-05
Manganese	15.0	1.50e-05	3.90e-04
Mercury	0.448	4.48e-07	1.16e-05
Molybdenum	0.567	5.67e-07	1.47e-05
Nickel	4.72	4.72e-06	1.23e-04
Selenium	92.8	9.28e-05	2.41e-03
Silver	0.200	2.00e-07	5.20e-06
Vanadium	1.57	1.57e-06	4.08e-05

[a]Page 1-11.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

DIOXINS/FURANS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Total TCDD	5.15e-05	5.15e-11	1.34e-09
Total HxCDD	2.23e-05	2.23e-11	5.80e-10
Total HpCDD	7.61e-06	7.61e-12	1.98e-10
Total OCDD	2.03e-05	2.03e-11	5.28e-10
2,3,7,8-TCDF	6.58e-07	6.58e-13	1.71e-11
Total PeCDF	2.79e-06	2.79e-12	7.25e-11
Total HxCDF	2.51e-05	2.51e-11	6.53e-10
Total HpCDF	2.68e-06	2.68e-12	6.97e-11
Total OCDF	1.07e-05	1.07e-11	2.78e-10

[a]Page 1-11.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

SEMIVOLATILE ORGANICS EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Benzyl Chloride	53.9	5.39e-05	1.40e-03
Isophorone	23.3	2.33e-05	6.06e-04
Dimethyl Sulfate	1.83	1.83e-06	4.76e-05
Naphthalene	1.94	1.94e-06	5.04e-05

[a]Page 1-11.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
2-Butanone (Methyl Ethyl Ketone)	48.1	4.81e-05	1.25e-03
Formaldehyde	60.0	6.00e-05	1.56e-03
Benzene	3.40	3.40e-06	8.84e-05
Bromomethane (Methyl Bromide)	15.1	1.51e-05	3.93e-04
Chloroform	2.92	2.92e-06	7.59e-05
Chloromethane (Methyl Chloride)	6.38	6.38e-06	1.66e-04

ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Hexane	6.53	6.53e-06	1.70e-04
m,p-Xylene	2.98	2.98e-06	7.75e-05
Methyl Hydrazine	6.57	6.57e-06	1.71e-04
Methyl Tert Butyl Ether	1.36	1.36e-06	3.54e-05
Toluene	5.16	5.16e-06	1.34e-04

[a]Page 1-13.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

OTHER EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[b] (lb/ton)
Ammonia	40.7	4.07e-05	1.06e-03
Chlorine	1,547	1.55e-03	4.02e-02
Hydrogen Chloride	22,915	2.29e-02	5.96e-01
Hydrogen Cyanide	0.591	5.91e-07	1.54e-05
Hydrogen Fluoride	1,869	1.87e-03	4.86e-02
CO	753	7.53e-04	1.96e-02
THC	365	3.65e-04	9.49e-03
NOX		1.22e+00	3.17e+01
SOX		4.41e+00	1.15e+02

[a]Page 1-14. Note that SOx and NOx units are lb/MMBtu.
[b]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

REFERENCE 46 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 36 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: 500-MW DEMONSTRATION OF ADVANCED WALL-FIRED COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN OXIDE (NOX) EMISSIONS FROM COAL-FIRED BOILERS. RADIAN, CORPORATION, AUSTIN, TEXAS.

FACILITY: EPRI SITE 16
FILENAME SITE16.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[b]	Pulverized, dry bottom
Coal source[f]	Virginia/Kentucky
SCC	10100202
Control device 1[a]	Low Nox Burners/Overfire Air (LNB/OFA)
Control device 2[a]	ESP
Control device 3	none
Data Quality	A
Process Parameters[a]	500 MW
Test methods[c]	EPA, or EPA-approved, test methods
Number of test runs[d]	3
Coal HHV, dry (Btu/lb)[e]	13,800
Coal moisture percent by weight[e]	3.8%
Coal HHV, as received (Btu/lb)	13,295
Coal HHV, as received (MMBtu/lb)	0.013
Coal HHV, as received (MMBtu/ton)	26.59
Coal feed rate (lb/hr,dry)[e]	315,000
Coal feed rate, as received, (lb/hr)	327,443
Coal feed rate, as received, (ton/hr)	164

[a]Page 2-1
[b]Conversation with Greg Behrens, Radian, Austin, Texas.
[c]Page 3-1
[d]Page 3-21, 3-22, 3-23
[e]Page 3-7
[f]Appendix B of EPRI Synthesis Report, page B-2

