1. EXTERNAL COMBUSTION SOURCES

External combustion sources include steam/electric generating plants, industrial boilers, and commercial and domestic combustion units. Coal, fuel oil, and natural gas are the major fossil fuels used by these sources. Liquefied petroleum fuels are also used in relatively small quantities. Coal, oil, and natural gas currently supply about 95 percent of the total thermal energy consumed in the United States. Nationwide consumption in 1980 was over 530 x 10^6 megagrams (585 million tons) of bituminous coal, nearly 3.6 x 10^6 megagrams (4 million tons) of anthracite coal, 91 x 10 liters (24 billion gallons) of distillate oil, 114 x 10^9 liters (37 billion gallons) of residual oil, and 57 x 10^{12} cubic meters (20 trillion cubic feet) of natural gas.

Power generation, process heating, and space heating are some of the largest fuel combustion sources of sulfur oxides, nitrogen oxides, and particulate emissions. The following sections present emission factor data on the major fossil fuels and others.

1.2 Anthracite Coal Combustion

1.2.1 General[1-5]

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on volatile matter, fixed carbon, inherent moisture, and oxygen, although no one parameter defines rank. Typically coal rank increases as the amount of fixed carbon increases and the amount of volatile matter decreases.

Anthracite coal is a high-ranking coal with more fixed carbon and less volatile matter than bituminous, subbituminous, or lignite varieties. Anthracite also has higher ignition and ash fusion temperatures. In the U.S., nearly all anthracite is mined in northeastern Pennsylvania and consumed in Pennsylvania and its surrounding states. The only significant amount of anthracite is used for steam/electric production. Anthracite currently accounts for only a small fraction of the total quantity of coal combusted in the U.S. The anthracite burned is primarily reclaim from old production as no new anthracite is mined.

Another form of anthracite coal burned in boilers is anthracite refuse, commonly known as culm. Culm was produced as breaker reject material from the mining/sizing of anthracite coal and was typically dumped by miners on the ground near operating mines. It is estimated that there are over 16 million tons of culm scattered in piles throughout northeastern Pennsylvania. The heating value of culm is typically in the 2,500 to 5,000 British thermal units/pound (Btu/lb) range, as compared to 12,000 to 14,000 Btu/lb for anthracite coal.

1.2.2 Firing Practices[6-8]

Due to its low volatile matter content and non-clinkering characteristics, anthracite coal is primarily used in medium-sized industrial and institutional stoker boilers equipped with stationary or traveling grates. Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature. This fuel may also be burned in pulverized coal-fired (PC-fired) units, but, due to ignition difficulties, this practice is limited to only a few plants in eastern Pennsylvania. Anthracite coal has also been widely used in hand-fired furnaces. Culm has been combusted primarily in fluidized bed combustion (FBC) boilers because of its high ash content and low heating value.

Combustion of anthracite coal on a traveling grate is characterized by a coal bed 3 to 5 inches in depth and a high blast of underfire air at the rear or dumping end of the grate. This high blast of air lifts incandescent fuel particles and combustion gases from the grate and reflects the particles against a long rear arch over the grate towards the front of the fuel bed where fresh or "green" fuel enters. This special furnace arch design is required to assist in the ignition of the green fuel.

A second type of stoker boiler used to burn anthracite coal is the underfeed stoker. Various types of underfeed stokers are used in industrial boiler applications but the most common for anthracite coal firing is the single-retort side-dump stoker with stationary grates. In this unit, coal is fed intermittently to the fuel bed by a ram. In very small units the coal is fed continuously by a screw. Feed coal is pushed through the retort and upward towards the tuyere blocks. Air is supplied through the tuyere blocks on each side of the retort and through openings in the side grates. Overfire air (OFA) is commonly used with underfeed stokers to provide combustion air and turbulence in the flame zone directly above the active fuel bed.

In PC-fired boilers, the fuel is pulverized to the consistency of powder and pneumatically injected through burners into the furnace. Injected coal particles burn in suspension within the furnace region of the boiler. Hot flue gases rise from the furnace and provide heat exchange with boiler tubes in the walls and upper regions of the boiler. In general, PC-fired boilers operate either in a wet-bottom or dry-bottom mode; because of its high ash fusion temperature, anthracite coal is burned in dry-bottom furnaces.

