VOLUME II: CHAPTER 2

PREFERRED AND ALTERNATIVE METHODS FOR ESTIMATING AIR EMISSIONS FROM BOILERS

January 2001

DISCLAIMER

As the Environmental Protection Agency has indicated in Emission Inventory Improvement Program (EIIP) documents, the choice of methods to be used to estimate emissions depends on how the estimates will be used and the degree of accuracy required. Methods using site-specific data are preferred over other methods. These documents are non-binding guidance and not rules. EPA, the States, and others retain the discretion to employ or to require other approaches that meet the requirements of the applicable statutory or regulatory requirements in individual circumstances.

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1

INTRODUCTION

The purposes of the preferred methods guidelines are to describe emission estimation techniques for stationary point sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. This chapter describes the procedures and recommended approaches for estimating emissions from external combustion sources (i.e., boilers).

Section 2 of this chapter contains a general description of the boiler source category, a listing of emission sources commonly associated with boilers, and an overview of the available control technologies for various boiler types. Section 3 of this chapter provides an overview of available emission estimation methods. It should be noted that the use of site-specific emission data is often preferred over the use of industry-averaged data such as *AP-42* emission factors. However, depending upon available resources, site-specific data may not be cost effective to obtain. Section 4 presents the preferred emission estimation methods for boilers by pollutant, and Section 5 presents the alternative emission estimation techniques. Quality assurance (QA) and quality control (QC) procedures are described in Section 6, and data coding procedures are discussed in Section 7. Section 8 lists references. Appendix A provides an example data collection form for boilers to assist in information gathering prior to emissions calculations. Refer to Chapter 1 of this volume, *Introduction to Stationary Point Source Emission Inventory Development*, for general concepts and technical approaches.

This chapter does not specifically discuss State Implementation Plans (SIPs) or base year, periodic, and planning inventories. However, the reader should be aware that the U.S. Environmental Protection Agency (EPA) procedures manuals pertaining to the preparation of emission inventories for carbon monoxide and precursors of ozone are available (EPA, May 1991).

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2

GENERAL SOURCE CATEGORY DESCRIPTION

2.1 SOURCE CATEGORY DESCRIPTION

This section provides a brief overview discussion of boilers. The reader is referred to the *Air Pollution Engineering Manual* (sometimes referred to as *AP-40*) (Buonicore and Davis, 1992) and *AP-42* (EPA, January 1995) for a more detailed discussion on boilers, boiler designs, boiler operations and their influences on emissions.

The boiler source category comprises sources that combust fuels to produce hot water and/or steam. Utility boilers utilize steam to generate electricity. Industrial boilers often generate steam for electrical power as well as process steam. Space heaters use the hot water for heating commercial and residential building space. Fuels typically used in boilers include coal, oil, and natural gas. In addition, liquified petroleum gas (LPG), process and waste gases, and wood wastes may be used. In general, boilers are categorized as follows:

Types of Boilers	Size
Utility	>100 MMBtu/hr
Industrial	10 - 250 MMBtu/hr
Commercial/Institutional	<10 MMBtu/hr
Residential	<<10 MMBtu/hr

These categorizations are general to the types of boilers listed above. It should be noted that regulations developed under the Clean Air Act (such as New Source Performance Standards for Steam Generating Units) may have different size cut-offs for applicability than are listed here.

2.1.1 COAL-FIRED BOILERS

Coal is broadly classified into one of four types (anthracite, bituminous, subbituminous, or lignite) based on differences in heating values and amounts of fixed carbon, volatile matter, ash,

sulfur, and moisture. The following sections discuss the four main types of coal boilers (pulverized coal, cyclone, spreader stoker, and fluidized bed) and the processes that occur at all four types of coal-fired boilers. Pulverized coal and cyclone boilers employ a technique known as suspension firing; they are sometimes categorized by this technique.

Pulverized Coal Furnaces

Pulverized coal furnaces are used primarily in utility and large industrial boilers (Buonicore and Davis, 1992; EPA, January 1995). In a pulverized coal system, the coal is pulverized in a mill to the consistency of talcum powder. The pulverized coal is then entrained in primary air before being fed through the burners to the combustion chamber, where it burns in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry-bottom furnaces may either be tangential- or nontangential-fired units. Some examples of nontangential-fired pulverized coal furnaces are wall-fired, turbo, cell-fired, vertical, and arch. Dry-bottom furnaces fire coal with high ash fusion temperatures, whereas wet-bottom furnaces fire coal with low ash fusion temperatures. Wet-bottom furnace designs have higher nitrogen oxides (NO_x) emission rates and are no longer being built, though many remain in service.

Cyclone Furnaces

Cyclone furnaces are used mostly in utility and large industrial applications (Buonicore and Davis, 1992). Cyclone furnaces burn coal that has a low ash fusion temperature and has been crushed to a four-mesh size (larger than pulverized coal). Coal in a cyclone furnace is fed tangentially with primary air to a horizontal cylindrical combustion chamber. In this chamber, small coal particles are burned in suspension, while the larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small combustion chamber and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag that is drained from the bottom of the furnace through a slag tap opening (EPA, January 1995).

Spreader Stokers

In spreader stokers, a rotating flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. Because of significant amounts of carbon in the particulate, fly ash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue in the fuel bed is deposited in a receiving pit at the end of the grate (EPA, January 1995). Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature.

Fluidized Bed Combustors

In a fluidized bed combustor (FBC), coal is introduced to a bed of either sorbent (limestone or dolomite) or inert material (usually sand) that is fluidized by an upward flow of air. Combustion takes place in the bed at lower temperatures than other boiler types. Key benefits to this relatively new process are fuel flexibility and reduced emissions. FBCs are typically used for industrial-sized boilers and may be emerging as a competitive design for electric power generation (Stultz and Kitto, 1992).

2.1.2 OIL-FIRED BOILERS

There is little variation between the design of oil-fired units and the design of coal-fired units; almost all are either tangential-fired or wall-fired. Fuel oils are broadly classified into two major types: distillate and residual. Distillate oils (fuel oil grade Nos. 1 and 2) are used mainly in domestic and small commercial applications in which easy fuel burning is required. Distillates are more volatile and less viscous than residual oils. Being more refined, they have negligible ash content, and usually contain less than 0.3 weight percent sulfur. Residual oils (grade Nos. 4, 5, and 6) are used mainly in utility, industrial, and large commercial applications with sophisticated combustion equipment. Residual No. 4 oil is sometimes classified as a distillate, and No. 6 is sometimes referred to as Bunker C. The heavier residual oils (grade Nos. 5 and 6) are more viscous and less volatile than distillate oils and, therefore, must be heated to facilitate handling and proper atomization. Because residual oils are produced from the crude oil residue after lighter fractions (gasoline, kerosene, and distillate oils) have been removed, these oils contain significant quantities of ash, nitrogen, and sulfur (EPA, January 1995). However, low-sulfur residual oil is becoming more commonplace.

2.1.3 NATURAL GAS-FIRED BOILERS

Natural gas is used for power generation, industrial process steam and production activities, and domestic and commercial space heating. The primary component of natural gas is methane, although small amounts of ethane, nitrogen, helium, and carbon dioxide (CO_2) can also be present (EPA, January 1995).

Natural gas boilers are considered clean relative to coal- or oil-fired boilers, but improper operating conditions (such as poor air-fuel mixing) may still result in smoke (unburned carbon) in the exhaust, as well as carbon monoxide (CO) and perhaps small amounts of unburned hydrocarbons. NO_x emissions are usually the major pollutants of concern in a well-operated natural gas boiler. NO_x emissions are primarily a function of the combustion chamber temperature.

Several modifications can be made to natural gas boilers to reduce NO_x emissions. Staged combustion can reduce NO_x emissions by 5 to 20 percent (EPA, January 1995); low excess air levels and flue gas recirculation also often lower NO_x emissions.

2.1.4 BOILERS USING OTHER TYPES OF FUEL

Other fuels such as LPG, process gas, wood and/or bark, bagasse and solid/liquid waste may be used in boilers.

LPG is either butane, propane, or a mixture of the two. This gas is often called bottled gas. Grade A LPG is mostly butane and Grade F is mostly propane, with Grades B through E consisting of varying mixtures of butane and propane. Although LPG is considered a clean fuel, gaseous pollutants such as CO, organic compounds (including volatile organic compounds or VOCs), and NO_x are emitted as are small amounts of sulfur dioxide (SO_2).

Process gases that are used for fuel include petroleum refinery gas, blast furnace gas, coke oven gas, landfill gas, and any other process gases with sufficient and economically recoverable heating values.

The burning of wood and/or bark in boilers is mostly confined to situations where steady supplies of wood or bark are available as a byproduct or in close proximity to the boiler. In most cases, the wood is waste that would otherwise present a solid waste disposal problem. The common types of boilers used to burn wood/bark are Dutch ovens, fuel cell ovens, spreader stokers, vibrating grate stokers, and cyclone (tangential-fired) boilers (EPA, January 1995).

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Fuel cells, horseshoe boilers, and spreader stoker boilers are used to burn bagasse.

Solid or liquid waste may consist of general waste solids or liquids, refuse-derived fuel, or waste oil. Waste oil, or used oil, refers to spent lubrication and other industrial oils that would otherwise present a liquid waste disposal problem. The most common type of waste oil is used vehicle crankcase oil. Other oils include metalworking lubricants, animal and vegetable oils and fats, and transformer and other heat transfer fluids. Waste oils may have higher emissions of SO_2 and particulates than refined fuel oils, but will have similar levels of emissions for NO_x, CO, and organic compounds (EPA, January 1995). Heavy metal emissions may be greater from crankcase oil combustion.

2.1.5 COGENERATION UNITS

Cogeneration is the production of more than one useful form of energy (such as process heat and electric power) from the same energy source. Cogeneration plants produce electric power and

also meet the process heat requirements of industrial processes (Cengel and Boles, 1989). A steam turbine, gas-cycle turbine, or combined-cycle turbine can be used to produce power in a cogeneration plant.

In a typical cogeneration plant, energy is transferred to water by burning coal, oil, natural gas, or other (nonfossil) fuels in a boiler. The high-pressure, high-temperature steam leaving the boiler is expanded in a turbine that drives a generator to produce electric power. The low-pressure, low-temperature steam leaving the turbine is used as process heat. Industries likely to use cogenerated process heat are the chemical, pulp and paper, oil production and refining, steel making, food processing, and textile industries. Besides the steam-turbine cycle described above, a gas-cycle or a combined-cycle turbine can be used to produce power in a cogeneration plant (Cengel and Boles, 1989). Combustion turbines are also commonly used for cogeneration.

2.1.6 AUXILIARY SOURCES

Auxiliary sources associated with boilers include fuel storage piles, fuel storage tanks, materials handling, and other sources of fugitive emissions. These sources are often overlooked and not reported as a part of the emission inventory. However, it is essential that these sources be considered in the emission inventory to develop a complete record of the emissions coming from the facility.

Coal storage piles are used to store coal at the boiler site. Material handling involves the receipt of coal, movement of coal to the preparation (crushing) facility, and movement of coal to the boilers, which may result in the release of particulate matter (PM) emissions. A coal-fired boiler may also use fuel oil or gas for the initial light-off of the boilers. In this case, as well as for oil-fired boilers, VOC losses from fuel oil storage tanks should be considered (EPA, January 1995).

Because coal crushing operations can generate a significant amount of fine PM, they should be included in the inventory. Because of the potential for explosion from this fine particulate, crushing operations are typically well controlled (EPA, January 1995).

2.2 EMISSION SOURCES

Air pollutant emissions associated with boilers can occur at the following points/processes. Section 7 lists the source classification codes (SCCs) for these emission points.

2.2.1 MATERIAL HANDLING (FUGITIVE EMISSIONS)

Material handling includes the receipt, movement, and processing of fuel and materials to be used at the boiler facility. Coal, limestone, wood, bark, and solid waste may all be included, and their handling may result in particulate emissions. Organic compound emissions can also result from the transfer of liquid and gaseous fuels. This source category includes storage bins and

open stockpiles, as well as the processes used to transfer these materials (e.g., unloading, loading, and conveying).

2.2.2 STORAGE TANKS

Storage tanks are used to store fuel oils at boiler facilities, and should be inventoried as a source of organic compound emissions. Storage tanks at boiler facilities are usually one of two types: fixed roof or floating roof. Emissions at fixed-roof tanks are typically divided into two categories: working losses and breathing losses. Working losses refer to the combined loss from filling and emptying the tank. Filling losses occur when the organic compounds and VOCs contained in the saturated air are displaced from a fixed-roof vessel during loading. Emptying losses occur when air drawn into the tank becomes saturated and expands, exceeding the capacity of the vapor space. Breathing losses are the expulsion of vapor from a tank through vapor expansion caused by changes in temperature and pressure.

Emissions at floating roof tanks are reported in two categories: standing losses and withdrawal losses. Withdrawal loss is the vaporization of liquid that clings to the tank wall and that is exposed to the atmosphere when a floating roof is lowered by withdrawal of liquid. Standing losses result from wind-induced mechanisms and occur at rim seals, deck fittings, and deck seams (EPA, January 1995).

The TANKS program is commonly used to quantify emissions from oil-fired boilers. Its use at boiler installations should be carefully evaluated because it is a complicated program with a great number of input parameters. It is commonly used at large oil-burning facilities where VOC emissions may be significant. Check with your local or state authority as to whether TANKS is required for your facility. The use of the TANKS program for calculating emissions from storage tanks is discussed in Chapter 1 of Volume II, *Introduction to Stationary Point Source Emissions Inventory Development*. TANKS can be downloaded from the EPA's CHIEF website at www.epa.gov/ttn/chief.