STACK EMISSION FACTORS

Pollutant	(lb/10^12 Btu)[a]	(lb/MMBtu)	(lb/ton)
Arsenic	110	1.10e-04	2.92e-03
Barium	140	1.40e-04	3.72e-03
Beryllium	3.1	3.10e-06	8.24e-05
Cadmium	3.6	3.60e-06	9.57e-05
Chloride	15,000	1.50e-02	3.99e-01
Chromium	21	2.10e-05	5.58e-04
Chrome VI	5.4	5.40e-06	1.44e-04
Cobalt	6.5	6.50e-06	1.73e-04
Copper	30	3.00e-05	7.98e-04
Fluoride	5,100	5.10e-03	1.36e-01
Lead	11	1.10e-05	2.92e-04
Manganese	21	2.10e-05	5.58e-04
Mercury	4.8	4.80e-06	1.28e-04
Molybdenum	12	1.20e-05	3.19e-04
Nickel	17	1.70e-05	4.52e-04
Phosphorous	180	1.80e-04	4.79e-03
Selenium	140	1.40e-04	3.72e-03
Vanadium	41	4.10e-05	1.09e-03
Benzene[c]	0.51	5.10e-07	1.36e-05
Toluene	0.7	7.00e-07	1.86e-05
Formaldehyde	1.3	1.30e-06	3.46e-05
Acenaphthene	0.0081	8.10e-09	2.15e-07
Acenaphthylene	0.0030	3.00e-09	7.98e-08
Anthracene	0.0037	3.70e-09	9.84e-08
Benzo(a)pyrene[c]	0.0041	4.10e-09	1.09e-07
Benzo(b,j,k)fluoranthenes	0.0015	1.50e-09	3.99e-08
Benzo(g,h,i)perylene[c]	0.0031	3.10e-09	8.24e-08
Benz(a)anthracene	0.0070	7.00e-09	1.86e-07
Chrysene	0.0018	1.80e-09	4.79e-08

REFERENCE 46 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 36 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

STACK EMISSION FACTORS			
Pollutant	(lb/10^12 Btu)[a]	(lb/MMBtu)	(lb/ton)
Fluoranthene	0.010	1.00e-08	2.66e-07
Fluorene	0.0099	9.90e-09	2.63e-07
Indeno(1,2,3-c,d)pyrene[b]	0.0027	2.70e-09	7.18e-08
Phenanthrene	0.044	4.40e-08	1.17e-06
Pyrene	0.011	1.10e-08	2.92e-07

[a]Pages 3-24, 3-25. Individual run data on pages 3-21, 3-22, 3-23.

REFERENCE 47 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 37 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING REPORT: SITE 122. SOUTHERN RESEARCH INSITUTUE, BIRMINGHAM, ALABAMA. MAY, 1995.

FACILITY: EPRI SITE 122
FILENAME SITE122.tbl

PROCESS DATA	
Coal type[a]	Bituminous
Boiler configuration[a]	Cyclone
Coal source[a]	Illinois
SCC	10100203
Control device 1[a]	Electrostatic Precipitator, Cold side
Control device 2[a]	none
Control device 3[a]	none
Data Quality	A
Process Parameters[a]	275 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	2 for manganese, 3 for all others
Coal HHV, as fired (Btu/lb)[d]	12,327
Coal HHV, as fired (Btu/ton)	24,654,000
Coal HHV, as fired (MMBtu/ton)	24.7

[a]Page 2-1.
[b]Page 1-3.
[c]Pages 3-17, 3-20 and 3-22.
[d]Page 3-4.

METALS, NONMETALS AND ORGANIC EMISSION FACTORS

Pollutant	Emission Factor[a] (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor[c] (lb/ton)
Arsenic	220	2.20e-04	5.42e-03
Barium	69	6.90e-05	1.70e-03
Beryllium	4.0	4.00e-06	9.86e-05
Cadmium	3.6	3.60e-06	8.88e-05
Chromium	100	1.00e-04	2.47e-03
Cobalt	26	2.60e-05	6.41e-04
Lead	180	1.80e-04	4.44e-03
Manganese[b]	205	2.05e-04	5.05e-03
Mercury	8.2	8.20e-06	2.02e-04
Nickel	71	7.10e-05	1.75e-03
Selenium	67	6.70e-05	1.65e-03
Vanadium	148	1.48e-04	3.65e-03
Fluorine	3.8e+03	3.80e-03	9.37e-02
Chlorine	2.3e+05	2.30e-01	5.67e+00
Sulfur (sulfur dioxide)	1.5e+06	1.50e+00	3.70e+01
Formaldehyde	0.7	7.00e-07	1.73e-05
Benzene	7.8	7.80e-06	1.92e-04
Toluene	1.9	1.90e-06	4.68e-05

[a]Page 3-30.
[b]EF developed from two sampling runs. See footnote c to Table 3.10, page 3-17.
[c]Multiply emission factor, lb/MMBtu, by coal HHV, MMBtu/ton.

