EMISSION FACTOR DOCUMENTATION FOR

AP-42 SECTION 1.7,

LIGNITE 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 1970. 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. 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 needs of State and local air pollution control programs, industry, and the Agency itself. Section 1.7 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to lignite combustion in stationary, external equipment.

The last comprehensive update of AP-42 Section 1.7 was in 1982, focusing on uncontrolled, baseline, emission factors for the criteria pollutants. The section was appended in 1986 with data on particle sizing distributions. The purpose of the present effort on AP-42 Section 1.7 is to update the data base for the earlier revisions and to extend the scope to other pollutant species and revised equipment classifications. Specifically, the scope of the current update includes the following activities:

- Updating of emission factors for criteria pollutants for baseline, uncontrolled operation using data generated since the 1982 revision;
- Inclusion of several non-criteria emission species for which data are available: organics speciation, air toxics, and greenhouse or

ozone depletion gases [such as nitrous oxide (N_2O), and carbon dioxide (CO_2)];

- Revise and expand emission source classifications to include fluidized bed combustion and to separate wall-fired boilers from tangentially-fired boilers; and
- Expand and update technical discussion and control efficiency data for boiler operation with nitrogen oxides (NO_x), carbon monoxide (CO), or particulate matter (PM) control.

The update began with a review of the existing version of Section 1.7 (last revised by Supplement A, published in October 1986). Spot checks were made on the quality of existing emission factors by selecting primary data references from the Section 1.7 Background File and recalculating emission factors.

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). The data points obtained from test reports receiving sufficiently high quality ratings were then combined with existing data, wherever possible, and used to produce new emission factors.

In this revision, several new emission factors for non-criteria pollutants have been added. These new emission factors pertain to speciated volatile organic compounds (VOCs), hazardous air pollutants (HAPs), N_2O, CO_2, and fugitive emissions. Additionally, in this revision, the information on control technologies for PM, sulfur oxides (SO_x), and NO_x emissions has been updated.

The purpose of this EFD is to provide background information and to document the procedures used for the revision, update, and development of emission factors for lignite combustion. Data from two state air pollution control agencies were used to add controlled emission factors for lignite-fired boilers. Emission factors were also developed for fluidized bed combustion as a new boiler configuration category.

Because of a lack of new baseline emissions data, the existing data contained in the Background File for the 1986 Section 1.7 were identified as the best baseline data available for this update. These data were reviewed and the low quality data were purged from the section. The remaining data of higher quality were used as the basis of the revised baseline criteria pollutant emission factors. In addition, data contained in the Background File that had not been included in the 1986 section were used to revise emission factors (since these data were of higher quality than any new data collected as a result of data search efforts in 1992). The baseline emission factors were recalculated using different calculation procedures than those used for the previous section. These revised calculation procedures allowed for more accurate comparison of emission test data. Using these same calculation procedures, the new controlled emissions data obtained from the North Dakota Department of Health and the Texas Air Control Board were used to generate controlled emission factors.

Including this Introduction (Chapter 1), this EFD contains five chapters. Chapter 2 provides an overall characterization of lignite combustion, a description of lignite usage in both the North Dakota and the Texas regions, and source/control descriptions. Chapter 3 gives a review of the emissions data collection and review procedures. The sources examined during the literature search are discussed. The data quality and emission factor rating procedures are also discussed in this section. Chapter 4 details the emission factor development procedures. It includes the review of specific data and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.7. Appendix A provides sample calculations for emission factor development. A marked-up copy of the 1986 Section 1.7, showing areas of revision, is included in Appendix B.

2. SOURCE DESCRIPTION

The two geographical areas of the United States with extensive lignite deposits are centered around the states of North Dakota and Texas. Lignite combustion occurs almost exclusively in these two regions. The typical uses of lignite combustion will be discussed for each of these regions. A process description for each lignite combustion source category is provided; the pollutants generated from lignite combustion are also discussed. Finally, the pollution controls used to abate emissions generated from lignite combustion are described.

2.1 CHARACTERIZATION OF LIGNITE APPLICATIONS[1-5]

Lignite is a relatively young coal with properties intermediate to those of bituminous coal and peat. The two geographical areas of the United States with extensive lignite deposits are centered around the states of North Dakota and Texas. Lignite in both areas has a high moisture content (30 to 40 weight percent) and a low wet-basis heating value [1400 to 1900 kcal/kg (2500 to 3400 Btu/lb)]. Consequently, lignite is burned only near where it is mined because effective transportation costs for low heating value fuels are prohibitive. A small amount is used for industrial and domestic combustion. Lignite is mainly used for steam/electric production in power plants. Lignite combustion was initially limited to small stokers, but the technology has advanced to the current practice of firing in large cyclone and pulverized coal boilers.

The major advantages of lignite are that, in these two localized areas, it is plentiful and low in sulfur content. The disadvantages are that more fuel and larger facilities are necessary to generate a unit of power than is the case with bituminous coal. There are several reasons for: (1) the higher moisture content means that more energy is lost in heating the moisture to combustion temperatures, which reduces boiler efficiency; (2) more energy is required to grind lignite to specified size limits, especially in pulverized coal-fired units; (3) greater tube spacing and additional soot blowing are required because of lignite's higher ash fouling tendencies; and (4) because of its lower heating value, more lignite must be handled to produce a given amount of power. Lignite usually is not cleaned or dried before combustion (except for some incidental drying in the crusher or pulverizer and during transfer to the burner). No major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

2.1.1 North Dakota Region[5]

The North Dakota region has the largest lignite reserves in the world. The lignite deposits of this region are contained in North Dakota, South Dakota, Montana, and adjacent portions of Canada. The state of North Dakota has identified lignite resources of approximately 350 billion tons. Overall, the North Dakota region has identified lignite resources of 465 billion tons. Only a fraction of the identified resources are demonstrated as economically recoverable lignite reserves.

Most of the lignite-fired combustion sources in the region are located in the State of North Dakota. Minnesota and South Dakota also have large lignite-fired stations. As shown in Table 2-1 the state of North Dakota has 15 lignite-fired utility boilers.[6] The firing capacity of the newer boilers is generally much larger than that for the older units. Six of the newer boilers in the State have capacities greater than 400 MW (unless otherwise indicated, MW refers to megawatts of electrical output in this report). Many of the smaller stoker-fired utility boilers have been retired since the 1982 update of AP-42 Section 1.7. The largest spreader stoker in the State was converted to a circulating fluidized bed boiler in 1987.

The small lignite-fired stokers are used for on-site power generation, space heating, and process heat. The North Dakota Department of Health had 8 spreader stokers and 5 other stokers (underfeed and overfeed units) under permit in 1980 at commercial/institutional facilities.[7] The Department also had 5 spreader stokers under permit in 1980 for industrial facilities.[7] The number of small lignite-fired stoker units seems to be on the decline, however. There are probably less than 50 commercial/institutional and industrial lignite-fired boilers in the entire U.S.

2.1.2 Gulf Region[5]

The Gulf lignite region covers portions of five States including Alabama, Mississippi, eastern and southeastern Arkansas, northern Louisiana, and southeastern Texas. Figure 2-1 shows the lignite belt in these states. The Gulf region has 68 billion tons of identified lignite resources. Texas has approximately 52 billion tons of identified lignite resources. In Texas, the lignite belt runs parallel to the Gulf Coast approximately 150 miles inland from the coast. All of the major lignite-fired power plants in Texas are located on the lignite belt.

Table 2-2 is a partial listing of boilers located in the Gulf region. There are eight power generation facilities with lignite- fired utility boilers, including a facility in Louisiana. One older industrial lignite-fired boiler is operating in Texas. No small commercial or institutional boilers fired on lignite were identified in Texas during this update.

2.2 PROCESS DESCRIPTION[3]

In a pulverized fuel steam generator, the fuel is fed from the stock pile into bunkers adjacent to the steam boiler. From the bunkers, the fuel is metered into several pulverizers which grind it to approximately 200 mesh particle size. A stream of hot air from the air preheater begins the fuel-drying process and conveys the fuel pneumatically to the burner nozzle where it is injected into the burner zone of the boiler.

Three burner arrangements are used for firing pulverized lignite in existing steam generators:

- Tangential firing,
- Horizontally-opposed burners,
- Front wall burners.

These arrangements are shown schematically in Figure 2-2.

In the tangential method of firing pulverized coal into the burner zone, the pulverized coal is introduced from the corners of the boiler in vertical rows of burner nozzles. Such a firing mechanism produces a vortexing flame pattern which essentially uses the entire furnace enclosure as a burner.

Other manufacturers have developed both front-wall firing and horizontally-opposed firing boilers. In these firing mechanisms, the pulverized coal is introduced into the burner zone through a horizontal row of burners. For furnaces less than about 200 MW, the burners are usually located on only one wall (i.e., front wall firing). For larger boilers, the burners are located on the front and back walls firing directly opposed to each other (i.e., horizontally opposed burners). This type of firing mechanism produces a more intense combustion pattern than the tangential firing and has a slightly higher heat release rate in the burner zone itself.

In all of these methods for firing pulverized fuel, the ash is removed from the furnace both as fly ash and bottom ash. The bottom of the furnace is often characterized as either wet or dry, depending on whether the ash is removed as a liquid slag or as a solid. Pulverized coal units have been designed for both wet and dry bottoms, but the current practice is to design only dry bottom furnaces. The wet bottom furnace requires higher temperatures [usually > 1,430 °C (> 2,600 °F)] in order to melt the ash before it is removed from the furnace. This is important to NO_x control since higher temperatures result in higher NO_x emissions from thermal fixation (see Section 2.3.2 for discussion of thermal NO_x formation).

2.2.1 Cyclone Firing

The cyclone burner is a slag-lined high-temperature vortex burner. The coal is fed from the storage area to a crusher that crushes the coal (or lignite) into particles of approximately 6 mm (0.25 inch) in diameter or less. Crushed lignite is partially dried in the crusher and is then fired in a tangential or vortex pattern into the cyclone burner. The burner itself is shown schematically in Figure 2-3. The temperature within the burner is hot enough to melt the ash to form a slag. Centrifugal force from the vortex flow forces the melted slag to the outside of the burner where it coats the burner walls with a thin layer of slag. As the solid lignite particles are fed into the burner, they are forced to the outside of the burner and are imbedded in the slag layer. The solid lignite particles are trapped there until complete burnout is attained.

The ash from the burner is continuously removed through a slag tap which is flush with the furnace floor. Such a system ensures that the burner has a sufficient thickness of slag coating on the burner walls at all times.

One of the disadvantages of cyclone-firing is that in order to maintain the ash in a slagging (liquid) state, the burner temperature must be maintained at a relatively high level. This higher temperature promotes NO_x fixation. Unfortunately, this cannot be offset via the reduction of available oxygen without employing an auxiliary fuel to maintain stability. Tests on cyclone burners firing lignite alone have shown that the burner cannot be satisfactorily operated at substoichiometric air conditions because of flame stability problems (i.e., the fire goes out at air addition rates less than the theoretical requirements).

2.2.2 Stoker Firing

In a stoker-firing furnace, shown schematically in Figure 2-4, the lignite is spread across a grate to form a bed which burns until the lignite is completely burned out. In such a mechanism, the lignite is broken up into approximately 5-cm (2-inch) pieces and is fed into the furnace by one of several feed mechanisms: underfeed, overfeed, or spreading. The type of feed mechanism used has little effect on NO_x emissions.

The physical size of stoker-fired boilers is limited because of the structural requirements and difficulties in obtaining uniform fuel and air distribution to the grate. Most manufacturers of stoker-fired equipment limit their design to 30 MW.

In most stoker units, the grate on which the lignite is burned gradually moves from one end of the furnace to the other. The lignite is spread on the grate in such a fashion that at the end of the grate only ash remains (i.e., all of the lignite has been burned to the final ash product). When the ash reaches the end of the grate, it falls into an ash collection hopper and is removed from the furnace.

Stoker-fired furnaces are dry-bottom furnaces and, as such, generally have lower heat release rates and lower temperature profiles than the corresponding pulverized lignite or cyclone-fired units. Hence, stoker-fired units typically have lower NO_x emission rates than other lignite-burning equipment used for generating steam.

2.2.3 Fluidized Bed Combustion

There are two major categories of fluidized bed combustors (FBCs): (1) atmospheric FBCs, operating at or near ambient pressures, and (2) pressurized FBCs, operating at from 4 to 30 atmospheres (60 to 450 psig). Pressurized FBC systems are not considered a demonstrated technology for lignite combustion.

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 16 and 39 meters/sec (5 and 12 ft/sec), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 meters/sec (30 ft/sec) 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 unburned solid fuel and bed material for return to the primary combustion chamber for more efficient fuel utilization.

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. Captured SO_2 is retained as a solid sulfate and is either purged from the bed or 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.

2.3 EMISSIONS

The emissions generated from lignite combustion include the criteria pollutants PM, NO_x, SO_x, total organic compounds (TOC), and CO. The non-criteria pollutants generated from lignite combustion include CO_2, N_2O, trace elements, fugitive emissions, and PM with an aerodynamic diameter of less than 10 microns (PM-10).

2.3.1 Particulate Emissions

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 an EPA Method 5 or EPA Method 17 sampling train. Particles less than 0.3 microns and vapor-phase elements 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 CPM emitted from lignite-fired boilers is primarily inorganic in nature. The PM-10 is a portion of total PM and is of concern since particles smaller than 10 microns can easily enter the lungs.

Particulate emissions from lignite combustion are directly related to the ash content of the lignite and firing configuration of the boiler. Cyclone furnaces emit less PM because, in a wet bottom boiler, more of the incoming ash is retained in the slag. Pulverized lignite units generate more fine PM because of the size of the fuel that is fired.

2.3.2 NO_x Emissions

The NO_x 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"). Although five oxides of nitrogen exist, the term NO_x is customarily used to include the composite of nitric oxide (NO), and nitrogen dioxide (NO_2). Nitrous oxide is of increasing interest as an upper atmosphere gas, but is not included in NOx. Test data have shown that for most stationary combustion systems, over 90 percent of the emitted NO_x is typically in the form of NO.

Thermal NO_x formation rates in flames are exponentially dependent on temperature; they are proportional to the molecular nitrogen (N_2) concentration in the flame, the square root of the molecular oxygen (O_2) concentration in the flame, and the residence time.[20] This is corroborated by experimental data which shows thermal NOx formation is most strongly dependant on three factors: (1) peak temperature, (2) O_2 concentration or stoichiometric ratio, and (3) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly consistent for all types of boilers: an increase in flame temperature, O_2 availability, and/or residence time at high temperatures leads to an increase in NO_x production (under oxidizing conditions), regardless of the boiler type.

Fuel nitrogen conversion is the most important NO_x-forming mechanism in lignite lignite-fired boilers. It can account for approximately 80 percent of the total NO_x emissions in lignite firing. The percent conversion of fuel nitrogen to NO_x, however, varies greatly with the local stoichiometric ratio and the air/fuel mixing in the near-burner flame zone.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is the firing configuration. The NO_x emissions from tangentially (or corner)-fired boilers are, on average, less than those of wall-fired and cyclone units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, staged combustion (SC), low NO_x burners (LNBs), or some combination thereof may result in NO_x reductions of 10 to 60 percent. Load reduction can likewise decrease NO_x production.

The N_2O emissions for most coal-fired boilers are only a small fraction of the NO_x levels. During this AP-42 Section 1.7 update, no N_2O data for direct lignite-firing were located, with the exception of FBC units.

2.3.3 SO_x Emissions[2]

The SO_x emissions from lignite combustion depend on the sulfur content of the lignite and the lignite composition (viz., sulfur content, heating value, and alkali concentration). The conversion of lignite sulfur to SO_x is generally inversely proportional to the concentration of alkali constituents in the lignite. The sodium oxide content is believed to have the greatest effect on sulfur conversion because the natural sodium content in ash acts as a built-in sorbent for SO_x removal.

2.3.4 Carbon Monoxide Emissions[16-19]

The CO emission rate 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 do larger combustors. This is because smaller units usually have a higher ratio of heat transfer surface area to flame volume, leading to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency than large combustors. Larger combustors also have more complex combustion control systems to trim oxygen to a level which gives low CO and high combustion efficiency.