2.2.3 PROCESS EMISSIONS

For boilers, emissions resulting from the process (combustion of fuel to generate hot water and steam) are typically vented to the atmosphere via a stack or vent. The major pollutants of concern from boiler stacks are PM, sulfur oxides (SO_2 and sulfur trioxide [SO_3]), VOC, and NO_x. CO and unburned combustibles, including numerous organic compounds (e.g., benzene) can also be emitted under certain boiler operating conditions. Most of the carbon in fossil fuels is emitted as CO_2 during combustion, and may be inventoried due to its role as a greenhouse gas. Trace metals, such as arsenic and cadmium, may also be emitted as a result of combustion of coal and oil. Additionally, organic pollutants such as formaldehyde, and polycyclic organic matter (POM) may be formed during combustion and emitted (EPA, April 1989). Typical pollutants associated

with boiler emissions are listed in Table 2.2-1 by fuel type. Not all listed pollutants will be emitted in every case, so site-specific pollutant data (from fuel analysis or stack tests) should always be used if available.

2.3 FACTORS AND DESIGN CONSIDERATIONS INFLUENCING EMISSIONS

2.3.1 PROCESS OPERATING FACTORS

The combustion process is defined as the rapid oxidation of substances (fuels) with the evolution of heat. Boilers utilize the heat generated by combustion to produce hot water, steam, or both. The fuel types discussed in this chapter include coal, oil, natural gas, and other fuels such as wood, LPG, and process gases. When these burn, they are converted into CO_2 and water, referred to as the combustion products. The noncombustible portion of a fuel remains as a solid residue or ash. The coarser, heavier portion remains within the combustion chamber and is called "bottom ash." The finer portion, referred to as "fly ash," exits the furnace with the flue gas.

Combustion products from boiler operation can also include partially oxidized hydrocarbons, CO, SO_2, SO_3, NO_x, acids such as hydrochloric acid, and organohalides such as dioxins and furans. The generation of undesirable combustion products is strongly influenced by fuel type, furnace type, firing configuration, and boiler operating conditions. Although a detailed discussion of boiler operations cannot be presented here, some general observations are included to assist in understanding the relative impact of various boilers and fuel types on air emissions.

The discussion on coal-fired boilers introduced the four primary classifications of coal: lignite, anthracite, bituminous, and subbituminous. Fuel is ranked based on American Society for Testing and Materials (ASTM) standard methods referred to as "proximate" and "ultimate" analyses. Proximate analyses report fuel composition in broad categories such as moisture content and ash content. Ultimate analyses provide an estimate of the carbon, hydrogen, sulfur, oxygen, nitrogen, and water content of the fuel. An ultimate analysis is used to compute combustion air requirements and can also be used to calculate fuel factors (F_d) for determining exhaust gas flow rates (see Equation 2.4-4). Sections 3 and 4 discuss how fuel analysis can be used to estimate emissions of sulfur oxides and metals from fuel combustion. Generally, boiler size, firing configuration, and operation have little effect on the percent conversion of fuel sulfur to sulfur oxides, so fuel analysis is typically a valid means of predicting emissions of sulfur oxides.

By contrast, NO_x formation is highly dependent on boiler conditions, especially temperature and air/fuel ratios near the burner. NO_x is produced by three mechanisms: conversion of fuel-

TABLE 2.2-1

POLLUTANTS ASSOCIATED WITH BOILER EMISSIONS

Criteria Pollutants	Hazardous Air Pollutants
Coal	
• Carbon Monoxide	• Antimony & Compounds
• Lead	• Benzene
• Nitrogen Oxides	• Beryllium & Compounds
• PM-Primary	• Cadmium & Compounds
• PM-Filterable	• Chromium & Compounds
• PM-Condensible	• Cobalt Compounds
• PM10-Primary*	• Dioxin/Furans as 2,3,7,8-TCDD TEQ
• PM10-Filterable*	• Ethylbenzene
• PM2.5- Primary*	• Formaldehyde
• PM2.5-Filterable*	• Hydrogen Chloride
• Sulfur Oxides	• Hydrogen Fluoride
	• Lead & Compounds
	• Manganese & Compounds
	• Mercury & Compounds
	• Methyl Chloroform (1,1,1-Trichloroethane)
	• Methyl Ethyl Ketone (2-Butanone)
	• Nickel & Compounds
	• Toluene
	• Xylenes (includes o, m, and p)
Natural Gas	
• Carbon Monoxide	• Benzene
• Lead	• Cadmium & Compounds
• Nitrogen Oxides	• Chromium & Compounds
• PM-Primary	• Cobalt Compounds
• PM-Filterable	• Formaldehyde
• PM-Condensible	• Lead & Compounds

TABLE **2.2-1**

(CONTINUED)

Criteria Pollutants	Hazardous Air Pollutants
Natural Gas (Continued)	
• PM10-Primary*	• Manganese & Compounds
• PM10-Filterable*	• Mercury & Compounds
• PM2.5- Primary*	• Nickel & Compounds
• PM2.5-Filterable*	• Toluene
• Sulfur Oxides	
Oil	
• Carbon Monoxide	• Benzene
• Lead	• Beryllium & Compounds
• Nitrogen Oxides	• Cadmium & Compounds
• PM-Primary	• Chromium & Compounds
• PM-Filterable	• Cobalt Compounds
• PM-Condensible	• Dioxins/Furans as 2,3,7,8-TCDD TEQ
• PM10-Primary*	• Ethylbenzene
• PM10-Filterable*	• Formaldehyde
• PM2.5- Primary*	• Lead & Compounds
• PM2.5-Filterable*	• Manganese & Compounds
• Sulfur Oxides	• Mercury & Compounds
	• Methyl Chloroform (1,1,1-Trichloromethane)
	• Nickel & Compounds
	• Toluene
	• Xylenes (includes o, m, and p)
	• Dioxins/Furans as 2,3,7,8-TCDD TEQ
	• Ethylbenzene
	• Formaldehyde
	• Lead & Compounds
	• Manganese & Compounds
	• Mercury & Compounds

* PM10 and PM2.5 refer to PM less than or equal to an aerodynamic diameter of 10μm and 2.5μm, respectively.

bound nitrogen in fuel, oxidation of molecular nitrogen from combustion air (referred to as thermal NO_x formation) and reaction of hydrocarbon fragments and atmospheric nitrogen (prompt NO_x). Thermal NO_x formation is highly temperature dependent and becomes rapid as temperatures exceed 3,000°F (Buonicore and Davis, 1992). Lower operating temperatures result in decreased thermal NO_x production. Shorter residence time also lowers thermal NO_x generation. Prompt NO_x is formed very early in the combustion process and is significant only in very fuel-rich flames.

Fuel NO_x will generally account for over 50 percent of the total NO_x generated by oil- and coal-fired boilers. NO_x emissions from tangential-fired oil boilers are typically lower than those from horizontally opposed units. Many boilers employ combustion modifications to reduce NO_x emissions. These include staged combustion, off-stoichiometric firing, flue gas recirculation, and low-NO_x burners with overfire air (OFA). These control strategies can reduce NO_x emissions by 5 to 50 percent (Buonicore and Davis, 1992). For a more detailed discussion of NO_x control strategies, see Chapter 12 of EIIP Volume II, *How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates*.

The utility sector is dominated by pulverized dry-bottom, coal-fired units. Stoker boilers, currently accounting for a small percentage of total national capacity, are less common. Coal-fired pulverized wet-bottom and cyclone boilers are no longer manufactured due to their inability to meet NO_x standards, although many are still in use.

In the industrial sector, more natural gas is used relative to coal and oil. The commercial/institutional sector consumes a greater proportion of oil and natural gas relative to coal consumption than the other two sectors.

2.3.2 CONTROL TECHNIQUES

Table 2.2-2, "Boiler Controls," lists the control technologies associated with boiler operations, along with their typical efficiencies. Control efficiency for a specific piece of equipment will vary depending on the age of the equipment and quality of the maintenance/repair program at a particular facility.

Particulate Control

In addition to PM and PM with an aerodynamic diameter of less than 10 μm (PM_{10}) emissions, particulate control also serves to remove trace metals, as well as metals (such as lead) that are vaporized in the combustion chamber and condensed onto fly ash in the exhaust. However, the PM control efficiencies listed in Table 2.2-2 may not correspond to actual removal efficiencies of specific hazardous air pollutants (HAPs) or metals, due to the phenomena of fine particle

TABLE 2.2-2

BOILER CONTROLS

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Bagasse	PM	Mechanical Collector		20	60
		Wet PM Scrubber		90	
Coal	NO_x	Flue Gas Recirculation		5	45
		Low Excess Air		5	30
		Low NO_x Burners		35	55
		Natural Gas Burners/Reburn		50	70
		Overfire Air		5	30
		Selective Catalytic Reduction		63	94
		Selective Non-catalytic Reduction		30	60
		Low NO_x Burner w/ Selective Non-catalytic Reduction		50	80
		Low NO_x Burner w/ Overfire Air and Selective Catalytic Reduction		85	95
		Low NO_x Burner w/ Overfire Air		40	60
	SO_2[b]	Wet Acid Gas Scrubber		80	99
		Spray Dryer Absorber		70	90

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range [a](%)	
				Minimum Value	**Maximum Value**
Coal (Continued)	PM	Electostatic Precipitator	99	90	99.9
		Fabric Filter	99	99	
		Mechanical Collector	65	90	95
		Wet PM Scrubber		50	99
Coal (Anthracite)	PM	Electrostatic Precipitator	98.4		
		Fabric Filter		98.4	99.4
Coal (Bituminous)	PM	Electrostatic Precipitator		96	99.4
		Fabric Filter		98.3	99.9
	PM-10	Fuel Switching to Sub-bituminous Coal (Industrial Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Industrial Sources)[c]	62.9		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	98.2		

TABLE **2.2-2**

(CONTINUED**)**

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Coal (Bituminous) (Continued)	PM -10 (Continued)	Fuel Switching to Sub-bituminous Coal (Utility Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Utility Sources)[c]	69.5		
		Fuel Switching to Natural Gas (Utility Sources)[c]	99.3		
	PM - 2.5	Fuel Switching to Sub-bituminous Coal (Industrial Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Industrial Sources)[c]	7.4		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	93.1		
		Fuel Switching to Sub-bituminous Coal (Utility Sources)[c]	21.4		

TABLE **2.2-2**

(CONTINUED**)**

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	**Maximum Value**
Coal (Bituminous) (Continued)	PM - 2.5 (continued)	Fuel Switching to Natural Gas (Utility Sources)[c]	97.5		
Coal (Sub-bituminous)	PM - 10	Fuel Switching to Residual Oil (Industrial Sources)[c]	52.8		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	97.7		
		Fuel Switching to Residual Oil (Utility Sources)[c]	61.2		
		Fuel Switching to Natural Gas (Utility Sources)[c]	99.2		
	PM - 2.5	Fuel Switching to Natural Gas (Industrial Sources)[c]	91.2		
		Fuel Switching to Natural Gas (Utility Sources)[c]	96.8		

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Lignite	SO_2[b]	Wet Acid Gas Scrubber		90	
	PM	Electrostatic Precipitator		95	99.5
		Mechanical Collector		60	80
Oil, Distillate, No. 2	NO_x	Flue Gas Recirculation		45	55
		Low Excess Air		2	19
		Overfire Air		20	45
		Selective Catalytic Reduction			90
Oil, Residual, Nos. 4, 5, and 6	NO_x	Flue Gas Recirculation	21	2	31
		Low Excess Air		5	31
		Overfire Air		24	47
		Selective Catalytic Reduction		70	80
		Selective Non-catalytic Reduction		35	70

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	**Maximum Value**
Oil, Residual, Nos. 4, 5, and 6	PM - 10	Fuel Switching to Natural Gas (Industrial Sources)[c]	95.1		
		Fuel Switching to Natural Gas (Utility Sources)[c]	97.9		
	PM - 2.5	Fuel Switching to Natural Gas (Industrial Sources)[c]	92.5		
		Fuel Switching to Natural Gas (Utility Sources)[c]	97.0		
Utility Oil or Natural Gas	NO_x	Flue Gas Recirculation		40	65
Municipal Waste	NO_x	Selective Catalytic Reduction	69		80
Natural Gas	NO_x	Flue Gas Recirculation		49	68
		Low Excess Air		0	31
		Low NO_x Burners		40	85
		Overfire Air	60	13	73
		Selective Catalytic Reduction		80	90

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Natural Gas (Continued)	NO_x (Continued)	Selective Non-catalytic Reduction		35	80
Natural Boiler Gas	NO_x	Low NOX Burner w/ Overfire Air		40	50
Sewage Sludge	PM	Wet PM Scrubber		60	99
Wood	NO_x	Selective Non-catalytic Reduction		50	70
	PM	Electrostatic Precipitator		93	99.8
		Fabric Filter	98	95.9	99.9
		Mechanical Collector		65	95
		Wet PM Scrubber	90	95	99
		Wet PM Scrubber[d]		92.1	93.3
Wood Bark	PM	Wet PM Scrubber[d]		83.8	85.1

TABLE **2.2-2**

(CONTINUED**)**

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	**Maximum Value**
Not Identified	SO$_2$[b]	Wet Acid Gas Scrubber (Chemical Manufacturing) (b)		90	99

Source: EIIP Volume II, Chapter 12, *How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates*.
 a) A blank field indicates that no data was available for this pollutant, fuel type, and control device.
 b) Control device controls SO$_x$.
 c) These are the potential emission reductions from fuel switching. Source: EPA. 1998. *Stationary Source Control Techniques Document for Fine Particulate Matter*. U.S. Environmental Protection Agency. EPA 452/R-97-001.
 d) Control efficiency is applicable to general fuel combustion operations.

enrichment. This phenomena may be especially important for metals that volatilize at peak combustion temperatures and condense on particulate at flue gas temperatures downstream.