For anthracite culm, combustion in conventional boiler systems is difficult due to the fuel's high ash content, high moisture content, and low heating value. However, the burning of culm in an FBC system was demonstrated at a steam generation plant in Pennsylvania. The FBC system consists of inert particles (e. g., rock and ash) through which air is blown so that the bed behaves as a fluid. Anthracite coal enters in the space above the bed and burns in the bed. Fluidized beds can handle fuels with moisture contents approaching 70 percent (total basis) because of the large thermal mass represented by the hot inert bed particles. Fluidized beds can also handle fuels with ash contents as high as 75 percent. Heat released by combustion is transferred to in-bed steam-generating tubes. Limestone may be added to the bed to capture sulfur dioxide SO_2 formed by combustion of fuel sulfur.

1.2.3 Emissions[2,6,8]

Emissions from coal combustion depend on coal type and composition, the design type and capacity of the boiler, the firing conditions, load, the type of control devices, and the level of equipment maintenance. Emissions from anthracite coal firing primarily include particulate matter (PM), sulfur oxides (SO_x), nitrogen oxides (NO_x), and carbon monoxide (CO); and trace amounts of organic compounds and trace elements.

Particulate Matter -

PM emissions from anthracite coal combustion are a function of furnace firing configuration, firing practices (boiler load, quantity and location of underfire air, soot blowing, fly ash reinjection, etc.), and the ash content of the coal. PC-fired boilers emit the highest quantity of PM per unit of fuel because they fire the anthracite in suspension, which results in a high percentage of ash carryover into exhaust gases. Traveling grate stokers and hand-fired units produce less PM per unit of fuel fired, and coarser particulates, because combustion takes place in a quiescent fuel bed without significant ash carryover into the exhaust gases. In general, PM emissions from traveling grate stokers will increase during soot blowing and fly ash reinjection and with higher fuel bed underfeed air flowrates. Smoke production during combustion is rarely a problem, because of anthracite's low volatile matter content.

Sulfur Oxides -

Limited data are available on the emission of gaseous pollutants from anthracite combustion. It is assumed, based on bituminous coal combustion data, that a large fraction of the fuel sulfur is emitted as SO_x. SO_x emissions are directly proportional to the sulfur content of fuel. Some minor differences will occur from unit to unit, however, due to (1) ash partitioning between fly ash and bottom ash and (2) the sodium content of the coal (which tends to react with and bind coal sulfur in the bottom ash as sodium sulfite or sodium sulfate). For FBC boilers, SO_x emissions are inversely proportional, in general, to the molar ratio of calcium (in the limestone) to sulfur (in the fuel) added to the bed.[8]

Nitrogen Oxides[8] -

NO_x emissions are lower in traveling grate and underfeed stokers compared to PC-fired boilers. Underfeed and traveling grate stokers have large furnace areas and consequently lower volumetric- and surface area-based heat release rates. Lower heat release rates reduce peak combustion temperatures and, hence, contribute to lower NO_x emissions. In addition, the partially staged combustion that naturally occurs in all stokers due to the use of underfire and overfire air contributes to reduced NO_x emissions relative to PC-fired units. The low operating temperatures which characterize FBC boilers firing culm also favor relatively low NO_x emissions. Reducing boiler load tends to decrease combustion intensity which, in turn, leads to decreased NO_x emissions for all boiler types.

Carbon Monoxide -

CO and total organic compound (TOC) emissions are dependent on combustion efficiency. Generally their emission rates, defined as mass of emissions per unit of heat input, decrease with increasing boiler size. Organic compound emissions are expected to be lower for PC-fired units and higher for underfeed and overfeed stokers due to relative combustion efficiency levels.