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 O_2 availability;
- Extremely high levels of excess air (which leads to quenching);
- Poor fuel/air mixing;
- Cold-wall flame quenching;
- Reduced combustion temperature;
- Decreased combustion gas residence time; and
- Load reduction (i.e., 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 Total Organic Compounds

Small amounts of TOCs are emitted from lignite combustion. These TOCs include VOCs, semi-volatile organic compounds, and condensible organic compounds. 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.).[30,31]

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 the 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.

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels including lignite. 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 generally have lower formaldehyde emission rates than do small, less efficient combustion units.

2.3.6 Trace Element Emissions

Trace elements are also emitted from the combustion of lignite. 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) are considered.[36] 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.[37] Various classification schemes to describe this partitioning have been developed.[38-40] The classification scheme used by Baig, et al. is as follows:[35]

- 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.[37] For example, several NOx 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.

2.4 CONTROL TECHNOLOGIES.

This section discusses the different emission controls used on lignite-fired boilers. The PM, NO_x and SO_x controls will be discussed in this section.

2.4.1 Particulate

The primary PM control systems for large industrial and utility boilers are electrostatic precipitators (ESPs) and fabric filters (or baghouses). Multiple cyclones and scrubbers are used for PM control mainly on small industrial stokers, either alone or in series with an ESP or baghouse. Filterable particulate emissions can be efficiently controlled by all four of these methods. Cyclones, ESPs, and fabric filters have little effect on measured CPM because they are generally operated at temperatures above the upper limit of the front-half of EPA Method 5 [i.e., 135 °C (275 °F)]. Thus, most CPM would remain vaporized and pass through the control device. Wet scrubbers, however, reduce the gas stream temperature; as a result, they could theoretically remove some of the CPM.

The operating parameters that influence ESP performance include:[19]

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

The larger ESPs built since the mid 1970s can achieve control efficiencies of 99.5 or better percent for total PM.[11]

The PM removal efficiency of fabric filters is dependent on a variety of particle and operational characteristics.[20-21] Particle characteristics that effect the collection efficiency include particle size distribution and particle cohesion characteristics. Operational parameters that effect fabric filter collection efficiency include:

- Air-to-cloth ratio,
- Operating pressure loss,
- Cleaning sequence,
- Interval between cleaning,
- Cleaning method, and
- Cleaning intensity.

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

- Structure of fabric,
- Fiber composition, and
- Bag properties.

Baghouses are typically categorized by one of three cleaning methods: (1) mechanical or shake/deflate cleaned baghouses, (2) reverse gas cleaned baghouses, and (3) pulsed-jet cleaned baghouses. Baghouses can achieve collection efficiencies of 99.7 percent or better for total particulate matter.[12]

2.4.2 NO_x Control

Combustion modifications, such as LEA-firing, flue gas recirculation (FGR), SC, 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 the rate-determining step due to its large activation energy.[13] Kinetically, thermal NO_x formation is related to N_2 concentration, combustion temperature, and O_2 concentration by the following equation:[13]

(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

From these considerations, it can be seen that 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 O_2 level, and (4) reduction of the residence time of exposure at peak temperature. Combustion modification techniques to control thermal NO_x in boilers have focused on reducing the O_2 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 O_2 concentration, and linearly on residence time. Therefore, initial efforts to control NO_x emissions have often focused on methods to reduce peak flame temperatures.

In coal-fired boilers, 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.[14-16] 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.[17] 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. 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 (under oxidizing conditions):
    - Decrease adiabatic flame temperature through dilution,
    - Decrease combustion intensity,
    - Increase flame cooling,
    - Decrease primary flame zone residence time;
- Decrease primary flame-zone O_2 level:
    - Decrease overall O_2 level,
    - Control (delayed) mixing of fuel and air,
    - Use of fuel-rich primary flame zone.

The most prevalent NO_x control for lignite-fired boilers is overfire air using dedicated air ports, or by taking a top row of burners out of service and adjusting air flow to the furnace. Control of NO_x via LEA combustion can significantly increase the ash fouling potential in the boiler.[18] Creating overfire air conditions in one tangentially-fired unit by removing the top three burners from service and adjusting the dampers did not increase the ash fouling potential.[18]

No post-combustion, ammonia-based NO_x controls have been used with lignite combustors due to the lack of regulatory requirements.

2.4.3 SO_x Control

Several techniques are used to reduce SO_x from lignite combustion. Flue gases can be treated through wet, semi-dry, or dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery (regenerable) type (in which the SO_x absorbent is regenerated and reused). 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 in excess of 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, spray drying, and dual alkali scrubbing are among the commercially proven flue gas desulfurization techniques. Limestone may also be injected directly into the furnace section of boilers to capture SO_2 shortly after formation. Effectiveness of these devices depends not only on the control device design but also on operating variables, such as liquid-to-gas ratio and sorbent reactivity.

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. 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. The SO_2 is removed from the flue gas as in sodium scrubbing. Most of the scrubber effluent 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.

The lime and limestone process uses a slurry of calcium oxide (CaO) or limestone ($CaCO_3$) to absorb SO_2 in a wet scrubber. 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.

Spray drying is a dry scrubbing approach to flue gas desulfurization. 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 latent heat of the flue gas to about one percent free moisture. The dried alkali 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 PM removal report additional SO_2 sorption occurring across the baghouse. Gas exit temperatures are typically in the 65 to 93 °C (150 to 200 °F) range which provides a safe margin against water condensation.

Limestone may also be injected into the furnace, typically in an FBC, to react with SO_2 and form calcium sulfate. An FBC is comprised of a bed of inert material that is suspended or "fluidized" by a stream of air. Lignite is injected into this bed and burned. Limestone is also injected into this bed where it is calcined to lime and reacts with SO_2 to form calcium sulfate. Bed temperatures are typically maintained between 760 and 870 °C (1,400 and 1,600 °F). Particulate matter emitted from the boiler is generally captured in a cyclone and recirculated or sent to disposal. Additional PM control equipment, such as an ESP or baghouse, is used after the cyclone to further reduce particulate emissions.

TABLE 2-1. LIGNITE-FIRED BOILERS IN THE NORTH DAKOTA REGION[a]

Company	Plant	Firing configuration	Capacity, MW	Year in service[b]
Basin Electric Power Coop.	Antelope Valley Station Unit #1	Pulverized Coal Tangential	440	1984
Basin Electric Power Coop.	Antelope Valley Station Unit #2	Pulverized Coal Tangential	440	1986
Basin Electric Power Coop.	Leland Olds #1	Pulverized Coal Horizontally Opposed	216	1966
Basin Electric Power Coop.	Leland Olds #2	Cyclone	440	1975
Basin Electric Power Coop.	W.J. Neal #1	Pulverized Coal Front Wall	25	1953
Basin Electric Power Coop.	W.J. Neal #2	Pulverized Coal Front Wall	25	1953
Montana Dakota Utilities	Coyote	Cyclone	440	1981
Montana Dakota Utilities	Heskett #1	Spreader Stoker	25	1963
Montana Dakota Utilities	Heskett #2	Fluidized Bed	66	1987
Minnkota Power Coop.	Milton R. Young #1	Cyclone	240	1970
Minnkota Power Coop.	Milton R. Young #2	Cyclone	440	1976
United Power Association	Coal Creek #1	Pulverized Coal Tangential	500	1978
United Power Association	Coal Creek #2	Pulverized Coal Tangential	500	1979
United Power Association	Stanton #1	Pulverized Coal Front Wall	130	1966
United Power Association	Stanton #2	Pulverized Coal Tangential	60	After 1978
Otter Tail Power Company	Big Stone (South Dakota)	Cyclone	440	1975
Otter Tail Power Company	Hoot Lake (Minnesota)	Pulverized Coal Tangential	59	1959

[a] References 2-3, 6.

[b] The year in sevice is an estimate.

TABLE 2-2. LIGNITE-FIRED BOILERS IN THE GULF REGION[a]

Company	Plant	Firing configuration	Capacity, MW	Year in service[b]
Texas Utilities	Martin Lake #1,#2,#3,#4	Pulverized Coal Tangential	750	1977, 1978 1979, 1980
Texas Utilities	Monticello #1,#2,#3,#4	Pulverized Coal Horizontally Opposed	750	1975, 1976 1979
Texas Utilities	Big Brown #1, #2	Pulverized Coal Tangential	590	Late 60's
Southwestern Electric Power Co.	H.W. Pirkey #1	Pulverized Coal Horizontally Opposed	720	1984
Southwestern Electric Power Co.	Dolet Hills (Louisiana)	Pulverized Coal	720	1986
Houston Lighting & Power	Limestone #1, #2	Pulverized Coal Tangential	800	1986, 1987
South Texas Electric Coop.	San Miguel #1	Pulverized Coal Horizontally Opposed	400	1979
Texas New Mexico Power Co.	Calvert #1, #2	Circulating Fluidized Bed	150	1990, 1991
Alcoa	Sandow 1, 2, & 3	Wet Bottom Tangential, Dried Lignite	100	1953

[a] References 3, 9.
[b] The year in service is an estimate.

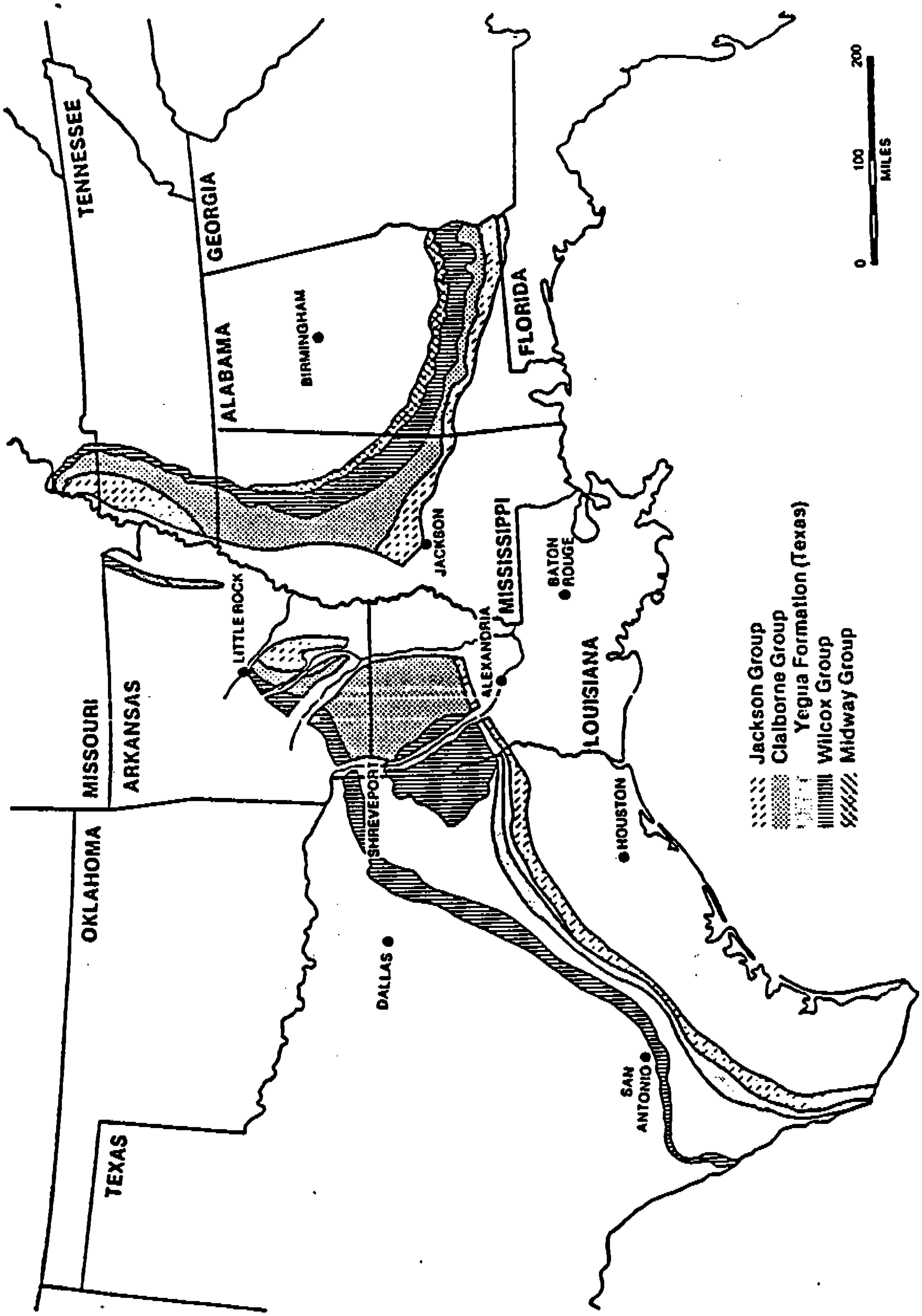

Figure 2-1. Lignite-bearing strata of the Gulf Coast Region.[8]

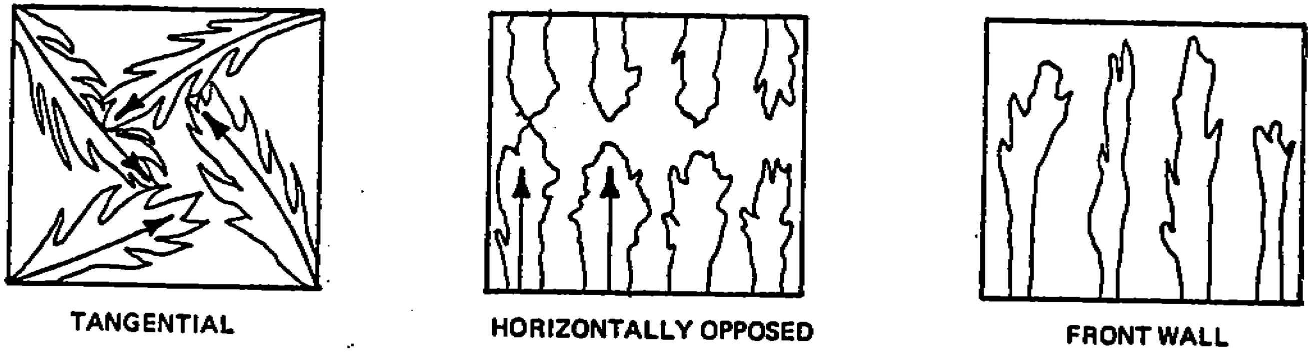

Figure 2-2. Burner arrangements for pulverized fuel-firing in a utility boiler (viewed from above).[3]

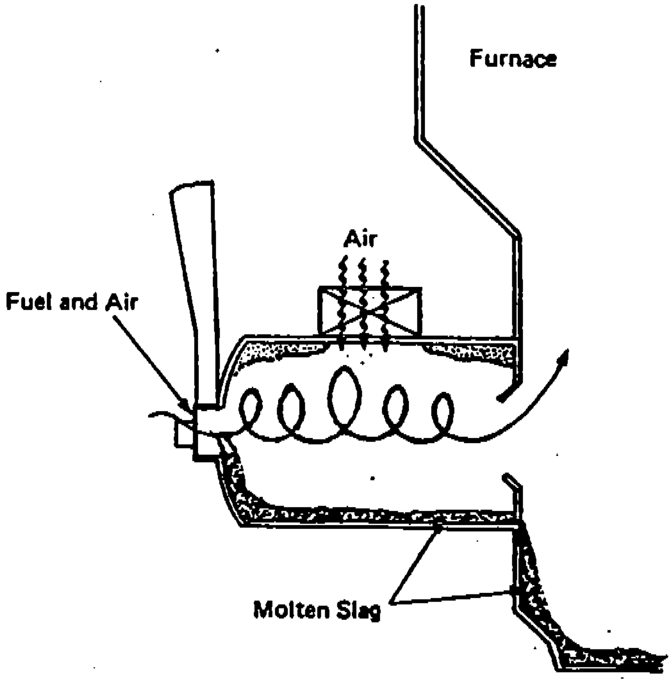

Figure 2-3. Schematic of cyclone-firing of lignite in a utiity boiler.[3]