Electrostatic Precipitators (ESPs). ESPs are widely used to control emissions from coal-fired boilers and account for 95 percent of all utility particulate controls in the United States (Buonicore and Davis, 1992). ESPs are PM control devices that employ electrical forces to remove particles from the flue gas onto collecting plates (EPA, June 1991). The accumulated particles are then knocked or washed off the plates and into collecting hoppers.

Fabric Filters. Fabric filter systems (also called baghouses) filter particles through fabric filtering elements (bags). Particles are caught on the surface of the bags, while the cleaned flue gas passes through. To minimize pressure drop, the bags must be cleaned periodically as the dust layer builds up. Fabric filters can achieve the highest particulate collection efficiency of all particulate control devices. A trend toward using more fabric filters in the electric utility industry is expected because of increasing restrictions on emissions of PM_{10} and the growing use of dry SO_2 control technologies, such as dry injection and spray drying (Buonicore and Davis, 1992).

Multiple Cyclones. The cyclone (also known as a "mechanical collector") is a particulate control device that uses gravity, inertia, and impaction to remove particles from the flue gas. A multiple cyclone consists of numerous small-diameter cyclones operating in parallel. Multiple cyclones are less expensive to install and operate than ESPs and fabric filters, but are not as effective at removing particulates. They are often used as precleaners to remove the bulk of heavier particles from the flue gas before it enters the main control device. They are often used on wood-fired boilers in series with scrubbers, ESPs, or fabric filters (Buonicore and Davis, 1992).

Venturi Scrubbers. Venturi scrubbers (sometimes referred to as high-energy wet scrubbers) are used to remove coarse and fine PM. Flue gas passes through a venturi tube while low-pressure water is added at the throat. The turbulence in the venturi tube promotes intimate contact between the particles and the water. The wetted particles and droplets are collected in a cyclone spray separator (sometimes called a cyclonic demister). Venturi scrubbers are often used on wood-fired boilers. Venturi scrubbers have a relatively high pressure drop, often ranging from 25 to 50 inches of water.

Sulfur Dioxide Control

Dry Scrubbers. Dry scrubbing is sometimes referred to as spray drying or spray absorption. It involves spraying a highly atomized slurry (which may contain water) of an alkaline reagent (slaked lime) into the hot flue gas to absorb the SO_2. The high temperatures of the flue gas evaporates the water (if a wet reagent was used) and a dust collector removes the "dry" reagent which has absorbed the SO_2. Unlike wet scrubbers, the dry scrubber is positioned before the dust

collector. Dry scrubbers are often applied on smaller industrial boilers, waste-to-energy plants, and units burning low-sulfur fuels (Stultz and Kitto, 1992).

Wet Scrubbers. In wet scrubbers, an alkaline liquid slurry is introduced into the flue gas. Wet scrubbing results in the generation of wet waste, which typically must be treated and disposed of in accordance with landfill and wastewater regulations. Limestone scrubbing is widely used on coal-fired utility boilers. Less common are regenerable systems that treat the absorber product to recover reagents, sometimes producing salable gypsum, elemental sulfur, or sulfuric acid.

Low-Sulfur Fuel. This approach to reducing SO_2 emissions reduces the sulfur fed to the combustor by burning low-sulfur coals or oils. Fuel blending is the process of mixing high-sulfur-content fuels with low-sulfur-content fuels. The goal of effective fuel blending is to meet the blend specification, including sulfur content, heating value, moisture content, and (for coal) grindability. This practice is highly effective since most studies estimate that over 95 percent of the fuel sulfur is converted to SO_2 during combustion. The minor amount of sulfur not converted is typically bound in the ash. High-alkali coal tends to bind more SO_2 in the ash.

Nitrogen Oxides Control

Selective Catalytic Reduction. SCR is an add-on control technology that catalytically promotes the reaction between ammonia (which is injected into the flue gas) and NO_x to form nitrogen (N_2) and water. SCR is currently used primarily with natural gas- and oil-fired boilers. In addition, several SCR systems have recently been installed on coal-fired boilers. If sulfur is present in the fuel, ammonium sulfate and bisulfate can form at around 500°F and can deposit on and foul the catalyst. If chlorine is present, ammonium chloride can form at around 250°F and result in a visible plume.

Selective Noncatalytic Reduction. SNCR technologies inject a reducing agent into NO_x-laden flue gas to reduce the NO_x to N_2 and water (H_2O). Two basic processes are currently available, one based on ammonia injection (Thermal DeNO$_x$®), and one based on urea injection (sponsored by the Electric Power Research Institute [EPRI]). Both systems require careful attention to the problem of unreacted ammonia, which can form corrosive ammonia salts that damage downstream equipment.

Low NO$_x$ Burners and Overfire Air. LNB and OFA have been demonstrated to be effective means of lowering NO_x production at utility boilers. These are combustion control methods that reduce peak temperatures in the combustion zone, reduce the gas residence time in the high-temperature zone, and provide a rich fuel/air ratio in the primary flame zone. This is considered a design change although it results in a reduction of emissions.

Low Excess Air. LEA is another combustion modification designed to lower NO_x emissions by inhibiting the creation of thermal NO_x. This is accomplished by limiting the amount of free nitrogen in the combustion zone. Excess air must be present to ensure good fuel use and to prevent smoke formation.

Natural Gas Burner/Reburn. In a reburn configured boiler, reburn fuel (natural gas, oil, or pulverized coal) is injected into the upper furnace region to convert the NO_x formed in the primary fuel's combustion zone to molecular nitrogen and water.

Flue Gas Recirculation (FGR). A portion of flue gas is recycled back to the primary combustion zone. This system reduces NO_x formation by two mechanisms:

- Heating in the primary combustion zone of the inert combustion products contained in the recycled flue gas lowers the peak flame temperature, thereby reducing thermal NO_x formation.

- To a lesser extent, FGR reduces thermal NO_x formation by lowering the oxygen concentration in the primary flame zone.

The recycled flue gas may be pre-mixed with the combustion air or injected directly into the flame zone. Direct injection allows more precise control of the amount and location of FGR.

Staged Overfire Air. Staged combustion, or off-stoichiometric combustion, combusts the fuel in two or more steps.   A percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the furnace remains unchanged. Initially, fuel is combusted in a primary, fuel-rich, combustion zone. Combustion is completed at lower temperatures in a secondary, fuel-lean, combustion zone. The sub-stoichiometric oxygen introduced with the primary combustion air into the high temperature, fuel-rich zone reduces fuel and thermal NO_x formation. Combustion in the secondary zone is conducted at a lower temperature, reducing thermal NO_x formation.

VOC Control

Boilers do not have controls for organics or VOCs since the combustion process destroys most organic pollutants. Boilers do have residual amounts of organics and HAPs in their exhaust streams, which may be reduced by some add-on controls such as scrubbers used to control other pollutants.

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3

OVERVIEW OF AVAILABLE METHODS FOR ESTIMATING EMISSIONS

3.1 EMISSION ESTIMATION METHODOLOGIES

Several methodologies are available for calculating emissions from boilers. The method used is dependent upon available data, available resources, and the degree of accuracy required in the estimate. In general, site-specific data that are representative of normal operation at that site are preferred over industry-averaged data such as *AP-42* emission factors. For purposes of calculating peak season daily emissions for SIP inventories, refer to the EPA *Procedures* manual (EPA, May 1991).

This section discusses the methods available for calculating emissions from boilers and identifies the preferred method of calculation on a pollutant basis. This discussion focuses on estimating emissions from fuel combustion. Emission estimation approaches for auxiliary processes, such as using EPA's TANKS program to calculate storage tank emissions, are briefly discussed in Chapter 1 of this volume.

3.1.1 CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

A CEMS provides a continuous record of emissions over an extended and uninterrupted period of time. Various principles are employed to measure the concentration of pollutants in the gas stream; they are usually based on photometric measurements. Once the pollutant concentration is known, emission rates are obtained by multiplying the pollutant concentration by the volumetric stack gas flow rate. The accuracy of this method may be problematic at low pollutant concentrations.

3.1.2 PREDICTIVE EMISSION MONITORING (PEM)

PEM is based on developing a correlation between pollutant emission rates and process parameters and could be considered a hybrid of continuous monitoring, emission factors, and stack tests. A correlation test must first be performed to develop this relationship. Emissions at a later time can then be estimated or predicted using process parameters to predict emission rates based on the results of the initial source test. For example, emissions from a boiler controlled by

an SO_2 scrubber could be predicted, based on the correlation of the scrubbing solution to the pH and flow rate.

3.1.3 STACK SAMPLING

Stack sampling provides a "snapshot" of emissions during the period of the test. Samples are collected using probes inserted into the stack, and pollutants are collected in or on various media and sent to a laboratory for analysis. Some stack test methods provide real time data where the gas sample is analyzed on-site by continuous analysis (e.g., EPA Method 6C and 7E). Pollutant concentrations are obtained by dividing the amount of pollutant collected during the test by the volume of the sample. Emission rates are then determined by multiplying the pollutant concentration by the volumetric stack flow rate. Only experienced stack testers should perform the stack tests. The accuracy of this method may be problematic at low pollutant concentrations.

3.1.4 FUEL ANALYSIS

Fuel analysis data can be used to predict emissions by applying mass conservation laws. For example, if the concentration of a pollutant, or pollutant precursor, in a fuel is known, emissions of that pollutant can be calculated by assuming that all of the pollutant is emitted. This approach is appropriate for pollutants such as metals, SO_2, and CO_2. It should be noted, however, that some of the pollutant may end up in physical or chemical states (ash, unburned hydrocarbons, etc.) not emitted to the atmosphere.

3.1.5 EMISSION FACTORS

Emission factors are available for many source categories and are based on the results of source tests performed at one or more facilities within an industry. Basically, an emission factor is the pollutant emission rate relative to the level of source activity. Chapter 1 of this volume contains a detailed discussion of the reliability, or quality, of available emission factors. EPA provides compiled emission factors for criteria and HAPs in *AP-42*, the locating and estimating (L&E) series of documents, and the Factor Information Retrieval (FIRE) System. These may be found online at: www.epa.gov/ttn/chief/

3.2 COMPARISON OF AVAILABLE EMISSION ESTIMATION METHODOLOGIES

Table 2.3-1 identifies the preferred and alternative emission estimation approach for selected pollutants. For many of the pollutants emitted from boilers, several of the previously defined emission estimation methodologies can be used.

TABLE 2.3-1

**SUMMARY OF PREFERRED AND ALTERNATIVE EMISSION
ESTIMATION METHODS FOR BOILERS**

Parameter	Preferred Emission Estimation Approach	Alternative Emission Estimation Approach[a]
SO_2	CEMS/PEM data	1. Fuel Analysis[b] 2. Stack sampling data 3. EPA/state published emission factors
NO_x	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
CO	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
CO_2	CEMS/PEM data	1. Stack sampling data 2. Fuel analysis 3. EPA/state published emission factors
VOC[c]	Stack sampling data	EPA/state published emission factors
THC[d]	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
$PM/PM_{10}/PM_{2.5}/PM_{condensible}$	Stack sampling data	EPA/state published emission factors

TABLE 2.3-1

(CONTINUED)

Parameter	Preferred Emission Estimation Approach	Alternative Emission Estimation Approach[a]
Heavy metals	Fuel analysis[e]	1. Stack sampling data 2. EPA/state published emission factors
Speciated organics	Stack sampling data	EPA/state published emission factors
Sulfuric acid mist	Stack sampling data	EPA/state published emission factors
Flow rate	CFRM[f] data/stack sampling data	1. Stack sampling data 2. EPA/state published emission factors

[a] In most cases, there are several alternative emission estimation approaches.
[b] May be used when no SO_2 control device is present.
[c] There is no direct measurement method for VOC. VOC is defined by EPA as those volatile organic compounds that are photo reactive and contribute to ozone formation. There are 2 common ways for determining VOC. The first is to measure as many of the individual organic compounds as possible and add those that are considered VOC. The second is to measure total hydrocarbons, subtract methane and ethane, and add formaldehyde. The second procedure is more of an estimate of VOC, but is considered acceptable. When using emission factors for VOC and speciated organics it should be noted that the sum of individual organic compounds may exceed the VOC emission factor due to the differences in test methods and the availability of test data for each pollutant.
[d] THC = Total hydrocarbons.
[e] Preferred for oil combustion only when no particulate control device is present; otherwise use stack sampling data.
[f] CFRM = Continuous flow rate monitor.

The preferred method for estimating boiler emissions is to use some form of direct or indirect measurement. This includes stack samples using a standard EPA reference method or other method of known quality, CEMS, or PEM. The preferred method is determined by the time specificity of the emission estimate (i.e., is an average acceptable or is the value on a given day needed?) and the data quality; the quality of the data will depend on a variety of factors including the number of data points generated, the representativeness of those data points, and the proper operation and maintenance of the equipment being used to record the measurements.