TITLE: Hydrogen Chloride and Hydrogen Fluoride Emission Factors for the NAPAP Emission Inventory. EPA-600/7-85-041. October, 1985.

Filename: NAPAP.tbl

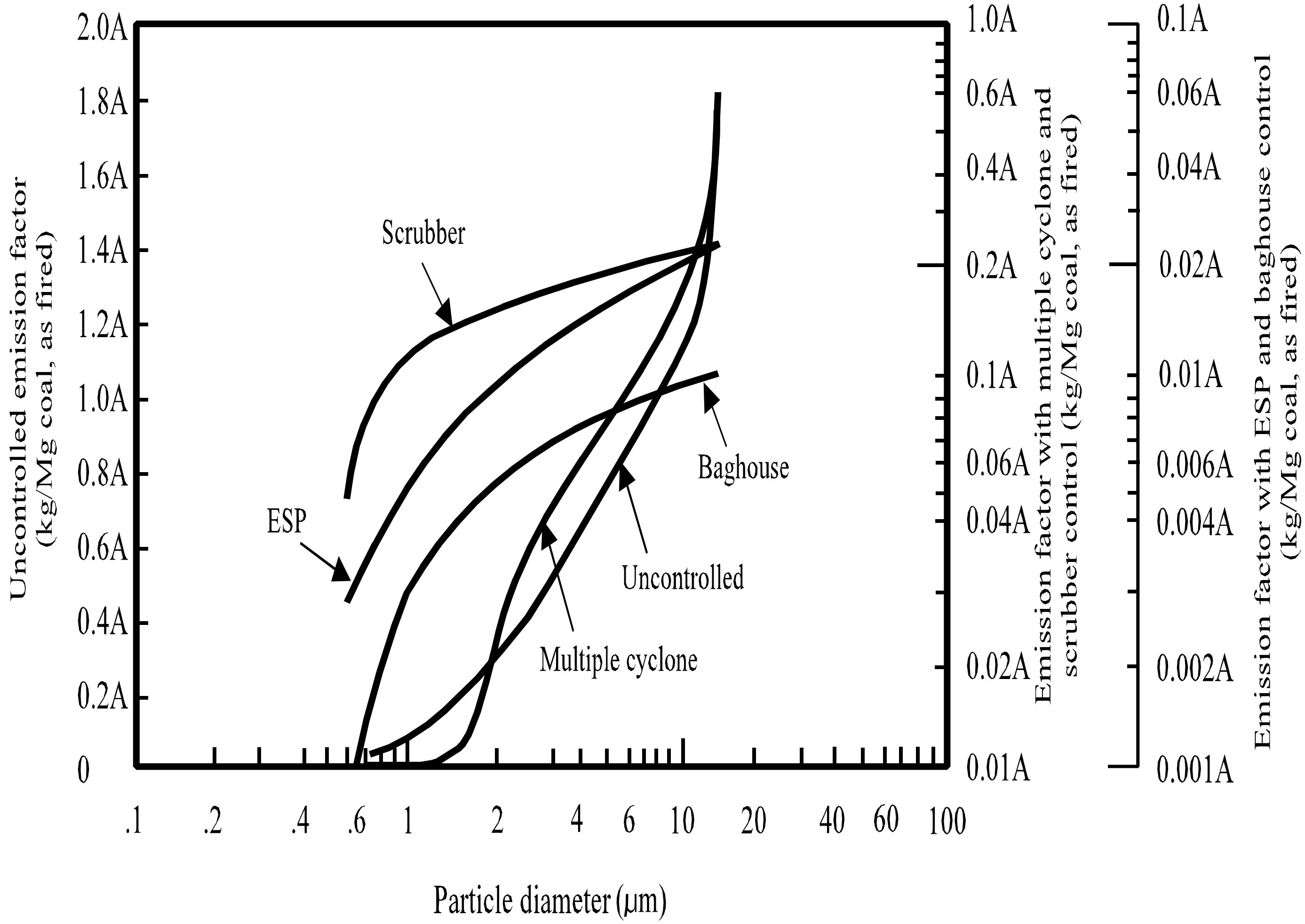
BOILER SCC DESCRIPTIONS	Source Classification Codes	Hydrogen Chloride (lb/ton)[a,b]	Hydrogen Fluoride (lb/ton)[a,b]
Commerical/Industrial Boilers			
Bituminous and Subbituminous Coal			
Firing Types			
Pulverized Coal Wet Bottom	1-03-002-05/21	* 1.48	* 0.17
Pulverized Coal Dry Bottom	1-03-002-06/22		
Overfeed Stoker	1-03-002-07		
Underfeed Stoker	1-03-002-08		
Spreader Stoker	1-03-002-09/24		
Hand-fired	1-03-002-14		
Pulverized Coal Dry Bottom Tangential	1-03-002-16/26		
Atmospheric Fluidized Bed Combustor	1-03-002-17/18		
Cyclone Furnace	1-03-002-23		
Traveling Grate Overfeed Stoker	1-03-002-25		
Electric Generation & Industrial Boilers			
Bituminous and Subbituminous Coal			
Firing Types			
Pulverized Coal Wet Bottom	1-01-002-01/21	* 1.9	* 0.23
	1-02-002-01/21		
Pulverized Coal Dry Bottom	1-01-002-02/22		
	1-02-002-02/22		
Cyclone Furnace	1-01-002-03/23		
	1-02-002-03/23		
Spreader Stoker	1-01-002-04/24		
	1-02-002-04/24		