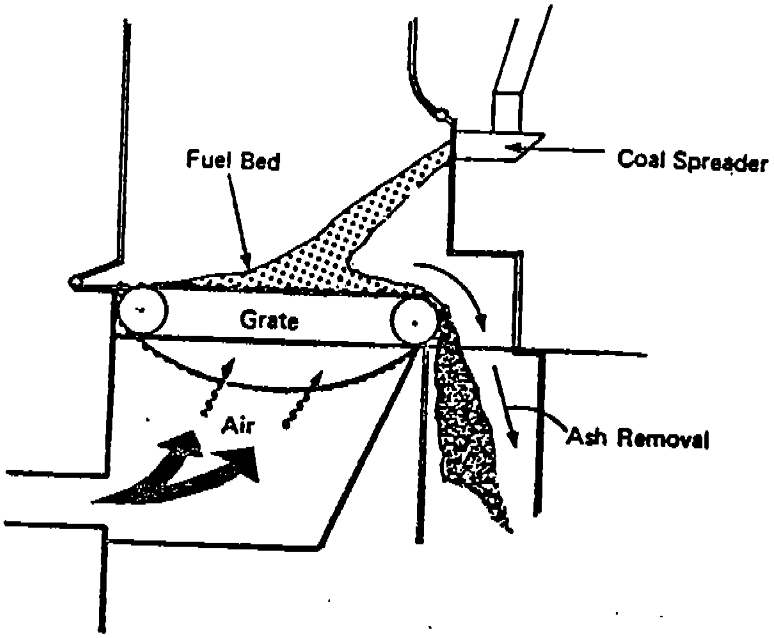

Figure 2-4. Schematic of stoker-firing in a boiler.[3]

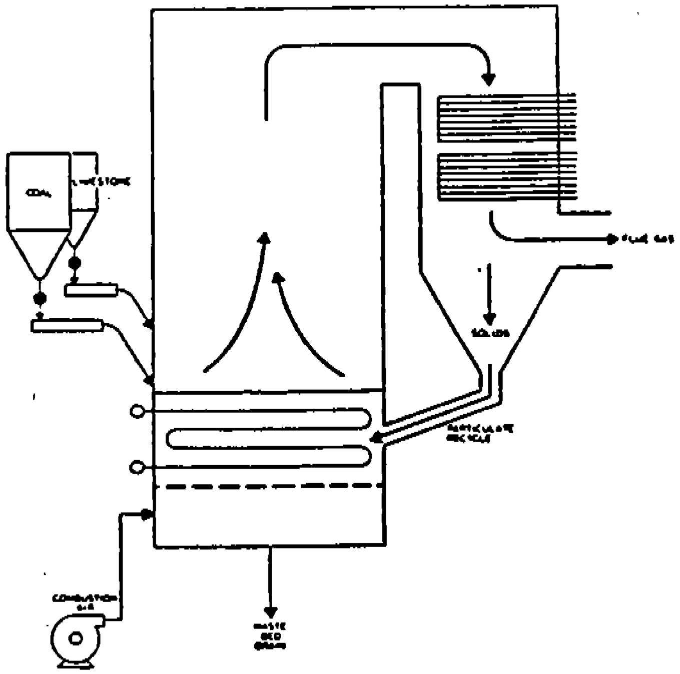

Figure 2-5. Bubbling FBC schematic.[10]

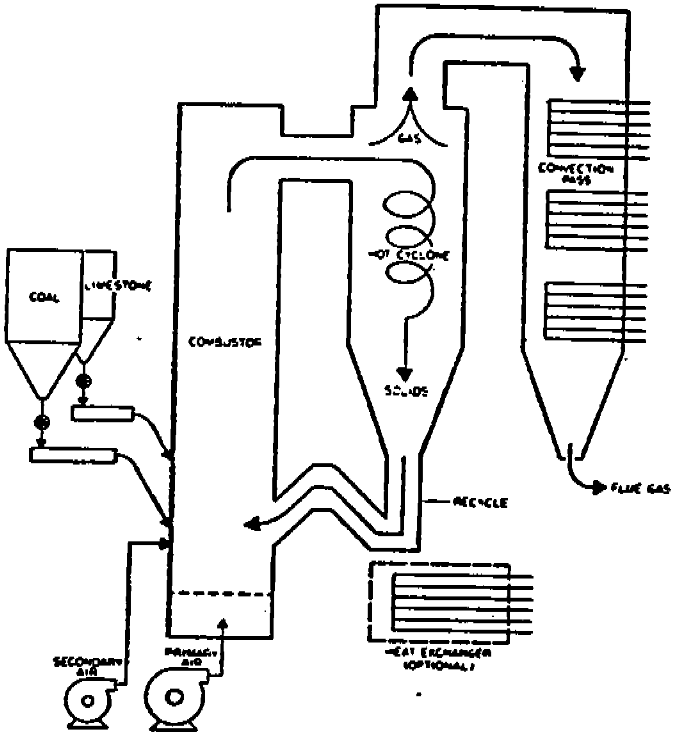

Figure 2-6. Circulating FBC schematic.[10]

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3. GENERAL EMISSIONS DATA REVIEW AND ANALYSIS PROCEDURES

This section summarizes the procedures for the literature search and the criteria for evaluating the data which were identified. The results of the search and conclusions regarding the usefulness of the data obtained for developing emission factors are also presented. The data and emission factor rating and review criteria are also contained in this chapter.

3.1 CRITERIA POLLUTANTS

3.1.1 Literature Search

An extensive literature search was conducted to identify sources of criteria and non-criteria emissions data for lignite combustion. The following sources were searched for emissions data:

- Existing AP-42 Background files,
- Files maintained by the EPA's Emission Standards Division and Emission Factor and Methodologies Section,
- PM-10 background documents,
- New Source Performance Standards Background Information Documents,
- National Technical Information Service (NTIS) holdings,
- Various EPA emissions assessment documents for coal combustion,
- Contractor in-house files,
- U.S. Department of Energy (DOE) Clean Coal Project Documents,
- NO_x, SO_x, and Particulate Control Symposia,

- Lignite and Low Rank Coal Symposia,
- Proceedings of the American Power Conference,
- Information from boiler manufacturers,
- Proceedings of the International Conference on Fluidized Bed Combustion,
- Electric Power Research Institute (EPRI) reports and communications.

The main conclusion from the literature search was that the data base on lignite emissions and control is relatively sparse compared to higher rank coals or oil. Some articles on lignite combustion were found in the Proceedings of the American Power Conference, Proceedings of the International Conference on Fluidized Bed Combustion, Lignite Symposia, and the Low Rank Coal Symposia. Most of the articles did not contain emissions data but some of these articles supplied specific plant operational and design data. The lignite symposia, and the conferences on fluidized bed combustion did contain emissions data for a pilot-scale fluidized bed unit which were not used since emissions data for the full-scale units were available. The Reference 1 article was useful for characterizing emissions control techniques. However, the emissions data in the article were not used because a large amount of primary data were available for the specific plant tested. The article offered data and discussion on the effect of NO_x control on slagging in a boiler firing North Dakota lignites. Another useful report was a DOE study (Reference 2). This report offers a large amount of lignite proximate/ultimate analysis data and discusses the lignite resources in the U.S.

The information contained in the AP-42 Background File was reviewed. From this, it was concluded that the most promising source of new emissions data for lignite combustion would be the air pollution control agencies in the EPA Regions where lignite combustion is prevalent. The North Dakota Department of Health and the Texas Air Control Board were both contacted as a result.

The North Dakota Department of Health had supplied emissions data for the previous updates, and agreed to supply emissions data for this update. The Department has collected a large amount of data since the last complete update of

Section 1.7 in 1982. The continuous emission monitoring (CEM) equipment at each of the seven largest lignite-fired utility boilers in North Dakota are re-certified by the Department every three years using relative accuracy testing. The older utility boilers are only required to monitor opacity, and consequently fewer emissions data are available for these plants. The smaller stoker units generally have only PM emissions data available.

The Texas Air Control Board (TACB) also agreed to supply emission data for this update of Section 1.7. The TACB has a main office in Austin and 12 regional offices. Following the lignite belt and using a map identifying TACB regions, the two regions with the majority of lignite combustors were determined to be Regions 3 and 12. The emissions data available from the TACB are NSPS performance testing and CEM recertification testing.

The regional offices were expected to have a considerable amount of emissions data available for each lignite-fired power plant. Due to the time constraints of this update, however, and the limited staff resources available at both of these air pollution agencies, only a limited amount of the emissions data available could be obtained. In future, the best way to obtain the data would be to go directly to the North Dakota Department of Health offices and the main and regional offices of the TACB to search and find the available emissions data.

3.1.2 Literature Evaluation[3]

To establish a final group of references for use in the updated section, the following general criteria were used:

- Emissions data must be from a well documented reference;
- The referenced study must contain results based on more than one test run; and
- The report must contain sufficient data to evaluate the testing procedures and source operating conditions.

By 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 standardize and document this evaluation. The completed checklists were placed in the background files for this update to Section 1.7. Data with the following characteristics were always 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. The series in which the source 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 Reference 3. 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 that 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 were 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.

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 noted where applicable.

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 lignite-fired boilers. Some specific areas searched include Tennessee Valley Authority (TVA), EPRI/PISCES, EPA/Air and Waste Management Association (A&WMA) Air Toxic Symposiums, and Toxic Air Pollutants: State and Local Regulatory Strategies 1989.

3.2.2 Literature Evaluation

Until recently, little concern existed for VOC speciation on stationary external sources. Therefore, available data for VOC speciation were inadequate to develop emission factors. Some qualitative information is available in the EPA Office of Air Quality Planning and Standards (OAQPS) databases. The primary databases are the VOC/PM Speciation Data System (SPECIATE) and the Crosswalk/Air Toxic Emission Factor Database (XATEF), and their associated references. Some VOC speciation data were also identified in the general HAPs data search.

3.3 Hazardous Air Pollutants

3.3.1 Literature Search

When possible, primary references were obtained in order to calculate or verify emission factors presented. Many of the data evaluated were not of suitable quality for developing emission factors and were, therefore, eliminated for use in this update.

A literature search was conducted using the Dialog Information Retrieval Service. This is a broad-based data retrieval system that has access to over 400 data bases. Specifically for the air toxics search, six data bases were queried by key words relating to the processes and chemicals of concern. The data bases accessed include: NTIS, COMPENDEX PLUS, POLLUTION ABSTRACT, CONFERENCE PAPERS, ENERGY SCIENCE & TECHNOLOGY, and EPRI. The list of literature generated from the search was evaluated for applicability and the relevant documents were obtained.

Searches of the EPA's HAPs data bases were also performed. These data bases include XATEF, SPECIATE, and the Air Chief CD ROM which contains additional data. The computer searches were performed by source classification code (SCC) for all boiler sizes and types that are fired on coal. The reference numbers were recorded for each of the "hits" and these references were obtained for review.

Several industry and non-agency sources were also contacted in order to obtain source test data for development of emission factors. Since few data were available for lignite directly, data for coal combustion in general were compiled to obtain data for related conditions.

3.3.2 Literature Evaluation for HAPs

The references obtained from the literature search were evaluated for their applicability for generating emission factors. Table 3-1 summarizes the data sources and indicates which sources were used in generating the emission factors. 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 Chapter 4, Section 4.3.1. The criteria used to perform this evaluation are discussed in detail in Section 3.1.2.

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 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 EPA has prepared a document that specifies technical procedures for the development of AP-42 emission factors and the preparation of supporting documentation.[3] See Section 3.1.2 for the description of the evaluation and rating criteria.

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 the device. General design parameters such as boiler size, firing configuration, fuel type, operating parameters during the test, (e.g. load), are all required in order to evaluate the quality of the data. Information on the type and number of samples, sampling and analytical methods used, sampling locations, quality control samples and procedures, modifications to methods, fuel composition and feed rates are also needed. Sufficient documentation to determine how the data were reduced and how emissions estimates were made are required. This documentation should include sample calculations, assumptions, and correction factors. Equivalent information for the abatement device(s) must also be included.

When primary data could not be obtained in the time frame of this update, secondary sources were evaluated to determine the representativeness of the emission factors for a source category. A judgement on the quality of the author's analysis of the primary data was made in this case, which automatically warrants a lower quality rating for the emission factor. The secondary sources provide at least an order of magnitude estimate of emissions and possibly better; however, this cannot be evaluated without reviewing the primary data.

3.4 N_2O

3.4.1 Literature Search

An extensive literature search was conducted to identify sources of N_2O emissions data associated with lignite-fired boilers. Some specific areas of search included University of North Dakota, Air and Energy Engineering Research Laboratory (AEERL), Combustion and Flame, Journal of Geophysical Research, International Conferences of Fluidized Bed Combustion, and A&WMA.

3.4.2 Literature Evaluation

Because of the limited test reports for lignite, data from tests of other coal types were also used. Because the data and emission factor quality rating criteria have been available only since 1988, data with quality problems (e.g., lack of complete documentation), were used in order to get, at a minimum, a semi-quantitative estimate.

Data obtained through the literature search, except that derived from on-line N_2O analysis with gas chromatography/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 had been identified in using grab sampling techniques for measuring N_2O emissions. Storing combustion products in grab samples containing SO_2, NO_x and water for periods as short as 1 hour had led to formation of several hundred parts per million of N_2O where none originally existed. Improved methodologies for N_2O sampling and analysis and their relative effects on data quality ratings are as follows:

1. On-line N_2O analysis with GC/ECD (preferred method), and
2. Grab samples:
    a. Removing H_2O - drying the sample reduces the most important reactant, but may not entirely eliminate N_2O formation,

b. Removing SO_2 - scrubbing the sample through NaOH solution, or

c. A combination of the two (second preference).

The N_2O data for fluidized bed combustors were developed from test reports using lignite and the data were assigned a quality rating of D. Because the data were not recorded with an on-line N_2O analysis GC/ECD and the facilities tested do not represent a cross section of the industry; as a result, the emission factor received an E rating.

3.5 FUGITIVE EMISSIONS

A literature search was conducted on fugitive emissions for coal-fired sources in general. A literature evaluation and data rating was not conducted for lignite storage and handling operations, because those fugitive emissions for lignite-fired boilers are covered in sub-sections of 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 PM emissions from these systems are therefore minimal. Fugitive PM emissions can sometimes occur during transfer operations from silos to trucks or rail cars. The PM emission factors corresponding to these operations can be developed using the procedures in Chapter 11.

3.6 PARTICLE SIZE DISTRIBUTION

3.6.1 Literature Search[3]

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 previous AP-42 update of particulate sizing emission data, the largest gap appeared to be the lack of CPM data.

The Background Files for AP-42 Section 1.7 were reviewed. A Dialog 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:

Reference 9: The factors applicable to sections 1.1, 1.3, and 1.7 all came from AP-42.

Reference 10: Not applicable to stationary source combustion.

Reference 11: 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); and
- 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 was not updated since the printouts obtained during the previous AP-42 update. The printouts used for the previous update were available in the Background Files.

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

Contacts were also made with EPRI, Wheelabrator Air Pollution Control, Southern Research Institute, and Entropy Environmental.

3.6.2 Literature Evaluation

The previous AP-42 update was reviewed and evaluated.[12] The size distribution data was evaluated by spot-checking the tabulated results against the original FPEIS printouts. If during the literature search, an 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:

- To ensure that only filterable PM was included in the cumulative percent mass results, and
- To 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 as described in Section 3.1.2 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:

- Particle sizing tests performed by cascade impactors or PM-10 measurements performed via EPA Method 201 or EPA Method 201A. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.
- Particle sizing tests performed via source assessment sampling system (SASS) trains if the sampling flow-rate isokinetic value was reported and sufficient operating data were used. Cascade impactor data or EPA

Method 201 or EPA Method 201A data were not used if isokinetics were not reported or if isokinetics were not within the 90 to 110 percent range.

- SASS train data if the isokinetics were not reported or if the isokinetics did not fall within the 90 to 110 percent range.
- Test results based on a generally unaccepted particulate 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, and
- Losses to the impactor walls.