For annual emission inventories, CEMS data should always be used if available, and CEM is the preferred method for SO_2, NO_x, CO, CO_2, and THC. PEM also provides an accurate estimate of emissions, but since emissions are not directly measured on a continuous basis, PEM should not be used if CEMS data is available.

In general, short-term stack samples obtained using an EPA reference method will give the highest quality (most accurate) data for any given point in time. However, for long-term estimates (such as annual emissions), CEMS data is expected to provide the most accurate emission estimate as emissions are being measured directly over the entire period of interest.

The performance of CEMS and PEM is measured with respect to the EPA reference method using an index known as relative accuracy (RA). The RA for CEMS or PEM is generally expressed as a percentage, and should have been quantified for any CEMS/PEM installed for regulatory compliance purposes. Also, the stack sampling data used to establish RA should be available; if the standard error of the sample data is greater than the RA, and if the CEMS is known to be adequately maintained, the CEMS data should be used to calculate emissions for any averaging period. The same discussion applies to PEM. For more discussion of statistical measures of uncertainty and data quality, refer to the *Quality Assurance Procedures* in Volume VI of the EIIP Document Series (refer to Section 7 of Chapter 3 and refer to Chapter 4).

3.2.1 CEMS

The use of site-specific CEMS data is preferred for estimating NO_x, CO, CO_2, SO_2, and total hydrocarbon (THC) emissions because it provides a detailed record of emissions over time. Other alternative methods available to estimate emissions of these pollutants provide only short-term emissions data (in the case of stack sampling) or industry averages (in the case of emission factors) that may not be accurate or representative for a specific source.

Instrument calibration drift can be problematic for CEMS and uncaptured data can create long-term incomplete data sets. However, it is misleading to assert that a snapshot (stack sampling) can better predict long-term emission characteristics. It is the responsibility of the source owner to properly operate, calibrate, and validate the monitoring equipment and the corresponding emission data.

The preferred approach for obtaining stack gas flow rate is through the use of continuous monitoring. While flow rate can be measured using short-term stack sampling measurements, continuous monitoring provides more accurate long-term data.

3.2.2 PEM

PEM is a predictive emission estimation methodology whereby emissions are correlated to process parameters based on demonstrated correlations between emissions and process parameters. For example, testing may be performed on a boiler stack while the boiler is operated at various loads. Parameters such as fuel usage, steam production, and furnace temperature are monitored during the tests. These data are then used to produce emission curves. Periodic stack sampling may be required to verify that the emission curves are still accurate or to develop new curves based on the test results.

3.2.3 STACK SAMPLING

Stack sampling is the preferred emission estimation methodology for PM, PM_{10}, speciated organics, and sulfuric acid mist. There are currently no CEMS methods for measuring these pollutants so the use of short-term, site-specific information is preferred over using emission factors that provide averaged emission data for a particular industry.

Fourier Transform Infrared (FTIR) Spectroscopy is a stack sampling method that may be used for multiple pollutants simultaneously. The sampling procedure is described in EPA Test Method 320. It is extractive, meaning flue gas is extracted from the exhaust of the affected source and transported to the FTIR gas cell through a heated handling system. This method applies to the analysis of vapor phase organic or inorganic compounds which absorb energy in the mid-infrared spectral region. This method is used to determine compound-specific concentrations in a multi-component vapor phase sample. Typically, the sampling appartus is similar to that used for single-component CEM measurements.

Spectra of samples are collected using double beam infrared absorption spectroscopy and a computer program is used to analyze spectra and report compound concentrations. Analytes includes HAPs for which EPA reference spectra have been developed. Other compounds can also be measured with this method if reference spectra are prepared according to the protocol. NO_x, CO, CO_2, SO_2, NH_3, formaldehyde, and HC1 are commonly sampled and analyzed by FTIR.

3.2.4 FUEL ANALYSIS

Site-specific fuel analysis is the preferred emission estimation methodology for metals when air pollution control equipment (e.g., scrubber, ESP) are not installed. In cases where control

equipment is installed, fuel analysis may be preferred if accurate data are available on pollutant-specific collection efficiencies and the amount of pollutant present in bottom ash and fly ash are known. Once the pollutant concentrations are known, their emissions can be calculated based on mass conservation laws. Fuel analysis is also useful in determining SO_2 and CO_2 emissions. While emission factors are available for most metals, the use of site-specific fuel analysis data provides a more accurate emission estimate. For SO_2, fuel analysis, (specifically, the percentage of sulfur in the fuel) may be used with the appropriate emission factors in AP-42 to estimate SO_2 emissions.   Fuel analysis may also be used to calculate CO_2 emissions by assuming complete conversion of the carbon in the fuel to CO_2.

3.2.5 EMISSION FACTORS

Due to their availability and acceptance in the industry, emission factors are commonly used to prepare emission inventories. However, the emission estimate obtained from using emission factors is based upon emission testing performed at similar facilities and may not accurately reflect emissions at a single source. Thus, the user should recognize that, in most cases, emission factors are averages of available industry-wide data with varying degrees of quality and may not be representative for an individual facility within that industry.

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4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

The preferred method for estimating emissions of most pollutants emitted from boilers is usually the use of site-specific information (either CEMS data, PEM data, or recent stack tests). This section provides an outline for calculating emissions from boilers based on raw data collected by the CEMS and stack tests. The CEMS is usually used to measure SO_2, NO_x, THC, CO, flow rate, and a diluent, which can be either oxygen (O_2) or CO_2.

For oil combustion, fuel analysis is the preferred method for estimating emissions of metals.

For PM, sulfuric acid mist, speciated organic emissions, metals from coal combustion, and metals from fuel oil combustion where a particulate control device is used, the preferred emission estimation method is the use of stack sampling test data. Table 2.4-1 lists the variables and symbols used in the following discussion.

4.1 EMISSION CALCULATIONS USING CEMS DATA

To monitor SO_2, NO_x, THC, and CO emissions using a CEMS, a facility uses a pollutant concentration monitor, which measures concentration in parts per million by volume dry air (ppmvd). Flow rates are measured using a volumetric flow rate monitor, a type "S" pitot tube (as in EPA Method 2) or they can be estimated based on heat input using fuel factors, or "F-Factors".

Table 2.4-2 presents an example output from a boiler using a CEMS consisting of SO_2, NO_x, CO, O_2, and flow rate monitors. The output usually includes pollutant concentration in parts per million (ppm) and emission rates in pounds per hour (lb/hr).

The measurements presented in Table 2.4-2 represent a "snapshot" of a boiler's operation; in this case, over a time period of 1 hour and 45 minutes. From these data, it is possible to determine that between 11:00 a.m. and noon, emissions of SO_2 averaged 1,631 (lb/hr). Assuming the CEMS operates properly all year long, an accurate emission estimate can be made by summing the hourly emission estimates.

TABLE 2.4-1

LIST OF VARIABLES AND SYMBOLS

Variable	Symbol	Units
Concentration	C	parts per million by volume dry air (ppmvd)
Molecular weight	MW	lb/lb-mole
Molar volume	V	cubic feet (ft^3)/lb-mole
Flow rate	Q	dry standard cubic feet per minute (dscfm) or actual cubic feet per minute (acfm)
Hourly emissions	E_x	typically lb/hr of pollutant x
Heat input rate	H_{in}	million British thermal units (Btu) per hour (MMBtu/hr)[a]
Annual heat input rate	$H_{in,ann}$	MMBtu/yr
Annual emissions	$E_{tpy,x}$	tons per year (tpy) of pollutant x
Higher heating value	HHV	Btu/lb
Fuel factor (dry)	F_d	dscf/MMBtu at 0% O_2
Filter catch	C_f	g
Metered volume	V_m	ft^3
Fuel flow	Q_f	typically, lb/hr
Annual fuel use	$Q_{f,ann}$	lb/yr
Emission factor	EF_x	typically lb/MMBtu, lb/ft^3, or lb/gal of pollutant x
Annual Op hours	OpHrs	annual operating hours (hr/yr)

[a] MMBtu = 10^6 Btu.

TABLE 2.4-2

EXAMPLE CEMS OUTPUT FOR A BOILER BURNING NO. 6 FUEL OIL

Period	O₂ (%V)	SO₂ (C) (ppmvd)	NOₓ (C) (ppmvd)	CO (C) (ppmvd)	Fuel Rate (Q_f) (10³lb/hr)	Stack Gas Flow Rate (Q) (dscfm)	Emissions			
							SO₂ᵃ (lb/MMBtu)	NOₓᵃ (lb/MMBtu)	SO₂ (lb/hr)	NOₓ (lb/hr)
11:00	2.1	1,004.0	216.2	31.5	46.0	155,087	1.9	0.4	1,551	240
11:15	2.0	1,100.0	200.6	25.5	46.5	155,943	2.0	0.4	1,709	224
11:30	2.1	1,050.0	216.7	25.1	46.0	155,087	2.0	0.4	1,622	241
11:45	1.9	1,070.0	220.5	20.8	46.2	154,122	2.0	0.4	1,643	243
12:00	1.9	1,070.0	213.8	19.4	46.8	156,123	2.0	0.4	1,664	239
12:15	1.8	1,050.0	214.0	19.4	46.3	153,647	1.9	0.4	1,607	235
12:30	2.0	1,100.0	209.1	21.5	46.3	155,273	2.0	0.4	1,701	232
12:45	2.0	1,078.0	210.8	50.3	46.5	155,943	2.0	0.4	1,675	235

ᵃ Based on a fuel heating value of 18,000 Btu/lb.

4.1.1 CALCULATING HOURLY EMISSIONS FROM CONCENTRATION MEASUREMENTS

Although CEMS can report real-time hourly emissions automatically, it may be necessary to manually estimate predicted annual emissions from hourly concentration data. This section describes how to calculate emissions from raw CEMS concentration data.

Hourly emissions can be based on concentration measurements as shown in Equation 2.4-1.

$$E_x = \frac{(C * MW * Q * 60)}{(V * 10^6)}$$

(2.4-1)

where:

60	=	60 min/hr
E_x	=	Hourly emissions in lb/hr of pollutant x
C	=	Pollutant concentration in ppmvd
MW	=	Molecular weight of the pollutant (lb/lb-mole)
Q	=	Stack gas volumetric flow rate in dscfm
V	=	Volume occupied by 1 mole of ideal gas at standard temperature and pressure (385.5 ft^3/lb-mole @ 68°F and 1 atm)

4.1.2 CALCULATING STACK GAS FLOW RATE

When direct measurements of stack gas flow rates are not available, Q can be calculated using fuel factors (F factors) according to EPA Method 19 as shown below.

$$Q = F_d * \frac{20.9}{(20.9 - \%O_2)} * \frac{H_{in}}{60}$$

(2.4-2)

where:

F_d	=	Fuel factor, dry basis (from EPA Method 19) in dscf/MMBtu
$\%O_2$	=	Measured oxygen concentration, dry basis expressed as a percentage
H_{in}	=	Heat input rate in MMBtu/hr

The F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. F_d includes all components of combustion less water. F_d can be calculated from fuel analysis results using the following equation:

$$F_d = \frac{10^6\ [3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{HHV} \qquad (2.4\text{-}3)$$

where:

H, C, S, N, and O	=	Concentrations of hydrogen, carbon, sulfur, nitrogen, and oxygen in the fuel expressed as a percentage as determined by a fuel analysis
HHV	=	Higher heating value of the fuel in Btu/lb

Fuel heating values are available in publications such as *Steam, Its Generation and Use* (Stultz and Kitto, 1992). The average F_d factors are provided in EPA Reference Method 19 for different fuels and are shown in Table 2.4-3.

4.1.3 CALCULATING EMISSION FACTORS FROM HEAT INPUT

Sometimes it is desirable to calculate emissions in terms of pounds of pollutant per unit of heat combusted. For regulatory purposes, heat input is calculated based on the HHV of the fuel as measured by analysis. The heat input in terms of MMBtu/hr is calculated using:

$$H_{in} = \frac{(Q_f \ * \ HHV)}{10^6} \qquad (2.4\text{-}4)$$

where:

H_{in}	=	Heat input rate in MMBtu/hr
Q_f	=	Mass fuel flow rate in lb/hr
HHV	=	Higher heating value in Btu/lb

An emission factor relating emissions to the heat input rate for the boiler is expressed as:

$$EF_x = E_x/H_{in} \qquad (2.4\text{-}5)$$

where:

EF_x	=	Emission factor in lb/MMBtu of pollutant x
E_x	=	Emissions of pollutant x in lb/hr

TABLE 2.4-3

F$_d$ FACTORS FOR VARIOUS FUELS[a]

	F$_d$	
Fuel Type	**dscm/J**[b]	**dscf/MMBtu**
Coal		
Anthracite[c]	$2.71 * 10^{-7}$	10,100
Bituminous[c]	$2.62 * 10^{-7}$	9,780
Lignite	$2.65 * 10^{-7}$	9,860
Oil[d]	$2.65 * 10^{-7}$	9,190
Gas		
Natural	$2.34 * 10^{-7}$	8,710
Propane	$2.34 * 10^{-7}$	8,710
Butane	$2.34 * 10^{-7}$	8,710
Wood	$2.48 * 10^{-7}$	9,240
Wood Bark	$2.58 * 10^{-7}$	9,600

[a] Determined at standard conditions: 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).
[b] dscm/J = Dry standard cubic meters per joule.
[c] As classified according to ASTM Method D 388-77.
[d] Crude, residual, or distillate.