BOILER SCC DESCRIPTIONS	Source Classification Codes	Hydrogen Chloride (lb/ton)[a,b]	Hydrogen Fluoride (lb/ton)[a,b]
Traveling Grate Overfeed Stoker	1-01-002-05/25		
	1-02-002-25		
Overfeed Stoker	1-02-002-05		
Pulverized Coal Dry Bottom,	1-01-002-12/26		
Tangential Firing	1-02-002-12		
Atmospheric Fluidized Bed	1-01-002-17		
	1-01-002-18		
	1-02-002-17		
	1-02-002-18		
Underfeed Stoker	1-02-002-06		
Commerical/Industrial Boilers			
Lignite			
Firing Types			
Pulverized Coal	1-03-003-05	* 0.351	* 0.063
Pulverized Coal Tangential Firing	1-03-003-06		
Traveling Grate Overfeed Stoker	1-03-003-07		
Spreader Stoker	1-03-003-09		
Electric Generation & Industrial Boilers			
Lignite			
Firing Types			
Pulverized Coal	1-01-003-01	0.01	0.01
	1-02-003-01		
Pulverized Coal Tangential Firing	1-01-003-02		
	1-02-003-02		
Cyclone Furnace	1-01-003-03		
	1-02-003-03		

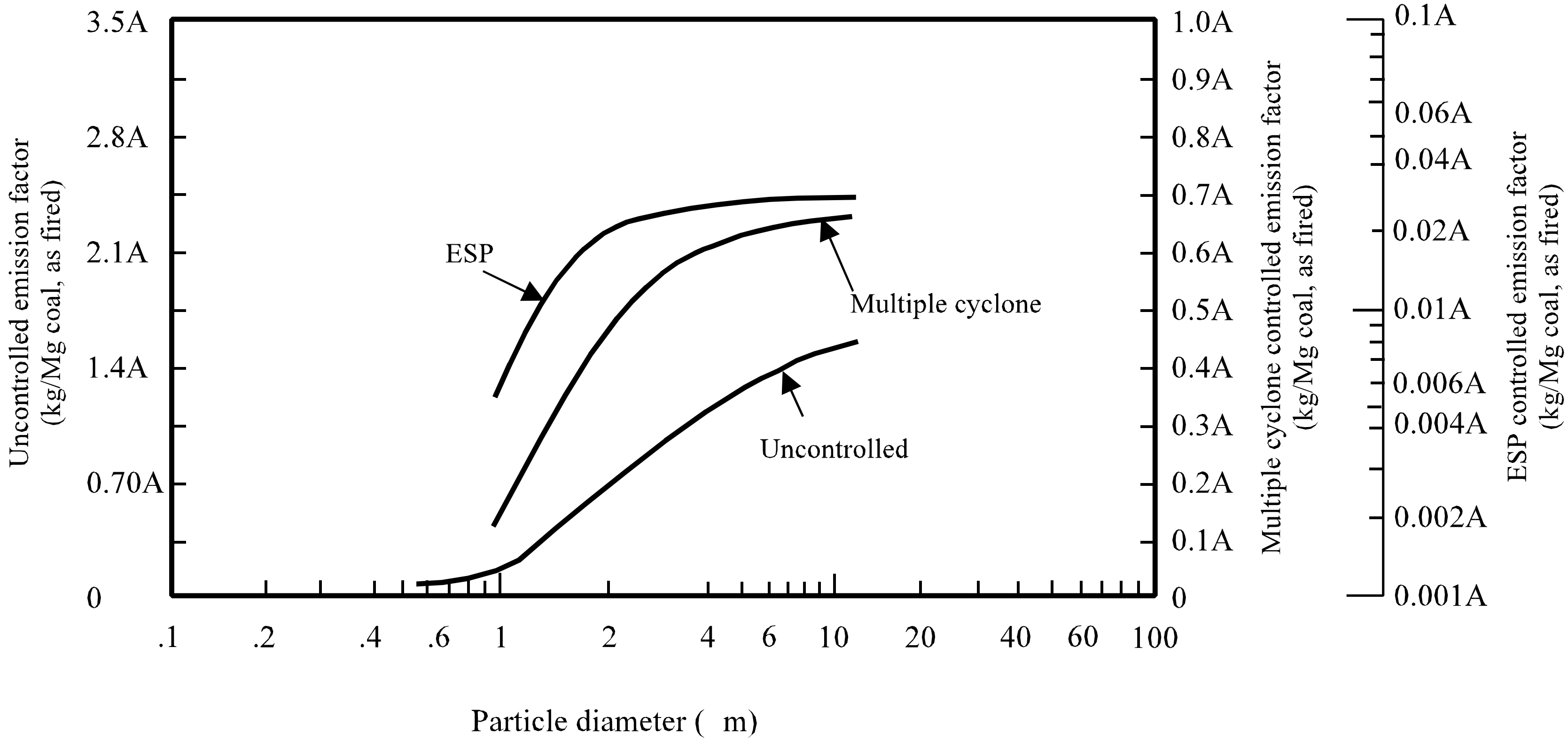
BOILER SCC DESCRIPTIONS	Source Classification Codes	Hydrogen Chloride (lb/ton)[a,b]	Hydrogen Fluoride (lb/ton)[a,b]
Traveling Grate Overfeed Stoker	1-01-003-04		
	1-02-003-04		
Spreader Stoker	1-01-003-06		
	1-02-003-06		
	Overall Average	1.2	0.15
	Quality Rating	B	B