The effects of such errors are described in the literature.[13]

The ranking of CPM data was based primarily on the methodology. Most CPM source tests have been conducted using the back-half of an EPA Method 5, EPA Method 17, or South Coast Methods 5.2 or South Coast Method 5.3 trains. However, these test methods do not require an 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.[14] In contrast, EPA Method 202 includes a one-hour N_2 purge of the impingers immediately after sampling to remove dissolved SO_2. Therefore, EPA Method 202 CPM data should be ranked higher than EPA Method 5 or EPA Method 17 CPM data, even though EPA Method 202 is a relatively new method. The following ratings were selected for CPM data:

A - CPM tests performed via EPA 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 EPA Method 202 but isokinetics not reported or isokinetics not within the 90 to 110 percent range. CPM tests performed via EPA Method 5 or EPA 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 EPA Method 5 or EPA 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. EVALUATION OF REFERENCES

Reference	Evaluation summary	Parameter of interest
4	Not a primary reference; however, emission factors provided for emission estimates.	POM
5	Not a primary reference; however, data are of sufficient quality for estimates.	Copper
6	Not a primary reference; however, data of sufficient quality for estimates.	Metals
7	Source test data of sufficient quality for calculate emission factors and enrichment ratios.	PAH, metals, radionuclides
8	Emission factors of sufficient quality to perform emission estimates.	Manganese

REFERENCES FOR CHAPTER 3

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4. Brooks, G.W., M.B. Stockton, K.Kuhn, and G.D. Rives, Locating and Estimating Air Emission from Source of Polycyclic Organic Matter (POM). EPA-450/4-84-007p. U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1988.

5. Locating and Estimating Air Emissions from Sources of Chromium, EPA-450/4-84-007g, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1984.

6. Estimating Air Toxic Emissions from Coal and Oil Combustion Sources, EPA-450/2-89-001, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1989.

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8. Locating and Estimating Air Emissions from Sources of Manganese, EPA-450/4-84-007h, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1985.

9. PM-10 Emission Factor Listing Developed by Technology Transfer, EPA-450/4-89-022, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1989.

10. Gap Filling PM-10 Emission Factors for Selected Open Area Dust Sources, EPA-450/88-003, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1988.

11. *Generalized Particle Size Distributions for Use in Preparing Size Specific Particulate Emission Inventories*, EPA-450/4-86-013, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1986.

12. "Compilation of Air Pollutant Emission Factors", AP-42, Section 1.7, Supplement A, U.S. Environmental Protection Agency, Research Triangle Park, NC, October 1986.

13. Ondov, John M., "Cascade Impactors in the Chemical and Physical Characterization of Coal-Combustion Aerosol Particles", Chapter 25 of *Fossil Fuels Utilization: Environmental Concerns*, 1986.

14. Telephone conversation between S. Hughes, Acurex Environmental, and Ron Myers, U.S. Environmental Protection Agency, March 24, 1992.

4. EMISSION FACTOR DEVELOPMENT

This chapter describes how the revised AP-42 Section 1.7 was developed from data in the 1986 section, and new data obtained from the literature search.[17] The data are reviewed and assigned a data quality ranking according to the procedures outlined in Chapter 3. All of the data incorporated into the revised section are compiled into summary tables which show the primary data used to develop the emission factors.

4.1 CRITERIA POLLUTANTS

New emissions data for lignite combustors were collected during this update for NO_x and SO_2. Emissions data for CO and organic compounds were very limited and highly dependant on source design and operating conditions. The sources of criteria emissions data were assigned a data quality rating. In addition to the rating rationale, a brief discussion is provided below for each developed emission factor of the methods used to collect the data, the level of documentation provided, the data consistency, and the number of runs per test.

4.1.1 Review of Previous Data

The emissions data that are the basis of the 1986 Section 1.7 emission factors were reviewed and assigned a quality rating to determine the data that should be included in the revised section. Major references containing emissions data for more than one firing configuration are discussed in the following paragraphs.

In developing the 1986 AP-42 Section 1.7, Reference 2 was used extensively. This reference was the basis of the SO_x emission factors for all of the firing configurations. It presents a summary of SO_x emissions from 28 days of testing at a pulverized lignite-fired tangentially-fired unit; 8 days of testing at a pulverized coal (PC) horizontally-opposed unit firing lignite; 3 days of testing at a lignite PC front-fired unit; 5 days of testing at a cyclone-fired unit, and 2 days of testing at a spreader stoker. The sampling method used to collect the SO_x data was the controlled condensation method of Lisle and Sensenbaugh in which the flue gas is drawn through a condenser at 60 to 90 °C (140 to 194 °F) [where the sulfur trioxide (SO_3) is selectively condensed and collected] and then passes through an impinger containing a 3 percent hydrogen peroxide (H_2O_2) solution. The analytical method employed was a titration using a standard NaOH solution. This reference also contains some NO_x emissions data for all of the plants tested. The method used to collect the NO_x data was EPA Method 7. The calculation procedure is discussed; it was not equivalent to current EPA procedures, but was valid. This reference was assigned a data rating of B. Even though the data date to 1973, these tests represent a large number of source test runs executed over a long time period by valid methods. These data are true baseline data because most of the sampling occurred at the exit of the boilers, rather than at the stack or after PM controls.

A second key reference for the 1986 Section 1.7 update was Reference 5. This reference is the basis of many of the previous emission factors. Individual source test reports from Reference 5 will be discussed individually for the purpose of data review.

Reference 8 is NSPS support testing for NO_x at the Texas Utilities (TU) Big Brown Power Station in Fairfield, Texas. The background file for the unrevised section attached to the Big Brown source test report contains two other source test reports also performed in support of the NSPS testing. The other two reports are for a PC unit (Leland Olds) and a cyclone fired unit (Milton R. Young I) in North Dakota. These three source test reports are the primary documents used in support of the NSPS. The NO_x emissions data from the two reports for Milton R. Young and Leland Olds appear unchanged in Reference 3, the NSPS standards support document. The NO_x emissions data for Big Brown Station in the lignite NSPS support document include fuel data and different process operation data than appear in the primary test report. The author of the NSPS support document apparently obtained additional process and fuel data from the plant for the NSPS support document. Therefore, the emissions and process data in the NSPS support document for Big Brown are used in this update rather than the primary report.

4.1.2 Pulverized Coal Dry Bottom Emission Factors

The PC emission factors contained in the 1986 AP-42 Section 1.7 update for PM, SO_x, and NO_x are based on data from five sources: from Reference 5, Reference 18, Reference 6, Reference 2, and the results of the NSPS standards support source testing conducted at the Leland Olds and Big Brown power plants contained in Reference 3.

The Stanton source test report has uncontrolled and controlled emissions data for PM, SO_x, and NO_x.[18] The source test methods are specified for each pollutant (e.g., the particulate data was collected according to ASTM Power Test Code 27-1957). The source testing was conducted using sound methodologies, but the number of source test runs was inadequate. The boiler had divided flue gas ducting and only one run was conducted for each pollutant on each duct. The uncontrolled PM data were taken on two different days. No fuel ash or sulfur contents were given in the report, and the emission factors generated from these data are based on assumed sulfur and ash percentages. This report was assigned a data rating of D.

Reference 6 focuses on ash fouling rates when burning low- and high-sodium lignite. The article presents PM and SO_x emissions data from a tangentially-fired boiler. The particulate data was collected according to ASTM Power Test Code 27-1957. Two methods were used to collect the SO_x data: the selective condensation method of Lisle and Sensenbaugh, and the absorption method by Berk and Burdick. Agreement is reported as being good between the two methods. The author of this article is the primary author of Reference 2; the SO_x emissions data in this article are likely also contained in Reference 2. Since Reference 2 contains a large amount of SO_x data for this specific plant, the data from this article was not rated or treated as additional data. The coal composition and boiler operating conditions during testing are presented. The main problem with this source is that there is no documentation on how many source test runs were incorporated in the final results. The particulate testing results are presented as a percentage of incoming ash emitted in the flue gas. The particulate data in this article were given a D rating.

The NSPS standards support testing conducted at Leland Olds, a horizontally opposed-fired boiler, and at Big Brown I & II, twin tangentially-fired boilers, yielded a significant amount of baseline NO_x emissions data. Eight days of source testing were conducted at the twin units of Big Brown station, and three days of testing were conducted at Leland Olds. The results and original source test reports are contained in References 3 and 8, respectively. Simultaneous sampling for NO_x was conducted at both plants using EPA Method 7 and continuous emission monitors (CEM). The CEM data from both reports showed inconsistencies due to recurring problems with the CEM equipment. The CEM results for the Leland Olds plant had no information regarding the calibration procedures carried out during testing. The Big Brown source test report did contain actual copies of the strip charts with pre-test and post-test calibration results. The first five days of CEM data in the Big Brown report were voided by the source test contractor because of gas conditioning problems. The last three days of CEM data were considered valid by the contractor with calibration drifts for the three days reported as 5, 4, and 2 percent. The current EPA method specifies that the calibration drift be within 3 percent of the span. The CEM emissions data from the NSPS support testing were not assigned a data quality rating because sufficient EPA Method 7 data were available. The NO_x emission results for Big Brown Units I & II were based on 28 baseline EPA Method 7 runs. The NO_x emissions results for the Leland Olds Unit I were based on 31 baseline EPA Method 7 runs. No raw data sheets are presented in either of these reports. The EPA Method 7 NO_x emissions data were assigned a data quality rating of B.

An additional source of criteria emissions data for the Leland Olds Unit I was Reference 7. The emissions data were not included in the prior update.[17] This report contains a data summary for one day of baseline CEM data for Leland Olds for NO_x and CO. The detailed description of sampling equipment and methods are contained in another report which was not reviewed. The report does not specifically cite EPA CEM methods, but does discuss calibration procedures carried out during the test program. It was assumed that this test program used EPA CEM methods since it was conducted for the Agency. These data were assigned a data rating of B.

4.1.3 Cyclone Emission Factors

The cyclone fired-boiler emission factors contained in the previous update for PM, NO_x, and SO_x were based on emissions data from five sources: Reference 12, Reference 2, two source test reports from Reference 5, and results of the NSPS support testing from Reference 8.

The main source of baseline particulate emissions data for cyclone furnaces for the prior update was Reference 12. This contains the results of nine source tests on three cyclone-fired plants. The PM emission rate in lb/hr, the coal feed rate in tons/hr, and the ash content of the coal were provided. This source was assigned a B data rating.

The most comprehensive source of baseline NO_x emissions data was the NSPS standards support testing contained in Reference 8. This report contains simultaneous source testing for NO_x using EPA Method 7 and CEM taken over four days. The CEM results for this plant had no information regarding the calibration procedures carried out during testing. The CEM data were not given a data quality rating. The first two days of baseline EPA Method 7 NO_x data were given a data quality rating of B. The last two days of EPA Method 7 NO_x data cover only one of two boiler exhaust ducts and, therefore, were excluded from consideration.

An additional source of PM emissions data used in the previous Section 1.7 was a source test report from Reference 5 for Milton R. Young Unit I. This 1971 report presents the results from two test runs taken after the dust collector. One test run was called "preliminary" by the contractor and was conducted on one of the two divided flue gas ducts. The other run was conducted on both flue gas ducts. No specific method was specified in the report. Some of the raw data sheets are missing and the calculation procedures used were not equivalent to current EPA methods. These data were assigned a D rating.

Another source of NO_x and SO_x emissions data used in the previous Section 1.7 was a source test report from Reference 5 for Milton R. Young unit I. This 1971 source test report presents NO_x and SO_x emissions data taken using CEM. The report does not specify the CEM method. The report also discusses a problem with moisture in the flue gas affecting the SO_x CEM results. These data were given a C rating.

4.1.4 Spreader Stoker and Other Stoker Emission Factors

The spreader stoker emission factors contained in the 1986 AP-42 Section 1.7

update for PM, NO_x, and SO_x emissions are based on Reference 2 and four source test reports from Reference 5. The process data were often not reported in these references. A rough table of plants and the control device information for each plant was obtained from the Background File. This was the only source of control and process data available for this update effort. This information is essential for the data in the current update to meet the exclusion criteria.[19]

Two of the source test reports cited in Reference 5 are of low quality for developing emission factors. The first of these reports, Reference 20, has emissions data for PM, NO_x, and SO_x. The source test methods are specified as ASTM 27-1957 for PM testing, the Shell Development method for SO_x, and Saltzman Reagent for NO_x emissions testing. The main problem is that only one run was conducted at the inlet and outlet of the control device for PM. One run for NO_x and SO_x was conducted at the outlet of the control device. This source was assigned a D rating. The second report, Reference 21, contains controlled PM emissions data for three boilers. The method used for collecting the data was specified as ASTM 27-1957, but only one run was conducted for each plant. This source was assigned a D rating.

Reference 22 contains controlled PM emissions data for two spreader stoker boilers and uncontrolled PM data for two other overfeed stokers. The method used to collect the particulate data is specified as the latest National Air Pollution Control Agency and Public Health Bulletins as well as ASTM Power Test Code 27. The sampling train used to collect this data was equivalent to a current EPA Method 5 train. The calculation procedure is well documented but the equations are not completely equivalent to current EPA Method 5 calculational procedures. The results are based on three test runs. The main problem with this data is the lack of information regarding the control device. Reference 5 was the only source of information for the control device. Therefore, these data were assigned a C data rating.

The Reference 23 report contains SO_x and PM data for the F.P. Wood Plant. The particulate data is invalid because of strong cyclonic flow conditions at the sampling point. The SO_x data were taken at a different location and were not as sensitive to flow conditions. These SO_x data are also contained in Reference 2; no additional detail is contained in this report. Therefore these data will not be rated as an additional source.

A significant amount of baseline emissions data for spreader stokers and other stokers were contained in the Section 1.7 Background File. Reference 14 is a trip report describing a visit to the North Dakota Department of Health. The letter has an attachment describing source test results and process and fuel data for plants in the Department of Health's permit files. The North Dakota Department of Health provided copies of the summary pages of these reports in a letter for the 1973 update of this section. The process and fuel data contained in both letters combined with the summary pages of the source test reports were reviewed. Source test results which did not include critical fuel, process, or control data were excluded. Although poorly documented, the remaining data were collected during triplicate testing conducted at the inlet and outlet of the control device. The method used to collect this particulate data is equivalent to the EPA Method 5. The two letters and attachments described above are considered a single reference (i.e., the stoker data package).[14] The stoker data package was assigned a data rating of C.

4.1.5 Review of New Baseline and Controlled Data

This portion of the chapter reviews and assigns a data rating to new data obtained from the literature search that were used to derive new emission factors. The literature search discussed in Chapter 3 revealed that only a small amount of published emissions data for lignite combustion was available. The literature search, therefore, focused on obtaining data from the air pollution control agencies which regulate most of the lignite-fired boilers in the U.S.

The North Dakota Department of Health and the TACB both provided source test data for this update effort. Both of these agencies have a significant amount of source test data available for lignite combustion. The data obtained represents only a portion of the data held by these agencies, however.

Almost all of the new data obtained during the current effort is controlled data. This is mainly due to the promulgation of two series of NSPS (i.e., Subpart D and Subpart Da) which regulate emissions from new boilers; TACB and North Dakota

Department of Health air pollution regulations/permits also limit emissions from existing sources.

4.1.6 North Dakota Department of Health Data[15]

The North Dakota Department of Health supplied source test results for nine lignite-fired utility boilers. Seven of the utility boilers are required to recertify their CEM equipment every three years. The majority of the data package received from the Department is relative accuracy testing to certify the plant CEM equipment. The department also supplied particulate source test summaries for eight of the nine boilers. All of the emissions data in the data package were collected in accordance with EPA methods. The particulate results are all based on three sampling runs, and the CEM results are based on nine or ten 5-minute averages. The emissions data in the package were all collected downstream of particulate controls. Process information on each boiler and associated controls were obtained from copies of the permits for the units. Coal composition data were supplied for each source test and plant. Some of the coal composition data applied to the week of testing and some were specific to each run. All of the boilers tested were operated above 70 percent of design capacity.

All of the major firing configurations are described in the data package. Five of the boilers are tangentially-fired lignite PC units. Two of the plants are cyclone-fired units. One of the plants is a spreader stoker, and one of the units is a fluidized bed boiler. The fluidized bed boiler is a retrofitted spreader stoker unit.

The data package also contains a personal communication which discusses the conversion of the spreader stoker to the fluidized bed boiler.[14] An attachment to this letter contains emission calculations for the old spreader stoker and the new fluidized bed boiler. Average lb/million Btu (lb/MMBtu) emission rates and coal compositions are supplied for both units. The spreader stoker NO_x data were used to generate lb/ton emission factors. The other emissions data were used as a reference for comparison to other source test data.