4.1.4 CALCULATING EMISSION FACTORS USING EPA METHOD 19

EPA Method 19 may be used to develop site-specific emission factors (EF$_x$) for PM, SO$_2$, and NO$_x$ from pollutant concentration data, Oxygen percentage in the gas stream, and F factors (Fd) using:

$$EF_x = (C_d * F_d)/ [20.9/(20.9 - \%O_2)] \qquad (2.4\text{-}6)$$

where:

EF_x =   Emission factor in lb/MMBtu of pollutant x
C_d =   pollutant concentration (lb/dscf)
F_d =   F factor (dscf/MMBtu)

Example 2.4-1 illustrates the use of Equation 2.4-6.

Example 2.4-1
This example shows how a site-specific SO_2 emission factor may be calculated using stack
test data and the EPA Method 19 equation 2.4-6:

$$EF_{SO2} = (C_d * F_d)/ [20.9/(20.9 - \%O_2)]$$

The relevant data for this example is:

C_{ppm} =   1,000 ppm
F_d =   9,190 (dscf/MMBtu), from Table 2.4-3
$\%O_2$ =   2.1 (from the testing data presented in Table 2.4-2)

To convert C_{ppm} to C_d, use the appropriate conversion factor (1.66×10^{-7}) from EPA
Method 19:

C_d = $C_{ppm} * (1.66 - 10^{-7})$
        = $1,000 * (1.66 - 10^{-7})$
        = $1.66 * 10^{-4}$

The site-specific emission factor is then calculated as follows:

EF_{SO2} = $(C_d * F_d)/ [20.9/(20.9 - \%O_2)]$
EF_{SO2} = $(1.66 \times 10^{-4} * 9,190)/ [20.9/(20.9 - 2.1)]$
EF_{SO2} =   1.7 (lb/MMBtu)

4.1.5 CALCULATING ACTUAL ANNUAL EMISSIONS

Emissions in tons per year can be calculated either by multiplying the average hourly emission
rate by the number of annual operating hours (Equation 2.4-7) or by multiplying the average

emission factor in lb/MMBtu by the annual heat input (Equation 2.4-9). Equation 2.4-8 shows how to calculate the annual heat input. Example 2.4-2 depicts the use of these equations.

$$E_{tpy,x} = E_x * OpHrs/2,000 \qquad (2.4\text{-}7)$$

where:

$E_{tpy,x}$ = Actual annual emissions in ton/yr of pollutant x
E_x = Emissions of pollutant x in lb/hr
OpHrs = Operating hours per year
2,000 = lb/ton

Annual heat input may be calculated from annual fuel use using:

$$H_{in,ann} = \frac{(Q_{f,ann} * HHV)}{10^6} \qquad (2.4\text{-}8)$$

where:

$H_{in,ann}$ = Annual heat input rate in MMBtu/yr
$Q_{f,ann}$ = Annual fuel flow rate in lb/yr
HHV = Higher heating value in Btu/lb

$$E_{tpy,x} = EF_x * H_{in,ann} \qquad (2.4\text{-}9)$$

where:

$E_{tpy,x}$ = Actual annual emissions of pollutant x in ton/yr
EF_x = Emission factor in lb/MMBtu of pollutant x

E_{fx} may be obtained using either Equation 2.4-5 or 2.4-6, depending on available data.

Example 2.4-2

This example shows how SO_2 emissions can be calculated based on the raw CEMS data for 11:00 shown in Table 2.4-2. Hourly emissions are calculated using Equation 2.4-1:

$$
\begin{aligned}
E_{SO2} &= (C * MW * Q * 60)/(V * 10^6) \\
&= 1{,}004 * 64 * 155{,}087 * 60/(385.5 * 10^6) \\
&= 1{,}551 \text{ lb/hr}
\end{aligned}
$$

Heat input is calculated using Equation 2.4-4:

$$
\begin{aligned}
H_{in} &= (Q_f * HHV)/10^6 \\
&= 46{,}000 * 18{,}000/10^6 \\
&= 828 \text{ MMBtu/hr}
\end{aligned}
$$

An emission factor, in terms of lb/MMBtu, is calculated using Equation 2.4-5:

$$
\begin{aligned}
EF_{SO2} &= E_{SO2}/H_{in} \\
&= 1{,}551/828 \\
&= 1.9 \text{ lb/MMBtu}
\end{aligned}
$$

Emissions in tpy (based on a 5,840 hr/yr operating schedule) can then be calculated using Equation 2.4-7:

$$
\begin{aligned}
E_{tpy,SO2} &= E_{SO2} * OpHrs/2{,}000 \\
&= 1{,}551 * (5{,}840/2{,}000) \\
&= 4{,}529 \text{ tpy}
\end{aligned}
$$

Emissions in tpy (based on $2.69 * 10^8$ lb annual fuel use) can then be calculated by first using Equation 2.4-8 to calculate annual heat input:

$$
\begin{aligned}
H_{in,ann} &= (Q_{f,ann} * HHV)/10^6 \\
&= (2.69 * 10^8 * 18{,}000)/10^6 \\
&= 4.84 * 10^6 \text{ MMBtu/yr}
\end{aligned}
$$

Example 2.4-2 (Continued)

Emissions in tpy (based on $4.84 * 10^6$ MMBtu/yr) can then be calculated using Equation 2.4-9:

$$
\begin{aligned}
E_{tpy,SO2} &= EF_{SO2} * H_{in,ann}/2,000 \\
&= 1.9 * 4.84 * 10^6/2,000 \\
&= 4,598 \text{ tpy}
\end{aligned}
$$

Note that the last two calculations in Example 2.4-1 show an actual annual emission estimate based on a 15-minute average and are provided as an example only. Average values of E_x should be used to obtain a representative annual emissions estimate.

4.2 PEM

This section outlines an example of SO_2 emission monitoring that could be used to develop a PEM protocol for a boiler equipped with a wet scrubber. Boiler and scrubber parameters that affect emissions and that are most likely to be included in the testing algorithm are scrubber water pH and flow rate, and fuel combustion rate.

To develop this algorithm, correlation testing of the stack gas, scrubber, and boiler process variables could be conducted over a range of potential operating conditions using EPA Method 6A or Method 6C to measure SO_2 emissions. Potential testing conditions are shown in Table 2.4-4. Based on the test data, a mathematical correlation can be developed that predicts SO_2 emissions using these parameters.

4.3 EMISSION CALCULATIONS USING STACK SAMPLING DATA

Stack sampling test reports often provide emissions in terms of lb/hr or lb/MMBtu. Annual emissions may be calculated from these data using Equations 2.4-6 or 2.4-8 as shown in Example 2.4-1. Stack tests performed under a proposed permit condition or a maximum emissions rate may not accurately reflect the emissions that would result under normal operating conditions. Therefore, when using stack sampling test data to estimate emissions, tests should be conducted under "normal" operating conditions.

TABLE 2.4-4

PREDICTIVE EMISSION MONITORING ANALYSIS[a]

Test Number	Scrubber Water Flow Rate	Scrubber Water pH	Fuel Firing Rate
1	B	H	H
2	B	H	M
3	B	H	L
4	B	M	H
5	B	M	M
6	B	M	L
7	B	L	H
8	B	L	M
9	B	L	L

[a] H = High.
   M = Medium.
   L = Low.
   B = Baseline.

Example 2.4-3

This example shows how to calculate SO_2 emissions when the stack gas flow rate, Q, is not available.

The F factor for No. 6 fuel oil, based on Table 2.4-3, is 9,190 dscf/MMBtu. The oxygen content is 2.1 percent. From Example 2.4-1, H_{in} is 828 MMBtu/hr. The stack gas flow rate is calculated using Equation 2.4-10:

$$Q = F_d * (20.9)/(20.9 - \%O_2) * (H_{in}/60) \qquad (2.4\text{-}10)$$
$$Q = 9{,}190 * (20.9)/(20.9 - 2.1) * (828/60)$$
$$Q = 140{,}988 \text{ dscfm}$$

Using the CEMS data from Table 2.4-2 (for 11:00) and the calculated flow rate, hourly emissions can now be calculated using Equation 2.4-1:

$$E_{SO2} = (C * MW * Q * 60)/(V * 10^6) \qquad (2.4\text{-}1)$$
$$E_{SO2} = (1{,}004 * 64 * 140{,}988 * 60)/(385.5 * 10^6)$$
$$E_{SO2} = 1{,}410 \text{ lb/hr}$$

To express the emissions in terms of pounds per unit of heat combusted, use Equation 2.4-11:

$$EF_{SO2} = E_{SO2}/H_{in} \qquad (2.4\text{-}11)$$
$$EF_{SO2} = 1{,}410/828$$
$$EF_{SO2} = 1.7 \text{ lb/MMBtu}$$

Note that E_{SO2} and EF_{SO2} calculated using F factors is slightly different than the emissions calculated using flow rate measurements. This difference is due to different estimation approaches; depending on the use of the data, either approach may be acceptable.

This section shows how to calculate emissions in lb/hr based on raw stack sampling data. Calculations involved in determining SO_2 and PM_{10} emissions from raw EPA Method 201A data are presented in Examples 2.4-3 and 2.4-4, respectively. Because PM_{10} emissions cannot be measured continuously, the best method available for measuring PM_{10} emissions is Method 201A.

An example summary of a Method 201A test is shown in Table 2.4-5. The table shows the results of three different sampling runs conducted during one test event. The source parameters measured as part of a Method 201A run include gas velocity and moisture content, which are used to determine exhaust gas flow rates in dscfm. The filter weight gain is determined gravimetrically and divided by the volume of gas sampled as shown in Equation 2.4-12 to determine the PM concentration in lb/dscf. Pollutant concentration is then multiplied by the volumetric flow rate to determine the emission rate in pounds per hour, as shown in Equation 2.4-1.

$$E_x = (C_f/V_m) * Q * 60/453.6 \qquad\qquad (2.4\text{-}12)$$

where:

E_x	=	Emissions of pollutant x in lb/hr
C_f	=	Filter catch (g)
V_m	=	Metered volume of sample (ft^3)
Q	=	Stack gas volumetric flow rate (dscfm)
60	=	60 min/hr
453.6	=	453.6 g/lb

Example 2.4-4

This example shows how PM_{10} emissions may be calculated using Equation 2.4-12 and the stack sampling data for Run 1 (presented in Table 2.4-5).

E	=	$(C_f/V_m) * Q * 60/453.6$
	=	(0.003/120.23) * 206,404 * 60/453.6
	=	0.68 lb/hr

4.4 EMISSION CALCULATIONS USING FUEL ANALYSIS DATA

Fuel analysis can be used to predict emissions based on application of conservation laws. The presence of certain elements in fuels may be used to predict their presence in emission streams. This includes toxic elements such as metals found in oil as well as other elements such as sulfur that may be converted to other compounds during the combustion process.

TABLE 2.4-5

SAMPLE TEST RESULTS - METHOD 201A

Parameter	Run 1	Run 2	Run 3
Total sampling time (minutes)	180.00	180.00	180.00
Corrected barometric pressure (in. Hg)	30.56	30.56	30.56
Absolute stack pressure, Ps (in. Hg)	30.49	30.49	30.49
Stack static pressure (in. H_2O)	-0.89	-0.89	-0.89
Average stack temperature (°F)	328.00	330.00	335.00
Stack area (ft^2)	113.09	113.09	113.09
Metered volume of sample, V_m (ft^3)	116.51	110.20	115.30
Average meter pressure (in. H_2O)	0.81	0.81	0.81
Average meter temperature (°F)	69.28	71.00	70.20
Moisture collected (g)	258.50	265.00	261.00
Carbon dioxide concentration (%V)	15.50	15.40	15.30
Oxygen concentration (%V)	2.30	2.30	2.30
Nitrogen concentration (%V)	82.20	82.30	82.40
Dry gas meter factor	1.01080	1.01080	1.01080
Pitot constant	0.84	0.84	0.84
PM_{10} filter catch (g)	0.003	0.004	0.003
Average sampling rate (dscfm)	0.67	0.67	0.67
Standard metered volume, V_m (std) (dscf)	120.23	121.30	118.50
Standard volume water vapor, Vw (scf)	12.19	13.00	12.50
Stack moisture (%V)	9.20	9.50	9.60
Mole fraction dry stack gas	0.908	0.908	0.908
Dry molecular weight (g)	29.37	29.37	29.37
Wet molecular weight (g)	28.32	28.32	28.32
Stack gas velocity, V_s (ft/min)	3000.00	2950.00	2965.00
Volumetric flow rate (acfm)	339270	333616	335312
Volumetric flow rate (dscfm)	206404	201791	201319
Percent isokinetic	96.48	97.00	98.00
Concentration of particulate (g/dscf)	0.00002	0.00003	0.00003
PM_{10} emission rate (lb/hr)	0.68	0.90	0.69

The basic equation used in fuel analysis emission calculations is:

$$E = Q_f * \text{Pollutant concentration in fuel} * \left(\frac{MW_p}{MW_f} \right) \qquad (2.4\text{-}13)$$

where:

Q_f = Fuel flow rate (lb/hr)
MW_p = Molecular weight of pollutant emitted (lb/lb-mole)
MW_f = Molecular weight of pollutant in fuel (lb/lb-mole)

For example, SO_2 emissions from oil combustion can be calculated based on the concentration of sulfur in the oil. This approach assumes complete conversion of sulfur to SO_2. Therefore, for every pound of sulfur (MW = 32 g) burned, 2 lb of SO_2 (MW = 64 g) are emitted. The application of this emission estimation technique is shown in Example 2.4-5.