1.2.4 Controls[6,8]

Controls on anthracite-fired boilers have mainly have been applied to reduce PM emissions. The most efficient particulate controls—fabric filters, electrostatic precipitators (ESP), and scrubbers—have been installed on large pulverized anthracite-fired boilers. In fabric filters (baghouses), particulate-laden dust passes through a set of filters mounted inside the collector housing. Dust particles in the inlet gas are collected on the filters by inertial impaction, diffusion, direct interception, and sieving. The collection efficiencies of fabric filters or coal-fired boilers can exceed 99 percent.

Particulate collection in an ESP occurs in three steps: suspended particles are given an electrical charge; the charged particles migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and the collected PM is dislodged from the collecting electrodes. Removal of the collected PM is accomplished mechanically by rapping or vibrating the collecting electrodes. When applied to anthracite coal-fired boilers, ESPs are only 90 to 97 percent efficient, because of the characteristic high resistivity of low sulfur anthracite fly ash. It is reported that higher efficiencies can be achieved using larger ESPs combined with flue gas conditioning.

The most widely used wet scrubbers for anthracite coal-fired boilers are venturi scrubbers. In a typical venturi scrubber, the particle-laden gas first contacts the liquor stream in the core and throat of the venturi section. The gas and liquid streams then pass through the annular orifice formed by the core and throat, atomizing the liquid into droplets which are impacted by particles in the gas stream. Impaction results mainly from the high differential velocity between the gas stream and the atomized droplets. The droplets are then removed from the gas stream by centrifugal action in a cyclone separator and (if present) a mist eliminator section.

Wet scrubbers have reported PM collection efficiencies of 90 percent or greater. Gaseous emissions such as SO_2, NO_x, CO, and organics may also be absorbed to a significant extent in a wet scrubber. Operational problems can occur with wet scrubbers due to clogged spray nozzles, sludge deposits, dirty recirculation water, improper water levels, and unusually low pressure drops. Mechanical collectors, or cyclones, use centrifugal separation to remove PM from flue gas streams. At the entrance of the cyclone, a spin is imparted to the particle-laden gas. This spin creates a centrifugal force which causes the PM to move away from the axis of rotation and toward the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to a dust collection hopper where they are deposited. Mechanical collectors typically have PM collection efficiencies up to 80 percent.

Emission factors and ratings for criteria pollutants from anthracite coal combustion are given in Tables 1.2-1, 1.2-2, and 1.2-3. Tables in this section present emission factors on a weight basis (lb/ton). To convert to an energy basis (lb/MMBtu), divide by a heating value of 24.6 MMBtu/ton. Cumulative particle size distribution data for uncontrolled and controlled boilers burning pulverized anthracite coal are given in Table 1.2-4. Figure 1.2-1 presents cumulative size-specific emission factors for stokers burning anthracite coal. Emission factors for speciated organic compounds are given in Table 1.2-5. Emission factors for TOCs and methane from burning anthracite are given in Table 1.2-6. Emission factors for speciated metals from stoker boilers firing anthracite coal are given in Table 1.2-7.

1.2.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

- An SCC (A2104001000) was provided for residential space heaters.

Supplement B, October 1996

- Text was enhanced concerning anthracite coal.
- Text was enhanced concerning emissions of SO_x, NO_x, and CO.
- Text was added concerning PM and SO_2 controls.
- Emission factor tables were rearranged so that criteria pollutants appear first.
- Mathematical errors were corrected for CO, TOC, and mercury.
- Emission factors were corrected for speciated organic compounds.

Table 1.2-1. EMISSION FACTORS FOR SO_x AND NO_x COMPOUNDS FROM UNCONTROLLED ANTHRACITE COAL COMBUSTORS[a]

Source Category	SO_x		NO_x	
	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Stoker-fired boilers[c] (SCC 1-01-001-02, 1-02-001-04, 1-03-001-02)	39S[b]	B	9.0	C
FBC boilers[d] (no SCC)	2.9	E	1.8	E
Pulverized coal boilers[e] (SCC 1-01-001-01, 1-02-001-01, 1-03-001-01)	39S[b]	B	18	B
Residential space heaters[e] (SCC A2104001000)	39S[b]	B	3	B

[a] Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.
[b] S = weight percent sulfur. For example, if the sulfur content is 3.4%, then S = 3.4.
[c] References 9-10.
[d] Reference 11. FBC boilers burning culm fuel; all other sources burning anthracite coal.
[e] Reference 2.