The entire North Dakota Department of Health data package was assigned a B rating. The source testing was performed using sound methods and the reports were reviewed by the EPA. If the complete documentation can be obtained for this data during future updates this data could receive an A data quality rating.

4.1.7 Texas Air Control Board[16]

The TACB has 12 regional offices in the State. The majority of lignite-fired boilers are located in Regions 3 and 12 of the State. Emissions data were obtained for three boilers in Region 3. Three complete source test reports were obtained for two twin 800 MW tangentially-fired boilers. The text and summary portions only of two source test reports were obtained for a circulating fluidized bed boiler located in Region 3.

Emissions data were obtained for four lignite-fired boilers in Region 12. Two complete source test reports were obtained for two twin 750 MW tangentially-fired boilers. Two complete source test reports were also obtained for a 720 MW and 750 MW horizontally opposed-fired boiler.

Process, control, and coal data used for calculation of emission factors were obtained from copies of portions of the permit files for each of the non-FBC boilers. The copies of the permit files were obtained from the main office of the TACB. All of the source test reports contained coal analyses for the boilers during testing. The process operating conditions were also contained in the source test reports. All source tests contained in the package were conducted while the boiler was operating near full load.

The majority of the Texas emissions data were NSPS compliance testing, and all of the testing was conducted in accordance with the procedures contained in the Appendix to the Code of Federal Regulations (CFR), Title 40, Chapter I, Part 60. The complete source test reports contain extensive documentation on calculation and calibration procedures. The emission rates were calculated using the F-factor calculation procedure specified by Reference Method 19 of 40 CFR Part 60 Appendix A.

All of the complete source test reports obtained from the TACB were assigned a data quality rating of A. The portions of source test reports obtained for the FBC were assigned a data quality rating of B due to a lack of adequate information detail regarding sampling and analytical methods.

4.1.8 Compilation of Baseline Emission Factors

The only new baseline, uncontrolled, data obtained were the fluidized bed emissions data, a stoker NO_x data point, and a cyclone NO_x data point. The new data for PC units are presented in the compilation of controlled emission factors because the designs of the current PC units pursuant to the NSPS are so different from the old units, and because all of the data were obtained after controls. The uncontrolled emission factors for the fluidized bed source category were not developed in the same sense as for the other categories. Fluidized bed design might be considered a combustion modification from the standpoint of NO_x emissions; however, these data were classified as baseline since no additional add-on NO_x controls were in place. The SO_x emission factor for this source category is a controlled factor reflecting the absorption of SO_x by the bed material. No baseline particulate emissions data were available for this source category.

As previously discussed, the majority of new data available for lignite combustion is controlled emissions data. The baseline emission factors for the revised section are based on the same data as the prior update section. The actual values of the emission factors have changed because different calculation procedures were used to generate emission factors from the previous source test data, and data of extremely poor quality were excluded from the revised Section 1.7.

The SO_x emission factor will still be based on the sulfur content and the sodium content of the lignite fired for all firing configurations. The values have changed slightly due to the elimination of duplicate data points and poor-quality data points. The primary reference for the SO_x emission factor is Reference 2. The data that the SO_x emission factor is based on are presented in Table 4.1. Most of the SO_x emissions data available cannot be used to generate emission factors because no ash analysis was available for the lignite fired during testing.

The only true NO_x baseline emissions data are the original data in the 1986 update; all subsequent data identified in the literature search were for post-NSPS units controlled for NO_x. Most of the NO_x data are based on sampling downstream of particulate controls. The particulate device normally does not affect NO_x emissions.

Many of the baseline particulate emission factors contained in the 1986 AP-42 update section were derived from controlled data. The control efficiencies used to back-calculate uncontrolled emissions were often based on poor source test data, design efficiencies, or values in the now-defunct National Emissions Data Base.

The data available for CO and VOC emissions from lignite-fired boilers are extremely limited. The Orsat data for CO was not used to generate emission factors.

The revised emission factors were developed by taking source test results in units of lbs of pollutant/MMBtu and multiplying by the Btu/ton gross wet heating value of the coal. Emissions data in parts per million by volume were converted to units of lb pollutant/MMBtu using an F-factor as specified by Reference Method 19 of 40 CFR Part 60 Appendix A. The PM emission factor for lignite PC boilers is based on a single data point from Reference 5 where the lb/hr particulate emission rate was divided by the coal burning rate of wet ton/hr. Baseline emission factors are summarized in Tables 4-1 through 4-9.

4.1.9 Compilation of Controlled Emission Factors

Most of the new data obtained from the literature search are for source testing conducted at the stack after pollution control systems. The plants constructed after the Subpart D NSPS were implemented were designed with controls integrated with the boiler to form a complete system. All of the plants built prior to the NSPS had some add-on PM control. The term baseline emissions is becoming an ambiguous concept. This is especially true for NO_x controls which are a function of boiler design and operation. The post-NSPS PC units are very different than the PC coal units built prior to 1971. The emissions data obtained for post-NSPS PC units are presented in this section. Volatile organic compound and CO emissions data are still considered essentially uncontrolled. The emissions of these compounds are related to the boiler design, however. Therefore, they were not combined with the baseline data for boilers designed prior to the NSPS implementation. The available NO_x control data for a specific boiler were often difficult to obtain for the current update. For example, most of the post-NSPS boilers were designed with overfire air ports for NO_x control, but many plants do not need to use overfire air to meet the first round of NSPS emission standards. Some older, wall-fired plants may take a top row of burners out of service to provide a form of overfire air. Most of the process and control information for this update was obtained from permit files; as a result, the information regarding NO_x controls was often sparse. It was assumed that all of the tangential boilers fired on lignite built after the NSPS were equipped with overfire air ports.

In general, the calculation procedure started with source test results in units of lbs of pollutant/MMBtu and multiplied by the Btu/ton gross wet heating value of the coal. Emissions data in parts per million by volume were converted to units of lb pollutant/MMBtu using the F-factors specified by Reference Method 19 of 40 CFR Part 60 Appendix A. Controlled emission factors are summarized in Tables 4-10 through 4-14.

4.2 Nitrous Oxide

The literature search for N_2O emissions from lignite firing revealed only data specific to lignite combustion in fluidized bed units. A survey of 42 documents revealed two documents which were used to develop the N_2O emission factor for these units:

Reference 26

This reference contained data from N_2O emissions of fluidized bed combustors. The data is in graphical form and presented in units of milligram per megajoule. The conversion from milligram per megajoule to ppm is one milligram per megajoule equals 1.7 ppm. The test was preformed on a circulating fluidized bed boiler controlled by recirculation of flue gases. The reference case is defined by a bed temperature of 850 °C (1600 °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 was assigned a rating of D.

Reference 27

This test report contained data from a pilot-scale 1MW CFBC. N_2O emissions were continuously monitored by a non-dispersive infrared spectrometer. A rating of C was assigned to the data for the lignite-fired boiler; therefore, the emission factor rating could not be higher than an E because the emission factor was developed from C quality data. The N_2O emission factors for lignite-fired FBC units are summarized in Table 4-15.

4.3 HAZARDOUS AIR POLLUTANTS

4.3.1 Review of New Data

A discussion of the hazardous air pollutants (HAPs) data evaluated for the development of emission factors for boilers fired on lignite is presented in this section.

The discussion includes a summary of the information presented in the source and an evaluation of the quality of the data for use in generating emission factors. The discussions are presented by the source. The data and emission factors presented in this section were rated with the criteria outlined in Section 3.3.3.[19]

Reference 28

This article summarizes the emissions of certain trace metals and HAPs from lignite coal combustion. The data presented are a summary of a literature review. Emission factors are presented in the units of mass emitted per heat unit combusted and are presented for boilers of different sizes and configurations. The article references several primary references which were evaluated and determined to be of insufficient quality for emission factor development.

Reference 29

This document is a compilation of the available information on sources and emissions 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 lignite coal. The emission factors provided are for post-control devices. Data for utility boilers is used in this update because this is the largest and most complete data set for coal combustion.

Reference 30

The data quality and documentation in this report are of unacceptable quality to generate emission factors due to low quality sampling and analytical methods and lack of information on fuel composition and control device performance.

Reference 31

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 33

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

Reference 34

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

Reference 35

This document provides a summary of the emissions factors for metals, polycyclic organic matter (POM), and formaldehyde for lignite 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 insufficient 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 HAPs 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 with a low quality because the data acquisition and manipulation could not be verified.

Reference 36

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

Reference 37

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

4.3.2 Baseline Emission Factors

Emission factors for trace metals, radionuclides, and other HAPs are quite often presented in units of mass emitted per unit of thermal heat input. These units are adequate for performing emission estimates of the organic HAPs but are not ideal for estimating emission factors of metals and radionuclides. Ideally, emission factors for trace elements should be developed as a function of the boiler firing configuration, boiler size, trace element concentration in the fuel, ash content, higher heating value, enrichment ratio, and the collection efficiency of the control device. The concepts of partitioning and enrichment are often used to characterize the behavior of trace elements in the combustion process. The concept of partitioning is used to describe the distribution of trace elements among the boiler outlet streams. These streams may include the bottom ash, fly ash, and flue gas. Enrichment refers to the difference in the trace element concentrations in the outlet streams. The process of enrichment can also take place in a control device. The physical and chemical properties of a trace metal governs how that metal will distribute in the outlet streams. For example, mercury (Hg) is a highly volatile metal and therefore, the majority of the mass of Hg in the feed coal tends to be entirely 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 left the boiler in an outlet stream. Another method for quantifying the distribution of a metal is to calculate an enrichment factor by comparing the trace element concentration of an outlet stream to the trace element concentration of the inlet stream. The enrichment ratio calculation that is outlined in Reference 38 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 fuel
C_{Rc} = concentration of reference element R i fuel

Enrichment ratios greater than 1 indicate that an element is enriched in a given stream, 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 (Al), iron (Fe), scandium (Sc), and titanium (Ti). The enrichment behavior of elements is somewhat consistent in different types of boilers and can be explained by a volatilization-condensation or adsorption mechanism. A summary of the enrichment behavior for the air toxic metals and the reference metals is presented in Table 4-16. Table 4-17 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 in order to estimate emissions of trace elements. The equation outlined in Reference 38 which is used to calculate the emission factor for a trace element is 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, ug/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, which is 0 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) sometimes based on Al

In many cases, the source test programs did not include key parameters such as: ultimate analyses and speciation 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 heat input were provided. Though this is not the optimal method of estimating emissions, it provides a means of performing a rough emission estimation.

Table 4-18 summarizes the enrichment ratios for metals and radionuclides for an uncontrolled boiler and for a high efficiency cold-side ESP. The quality of these enrichment ratios is low (E quality) because of the low number of boilers and control data used to perform the calculations. Enrichment ratio data are a significant data gap in the HAP data bases.

Tables 4-19 and 4-20 present a summary of emission factors in the units of mass emitted per unit thermal heat input for uncontrolled utility boilers. Data on utility boilers are the most studied group of boilers and, therefore, have the most significant amount of data. Data are presented for metals. No POM or formaldehyde uncontrolled emissions data were found. The tables are presented in metric units and English units, respectively. The quality rating of these data are low because many of the sources of information are of insufficient quality and the number of data points are too small to represent an entire source category.

4.3.3 Controlled Emission Factors

Tables 4-21 and 4-22 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 insufficient quality and the number of data points are too small to represent an entire source category.

4.4 PARTICULATE SIZE DISTRIBUTION

The scope of AP-42 is being extended to augment particulate size distribution emission factors with data on the split between filterable and condensible PM-10. The current AP-42 includes detailed analysis of particle size distribution data. Filterable PM-10 data is included in this analysis by default because it is among the cumulative size fractions considered. Condensible PM-10 is not in the current AP-42 and needs to be added to future versions of AP-42.

4.4.1 Review of Previous AP-42 Data

The 1986 AP-42 particle sizing update was evaluated with respect to sources of data, data analysis and emission factor development procedure. Data retrieved and analyzed for that update were exclusively filterable PM.

Very few lignite data sets were available through FPEIS or other sources at the time of the previous update.[39] All the data sets were considered C-quality. The FPEIS printouts were checked, as was the partial report referenced in the 1986 Emission Factor Documentation report as ERC No. 7246. The spot-checking indicated that the previous analysis was as accurate as possible given the data quality.

4.4.2 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 method development source test data were uncovered.

Although a variety of sources were contacted with regards to 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 time limitations and other staff limitations.

Two sets of data are available for filterable PM from pilot-scale atmospheric fluidized bed combustors (AFBCs).[38] A pilot AFBC unit was tested while firing either subbituminous coal or lignite. The purpose of the 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 particulate emissions exiting a multiclone system were measured for particulate size distribution. A flow sensor multiclone and laser aerodynamic particle sizer (APS) provided particle size distribution data at the inlet to the scrubber (after the multiclone controls).

The data is ranked C due to the pilot-scale size, the particulate collection methods, and lack of sufficient background data. In addition, the cumulative percent mass values were obtained via interpolation of log-log graphs of the results. The particulate size distribution data are shown on Table 4-23.

4.4.3 Compilation of Uncontrolled Emission Factors

The 1986 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 particulate 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 becomes 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.

4.4.4 Control Technology Emission Factors

There were two calculation steps in the development of controlled emission factors in the previous PM sizing update in 1986.[39] First, a controlled emission factor was developed for total PM by multiplying the uncontrolled total PM emission factor from the criteria pollutant table by one of the following 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 every size distribution table in Section 1.7 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 emission factors for the particulate size fractions.

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-specific emission factors rather than using generalized control efficiency results. Control-specific emission factors are better than generalized control efficiency results because control efficiency is dependent on particulate parameters, such as the resistivity, 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 41 percent of controlled PM from a multiple cyclone operating on lignite-fueled spreader stokers was less than or equal to 10 microns. Based on this value; on an uncontrolled emission factor of 3.4A kg/Mg; and on an estimated multiple cyclone efficiency of 80 percent, the controlled PM-10 emission factor is calculated as 0.279A:

$$0.41 \times 3.4A \times (1.0 - 0.80) = 0.279A \text{ kg/Mg}.$$

Although different methods could be used to develop controlled emission estimates, the procedures used in the 1986 document are 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 cited above are reasonable in light of available data for lignite-fired boilers and were retained in the current update.

Tests of ash from lignite combustion have indicated ash characteristics that may significantly affect the ability of a fabric filter to achieve high collection efficiencies.[40] For instance, lignite ash particles are noncohesive, smooth spheres with few surface deposits. The ash particles tend to penetrate through the fabric leading to bleed-through. The noncohesive particles form an unstable dustcake on the fabric surface. Low collection efficiencies are expected for shake/deflate and reverse gas-cleaned baghouses because the dustcake is the primary filter medium for those baghouses. Pulsed-jet cleaned baghouses can achieve higher efficiencies because the bag acts as the primary filter medium.

A transportable pulsed-jet fabric filter pilot plant was tested at the 575 MW Big Brown Unit 1 of the TU Electric Company in Fairfield, TX. A medium to low-sulfur Texas lignite was fired throughout the tests. Two pulse jet cleaning systems were tested: high-pressure/low-volume and low-pressure/high-volume. During the low-pressure/high-volume tests, the average particulate collection efficiency was 99.95% with outlet emissions equivalent to 0.0002 to 0.0003 ng/J (0.005 to 0.008 lb/MMBtu). During the high-pressure/low-volume tests the particulate efficiency was 99.81% with outlet emissions of 0.00007 ng/J (0.0017 lb/MMBtu).[40]

TABLE 4-1. BASELINE SULFUR OXIDES EMISSION DATA[a]

Na_2O in ash, % by weight	Emission factor[b]			
	kg SO_x/Mg coal x S[c]		lb SO_x/ton coal x S[c]	
	Individual tests	Average for Na_2O range	Individual tests	Average for Na_2O range
0.4	16.9	16.7	33.7	33.4
0.7	17.3		34.6	
0.8	18.1		36.1	
0.9	16.7		33.3	
1	15.1		30.2	
1.1	14.7		29.3	
1.6	18.3		36.5	
1.7	16.7		33.4	
2	17.1	16.2	34.2	32.3
2.1	18.7		37.4	
3	20.0		40.0	
3.1	16.6		33.2	
3.5	17.8		35.5	
3.8	13.9		27.8	
4.8	14.6		29.1	
5.1	13.4		26.8	
5.3	11.6		23.1	
5.4	13.0		25.9	
5.5	15.1		30.2	
5.6	12.7		25.4	
5.8	16.7		33.4	
6	17.7		35.3	
6.1	12.3		24.5	
6.2	15.9		31.7	
7	16.0		31.9	
7.5	13.2		26.4	
7.7	17.7		35.3	
7.8	13.6		27.2	
8	16.8	11.0	33.5	21.9
8.2	9.2		18.4	
8.6	8.5		16.9	
8.8	15.6		31.2	
9	10.5		21.0	
10.9	5.5		10.9	

[a] Reference 2.