Example 2.4-5

This example shows how SO_2 emissions can be calculated from oil combustion based on fuel analysis results and the fuel flow information provided in Table 2.4-2.

E_{SO2} may be calculated using Equation 2.4-13.

Q_f = 46,000 lb/hr
Percent sulfur (%S) in fuel = 1.17

E_{SO2} = Q_f * Pollutant concentration in fuel * (MW_p/MW_f)
= (46,000) * (1.17/100) * (64/32)
= 1,076 lb/hr

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5

ALTERNATIVE METHODS FOR ESTIMATING EMISSIONS

5.1 EMISSION FACTOR CALCULATIONS

Emission factors are commonly used to calculate emissions from boilers when site-specific stack monitoring data are unavailable. The EPA maintains a compilation of emission factors in *AP-42* (EPA, January 1995) for criteria pollutants and HAPs. The most comprehensive source for toxic and hazardous air pollutant emission factors is the FIRE data system (EPA, September 2000). FIRE also contains emission factors for criteria pollutants.

Much work has been done recently on developing emission factors for HAPs and recent *AP-42* revisions have included these factors. In addition, many states have developed their own HAP emission factors for certain source categories and may require their use in any inventories including HAPs. Refer to Chapter 1 of Volume II for a complete discussion of available information sources for locating, developing, and using emission factors as an estimation technique.

Emission factors developed from measurements for a specific boiler may sometimes be used to estimate emissions at other sites. For example, a company may have several boilers of a similar model and size; if emissions were measured from one boiler, a factor can be developed and applied to the other boilers. It is advisable to have the factor approved by state/local agencies or by the EPA.

The basic equation used in emission factor emissions calculations is:

$$E_x = EF_x * \text{Activity Rate} \qquad (2.5\text{-}1)$$

where:

$$
\begin{array}{lll}
E_x & = & \text{Emissions of pollutant x} \\
EF_x & = & \text{Emission factor}
\end{array}
$$

In cases where more than one fuel type is used, annual emissions should be calculated using appropriate emission factors and proportioned based on the amount of each type of fuel used. Examples 2.5-1 and 2.5-2 show the use of Equations 2.5-1.

Example 2.5-1

This example shows how CO emissions may be calculated for No. 6 oil combustion based on the boiler fuel rate information provided in Table 2.4-2 and a CO emission factor from *AP-42*, Table 1.3-2, for No. 6 fuel oil.

$$E_x \quad = \quad EF_x * \text{Activity Rate } (Q_f)$$

$$EF_{CO} \quad = \quad 5 \text{ lb/}10^3 \text{ gal}$$

$$
\begin{aligned}
Q_f \quad &= \quad (46.0 * 10^3 \text{ lb/hr}) * 1 \text{ gal/8 lb} \\
&= \quad 5,750 \text{ gal/hr}
\end{aligned}
$$

$$
\begin{aligned}
E_{CO} \quad &= \quad EF_{CO} * Q_f \\
&= \quad 5/10^3 * 5,750 \\
&= \quad 28.75 \text{ lb/hr}
\end{aligned}
$$

Example 2.5-2

This example shows how chromium emissions may be calculated for No. 6 oil combustion based on a heat input rate of 828 MMBtu/hr and a chromium emission factor from FIRE for SCC 1-01-004-01.

$$EF(\text{chromium}) \quad = \quad 6.31 * 10^{-6} \text{ lb/MMBtu}$$

$$
\begin{aligned}
\text{Chromium emissions} \quad &= \quad EF(\text{chromium}) * H_{in} \\
&= \quad (6.31 * 10^{-6}) * 828 \\
&= \quad 5.22 * 10^{-3} \text{ lb/hr}
\end{aligned}
$$

6

QUALITY ASSURANCE/QUALITY CONTROL

The consistent use of standardized methods and procedures is essential in the compilation of reliable emission inventories. QA and QC of an inventory is accomplished through a set of procedures that ensure the quality and reliability of data collection and analysis. These procedures include the use of appropriate emission estimation techniques, applicable and reasonable assumptions, accuracy/logic checks of computer models, checks of calculations, and data reliability checks. Chapter 3 of Volume VI of this series describes additional QA/QC methods and tools for performing these procedures.

Chapter 1, *Introduction to Stationary Point Source Emission Inventory Development*, of this volume presents recommended standard procedures to follow that ensure the reported inventory of this volume data are complete and accurate. Chapter 1, Section 9, should be consulted for current EIIP guidance for QA/QC checks for general procedures, recommended components of a QA plan, and recommended components for point source inventories. The QA plan discussion includes recommendations for data collection, analysis, handling, and reporting. The recommended QC procedures include checks for completeness, consistency, accuracy, and the use of approved standardized methods for emission calculations, where applicable. Chapter 1, Section 9, also describes guidelines to follow in order to assure the quality and validity of the data from manual and continuous emission monitoring methodologies used to estimate emissions.

6.1 GENERAL FACTORS INVOLVED IN EMISSION ESTIMATION TECHNIQUES

6.1.1 STACK TESTS AND CEMS

Data collected via CEMS, PEM, or stack tests must meet quality objectives. Stack test data must be reviewed to ensure that the test was conducted under normal operating conditions and that data were generated according to an acceptable method for each pollutant of interest. Calculation and interpretation of accuracy for stack testing methods and CEMS are described in detail in *Quality Assurance Handbook for Air Pollution Measurements Systems: Volume III. Stationary Source Specific Methods (Interim Edition)* (EPA, April 1994).

The acceptance criteria, limits, and values for each control parameter associated with manual sampling methods, such as dry gas meter calibration and leak rates, are summarized in of Chapter 1 of this volume. Continuous monitoring for NO_x, CO, CO_2, and THCs using various instruments is discussed in Section 3 of this chapter. QC procedures for all instruments used to continuously collect emissions data are similar. The primary control check for precision of the continuous monitors is daily analysis of control standards. The CEMS acceptance criteria and control limits are also listed in Chapter 1.

6.1.2 EMISSION FACTORS

The use of emission factors is straightforward when the relationship between process data and emissions is direct and relatively uncomplicated. When using emission factors, the user should be aware of the quality indicator associated with the value. Emission factors published within EPA documents and electronic tools have a quality rating applied to them. The lower the quality indicator, the more likely that a given emission factor may not be representative of the source type. It is always better to rely on actual stack test or CEMS data, where available. The reliability and uncertainty of using emission factors as an emission estimation technique are discussed in detail in Chapter 1 of this volume.

6.2 DATA ATTRIBUTE RATING SYSTEM (DARS) SCORES

One measure of emission inventory data quality is the DARS score (Beck et al. 1994). Four examples are given here to illustrate DARS scoring using the preferred and alternative methods. The DARS provides a numerical ranking on a scale of 1 to 10 for individual attributes of the emission factor and the activity data. Each score is based on what is known about the factor and the activity data, such as the specificity to the source category and the measurement technique employed. The composite attribute score for the emissions estimate can be viewed as a statement about the confidence that can be placed in the data. For a complete discussion of DARS and other rating systems, see the *QA Source Document* (Volume VI, Chapter 4) and Volume II, Chapter 1, *Introduction to Stationary Point Source Emission Inventory Development.* These are available on the EIIP web page at www.epa.gov/ttn/chief/eiip/.

Each of the examples below is hypothetical. A range is given where appropriate to cover different situations. The scores are assumed to apply to annual emissions from a boiler. Table 2.6-1 gives a set of scores for an estimate based on CEMS/PEM data. A perfect score of 1.0 is achievable using this method if data quality is very good. Note that maximum scores of 1.0 are automatic for the source definition and spatial congruity attributes. Likewise, the temporal congruity attribute receives a 1.0 if data capture is greater than 90 percent; this assumes that data are sampled adequately throughout the year. The measurement attribute score of 1.0 assumes that the pollutants of interest were measured directly. A lower score is given if the

emissions are speciated using a profile, or if the emissions are used as a surrogate for another pollutant. Also, the measurement/method score can be less than 1.0 if the relative accuracy is poor (e.g., >10 percent), if the data are biased, or if data capture is closer to 90 percent than to 100 percent.

TABLE 2.6-1

DARS SCORES: CEMS/PEM DATA[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.9 - 1	0.9 - 1	0.81 - 1	0.905	Lower scores given if relative accuracy poor (e.g., >10 percent) or data capture closer to 90 percent.
Source definition	1.0	1.0	1.0	1.0	
Spatial congruity	1.0	1.0	1.0	1.0	
Temporal congruity	1.0	1.0	1.0	1.0	
Weighted Score	0.98 - 1	0.98 - 1	0.95 - 1	0.98	

[a] Assumes data capture is 90 percent or better, and representative of entire year; monitors, sensors, and other equipment properly maintained.

The use of stack sample data can give DARS scores as high as those for CEMS/PEM data. However, the sample size is usually too low to be considered completely representative of the range of possible emissions making a score of 1.0 for measurement/method unlikely. A typical DARS score is generally closer to the low end of the range shown in Table 2.6-2.

Two examples are given for emissions calculated using emission factors. For both of these examples, the activity data are assumed to be measured directly or indirectly. Table 2.6-3 applies to an emission factor developed from CEMS/PEM data from one boiler and then applied to a different boiler of similar design and age. Table 2.6-4 gives an example for an estimate made with an *AP-42* emission factor. *AP-42* factors are defined for classes of boilers (based on size and fuel type); for some pollutants, the variability in emissions among this population may be high. The *AP-42* factor is a mean and could overestimate or underestimate emissions for any single boiler in the population. Also, the data on which some of these factors are based are often

TABLE 2.6-2

DARS SCORES: STACK SAMPLE DATA[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.7 - 1	0.7 - 1	0.49 - 1	0.745	
Source definition	1 - 1	1 - 1	1 - 1	1	
Spatial congruity	1 - 1	1 - 1	1 - 1	1	
Temporal congruity	0.7 - 1	0.7 - 1	0.49 - 1	0.745	Lower scores given if emissions vary temporally and sample does not cover range.
Weighted Score	0.85 - 1	0.85 - 1	0.75 - 1	0.87	

[a] Assumes use of an EPA reference method, high quality data.

limited in numbers and may be 10-20 years old. Thus, the confidence that can be placed in emissions estimated for a specific boiler with a general *AP-42* factor is lower than emissions based on source-specific data.

The example in Table 2.6-3 shows that emission factors based on high-quality data from a similar unit will typically give better results than a general factor. The main criterion affecting the score is how similar the boiler used to generate the factor is to the target boiler.

If sufficient data are available, the uncertainty in the estimate should be quantified. QA methods are described in the (Volume VI, Chapter 4).

TABLE 2.6-3

DARS SCORES: SOURCE-SPECIFIC EMISSION FACTOR[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.9 - 1	0.8 - 1	0.72 - 1	0.86	Factor score for this attribute depends entirely on data quality.
Source definition	0.5 - 0.9	0.8 - 0.9	0.4 - 0.81	0.61	Factor score lowest if unit differs much from original source of data.
Spatial congruity	1 - 1	1 - 1	1 - 1	1	
Temporal congruity	1 - 1	0.5 - 0.9	0.5 - 0.9	0.7	
Weighted Score	0.85 - 0.98	0.78 - 0.95	0.66 - 0.93	0.79	

[a] Assumes factor developed from PEM or CEMS data from an identical emission unit (same manufacturer, model).

TABLE 2.6-4

DARS SCORES: AP-42 EMISSION FACTOR[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.6 - 0.8	0.8 - 1	0.48 - 0.7	0.59	Score depends on quality and quantity of data points used to develop factor.
Source definition	0.5 - 0.9	0.8 - 0.9	0.4 - 0.81	0.605	Emission factor score will be low if variability in source population is high.
Spatial congruity	0.6 - 0.8	1 - 1	0.6 - 0.8	0.7	Factor score lower if geographic location has significant effect on emissions.
Temporal congruity	0.5 - 0.9	0.5 - 0.9	0.25 - 0.81	0.53	Lower scores given if emissions vary temporally and sample does not cover range.
Weighted Score	0.55 - 0.85	0.78 - 0.95	0.43 - 0.78	0.61	

[a] Assumes activity data (e.g., fuel use) or surrogate is measured directly in some manner.

7

DATA CODING PROCEDURES

This section describes the methods and codes available for characterizing emission sources at boiler facilities using SCC and Aerometric Information Retrieval System (AIRS) control device codes. Consistent categorization and coding will result in greater uniformity among inventories. The SCCs are the building blocks on which point source emissions data are structured. Each SCC represents a unique process or function within a source category that is logically associated with an emission point. Without an appropriate SCC, a process cannot be accurately identified for retrieval purposes. In addition, the procedures described here will assist the reader preparing data for input to a database management system. For example, the use of the SCCs provided in Table 2.7-1 are recommended for describing boiler operations. Refer to the Clearinghouse for Inventories and Emission Factors (CHIEF) for a complete listing of SCCs for boilers. While the codes presented here are currently in use, they may change based on further refinement by the emission inventory user community. As part of the Emission Inventory Improvement Program (EIIP), a common emissions data exchange format is being developed to facilitate data transfer between industry, states, and EPA.