Table 1.2-2. EMISSION FACTORS FOR CO AND CARBON DIOXIDE (CO_2) FROM UNCONTROLLED ANTHRACITE COAL COMBUSTORS[a]

	CO		CO_2	
Source Category	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Stoker-fired boilers[b] (SCC 1-01-001-02, 1-02-001-04, 1-03-001-02)	0.6	B	5,680	C
FBC boilers[c] (no SCC)	0.6	E	ND	NA

[a] Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] References 2,9,12.

[c] Reference 11. FBC boilers burning culm fuel; all other sources burning anthracite coal.

Table 1.2-3. EMISSION FACTORS FOR PM AND LEAD (Pb) FROM UNCONTROLLED ANTHRACITE COAL COMBUSTORS[a]

Source Category	Filterable PM		Condensible PM		Pb	
	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Stoker-fired boilers[b] (SCC 1-01-001-02, 1-02-001-04, 1-03-001-02)	0.8A[c]	C	0.08A[c]	C	8.9 E-03	E
Hand-fired units[d] (SCC 1-02-002-07, 1-03-001-03)	10	B	ND	NA	ND	NA

[a] Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data.
NA = not applicable.

[b] References 9-10,13-14.

[c] A = ash content of fuel, weight %. For example, if the ash content is 5%, then A = 5.

[d] Reference 2.

Table 1.2-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED ANTHRACITE COAL[a]

EMISSION FACTOR RATING: D

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size			Cumulative Emission Factor As Fired[c] (lb/ton)		
	Uncontrolled	Controlled[d]		Uncontrolled	Controlled[d]	
		Multiple Cyclone	Baghouse		Multiple Cyclone	Baghouse
15	32	63	79	3.2A[e]	1.26A	0.016A
10	23	55	67	2.3A	1.10A	0.013A
6	17	46	51	1.7A	0.92A	0.010A
2.5	6	24	32	0.6A	0.48A	0.006A
1.25	2	13	21	0.2A	0.26A	0.004A
1.00	2	10	18	0.2A	0.20A	0.004A
0.625	1	7	—[f]	0.1A	0.14A	—[f]
TOTAL	100	100	100	10A	2A	0.02A

[a] Reference 15. Source Classification Codes are 1-01-001-01, 1-02-001-01, and 1-03-001-01.
[b] Expressed as aerodynamic equivalent diameter.
[c] Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5.
[d] Estimated control efficiency for multiple cyclone is 80%; for baghouse, 99.8%.
[e] A = coal ash weight %, as fired. For example, if ash content is 5%, then A = 5.
[f] Insufficient data.