[b] Excluding fluidized beds which capture SOx by bed absorption.

[c] S = % sulfur wet basis.

TABLE 4-2. SUMMARY BASELINE NO_x AND CO EMISSIONS DATA FOR PULVERIZED LIGNITE UNITS[a]

Firing configuration	NO_x,		Data quality rating	Ref.	CO,		Data quality rating	Ref.
	kg/Mg	lb/ton			kg/Mg	lb/ton		
Tangential	4.25	8.5	B	2				
Tangential	3.05	6.1	B	3				
Horizontally Opposed Wall Fired	6.7 5.2 2.35	13.4 10.4 10.7	B B B	8 7 2	0.125	0.25	B	7
Front Wall Fired	5.0	10.0	B	2				

[a] All data, except for front wall firing configuration, taken after PM controls.

TABLE 4-3. SUMMARY BASELINE PM EMISSION DATA FOR PULVERIZED LIGNITE UNITS

Firing configuration	Particulate,[a]		Data quality rating	Reference
	kg/Mg	lb/ton		
Tangential	3.25 A	6.5 A	D	6
Front Wall	2.55 A	5.1 A	D	5

[a] A = wet basis % ash content of lignite.

TABLE 4-4. SUMMARY BASELINE NO_x EMISSIONS DATA FOR CYCLONE-FIRED UNITS

NO_x,		Data quality rating	Reference	Controls[a]
kg/Mg	lb/ton			
6.05	12.1	B	2	
6.1	12.2	B	8	P
6.6	13.2	B	15	P,S

[a] Data taken after PM controls is designated by P. Data taken after SO_2 controls is designated by S.

TABLE 4-5. SUMMARY BASELINE PM EMISSION DATA FOR CYCLONE-FIRED UNITS

Particulate,[a]		Data quality rating	Reference
kg/Mg	lb/ton		
2.65A	5.3A	B	12
3.1A	6.2A	B	12
4.3A	8.6A	B	12

[a] A = wet basis % ash content of lignite.

TABLE 4-6. SUMMARY BASELINE NO_x EMISSIONS DATA FOR SPREADER STOKER UNITS

NO_x,		Data quality rating	Reference	Controls[a]
kg/Mg	lb/ton			
2.6	5.2	B	2	P
3.2	6.4	B	15	P

[a] Data taken after particulate controls is designated by P.

TABLE 4-7. SUMMARY BASELINE PM EMISSIONS DATA FOR SPREADER STOKER UNITS

Particulate,[a]		Data quality rating	Reference
kg/Mg	lb/ton		
3.2A	6.4A	C	14
5.95A	11.9A	C	14
2.85A	5.7A	C	14

[a] A = wet basis % ash content of lignite.

TABLE 4-8. SUMMARY BASELINE PM EMISSIONS DATA FOR OTHER STOKER UNITS

Stoker type	Particulate,[a]		Data quality rating	Reference
	kg/Mg	lb/ton		
Underfeed	2.0A	4.0A	C	14
Overfeed	1.2A	2.4A	C	14
Overfeed	1.85A	3.7A	C	14

[a] A = wet basis % ash content of lignite.

TABLE 4-9. ATMOSPHERIC FLUIDIZED BED BASELINE NO_x, SO_x, AND CO EMISSIONS DATA[a]

Firing configuration	NO_x,		SO_x,[b]		CO,	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
North Dakota Region[c]						
66 MW Bubbling Bed Multiclone, ESP	2.3	4.6	4.95S	9.9S		
Texas Region[d]						
180 MW Circulating Bed Drum Type	1.3	2.6			0.075	0.15

[a] All of the source testing conducted at the stack downstream of controls.
[b] S = wet basis weight % sulfur content of lignite.
[c] Reference 15. All data are rated B.
[d] Reference 16. All data are rated A.

TABLE 4-10. CONTROLLED NO_x, SO_x, AND CO EMISSIONS DATA[a]

Firing configuration	NO_x,		SO_x,		CO,	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Subpart D Boilers, Pulverized Coal Tangential Firing						
North Dakota Region[c]						
440 MW Unit Spray Dryers, Baghouse Overfire Air	2.6	5.1	3.1S	6.1S		
440 MW Unit Spray Dryers, Baghouse Overfire Air	2.4	4.8	4.2S	8.4S		
500 MW Unit ESP, Wet lime scrubbers FGD 60 % of flue gas Overfire Air	3.6	7.2	8.3S	16.6S		
500 MW Unit ESP, Wet lime scrubbers FGD 60 % of flue gas Overfire Air	4.0	7.9	8.5S	16.9S		
Texas Region[d]						
780 MW Unit ESP, Wet lime scrubbers Overfire Air	3.7	7.4	7.8S	15.6S		
780 MW Unit ESP, Wet lime scrubbers Overfire Air	4.3	8.5	7.7S	15.3S		
Subpart D Boilers, Horizontally Opposed Firing						
730 MW Unit ESP, Wet lime scrubbers Overfire Air, Low NO_x burners	2.7	5.3	6.9S	13.7S	0.24	0.48
750 MW Unit ESP, Wet limestone scrubbers Overfire Air, Low NO_x burners	2.0	3.9	9.7S	19.4S		

TABLE 4-10. CONTROLLED NO_x, SO_x, AND CO EMISSIONS DATA (Continued)[a]

Firing configuration	NO_x,		SO_x,[b]		CO,	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Subpart Da Boilers, Pulverized Coal Tangential Firing						
North Dakota Region[c]						
55 MW Spray Dryer, Baghouse Overfire Air	3.3	6.6	4.0S	7.9S		
Texas Region[d]						
780 MW ESP, Wet limestone scrubbers Overfire Air	2.4	4.8	2.1S	4.2S	0.03	0.06
780 MW ESP, Wet limestone scrubbers Overfire Air	3.3	6.6	1.6S	3.2S	0.07	0.13

[a] All of the source testing conducted at the stack after all controls.
[b] S = wet basis weight % sulfur content of lignite.
[c] Reference 15. All data are rated B.
[d] Reference 16. All data are rated A.

TABLE 4-11. ATMOSPHERIC FLUIDIZED BED UNITS CONTROLLED SO_x EMISSIONS DATA[a]

Firing configuration	SO_x,[b]	
	kg/Mg	lb/ton
Texas Region[c]		
180 MW Circulating Bed Drum Type Limestone injection	3.5S	7.0S

[a] All of the source testing conducted at the stack after all controls.
[b] S = wet basis weight % sulfur content of lignite.
[c] Reference 16. All data are rated A.

TABLE 4-12. CONTROLLED PM EMISSIONS DATA[a]

Firing configuration	PM[b]	
	kg/Mg	lb/ton
Subpart D Boilers, Pulverized Coal Tangential Firing		
North Dakota Region[c]		
440 MW Unit Spray Dryers, Baghouse Overfire Air	0.05A	0.09A
440 MW Unit Spray Dryers, Baghouse Overfire Air	0.03A	0.06A
500 MW Unit ESP, Wet lime Scrubbers FGD 60 % of flue gas Overfire Air	0.01A	0.02A
500 MW Unit ESP, Wet lime Scrubbers FGD 60 % of flue gas Overfire Air	0.04A	0.08A
Texas Region[d]		
780 MW Unit ESP, Wet limestone scrubbers Overfire Air	0.02A	0.04A
780 MW Unit ESP, Wet lime scrubbers Overfire Air	0.04A	0.07A
Subpart D Boilers, Horizontally Opposed Firing		
730 MW Unit ESP, Wet limestone scrubbers Overfire Air, Low-NO_x burners	0.03A	0.05A
750 MW Unit ESP, Wet limestone scrubbers Overfire Air, Low NO_x-burners	0.02A	0.04A

TABLE 4-12. CONTROLLED PARTICULATE EMISSIONS DATA (Continued)[a]

Firing configuration	PM,[b]	
	kg/Mg	lb/ton
<u>Subpart Da Boilers,</u> <u>Pulverized Coal</u> <u>Tangential Firing</u>		
Texas Region[d]		
780 MW ESP, Wet limestone scrubbers Overfire Air	0.005A	0.01A
780 MW ESP, Wet limestone scrubbers Overfire Air	0.005A	0.01A

[a] All of the source testing conducted at the stack after all controls.
[b] A = wet basis % ash content of lignite.
[c] Reference 15. All data are rated B.
[d] Reference 16. All data are rated A.

TABLE 4-13. ATMOSPHERIC FLUIDIZED BED UNITS CONTROLLED PM EMISSIONS DATA[a]

Firing configuration	PM,[b]	
	kg/Mg	lb/ton
North Dakota Region[c]		
66 MW Bubbling Bed Multiclone, ESP	0.055A	0.11A
Texas Region[d]		
180 MW Circulating Bed Drum Type	0.01A	0.02A

[a] All of the source testing conducted at the stack after all controls.

[b] A = wet basis weight % ash content of lignite.

[c] Reference 15. All data are rated B.

[d] Reference 16. All data are rated A.

TABLE 4-14. CONTROLLED ORGANIC EMISSIONS DATA[a]

Firing configuration	Nonmethane TOC,		Methane,	
	kg/Mg	lb/ton	kg/Mg	lb/ton
Subpart Da Boilers, Pulverized Coal Tangential Firing				
Texas Region[c]				
780 MW ESP, Wet limestone scrubbers, Overfire Air	0.14	0.27		
780 MW ESP, Wet limestone scrubbers, Overfire Air	0.08[b]	0.16[b]	0.01	0.02
Subpart D Boilers, Horizontally Opposed				
730 MW ESP, Wet limestone scrubbers Overfire Air, Low-NO_x burners	0.01	0.02	0.01	0.02

[a] All of the source testing conducted at the stack after all controls.
[b] Nonmethane nonethane hydrocarbons as propane.
[c] Reference 16. All data are rated A.

TABLE 4-15. N_2O EMISSION FACTORS FOR EXTERNAL COMBUSTION OF LIGNITE

Firing configuration	Emission factor rating	N_2O,	
		kg/Mg	lb/ton
Fluidized Beds	E	1.24	2.48

TABLE 4-16. METAL ENRICHMENT BEHAVIORS

Class	Description	Reference 38	Reference 39	Reference 40
I	Equal distribution between fly ash and bottom ash		Al[a], Co, Fe[a], Mn, Sc[a], Ti[a]	Al[a], Co, Cr, Fe[a], Mn, Sc[a], Ti[a]
II	Enriched in fly ash relative to bottom ash	As, Cd	As, Cd, Pb, Sb	As, Cd, Pb, Sb
III	Somewhere in between Class I and II, multiple behavior	Be, Cr, Ni, Mn	Cr, Ni	Ni
IV	Emitted in gas phase	Hg	Hg	Hg

[a] Reference metals.

TABLE 4-17. ENRICHMENT RATIOS FOR CLASSES OF ELEMENTS

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

TABLE 4-18. FLY ASH ENRICHMENT RATIOS FOR A BOILER AND CONTROL DEVICE[a]

Device	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 boiler (10100301)	1.09	1.13	0.56	0.61	0.97	1.02	1.21	1.03	0.64	0.96	1.07	1.19	1.20	1.24	1.31	1.20	1.43
High efficiency cold-side ESP	6.6	6.3			3.0	2.1	6.1	2.2		2.4	4.5	0.70		0.86			

[a] All enrichment ratios are rated E quality.

TABLE 4-19. TRACE METAL EMISSION FACTORS (METRIC UNITS) FOR UNCONTROLLED LIGNITE-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized Wet Bottom (no SCC)	1175	56	21-33	525-809	1917-7065	9	70-504
Pulverized Dry Bottom (no SCC)	598	56	21	645-809	7043	9	404-504
Cyclone Furnace (10100303)	101-272	56	13	109-809	1635	9	68-504
Stoker Configuration Unknown (no SCC)		51			5130	9	303-504
Spreader Stoker (10100306)	231-473		10-20	486-809			
Traveling Grate (Overfed) Stoker (10100304)	473-904		20-39				

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

TABLE 4-20. TRACE METAL EMISSION FACTORS (ENGLISH UNITS) FOR UNCONTROLLED LIGNITE-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized (10100301)							
Pulverized Wet Bottom (no SCC)	2730	131	49-77	1220-1880	4410-16,250	21	154-1160
Pulverized Dry Bottom (no SCC)	1390	131	49	1500-1880	16,200	21	928-1160
Cyclone Furnace (10100303)	235-632	130	31	253-1880	3760	21	157-1160
Stoker Configuration Unknown (no SCC)		118			11800	21	
Spreader Stoker (10100306)	538-1100		23-47	1130-1880			696-1160
Traveling Grate (overfed) Stoker (10100304)	1100-2100		47-90				

[a] All emission factors in lb/10^{12} Btu. All emission factors are rated E.

TABLE 4-21. HAP EMISSION FACTORS (METRIC UNITS) FOR CONTROLLED LIGNITE-FIRED BOILERS[a]

Boiler configuration	Control device	Cr	Mn	POM
Pulverized Coal (10100301)	Multi-cyclones	29-32		
	ESP	8.6		
	High Efficiency Cold-Side ESP			0.99
Pulverized Wet Bottom (no SCC)	ESP		14.7	
Pulverized Dry Bottom (no SCC)	Multi-cyclones			0.78-7.9[b]
	ESP		18.1	1.1[b]
Cyclone Furnace (10100303)	ESP	<3.3	57.2	0.05[c]-0.68[b]
	Multi-cyclones		711	
Stoker Configuration Unknown (no SCC)	Multi-cyclones	13	47.3	
	ESP	<2.3		
Spreader Stoker (10100306)	Multi-cyclones			6.3[b]

[a] All emission factors in pg/J. All emission factors are rated E.
[b] Primarily trimethyl propenyl naphthalene.
[c] Primarily biphenyl.

TABLE 4-22. HAP EMISSION FACTORS (ENGLISH UNITS) FOR CONTROLLED LIGNITE-FIRED BOILERS[a]

Boiler configuration	Control device	Cr	Mn	POM
Pulverized Coal (10100301)	Multi-cyclones	67-74		
	ESP	20		
	High Efficiency Cold-Side ESP			2.32
Pulverized Wet Bottom (no SCC)	ESP		34.2	
Pulverized Dry Bottom (no SCC)	Multi-cyclones			1.8-18.3[b]
	ESP		42.2	2.6[b]
Cyclone Furnace (10100303)	ESP	27.7	133	0.11[c]-1.6[b]
	Multi-cyclones		1656	
Stoker Configuration Unknown (no SCC)	Multi-cyclones	30	110	
	ESP	<5.4		
Spreader Stoker (10100306)	Multi-cyclones			14.6[b]

[a] All emission factors in lb/10^{12} Btu. All emission factors rated E.
[b] Primarily trimethyl propenyl naphthalene.
[c] Primarily biphenyl.

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

Fuel	Filterable Particulate, cumulative mass percent less than stated size (microns)							Data quality rating	Reference
	0.625	1.00	1.25	2.50	6.00	10	15		
Gibbons Creek lignite	< 2	11	18	41	82	90	94	C	38

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5. AP-42 SECTION 1.7: LIGNITE COMBUSTION

The revision to Section 1.7 of AP-42 is presented in the following pages as it would appear in the document. A marked-up copy of the 1986 version of this section is included in Appendix B.