7.1 PROCESS EMISSIONS

Use of the codes in Table 2.7-1 are recommended for describing boilers that burn anthracite, bituminous, subbituminous, or lignite coal; oil- or natural gas-fired electric utility boilers; peaking plants; cogeneration units; and electric utility boilers that burn other types of fuel. More than one code may be necessary for each boiler if auxiliary fuel is used. Auxiliary fuels such as oil are used during start-up of utility boilers, or to sustain combustion (such as coal, oil, or natural gas used at utility boilers that predominantly burn wood/bark or waste).

7.2 STORAGE TANKS

The codes in Table 2.7-1 are recommended to describe emissions related to fuel storage.

7.3 FUGITIVE EMISSIONS

Fugitive emissions at boiler facilities may result from coal, wood/bark, and solid/liquid waste handling and storage. Limestone handling and storage emissions may also occur if the facility uses limestone in control devices such as scrubbers. There are undoubtedly sources of fugitive emissions within the facility or sources that have not been specifically discussed thus far; these

should be included. Conditions vary from plant to plant, so each specific case cannot be discussed within the context of this document.

Codes that may be used to describe fugitive emissions at boiler facilities are also presented in Table 2.7-1. It may be necessary to use a miscellaneous fugitive emission code for sources without a unique code. Many database systems used for inventory management contain a comment field that may be used to describe the fugitive emissions.

7.4 CONTROL DEVICES

The codes found in Table 2.7-2[1] are recommended for describing control devices used at electric utilities and may also be applicable to control devices used at commercial and institutional boilers. The "099" control code may be used to handle miscellaneous control devices that do not have a unique control equipment identification code. For a complete listing, the reader may consult the *AIRS User's Guide Volume XI: AFS Data Dictionary* (AFS is AIRS Facility Subsystem) (EPA, January 1992).

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[1] Note: At the time of publication, these control device codes were under review by the EPA. The reader should consult the EPA for the most current list of codes.

TABLE **2.7-1**

SOURCE CLASSIFICATION CODES FOR BOILERS

Source Description	Process Description	SCC	Units
External Combustion Boilers			
External Combustion Boilers: Electric Generation	Pulverized Coal (Anthracite)	1-01-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite Coal)	1-01-001-02	Tons Anthracite Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-01-002-01	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-01-002-02	Tons Bituminous Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-01-002-03	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-01-002-04	Tons Bituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Bituminous Coal)	1-01-002-05	Tons Bituminous Coal Burned
	Wet Bottom (Tangential) (Bituminous Coal)	1-01-002-11	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-01-002-12	Tons Bituminous Coal Burned
	Cell Burner (Bituminous Coal)	1-01-002-15	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-01-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-01-002-18	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-01-002-21	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-01-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-01-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-01-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-01-002-25	Tons Subbituminous Coal Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-01-002-26	Tons Subbituminous Coal Burned
	Cell Burner (Subbituminous Coal)	1-01-002-35	Tons Subbituminous Coal Burned
	Atmospheric Fluidized Bed Combustion - Circulating Bed (subbitum coal)	1-01-002-38	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-01-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-01-003-01	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-01-003-02	Tons Lignite Burned
	Cyclone Furnace (Lignite)	1-01-003-03	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-01-003-04	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-01-003-06	Tons Lignite Burned
	Atmospheric Fluidized Bed (Lignite)** (See 101003-17 & -18)	1-01-003-16	Tons Lignite Burned
	Atmospheric Fluidized Bed Combustion - Bubbling Bed (Lignite)	1-01-003-17	Tons Lignite Burned
	Atmospheric Fluidized Bed Combustion - Circulating Bed (Lignite)	1-01-003-18	Tons Lignite Burned
	Normal Firing, Grade 6 Oil (Residual)	1-01-004-01	1000 Gallons Residual Oil Burned
	Tangential Firing, Grade 6 Oil (Residual)	1-01-004-04	1000 Gallons Residual Oil Burned
	Normal Firing, Grade 5 Oil (Residual)	1-01-004-05	1000 Gallons Residual Oil Burned
	Tangential Firing, Grade 5 Oil (Residual)	1-01-004-06	1000 Gallons Residual Oil Burned
	Grades 1 and 2 Oil (Distillate)	1-01-005-01	1000 Gallons Distillate Oil Burned

TABLE **2.7-1**

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Normal Firing, Grade 4 Oil (Distillate)	1-01-005-04	1000 Gallons Distillate Oil Burned
	Tangential Firing, Grade 4 Oil (Distillate)	1-01-005-05	1000 Gallons Distillate Oil Burned
	Natural Gas Boilers > 100 Million Btu/hr except Tangential	1-01-006-01	Million Cubic Feet Natural Gas Burned
	Natural Gas Boilers < 100 Million Btu/hr except Tangential	1-01-006-02	Million Cubic Feet Natural Gas Burned
	Natural Gas Boilers: Tangentially Fired Units	1-01-006-04	Million Cubic Feet Natural Gas Burned
	Process Gas Boilers > 100 Million Btu/hr	1-01-007-01	Million Cubic Feet Process Gas Burned
	Process Gas Boilers < 100 Million Btu/hr	1-01-007-02	Million Cubic Feet Process Gas Burned
	Coke, All Boiler Sizes	1-01-008-01	Tons Coke Burned
	Bark-fired Boiler (Wood/Bark Waste)	1-01-009-01	Tons Bark Burned
	Wood/Bark Fired Boiler (Wood/Bark Waste)	1-01-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (Wood/Bark Waste)	1-01-009-03	Tons Wood Burned
	Fuel cell/Dutch oven boilers (Wood/Bark Waste)	1-01-009-10	Ton Wood/Bark Burned
	Stoker boilers (Wood/Bark Waste)	1-01-009-11	Ton Wood/Bark Burned
	Fluidized bed combustion boilers (Wood/Bark Waste)	1-01-009-12	Ton Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-01-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-01-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-01-010-03	1000 Gallons Propane/Butane Burned
	Bagasse, All Boiler Sizes	1-01-011-01	Tons Bagasse Burned
	Solid Waste, Specify Material in Comments	1-01-012-01	Tons Solid Waste Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Solid Waste, Refuse Derived Fuel	1-01-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-01-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-01-013-02	1000 Gallons Waste Oil Burned
	Geothermal Power Plants: Off-Gas Ejectors	1-01-015-01	Megawatt-Hour Electricity Produced
	Geothermal Power Plants: Cooling Tower Exhaust	1-01-015-02	Megawatt-Hour Electricity Produced
External Combustion Boilers: Industrial Boilers	Pulverized Coal (Anthracite)	1-02-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite)	1-02-001-04	Tons Anthracite Coal Burned
	Hand-fired (Anthracite)	1-02-001-07	Tons Anthracite Coal Burned
	Fluidized Bed Boiler Burning Anthracite-Culm Fuel	1-02-001-17	Tons Anthracite Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-02-002-01	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-02-002-02	Tons Bituminous Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-02-002-03	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-02-002-04	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-02-002-05	Tons Bituminous Coal Burned
	Underfeed Stoker (Bituminous Coal)	1-02-002-06	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-02-002-10	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-02-002-12	Tons Bituminous Coal Burned
	Wet Slurry (Bituminous Coal)	1-02-002-13	Tons Bituminous Coal Burned

TABLE **2.7-1**

(CONTINUED**)**

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-02-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-02-002-18	Tons Bituminous Coal Burned
	Cogeneration (Bituminous Coal)	1-02-002-19	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-02-002-21	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-02-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-02-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-02-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-02-002-25	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-02-002-26	Tons Subbituminous Coal Burned
	Cogeneration (Subbituminous Coal)	1-02-002-29	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-02-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-02-003-01	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-02-003-02	Tons Lignite Burned
	Cyclone Furnace (Lignite)	1-02-003-03	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-02-003-04	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-02-003-06	Tons Lignite Burned
	Cogeneration (Lignite)	1-02-003-07	Tons Lignite Burned
	Grade 6 Oil (Residual)	1-02-004-01	1000 Gallons Residual Oil Burned
	10-100 Million Btu/hr, (Residual Oil)	1-02-004-02	1000 Gallons Residual Oil Burned
	< 10 Million Btu/hr, (Residual Oil)	1-02-004-03	1000 Gallons Residual Oil Burned
	Grade 5 Oil (Residual)	1-02-004-04	1000 Gallons Residual Oil Burned
	Cogeneration (Residual Oil)	1-02-004-05	1000 Gallons Residual Oil Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Grades 1 and 2 Oil (Distillate)	1-02-005-01	1000 Gallons Distillate Oil Burned
	10-100 Million Btu/hr, (Distillate Oil)	1-02-005-02	1000 Gallons Distillate Oil Burned
	< 10 Million Btu/hr, (Distillate Oil)	1-02-005-03	1000 Gallons Distillate Oil Burned
	Grade 4 Oil (Distillate)	1-02-005-04	1000 Gallons Distillate Oil Burned
	Cogeneration (Distillate Oil)	1-02-005-05	1000 Gallons Distillate Oil Burned
	> 100 Million Btu/hr, (Natural Gas)	1-02-006-01	Million Cubic Feet Natural Gas Burned
	10-100 Million Btu/hr, (Natural Gas)	1-02-006-02	Million Cubic Feet Natural Gas Burned
	< 10 Million Btu/hr, (Natural Gas)	1-02-006-03	Million Cubic Feet Natural Gas Burned
	Cogeneration (Natural Gas)	1-02-006-04	Million Cubic Feet Natural Gas Burned
	Petroleum Refinery, (Process Gas)	1-02-007-01	Million Cubic Feet Process Gas Burned
	Blast Furnace, (Process Gas)	1-02-007-04	Million Cubic Feet Process Gas Burned
	Coke Oven, (Process Gas)	1-02-007-07	Million Cubic Feet Process Gas Burned
	Cogeneration (Process Gas)	1-02-007-10	Million Cubic Feet Process Gas Burned
	Other: Specify in Comments (Process Gas)	1-02-007-99	Million Cubic Feet Process Gas Burned
	All Boiler Sizes, (Coke)	1-02-008-02	Tons Coke Burned
	Cogeneration (Coke)	1-02-008-04	Tons Coke Burned
	Bark-fired Boiler (> 50,000 Lb Steam)	1-02-009-01	Tons Bark Burned
	Wood/Bark-fired Boiler (> 50,000 Lb Steam)	1-02-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (> 50,000 Lb Steam)	1-02-009-03	Tons Wood Burned
	Bark-fired Boiler (< 50,000 Lb Steam)	1-02-009-04	Tons Bark Burned
	Wood/Bark-fired Boiler (< 50,000 Lb Steam)	1-02-009-05	Tons Wood/Bark Burned
	Wood-fired Boiler (< 50,000 Lb Steam)	1-02-009-06	Tons Wood Burned
	Cogeneration (Wood)	1-02-009-07	Tons Wood Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Fuel cell/Dutch oven boilers	1-02-009-10	Tons Wood/Bark Burned
	Stoker boilers	1-02-009-11	Tons Wood/Bark Burned
	Fluidized bed combustion boiler	1-02-009-12	Tons Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-02-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-02-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-02-010-03	1000 Gallons Propane/Butane Burned
	Bagasse, All Boiler Sizes	1-02-011-01	Tons Bagasse Burned
	Solid Waste, Specify Material in Comments	1-02-012-01	Tons Solid Waste Burned
	Solid Waste, Refuse Derived Fuel	1-02-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-02-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-02-013-02	1000 Gallons Waste Oil Burned
	CO Boiler (Natural Gas)	1-02-014-01	Million Cubic Feet Natural Gas Burned
	CO Boiler (Process Gas)	1-02-014-02	Million Cubic Feet Process Gas Burned
	CO Boiler (Distillate Oil)	1-02-014-03	1000 Gallons Distillate Oil Burned
	CO Boiler (Residual Oil)	1-02-014-04	1000 Gallons Residual Oil Burned
	Methanol, Industrial Boiler	1-02-016-01	1000 Gallons Methanol Burned
	Gasoline, Industrial Boiler	1-02-017-01	1000 Gallons Gasoline Burned
External Combustion Boilers: Industrial Space Heating	Space Heaters (Coal)	1-05-001-02	Tons Coal Burned
	Space Heaters (Distillate Oil)	1-05-001-05	1000 Gallons Distillate Oil Burned