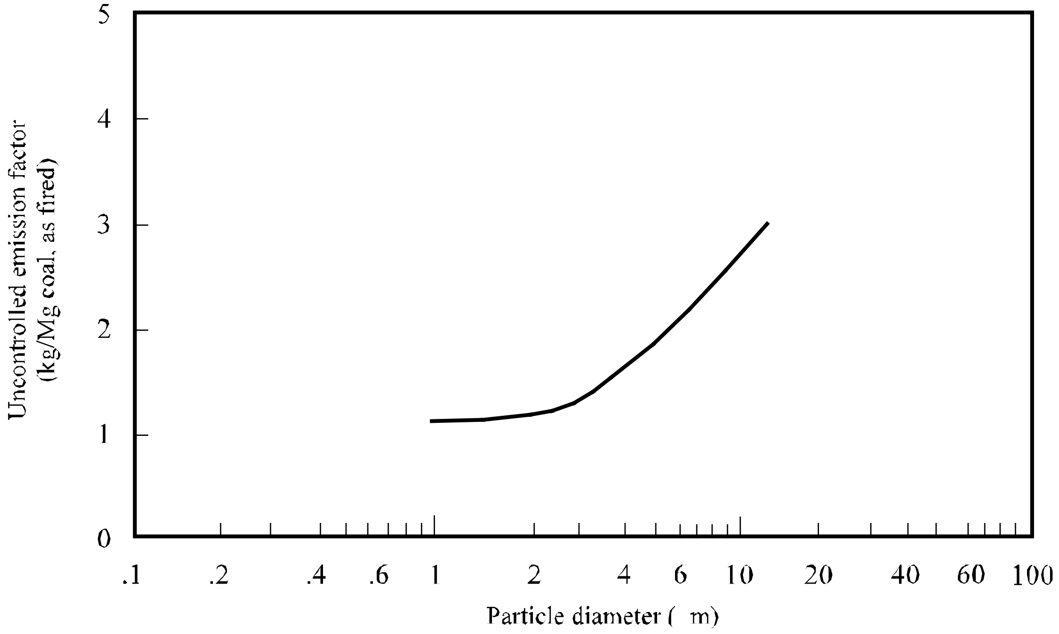

Figure 1.2-1. Cumulative size-specific emission factors for traveling grate stokers burning anthracite coal.

Table 1.2-5. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM ANTHRACITE COAL COMBUSTORS[a]

EMISSION FACTOR RATING: E

	Stoker-Fired Boilers[b] (SCC 1-01-001-02, 1-02-001-04, 1-03-001-02)	Residential Space Heaters[c] (SCC A2-10-400-1000)	
Pollutant	Emission Factor (lb/ton)	Emission Factor Range (lb/ton)	Average Emission Factor (lb/ton)
Acenaphthene	ND	1.1 E-05 - 2.9 E-05	2.2 E-05
Acenaphthylene	ND	1.1 E-05 - 2.2 E-04	8.6 E-05
Anthanthrene	ND	1.5 E-07 - 8.8 E-07	5.7 E-07
Anthracene	ND	7.0 E-06 - 3.7 E-05	2.5 E-05
Benzo(a)anthracene	ND	1.1 E-05 - 1.6 E-04	7.1 E-05
Benzo(a)pyrene	ND	3.1 E-06 - 7.0 E-06	5.3 E-06
Benzo(e)pyrene	ND	3.5 E-06 - 1.0 E-05	6.2 E-06
Benzo(g,h,i,) perylene	ND	3.1 E-06 - 9.5 E-06	5.5 E-06
Benzo(k)fluoranthrene	ND	1.1 E-05 - 4.5 E-05	2.5 E-05
Biphenyl	2.5 E-02	ND	ND
Chrysene	ND	1.8 E-05 - 1.8 E-04	8.3 E-05
Coronene	ND	8.8 E-07 - 6.4 E-06	3.9 E-06
Fluoranthrene	ND	7.5 E-05 - 2.7 E-04	1.7 E-04
Fluorene	ND	7.0 E-06 - 4.1 E-05	2.5 E-05
Indeno(123-cd) perylene	ND	3.5 E-06 - 1.1 E-05	6.9 E-06
Naphthalene	1.3 E-01	7.0 E-06 - 4.8 E-04	2.2 E-04
Perylene	ND	6.1 E-07 - 1.8 E-06	1.2 E-06
Phenanthrene	6.8 E-03	7.1 E-05 - 3.4 E-04	2.4 E-04
Pyrene	ND	4.2 E-05 - 1.9 E-04	1.2 E-04

[a] Units are lb of pollutant/ton of anthracite coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data.
[b] Reference 13.
[c] Reference 16.

Table 1.2-6. EMISSION FACTORS FOR TOC AND METHANE (CH_4) FROM ANTHRACITE COAL COMBUSTORS[a]

EMISSION FACTOR RATING: E

Source Category	TOC Emission Factor (lb/ton)	CH_4 Emission Factor (lb/ton)
Stoker fired boilers[b] (SCC 1-01-001-02, 1-02-001-04, 1-03-001-02)	0.30	ND
Residential space heaters[c] (A2-10-400-1000)	ND	8

[a] Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data.

[b] Reference 13.

[c] Reference 16.