1.7 LIGNITE COMBUSTION

1.7.1 General[1-4]

Lignite is a coal in the early stages of coalification, with properties intermediate to those of bituminous coal and peat. The two geographical areas of the U.S. with extensive lignite deposits are centered in the States of North Dakota and Texas. The lignite in both areas has a high moisture content (30 to 40 weight percent) and a low heating value, [1,400 to 1,900 kcal/kg (2,500 to 3,400 Btu/lb), on a wet basis]. Consequently, lignite is burned near where it is mined. A small amount is used in industrial and domestic situations, but lignite is mainly used for steam/electric production in power plants. Lignite combustion has advanced from small stokers and the first pulverized coal (PC) and cyclone-fired units to large (greater than 800 MW) PC power plants.

The major advantages of firing lignite are that it is relatively abundant (in the North Dakota and Texas regions), relatively low in cost, and low in sulfur content. The disadvantages are that more fuel and larger facilities are necessary to generate a unit of power than is the case with bituminous coal. The reasons for this are: (1) lignite's higher moisture content means that more energy is lost in evaporating water, which reduces boiler efficiency; (2) more energy is required to grind lignite to combustion-specified size, especially in PC-fired units; (3) greater tube spacing and additional soot blowing are required because of lignite's higher ash fouling tendencies; and (4) because of its lower heating value, more lignite must be handled to produce a given amount of power. Lignite usually is not cleaned or dried before combustion (except for incidental drying in the crusher or pulverizer and during transport to the burner). No major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

1.7.2 Emissions [2-11,17]

The major pollutants generated from firing lignite, as with any coal, are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Emissions rates of organic compounds and carbon monoxide (CO) are much lower than those for the major pollutants under normal operating conditions.

Emission levels for PM appear most dependent on the firing configuration of the boiler. Pulverized coal-fired units and spreader stokers fire much or all of the lignite in suspension; they emit a greater quantity of flyash per unit of fuel burned than do cyclones and other stokers. Cyclone furnaces collect much of the ash as molten slag in the furnace itself. Stokers (other than spreader) retain a large fraction of the ash in the fuel bed and bottom ash.

The NO_x emissions from lignite combustion are mainly a function of the boiler design, firing configuration, and excess air level. Stokers produce lower NO_x levels than PC units and cyclones, mainly because most stokers are relatively small and have lower peak flame temperatures. The boilers constructed since implementation of the 1971 and 1979 new source performance standards (40 Code of Federal Regulations, Part 60, Subparts D and Da respectively) have NO_x controls integrated into the boiler design and have comparable NO_x emission levels to the small stokers. In most boilers, regardless of firing configuration, lower excess combustion air results in lower NO_x emissions.

However, lowering the amount of excess air in a lignite-fired boiler can also affect the potential for ash fouling.

The rate of SO_x emissions from lignite combustion are a function of the alkali (especially sodium) content of the ash. For combustion of most fossil fuels, over 90 percent of the fuel sulfur is emitted as sulfur dioxide (SO_2) because of the low alkali content of the fuels. By contrast, a significant fraction of the sulfur in lignite reacts with alkaline ash components during combustion and is retained in the boiler bottom ash and flyash. Tests have shown that less than 50 percent of the available sulfur may be emitted as SO_2 when a high-sodium lignite is burned, whereas more than 90 percent may be emitted from a low-sodium lignite. As an approximate average, about 75 percent of the lignite sulfur will be emitted as SO_2; the remainder will be retained in the ash as various sulfate salts.

1.7.3 Controls[2,11-17]

Most lignite-fired utility boilers are equipped with electrostatic precipitators (ESPs) with collection efficiencies as high as 99.5 percent for total PM. Older and smaller ESPs have lower collection efficiencies of approximately 95 percent for total PM. Older industrial and commercial units also may be equipped with cyclone collectors that normally achieve 60 to 80 percent collection efficiency for total PM.

Flue gas desulfurization (FGD) systems (comparable to those used on bituminous coal-fired boilers) are in current operation on several lignite-fired utility boilers. Flue gases are treated through wet or dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO_x absorbent is regenerated and reused). Wet systems generally use alkali slurries as the SO_x absorption medium and can reduce SO_x emissions by 90 percent or more. Spray dryers (or dry scrubbers) spray a solution or slurry of alkaline material into a reaction vessel as a fine mist that mixes with the flue gas. The SO_2 reacts with the alkaline mist to form salts. The solids from the spray dryer and the salts formed are collected in a particulate control device.

Over 50 percent reduction of NO_x emissions can be achieved by changing the burner geometry, controlling air flow in the furnace, or making other changes in operating procedures. Overfire air and low NO_x burners are two demonstrated NO_x control techniques for lignite combustion.

Baseline emission factors for NO_x, SO_x, and CO are presented in Tables 1.7-1 and 1.7-2. Baseline emission factors for total PM and nitrous oxide (N_2O) are given in Table 1.7-3. Specific emission factors for the cumulative particle size distributions are provided in Tables 1.7-4 and 1.7-5. Uncontrolled and controlled size-specific emission factors are presented in Figures 1.7-1 and 1.7-2. Lignite combustion and bituminous coal combustion are quite similar with respect to emissions of carbon dioxide (CO_2) and organic compounds. As a result, the bituminous coal emission factors for these pollutants presented in Section 1.1 of this document may also be used to estimate emissions from lignite combustion.

Emission factors for trace elements from uncontrolled lignite combustion are summarized in Tables 1.7-6 and 1.7-7, based on currently available data.

Controlled emission factors for NO_x, CO, and PM are presented in Tables 1.7-8 and 1.7-9. Controlled SO_2 emissions will depend primarily of applicable regulations and FGD equipment performance, if applicable. Section 1.1 contains a discussion of FGD performance capabilities which is also applicable to lignite-fired boilers. Controlled emission factors for selected hazardous air pollutants are provided in Tables 1.7-10 and 1.7-11.

Table 1.7-1 (Metric Units). EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM UNCONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)[b]	SO_x[c]		NO_x[d]		CO[e]	
	Emission Factor	Rating	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	15S[e]	C	3.7	C		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	15S	C	5.6	C	0.13	C
Cyclone (SCC 10100303)	15S	C	6.3	C		
Spreader stoker (SCC 10100306)	15S	C	2.9	C		
Other stoker (SCC 10100304)[e]	15S	C	2.9	C		
Atmospheric fluidized bed (no SCC)	3S	D	1.8	C	0.08	C

[a] Units are kg of pollutant/Mg of fuel burned.
[b] SCC= Source Classification Code.
[c] Reference 2.
[d] References 2-3, 7-8, 15-16.
[e] References 7, 16.
[e] S= Weight % sulfur content of lignite, wet basis.
For high sodium ash ($Na_20 > 8\%$), use 11S.
For low sodium ash ($Na_20 < 2\%$), use 17S.
If ash sodium content is unknown, use 15S.

Table 1.7-2 (English Units). EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM UNCONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)[b]	SO_x[c]		NO_x[d]		CO[e]	
	Emission Factor	Rating	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	30S[e]	C	7.3	C		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	30S	C	11.1	C	0.25	C
Cyclone (SCC 10100303)	30S	C	12.5	C		
Spreader stoker (SCC 10100306)	30S	C	5.8	C		
Other stoker (SCC 10100304)[f]	30S	C	5.8	C		
Atmospheric fluidized bed (no SCC)	30S	C	3.6	C	0.15	C

[a] Units are lb. of pollutant/ton of fuel burned.

[b] SCC= Source Classification Code.

[c] Reference 2.

[d] References 2-3, 7-8, 15-16.

[e] References 7, 16.

[f] S= Weight % sulfur content of lignite, wet basis.
For high sodium ash ($Na_20 > 8\%$), use 22S.
For low sodium ash ($Na_20 < 2\%$), use 34S.
If ash sodium content is unknown, use 30S.

Table 1.7-3. EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND NITROUS OXIDE (N_2O) FROM LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	PM[b]		N_2O[c]	
	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	3.3A (6.5A)	E		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	2.6A (5.1A)	E		
Cyclone (SCC 10100303)	3.4A (6.7A)	C		
Spreader stoker (SCC 10100306)	4.0A (8.0A)	E		
Other stoker (SCC 10100304)	1.7A (3.4A)	E		
Atmospheric fluidized bed			1.2 (2.5)	E

[a] Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned. SCC= Source Classification Code.

[b] References 5-6, 12, 14. A = weight % ash content of lignite, wet basis.

[c] Reference 18.

Table 1.7-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR BOILERS FIRING PULVERIZED LIGNITE[a]

EMISSION FACTOR RATING: E

Particle Size[b] µm	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c]	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	51	77	1.7A (3.4A)	0.51A (1.0A)
10	35	67	1.2A (2.3A)	0.44A (0.88A)
6	26	57	0.86A (1.7A)	0.38A (0.75A)
2.5	10	27	0.33A (0.66A)	0.18A (0.36A)
1.25	7	16	0.23A (0.47A)	0.11A (0.21A)
1.00	6	14	0.20A (0.40A)	0.093A (0.19A)
0.625	3	8	0.10A (0.19A)	0.053A (0.11A)
TOTAL			3.3A (6.6A)	0.66A (1.3A)

[a] Reference 13. Based on tangential-fired units. For wall-fired units, multiply emission factors in the table by 0.79.

[b] Expressed as aerodynamic equivalent diameter.

[c] Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
A = weight % ash content of coal, wet basis.

[d] Estimated control efficiency for multiple cyclone is 80%.

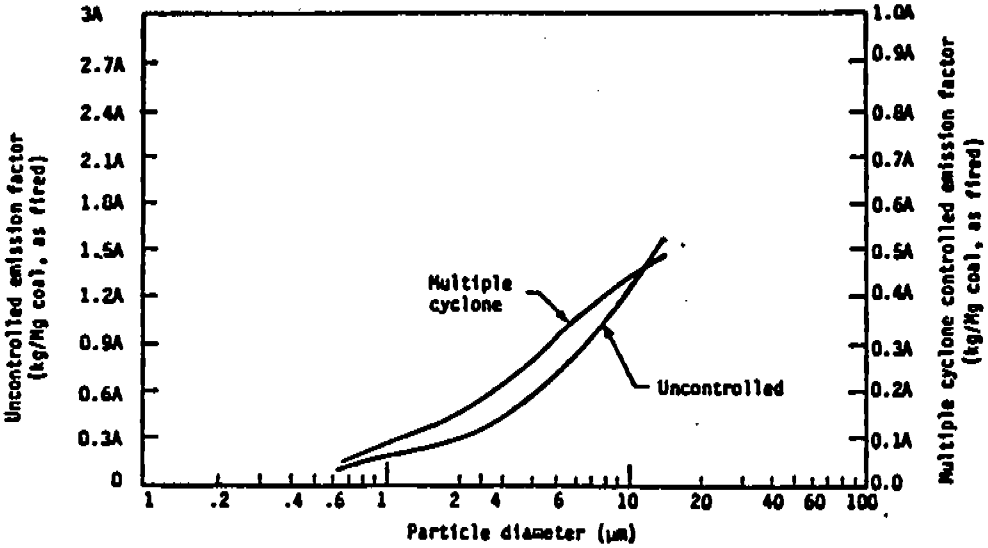

Figure 1.7-1. Cumulative size specific emission factors for boilers firing pulverized lignite.

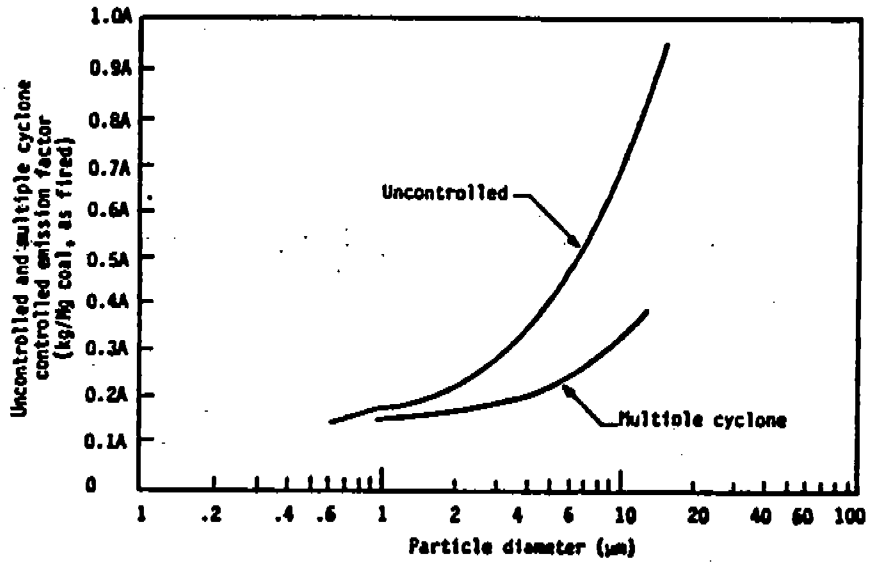

Figure 1.7-2. Cumulative size specific emission factors for lignite-fired spreader stokers.

Table 1.7-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR LIGNITE FIRED SPREADER STOKERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] µm	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c]	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	28	55	1.1A (2.2A)	0.44A (0.88A)
10	20	41	0.80A (1.6A)	0.33A (0.66A)
6	14	31	0.56A (1.1A)	0.25A (0.50A)
2.5	7	26	0.28A (0.56A)	0.21A (0.42A)
1.25	5	23	0.20A (0.40A)	0.18A (0.37A)
1.00	5	22	0.20A (0.40A)	0.18A (0.35A)
0.625	4	e	0.16A (0.33A)	e
TOTAL			4.0A (8.0A)	0.80A (1.6A)

[a] Reference 13.

[b] Expressed as aerodynamic equivalent diameter.

[c] Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
A = weight % ash content of lignite, wet basis.

[d] Estimated control efficiency for multiple cyclone is 80%.

[e] Insufficient data.

Table 1.7-6 (Metric Units). EMISSION FACTORS FOR TRACE ELEMENTS FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	pg/J						
	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized, wet bottom (no SCC)	1175	56	21-33	525-809	1917-7065	9	70-504
Pulverized, dry bottom (no SCC)	598	56	21	645-809	7043	9	404-504
Cyclone furnace (SCC 10100303)	101-272	56	13	109-809	1635	9	68-504
Stoker, configuration unknown (no SCC)		51			5130	9	303-504
Spreader stoker (SCC 10100306)	231-473		10-20	486-809			
Traveling grate (overfed) stoker (SCC 10100304)	473-904		20-39				

[a] References 19-20. Units are picograms (10^{-12}) of pollutant/Joule of fuel burned. SCC= Source Classification Code.

Table 1.7-7 (English Units). EMISSION FACTORS FOR TRACE ELEMENTS FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	lb/10^{12} Btu						
	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized (SCC 10100301)							
Pulverized, wet bottom (no SCC)	2730	131	49-77	1220-1880	4410-16,250	21	154-1160
Pulverized, dry bottom (no SCC)	1390	131	49	1500-1880	16,200	21	928-1160
Cyclone furnace (SCC 10100303)	235-632	130	31	253-1880	3760	21	157-1160
Stoker configuration unknown (no SCC)		118			11800	21	
Spreader stoker (SCC 10100306)	538-1100		23-47	1130-1880			696-1160
Traveling grate (overfed) stoker (SCC 10100304)	1100-2100		47-90				

[a] References 19-20. Units are lb. of pollutant/10^{12}Btu of fuel burned. SCC = Source Classification Code.

Table 1.7-8. CONTROLLED EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM CONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	NO_x[b]		CO[c]	
	Emission Factor kg/Mg (lb/ton)	Rating	Emission Factor kg/Mg (lb/ton)	Rating
Pulverized coal, dry bottom, tangential overfire air (no SCC)	3.3 (6.6)	C	0.05 (0.10)	D
Pulverized coal, dry bottom, tangential overfire air/low NO_x burners (no SCC)	2.3 (4.6)	C	0.24 (0.48)	D

[a] Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
SCC = Source Classification Code.

[b] Reference 15, 16.

[c] References 15.

Table 1.7-9. EMISSION FACTORS FOR PARTICULATE MATTER (PM) EMISSIONS FROM CONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	Control Device	PM	
		Emission Factor	Rating
Subpart D Boilers, Pulverized coal, Tangential and wall-fired (no SCC)	Baghouse	0.08A (0.16A)	C
	Wet scrubber	0.05A (0.10A)	C
Subpart Da Boilers, Pulverized coal, Tangential fired (no SCC)	Wet scrubber	0.01A (0.02A)	C
Atmospheric fluidized bed	Limestone addition	0.03A (0.06A)	D

[a] Reference 15-16. A = weight % ash content of lignite, wet basis.
Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
SCC = Source Classification Code.