TABLE **2.7-1**

(CONTINUED**)**

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Space Heating (Continued)	Space Heaters (Natural Gas)	1-05-001-06	Million Cubic Feet Natural Gas Burned
	Space Heaters (Liquified Petroleum Gas)	1-05-001-10	1000 Gallons LPG Burned
	Space Heaters, Air Atomized Burner (Waste Oil)	1-05-001-13	1000 Gallons Waste Oil Burned
	Space Heaters, Vaporizing Burner (Waste Oil)	1-05-001-14	1000 Gallons Waste Oil Burned
External Combustion Boilers: Commercial/ Institutional Boilers	Pulverized Coal (Anthracite)	1-03-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite Coal)	1-03-001-02	Tons Anthracite Coal Burned
	Hand-fired (Anthracite)	1-03-001-03	Tons Anthracite Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-03-002-03	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-03-002-05	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-03-002-06	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-03-002-07	Tons Bituminous Coal Burned
	Underfeed Stoker (Bituminous Coal)	1-03-002-08	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-03-002-09	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-03-002-11	Tons Bituminous Coal Burned
	Hand-fired (Bituminous Coal)	1-03-002-14	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-03-002-16	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-03-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-03-002-18	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-03-002-21	Tons Subbituminous Coal Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Boilers (Continued)	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-03-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-03-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-03-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-03-002-25	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-03-002-26	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-03-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-03-003-05	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-03-003-06	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-03-003-07	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-03-003-09	Tons Lignite Burned
	Grade 6 Oil (Residual)	1-03-004-01	1000 Gallons Residual Oil Burned
	10-100 Million Btu/hr, (Residual Oil)	1-03-004-02	1000 Gallons Residual Oil Burned
	< 10 Million Btu/hr, (Residual Oil)	1-03-004-03	1000 Gallons Residual Oil Burned
	Grade 5 Oil (Residual)	1-03-004-04	1000 Gallons Residual Oil Burned
	Grades 1 and 2 Oil (Distillate)	1-03-005-01	1000 Gallons Distillate Oil Burned
	10-100 Million Btu/hr, (Distillate Oil)	1-03-005-02	1000 Gallons Distillate Oil Burned
	< 10 Million Btu/hr, (Distillate Oil)	1-03-005-03	1000 Gallons Distillate Oil Burned
	Grade 4 Oil (Distillate)	1-03-005-04	1000 Gallons Distillate Oil Burned
	> 100 Million Btu/hr, (Natural Gas)	1-03-006-01	Million Cubic Feet Natural Gas Burned
	10-100 Million Btu/hr, (Natural Gas)	1-03-006-02	Million Cubic Feet Natural Gas Burned
	< 10 Million Btu/hr, (Natural Gas)	1-03-006-03	Million Cubic Feet Natural Gas Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Boilers (Continued)	POTW Digester Gas-fired Boiler (Process Gas)	1-03-007-01	Million Cubic Feet Process Gas Burned
	Other Not Classified (Process Gas)	1-03-007-99	Million Cubic Feet Process Gas Burned
	Landfill Gas	1-03-008-11	Million Cubic Feet Landfill Gas Burned
	Bark-fired Boiler (Wood/Bark Waste)	1-03-009-01	Tons Bark Burned
	Wood/Bark-fired Boiler (Wood/Bark Waste)	1-03-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (Wood/Bark Waste)	1-03-009-03	Tons Wood Burned
	Fuel cell/Dutch oven boilers (Wood/Bark Waste)	1-03-009-10	Tons Wood/Bark Burned
	Stoker boilers (Wood/Bark Waste)	1-03-009-11	Tons Wood/Bark Burned
	Fluidized bed combustion boilers (Wood/Bark Waste)	1-03-009-12	Tons Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-03-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-03-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-03-010-03	1000 Gallons Propane/Butane Burned
	Solid Waste, Specify Material in Comments	1-03-012-01	Tons Solid Waste Burned
	Solid Waste, Refuse Derived Fuel	1-03-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-03-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-03-013-02	1000 Gallons Waste Oil Burned
	Liquid Waste, Sewage Grease Skimmings	1-03-013-03	1000 Gallons Sewage Grease Skimmings Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Space Heating	Space Heaters (Coal)	1-05-002-02	Tons Coal Burned
	Space Heaters (Distillate Oil)	1-05-002-05	1000 Gallons Distillate Oil Burned
	Space Heaters (Natural Gas)	1-05-002-06	Million Cubic Feet Natural Gas Burned
	Space Heaters (Wood)	1-05-002-09	Tons Wood Burned
	Space Heaters (Liquified Petroleum Gas)	1-05-002-10	1000 Gallons LPG Burned
	Space Heaters, Air Atomized Burner (Waste Oil)	1-05-002-13	1000 Gallons Waste Oil Burned
	Space Heaters, Vaporizing Burner (Waste Oil)	1-05-002-14	1000 Gallons Waste Oil Burned
Waste Disposal			
Waste Disposal: Solid Waste Landfill	Waste Gas Recovery: Boiler	5-01-004-23	Million Cubic Feet Waste Gas Burned
Waste Disposal: Site Remediation	Thermal Destruction Combustion Unit: Boiler	5-04-105-37	Tons Feed Material Processed
Miscellaneous Industrial Processes with Applicable Codes			
Carbon Black Production	Main Process Vent with CO Boiler and Incinerator	3-01-005-10	Tons Carbon Black Produced
Integrated Iron and Steel Manufacturing	Miscellaneous Combustion Sources: Boilers	3-03-015-82	Tons Material Produced
Sulfate (Kraft) Pulping	Boiler Ash Handling	3-07-001-19	Tons Ash Handled
Fuel Storage and Transfer			
Petroleum Liquids Storage (non-Refinery)	Underground Tanks, Breathing Loss (No. 2 Distillate Oil)	4-04-004-13	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Underground Tanks, Working Loss (No. 2 Distillate Oil)	4-04-004-14	1000 Gallons No. 2 Distillate Oil Throughput
	Underground Tanks, Breathing Loss (Specify Liquid)	4-04-004-97	1000 Gallons Liquid Storage Capacity
	Underground Tanks, Working Loss (Specify Liquid)	4-04-004-98	1000 Gallons Liquid Throughput

<center>**TABLE 2.7-1**</center>

<center>**(CONTINUED)**</center>

Source Description	Process Description	SCC	Units
Fuel Storage and Transfer (Continued)			
Industrial Processes, In-Process Fuel Use	Fixed Roof Tanks, Breathing Loss (Residual Oil)	3-90-900-01	1000 Gallons Residual Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (Residual Oil)	3-90-900-02	1000 Gallons Residual Oil Throughput
	Fixed Roof Tanks, Breathing Loss (No. 2 Distillate Oil)	3-90-900-03	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (No. 2 Distillate Oil)	3-90-900-04	1000 Gallons No. 2 Distillate Oil Throughput
	Fixed Roof Tanks, Breathing Loss (No. 6 Oil)	3-90-900-05	1000 Gallons No. 6 Residual Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (No. 6 Oil)	3-90-900-06	1000 Gallons No. 6 Residual Oil Throughput
	Floating Roof Tanks, Standing Loss (Residual Oil)	3-90-910-01	1000 Gallons Residual Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (Residual Oil)	3-90-910-02	1000 Gallons Residual Oil Throughput
	Floating Roof Tanks, Standing Loss (No. 2 Distillate Oil)	3-90-910-03	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (No. 2 Distillate Oil)	3-90-910-04	1000 Gallons No. 2 Distillate Oil Throughput
	Floating Roof Tanks, Standing Loss (No. 6 Oil)	3-90-910-05	1000 Gallons No. 6 Residual Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (No. 6 Oil)	3-90-910-06	1000 Gallons No. 6 Residual Oil Throughput
	Pressure Tanks, Withdrawal Loss (Natural Gas)	3-90-920-50	1000 Gallons Natural Gas Throughput

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Fuel Storage and Transfer: (Continued)			
Industrial Processes, In-Process Fuel Use (Continued)	Pressure Tanks, Withdrawal Loss (Liquified Petroleum Gas)	3-90-920-51	1000 Gallons LPG Throughput
	Pressure Tanks, Withdrawal Loss (Landfill Gas)	3-90-920-52	1000 Gallons Landfill Gas Throughput
	Pressure Tanks, Withdrawal Loss (Digester Gas)	3-90-920-54	1000 Gallons Digester Gas Throughput
	Pressure Tanks, Withdrawal Loss (Process Gas)	3-909-20-55	1000 Gallons Process Gas Throughput

TABLE 2.7-2

AIRS CONTROL DEVICE CODES

Control Device	Code
Wet Scrubber - High-Efficiency	001
Wet Scrubber - Medium-Efficiency	002
Wet Scrubber - Low-Efficiency	003
Gravity Collector - High-Efficiency	004
Gravity Collector - Medium-Efficiency	005
Gravity Collector - Low-Efficiency	006
Centrifugal Collector - High-Efficiency	007
Centrifugal Collector - Medium-Efficiency	008
Centrifugal Collector - Low-Efficiency	009
Electrostatic Precipitator - High-Efficiency	010
Electrostatic Precipitator - Medium-Efficiency	011
Electrostatic Precipitator - Low-Efficiency	012
Fabric Filter - High-Efficiency	016
Fabric Filter - Medium-Efficiency	017
Fabric Filter - Low-Efficiency	018
Mist Eliminator - High-Velocity	014
Mist Eliminator - Low-Velocity	015
Modified Furnace or Burner Design	024
Staged Combustion	025
Flue Gas Recirculation	026
Reduced Combustion-Air Preheating	027
Steam or Water Injection	028

TABLE **2.7-2**

(CONTINUED**)**

Control Device	Code
Low-Excess Air Firing	029
Use of Fuel with Low Nitrogen Content	030
Catalytic Reduction	065
Selective Noncatalytic Reduction for NO$_x$	107
Catalytic Oxidation - Flue Gas Desulfurization	039
Dry Limestone Injection	041
Wet Limestone Injection	042
Venturi Scrubber	053
Wet Lime Slurry Scrubbing	067
Alkaline Fly Ash Scrubbing	068
Sodium Carbonate Scrubbing	069
Miscellaneous Control Device	099

Note: At the time of publication, these control device codes were under review by the EPA. The reader should consult the EPA for the most current list of codes.

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APPENDIX A

EXAMPLE DATA COLLECTION FORM AND INSTRUCTIONS - BOILERS

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EXAMPLE DATA COLLECTION FORM INSTRUCTIONS - BOILER

1.   This form may be used as a work sheet to aid the plant engineer in collecting the information necessary to calculate emissions from boilers. The information requested on the form relates to the methods (described in Sections 3 and 4) for quantifying emissions. This form may also be used by the regulatory agency to assist in area-wide inventory preparation.

2.   The completed forms should be maintained in a reference file by the plant engineer with other supporting documentation.

3.   The information identified on these forms is needed to generate a complete emissions inventory. If the information requested does not apply to a particular boiler, write "NA" in the blank.

4.   If you want to modify the form to better serve your needs, an electronic copy of the form may be obtained through the EIIP on the CHIEF system.

5.   If rated capacity is not documented in MMBtu/hr, please enter the capacity in lb/hr steam produced, or other appropriate units of measure.

6.   If hourly or monthly fuel use information is not available, enter the information in another unit (quarterly or yearly). Be sure to indicate on the form what the unit of measure is.

7.   Use the comments field on the form to record all useful information that will allow your work to be reviewed and reconstructed.

EXAMPLE DATA COLLECTION FORM - BOILER

GENERAL INFORMATION

Facility/Plant Name: _____

SIC Code: _____

SCC: _____

SCC Description:
 Utility   _____
 Commercial   _____
 Industrial   _____

Location: _____

_____ County: _____

_____ City: _____

_____ State: _____

Plant Geographical Coordinates:
 Latitude: _____
 Longitude: _____
 UTM Zone: _____
 UTM Easting: _____
 UTM Northing: _____

Contact Name: _____

Title: _____

Telephone Number: _____

Unit ID Number: _____

Permit Number: _____

SOURCE INFORMATION	**COMMENTS**
Unit ID:	
Manufacturer:	
Date Installed:	
Rated Capacity (units):	
Maximum Heat Input (units):	
Fuel Type:	
Operating Schedule:	
Hours/Day:	
Days/Week:	
Weeks/Year:	
FUEL USE[a]:	
Year:	
Maximum Hourly Fuel Use (units):	
Monthly Fuel Use (units):	
January:	
February:	
March:	
April:	
May:	
June:	
July:	
August:	
September:	
October:	
November:	
December:	
Total Annual Fuel Use (units):	

[a] This form should be completed for each fuel type used.

FIRING CONFIGURATION (Check the appropriate type)

Tangential Fired ☐   Horizontally Fired ☐   Vertically Fired ☐   Pulverized Coal Fired ☐

Dry Bottom ☐   Wet Bottom ☐

Cyclone Furnace ☐

Spreader Stoker ☐   Uncontrolled ☐   Controlled ☐

Overfeed Stoker ☐   Uncontrolled ☐   Controlled ☐

Underfeed Stoker ☐   Uncontrolled ☐   Controlled ☐

Hand-fired Units ☐

POLLUTION CONTROL EQUIPMENT (Enter control efficiency and source of information)

ESP:

Baghouse:

Wet Scrubber:

Dry Scrubber:

Spray Dryer:

Cyclone:

Other:

FUEL ANALYSIS	COMMENTS
Sulfur Content (S):	
Ash Content:	
Nitrogen Content (N):	
Lead Content (Pb):	
Mercury (Hg):	
Others:	
Higher Heating Value (HHV in Btu/lb):	
Reference (Attach Analysis if Available):	
STACK INFORMATION:	
Stack ID:	
Unit ID:	
Stack (Release) Height (feet):	
Stack Diameter (inch):	
Stack Gas Temperature (^{o}F):	
Stack Gas Velocity (ft/sec):	
Stack Gas Flow Rate (ascf/min):	
Do Other Sources Share This Stack (Y/N)?: (If yes, include Unit IDs for each).	
Site-specific Stack Sampling Report Available (Y/N)?:	
Reference (Include Full Citation of Test Reports Used):	

EMISSION ESTIMATION RESULTS

Unit ID:_____

Fuel Type:_____

Pollutant	Emission Estimation Method[a]	Emissions	Emissions Units	Emission Factor[b]	Emission Factor Units	Comments
VOC						
NO$_x$						
CO						
SO$_2$						
PM$_{10}$						
Total Particulate						
Hazardous Air Pollutants (list individually)						

[a]   Use the following codes to indicate which emission estimation method is used for each pollutant:
CEMS/PEM = CEMS/PEM   Emission Factor = EF
Stack Test Data = ST   Other (indicate) = O
Fuel Analysis = FA

[b]   Where applicable, enter the emission factor and provide the full citation of the reference or source of information from where the emission factor came. Include edition, version, table, and page numbers if *AP-42* is used.