[a]Pages 29, 30, 31. Factors are for both uncontrolled and controlled boilers.
[b]An asterisk to the left of a factor indicates that it was used in calculating the overall emission factor.

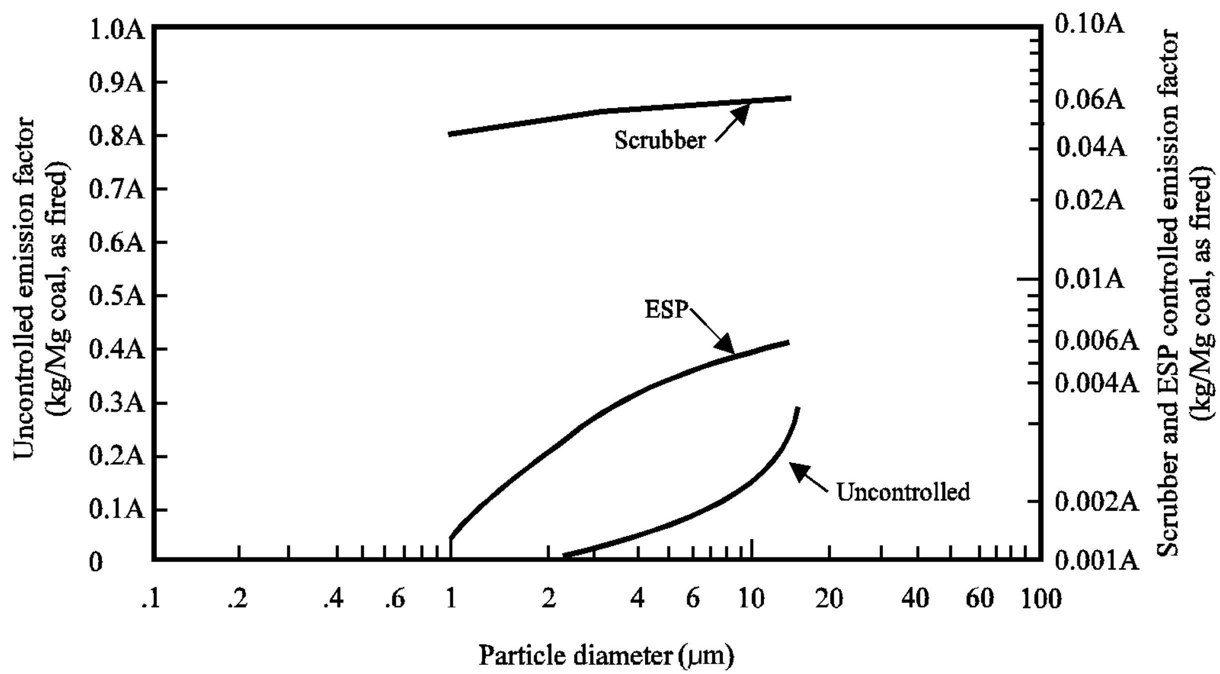
REFERENCE 48 OF AP-42 SECTION 1.1 BACKGROUND DOCUMENTATION
REFERENCE 38 OF AP-42 SECTION 1.7 BACKGROUND DOCUMENTATION