Table 1.2-7. EMISSION FACTORS FOR SPECIATED METALS FROM ANTHRACITE COAL COMBUSTION IN STOKER FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor Range (lb/ton)	Average Emission Factor (lb/ton)
Arsenic	BDL - 2.4 E-04	1.9 E-04
Antimony	BDL	BDL
Beryllium	3.0 E-05 - 5.4 E-04	3.1 E-04
Cadmium	4.5 E-05 - 1.1 E-04	7.1 E-05
Chromium	5.9 E-03 - 4.9 E-02	2.8 E-02
Manganese	9.8 E-04 - 5.3 E-03	3.6 E-03
Mercury	8.7 E-05 - 1.7 E-04	1.3 E-04
Nickel	7.8 E-03 - 3.5 E-02	2.6 E-02
Selenium	4.7 E-04 - 2.1 E-03	1.3 E-03

[a] Reference 13. Units are lb of pollutant/ton of coal burned. To convert from lb/ton to kg/Mg, multiply by 0.5. Source Classification Codes are 1-01-001-02, 1-02-001-04, and 1-03-001-02. BDL = below detection limit.

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1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

1.3.3 Emissions[5]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

1.3.3.1 Particulate Matter Emissions[6-15] -

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

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, filterable PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

1.3.3.2 Sulfur Oxides Emissions[1-2,6-9,16] -

Sulfur oxides (SO_x) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

1.3.3.3 Nitrogen Oxides Emissions[1-2,6-10,15,17-27] -

Oxides of nitrogen (NO_x) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x"), or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x refers to the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Test data have shown that for most external fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of nitric oxide (NO). Nitrous oxide (N_2O) is not included in NO_x but has recently received increased interest because of atmospheric effects.

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of O_2 concentration in the flame, and the residence time. Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) fuel nitrogen concentration, (3) oxygen concentration, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are generally consistent for all types of boilers: an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production.

Fuel nitrogen conversion is the more important NO_x-forming mechanism in residual oil boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing. The percent conversion of fuel nitrogen to NO_x varies greatly, however; typically from 20 to 90 percent of nitrogen in oil is converted to NO_x. Except in certain large units having unusually high peak flame temperatures, or in units firing a low nitrogen content residual oil, fuel NO_x generally accounts for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the dominant NO_x-forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate oil-fired boilers are usually smaller and have lower heat release rates, the quantity of thermal NO_x formed in them is less than that of larger units which typically burn residual oil.[28]

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), reduced air preheat (RAP), low NO_x burners (LNBs), burning oil/water emulsions (OWE), or some combination thereof may result in NO_x reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease NO_x production. Nitrogen oxide emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, only influence the NO_x emissions of large oil-fired boilers. Low excess air-firing is possible in many small boilers, but the resulting NO_x reductions are less significant.

1.3.3.4 Carbon Monoxide Emissions[29-32] -

The rate of carbon monoxide (CO) emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have a higher ratio of heat transfer surface area to flame volume than larger combustors have; this leads to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion, including insufficient oxygen (O_2) availability; poor fuel/air mixing; cold-wall flame quenching; reduced combustion temperature; decreased combustion gas residence time; and load reduction (i. e., reduced combustion intensity). Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

1.3.3.5 Organic Compound Emissions[29-39] -

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends, to some extent, on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

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

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

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

1.3.3.6 Trace Element Emissions[29-32,40-44] -

Trace elements are also emitted from the combustion of oil. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments are considered. The quantity of trace elements entering the combustion device depends solely on the fuel composition. The quantity of trace metals emitted from the source depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the separation of emissions into bottom ash and fly ash. In general, the quantity of any given metal emitted depends on the physical and chemical properties of the element itself; concentration of the metal in the fuel; the combustion conditions; and the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not. Various classification schemes to describe this partitioning have been developed. The classification scheme used by Baig, et al.[44] is as follows:

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

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.

- Class 3: Elements which are emitted in the gas phase.

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

Lower local O_2 concentrations is also expected to affect segregating metal emissions from boilers with particle controls. Lower O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase as they enter the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metal emissions should remain unchanged.

1.3.3.7 Greenhouse Gases[45-50] -

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during fuel oil combustion. Nearly all of the fuel carbon (99 percent) in fuel oil is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion in the fuel stream.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent). Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. Average emission factors based on reported test data have been developed for conventional oil combustion systems.