Table 1.7-10 (Metric Units). EMISSION FACTORS FOR TRACE METALS AND POLYCYCLIC ORGANIC MATTER (POM) FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Control Device	Emission Factor, pg/J		
		Cr	Mn	POM
Pulverized coal (SCC 10100301)	Multi-cyclones	29-32		
	ESP	8.6		
	High efficiency cold-side ESP			0.99
Pulverized wet bottom (no SCC)	ESP		15	
Pulverized dry bottom (no SCC)	Multi-cyclones			0.78-7.9[b]
	ESP		18	1.1[b]
Cyclone furnace (SCC 10100303)	ESP	<3.3	57	0.05[c]-0.68[b]
	Multi-cyclones		710	
Stoker, configuration unknown (no SCC)	Multi-cyclones	13	47	
	ESP	<2.3		
Spreader stoker (SCC 10100306)	Multi-cyclones			6.3[c]

[a] References 19-20. Units are picograms (10^{-12}) of pollutant/Joule of fuel burned. SCC = Source Classification Code.

[b] Primarily trimethyl propenyl naphthalene.

[c] Primarily biphenyl.

Table 1.7-11 (English Units). EMISSION FACTORS FOR TRACE METALS AND POLYCYCLIC ORGANIC MATTER (POM) FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Control Device	Emission Factor, lb/10^{12}Btu		
		Cr	Mn	POM
Pulverized coal (SCC 10100301)	Multi-cyclones	67-74		
	ESP	20		
	High efficiency cold-side ESP			2.3
Pulverized wet bottom (no SCC)	ESP		34	
Pulverized dry bottom (no SCC)	Multi-cyclones			1.8-18[b]
	ESP		42	2.6[b]
Cyclone furnace (SCC 10100303)	ESP	<28	133	0.11[c]-1.6[b]
	Multi-cyclones		1700	
Stoker, configuration unknown (no SCC)	Multi-cyclones	30	110	
	ESP	<5.4		
Spreader stoker (SCC 10100306)	Multi-cyclones			15[c]

[a] References 19-20. Units are lb. of pollutant/10^{12}Btu of fuel burned.
SCC = Source Classification Code.

[b] Primarily trimethyl propenyl naphthalene.

[c] Primarily biphenyl.

References for Section 1.7

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2. G. H. Gronhovd, et al., "Some Studies on Stack Emissions from Lignite Fired Powerplants", Presented at the 1973 Lignite Symposium, Grand Forks, ND, May 1973.

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9. *Coal Fired Power Plant Trace Element Study, A Three Station Comparison*, U. S. Environmental Protection Agency, Denver, CO, September 1975.

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12. *Source Test Data on Lignite-Fired Cyclone Boilers*, North Dakota State Department of Health, Bismarck, ND, March 1982.

13. *Inhalable Particulate Source Category Report for External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.

14. Personal communication dated September 18, 1981, Letter from North Dakota Department of Health to Mr. Bill Lamson of the U. S. Environmental Protection Agency, Research Triangle Park, NC, conveying stoker data package.

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15. *Source Test Data on Lignite-Fired Power Plants*, North Dakota State Department of Health, Bismarck, ND, April 1992.

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APPENDIX A

CONVERSION FACTORS

TABLE A-1. CONVERSION FACTORS

Given	To Obtain	Multiply By
ppm	lb/MBtu	2.59×10^{-9} (MW)Fd $(20.9/20.9\text{-}O_2)$ 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 B

MARKED-UP 1986 AP-42 SECTION 1.7

Significant changes to this section
are marked as below.

1.7 LIGNITE COMBUSTION

1.7.1 General[1-4]

Lignite is ~~a relatively young coal~~ a coal in the early stage of coalification, with properties intermediate to those of bituminous coal and peat. It has a high moisture content (35 to 40 weight percent) and a low wet basis heating value (1500 to 1900 kilocalories) and generally is burned only near where it is mined, in ~~some midwestern States~~ centered in North Dakota and Texas. Although a small amount is used in industrial and domestic situations, lignite is used mainly for steam/electric production in power plants. In the past, lignite has been burned mainly in small stokers, but today the trend is toward use in much larger pulverized coal fired or cyclone fired boilers.

The major advantages of firing lignite are that, in certain geographical areas, it is plentiful, relatively low in cost and low in sulfur content (0.4 to 1 wet basis weight percent). Disadvantages are that more fuel and larger facilities are necessary to generate a unit of power than is the case with bituminous coal. The several reasons for this are (1) the higher moisture content means that more energy is lost in the gaseous products of combustion, which reduces boiler efficiency; (2) more energy is required to grind lignite to combustion specified size, especially in pulverized coal fired units; (3) greater tube spacing and additional soot blowing are required because of the higher ash fouling tendencies; and (4) because of its lower heating value, more fuel must be handled to produce a given amount of power, since lignite usually is not cleaned or dried before combustion (except for some drying in the crusher or pulverizer and during transfer to the burner). No major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

1.7.2 Emissions And Controls[2-11]

The major pollutants from firing lignite, as with any coal, are particulate, sulfur oxides, and nitrogen oxides. Volatile organic compounds (VOC) and carbon monoxide emissions are quite low under normal operating conditions.

Particulate emission levels appear most dependent on the firing configuration in the boiler. Pulverized coal fired units and spreader stokers, which fire much or all of the lignite in suspension, emit the greatest quantity of flyash per unit of fuel burned. Cyclone furnaces, which collect much of the ash as molten slag in the furnace itself, and stokers (other than spreader), which retain a large fraction of the ash in the fuel bed, both emit less particulate matter. In general, the relatively high sodium content of lignite lowers particulate emissions by causing more of the resulting flyash to deposit on the boiler tubes. This is especially so in pulverized coal fired units wherein a high fraction of the ash is suspended in the combustion gases and can readily come into contact with the boiler surfaces.

Nitrogen oxide emissions are mainly a function of the boiler firing configuration and excess air. Stokers produce the lowest NO_x levels, mainly

Break into separate tables. Add references and factor ratings to each table (also SCCs)

TABLE 1.7-1. EMISSION FACTORS FOR EXTERNAL COMBUSTION OF LIGNITE COAL[a]

Firing configuration	Particulate[b]		Sulfur oxides[c]		Nitrogen oxides[d]		Carbon monoxide	Volatile organics	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton		Nonmethane	Methane
Pulverized coal fired dry bottom	3.1A	6.3A	15S	30S	6[e,f]	12[e,f]	g	g	g
Cyclone furnace	3.3A	6.7A	15S	30S	8.5	17	g	g	g
Spreader stoker	3.4A	6.8A	15S	30S	3	6	g	g	g
Other stoker	1.5A	2.9A	15S	30S	3	6	g	g	g

[a] For lignite consumption as fired.

[b] References 5-6, 9, 12. A = wet basis % ash content of lignite.

[c] References 2, 5-6, 10-11. S = wet basis weight % sulfur content of lignite. For high sodium/ash lignite (Na_2O >8%), use 8.5S kg/Mg (17S lb/ton); for low sodium/ash lignite (Na_2O <2%), use 17.5S kg/Mg (35S lb/ton). If unknown, use 15S kg/Mg (30S lb/ton). The conversion of SO_2 is shown to be a function of alkali ash constituents.

[d] References 2, 5, 7-8. Expressed as NO_2.

[e] Use 7 kg/Mg (14 lb/ton) for front wall fired and horizontally opposed wall fired units, and 4 kg/Mg (8 lb/ton) for tangentially fired units.

[f] May be reduced 20 - 40% with low excess firing and/or staged combustion in front fired and opposed wall fired units and cyclones.

[g] Factors in Table 1.1-1 may be used, based on combustion similarity of lignite and bituminous coal.

Add new tables for:

- N_2O
- Trace elements
- Controlled NO_x, CO
- Controlled PM
- Controlled trace elements and POM.

Add discussion of NSPS impacts

because most existing units are relatively small and have lower peak flame temperatures. In most boilers, regardless of firing configuration, lower excess combustion air means lower NO_x emissions.

Sulfur oxide emissions are a function of the alkali (especially sodium) content of the lignite ash. Unlike most fossil fuel combustion, in which over 90 percent of the fuel sulfur is emitted as SO_2, a significant fraction of the sulfur in lignite reacts with the ash components during combustion and is retained in the boiler ash deposits and fly ash. Tests have shown that less than 50 percent of the available sulfur may be emitted as SO_2 when a high sodium lignite is burned, whereas more than 90 percent may be emitted from low sodium lignite. As a rough average, about 75 percent of the fuel sulfur will be emitted as SO_2, the remainder being converted to various sulfate salts.

Newer lignite fired utility boilers are equipped with large electrostatic precipitators with as high as 99.5 percent particulate control. Older and smaller electrostatic precipitators operate at about 95 percent efficiency. Older industrial and commercial units use cyclone collectors that normally achieve 60 to 80 percent collection efficiency on lignite flyash. Flue gas desulfurization systems identical to those on bituminous coal fired boilers are in current operation on several lignite fired utility boilers. (See Section 1.1).

Nitrogen oxide reductions of up to 40 percent can be achieved by changing the burner geometry, controlling excess air and making other changes in operating procedures. The techniques for bituminous and lignite coal are identical.

Incorporate into EF tables

TABLE 1.7-2. EMISSION FACTOR RATINGS FOR LIGNITE COMBUSTION

Firing configuration	Particulate	Sulfur dioxide	Nitrogen oxides
Pulverized coal fired dry bottom	A	A	A
Cyclone furnace	C	A	A
Spreader stoker	B	B	C
Other stokers	B	C	D

Expand discussion of control systems to include:
- Wet and dry FGD systems
- Overfire air + LNB

TABLE 1.7-3. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR BOILERS BURNING PULVERIZED LIGNITE COAL[a]

EMISSION FACTOR RATING: E

Particle size[b] (μm)	Cumulative mass % ≤ stated size		Cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]	
	Uncontrolled	Multiple cyclone controlled	Uncontrolled	Multiple cyclone controlled[d]
15	51	77	1.58A (3.16A)	0.477A (0.954A)
10	35	67	1.09A (2.18A)	0.415A (0.830A)
6	26	57	0.81A (1.62A)	0.353A (0.706A)
2.5	10	27	0.31A (0.62A)	0.167A (0.334A)
1.25	7	16	0.22A (0.44A)	0.099A (0.198A)
1.00	6	14	0.19A (0.38A)	0.087A (0.174A)
0.625	3	8	0.09A (0.18A)	0.050A (0.100A)
TOTAL	100	100	3.1A (6.2A)	0.62A (1.24A)

[a] Reference 13.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = coal ash weight % content, as fired.

[d] Estimated control efficiency for multiple cyclone, 80%.

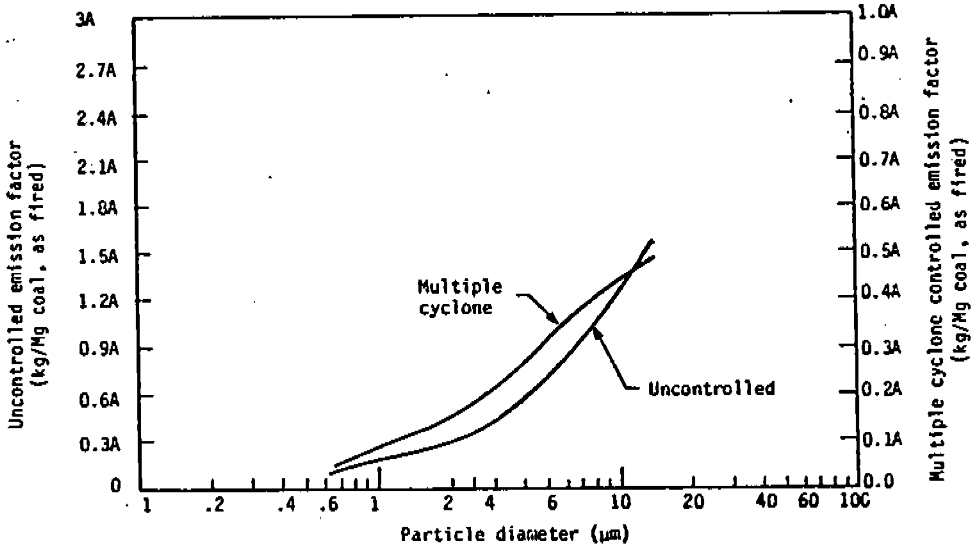

Figure 1.7-1. Cumulative size specific emission factors for boilers burning pulverized lignite coal.

TABLE 1.7-4 CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR LIGNITE FUELED SPREADER STOKERS[a]

EMISSION FACTOR RATING: E

Particle size[b] (µm)	Cumulative mass % ≤ stated size		Cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]	
	Uncontrolled	Multiple cyclone controlled	Uncontrolled	Multiple cyclone controlled[d]
15	28	55	0.95A (1.9A)	0.374A (0.748A)
10	20	41	0.68A (1.36A)	0.279A (0.558A)
6	14	31	0.48A (0.96A)	0.211A (0.422A)
2.5	7	26	0.24A (0.48A)	0.177A (0.354A)
1.25	5	23	0.17A (0.34A)	0.156A (0.312A)
1.00	5	22	0.17A (0.34A)	0.150A (0.300A)
0.625	4	e	0.14A (0.28A)	e
TOTAL	100	100	3.4A (6.8A)	0.68A (1.36A)

[a] Reference 13.

[b] Expressed as aerodynamic equivalent diameter.

[c] Coal ash weight % content, as fired.

[d] Estimated control efficiency for multiple cyclone, 80%.

[e] Insufficient data.

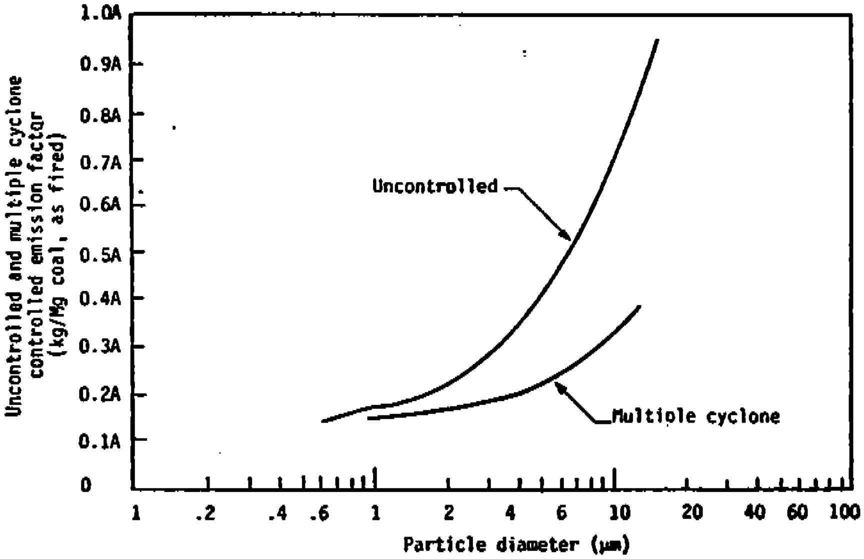

Figure 1.7-2. Cumulative size specific emission factors for lignite fueled spreader stokers.

Emission factors for particulate, sulfur dioxide and nitrogen oxides are presented in Table 1.7-1, and emission factor ratings in Table 1.7-2. Specific emission factors for particulate emissions, and emission factor ratings for the cumulative particle size distributions, are given in Tables 1.7-3 and 11.7-4. Uncontrolled and controlled size specific emission factors are presented in Figures 1.7-1 and 1.7-2. Based on the similarity of lignite combustion and bituminous coal combustion, emission factors for carbon monoxide and volatile organic compounds (Table 1.1-1), and cumulative particle size distributions for cyclone furnaces, uncontrolled spreader stokers and other stokers (Tables 1.1-5 through 1.1-8) may be used.

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Add and delete references as required.

11. C. C. Shih, et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume III: External Combustion Sources for Electricity Generation, EPA Contract No. 68-02-2197, TRW Inc., Redondo Beach, CA, November 1980.

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4.0 REVISED SECTION 1.7

This section contains the final Section 1.7.

5.0 REFERENCES

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