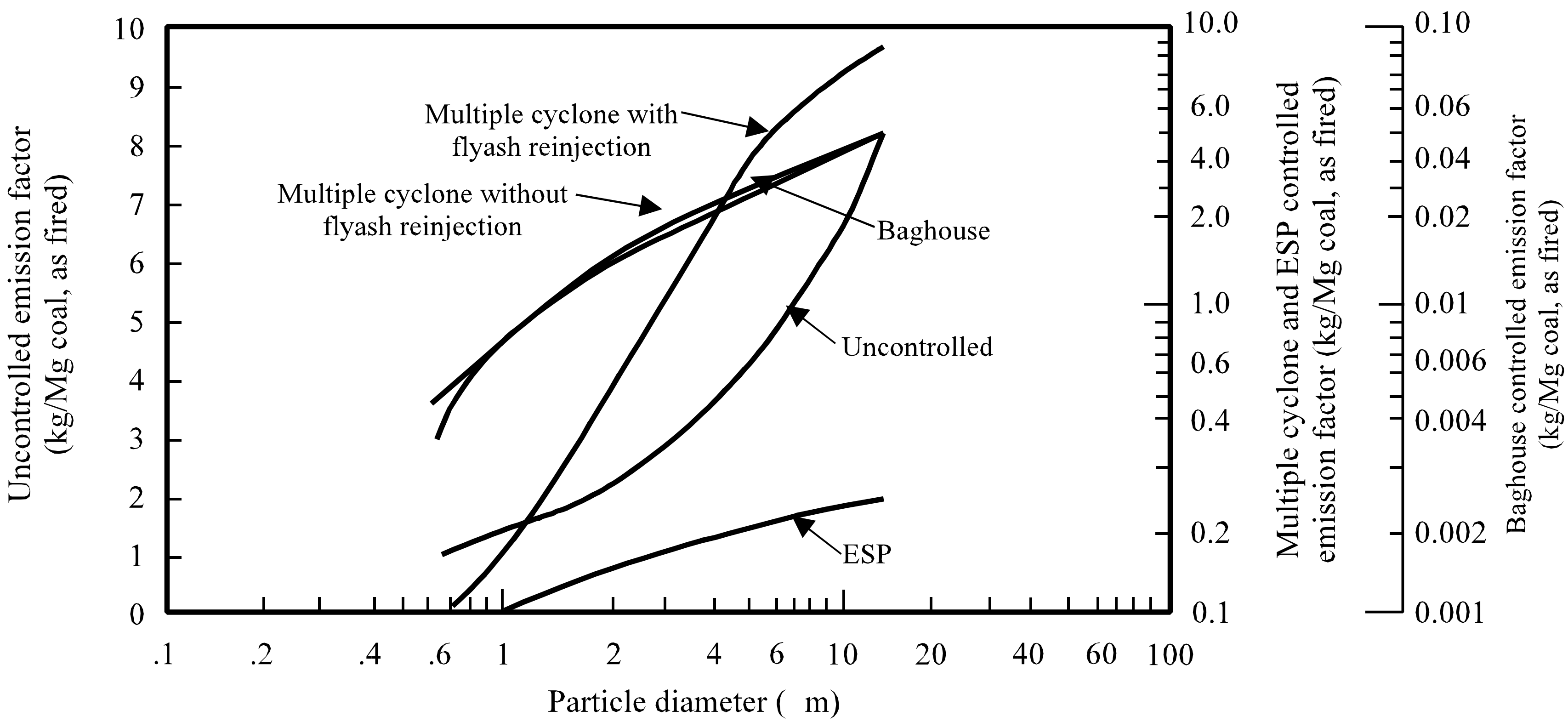


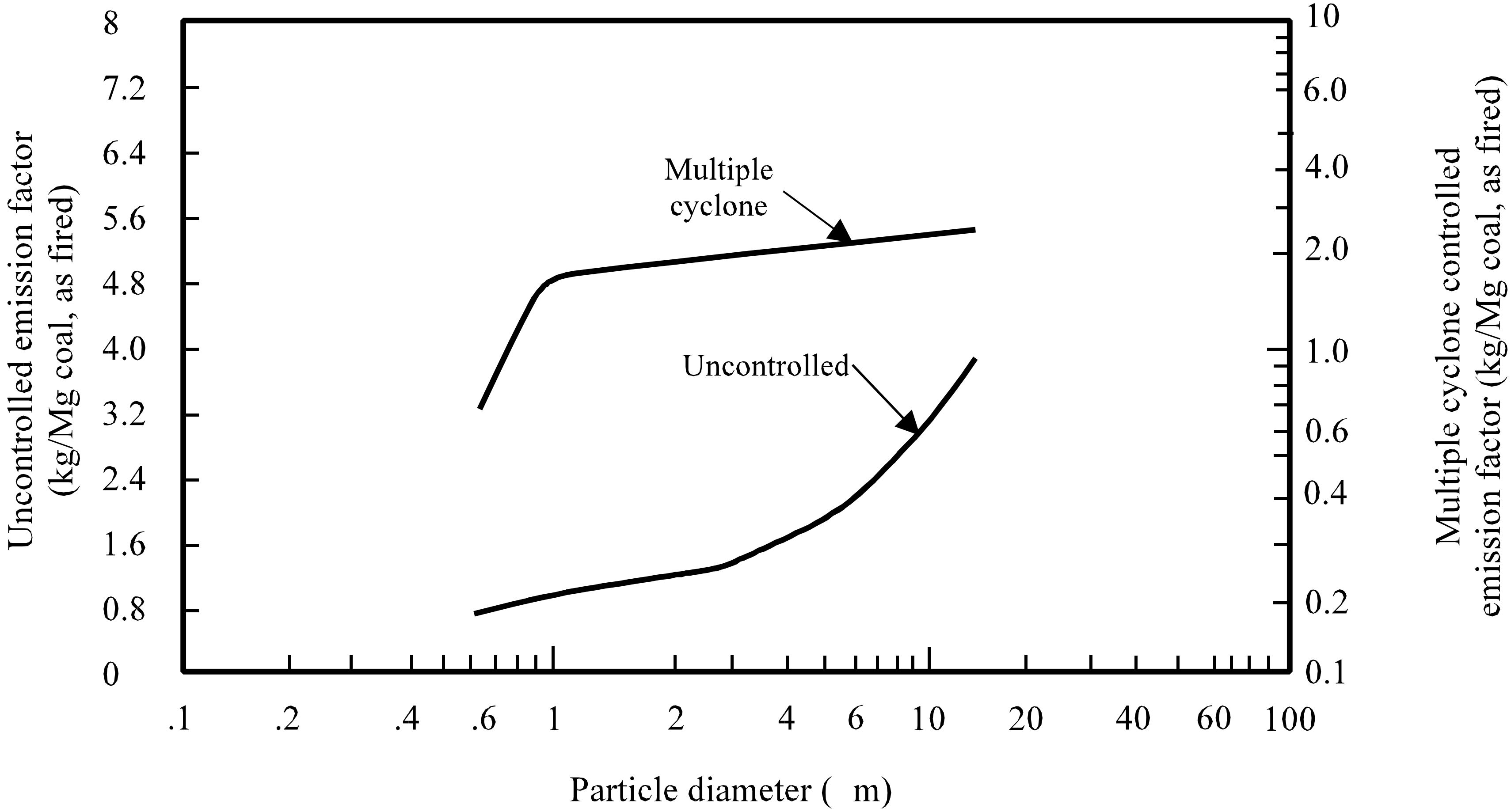
Uncontrolled emission factor (kg/Mg coal, as fired)
Emission factor with multiple cyclone and scrubber control (kg/Mg coal, as fired)
Emission factor with ESP and baghouse control (kg/Mg coal, as fired)
2.0A
1.8A
1.6A
1.4A
1.2A
1.0A
0.8A
0.6A
0.4A
0.2A
0
1.0A
0.6A
0.4A
0.2A
0.1A
0.06A
0.04A
0.02A
0.01A
0.1A
0.06A
0.04A
0.02A
0.01A
0.006A
0.004A
0.002A
0.001A
Scrubber
ESP
Baghouse
Uncontrolled
Multiple cyclone
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (µm)



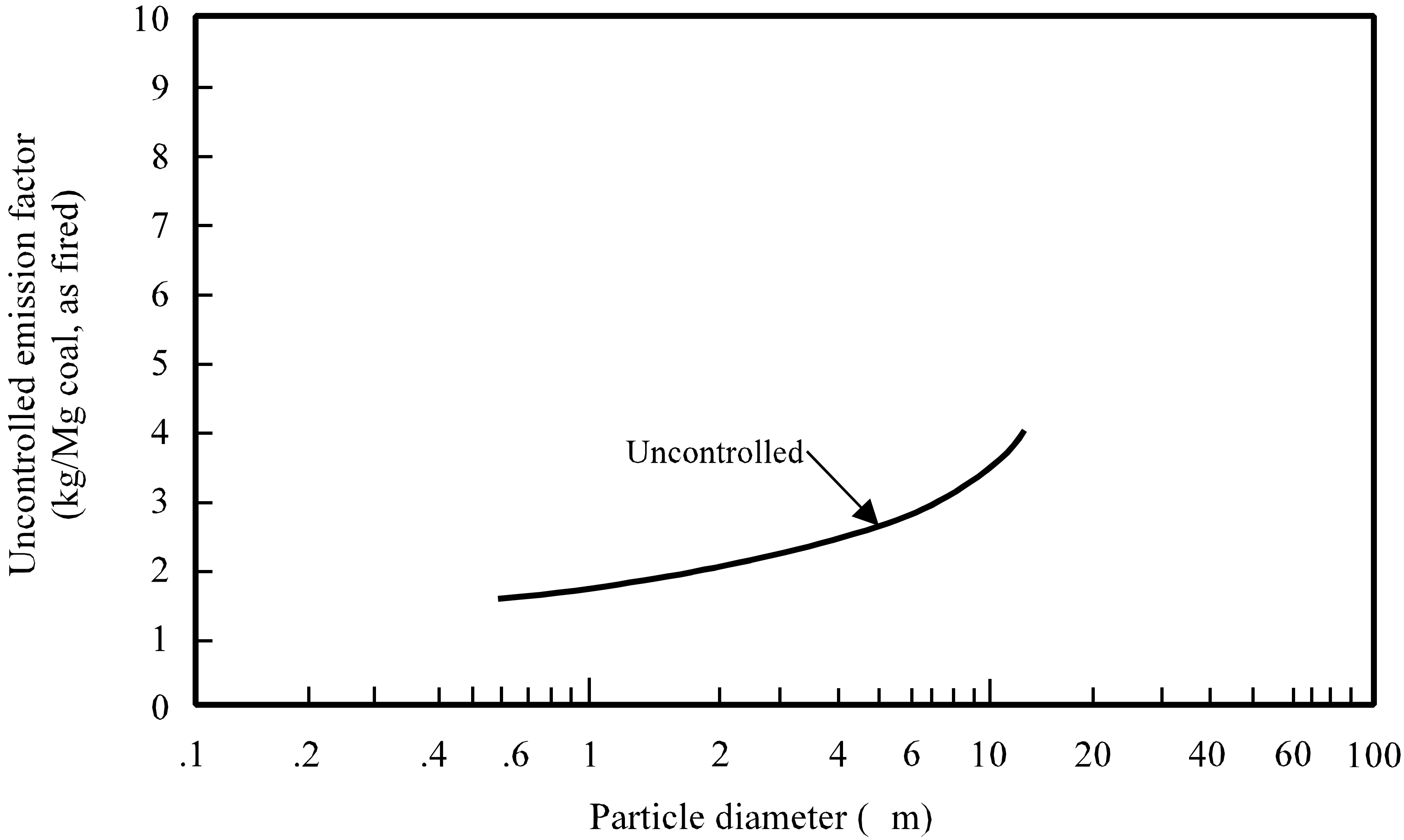
3.5A
2.8A
2.1A
1.4A
0.70A
0
Uncontrolled emission factor (kg/Mg coal, as fired)
1.0A
0.9A
0.8A
0.7A
0.6A
0.5A
0.4A
0.3A
0.2A
0.1A
0
Multiple cyclone controlled emission factor (kg/Mg coal, as fired)
0.1A
0.06A
0.04A
0.02A
0.01A
0.006A
0.004A
0.002A
0.001A
ESP controlled emission factor (kg/Mg coal, as fired)
ESP
Multiple cyclone
Uncontrolled
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)


1.0A
0.9A
0.8A
0.7A
0.6A
0.5A
0.4A
0.3A
0.2A
0.1A
0
Uncontrolled emission factor
(kg/Mg coal, as fired)
0.10A
0.06A
0.04A
0.02A
0.01A
0.006A
0.004A
0.002A
0.001A
Scrubber and ESP controlled emission factor
(kg/Mg coal, as fired)
Scrubber
ESP
Uncontrolled
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (µm)


Uncontrolled emission factor (kg/Mg coal, as fired)
Multiple cyclone and ESP controlled emission factor (kg/Mg coal, as fired)
Baghouse controlled emission factor (kg/Mg coal, as fired)
Particle diameter (m)
Multiple cyclone with flyash reinjection
Multiple cyclone without flyash reinjection
Baghouse
Uncontrolled
ESP
0
1
2
3
4
5
6
7
8
9
10
0.1
0.2
0.4
0.6
1.0
2.0
4.0
6.0
10.0
0.001
0.002
0.004
0.006
0.01
0.02
0.04
0.06
0.10
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100



Uncontrolled emission factor (kg/Mg coal, as fired)
8
7.2
6.4
5.6
4.8
4.0
3.2
2.4
1.6
0.8
0
Multiple cyclone
Uncontrolled
Multiple cyclone controlled emission factor (kg/Mg coal, as fired)
10
6.0
4.0
2.0
1.0
0.6
0.4
0.2
0.1
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)



Uncontrolled emission factor
(kg/Mg coal, as fired)
10
9
8
7
6
5
4
3
2
1
0
Uncontrolled
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)