Methane emissions vary with the type of fuel and firing configuration, but are highest during periods of incomplete combustion or low-temperature combustion, such as the start-up or shut-down cycle for oil-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.3.4 Controls

Control techniques for criteria pollutants from fuel oil combustion may be classified into three broad categories: fuel substitution/alteration, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel substitution reduces SO_2 or NO_x and involves burning a fuel with a lower sulfur or nitrogen content, respectively. Particulate matter will generally be reduced when a lighter grade of fuel oil is burned.[6,8,11] Fuel alteration of heavy oils includes mixing water and heavy oil using emulsifying agents for better atomization and lower combustion temperatures. Under some conditions, emissions of NO_x, CO, and PM may be reduced significantly. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control is a device after the combustion of the fuel and is applied to control emissions of PM, SO_2, and NO_x.

1.3.4.1 Particulate Matter Controls[51] -

Control of PM emissions from residential and commercial units is accomplished by improving burner servicing and improving oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered effective toward achieving the triple goals of low PM emissions, low NO_x emissions, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensable organic compound emissions are minimized. Particulate matter emissions are more a result of emitted fly ash with a carbon component in such units. Therefore, postcombustion controls (mechanical collectors, ESP, fabric filters, etc.) or fuel substitution/alteration may be used to reduce PM emissions from these sources.

Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85 percent control of particulate. Under normal firing conditions, or when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are commonly used in oil-fired power plants. Older precipitators, usually small, typically remove 40 to 60 percent of the emitted PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Currently, new or rebuilt ESPs can achieve collection efficiencies of up to 90 percent.

In fabric filtration, a number of filtering elements (bags) along with a bag cleaning system are contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of the fabric filter system is dependent on a variety of particle and operational characteristics including particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleaning, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may be more than 99 percent.

Scrubbing systems have also been installed on oil-fired boilers to control both sulfur oxides and particulate. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

Fuel alteration of heavy oil by mixing with water and an emulsifying agent has reduced PM emissions significantly in controlled tests.

1.3.4.2 SO_2 Controls[52-53] -

Commercialized postcombustion flue gas desulfurization (FGD) processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded).

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

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

1.3.4.3 NO_x Controls[41,54-55] -

In boilers fired on crude oil or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since fuel NO_x typically accounts for 60 to 80 percent of the total NO_x formed. Fuel nitrogen conversion to NO_x is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

Several techniques are used to reduce NO_x emissions from fuel oil combustion. Fuel substitution consists of burning lower nitrogen fuels. Fuel alteration includes burning emulsified heavy oil and water mixtures. In addition to these, the primary techniques can be classified into one of two fundamentally different methods — combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process while postcombustion controls reduce NO_x emissions after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. Postcombustion control methods include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). These controls can be used separately, or combined to achieve greater NO_x reduction.

Operating at low excess air involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. Burners out of service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased-burner firing involves firing the lower rows of burners more fuel-rich than the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NO_x by as much as 40 to 50 percent in some boilers.

Overfire air is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. Overfire air limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) a reduced flame temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

Low NO_x burners are applicable to tangential and wall-fired boilers of various sizes. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet NSPS limits. Low NO_x burners can be combined with overfire air to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

SNCR is a postcombustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compound that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia to NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. NO_x emission reductions of 75 to 85 percent have been achieved through the use of SCR on oil-fired boilers operating in the U.S.

Fuel alteration for NO_x reduction includes use of oil/water emulsion fuels. In controlled tests, a mixture of 9 percent water in No. 6 oil with a petroleum based emulsifying agent reduced NO_x emissions by 36 percent on a Btu basis or 41 percent on a volume basis, compared with the same fuel in unaltered form. The reduction appears to be due primarily to improved atomization with a corresponding reduction of excess combustion air, with lower flame temperature contributing slightly to the reduction.[84]

Tables 1.3-1 and 1.3-3 present emission factors for uncontrolled criteria pollutants from fuel oil combustion. Tables in this section present emission factors on a volume basis ($lb/10^3gal$). To convert to an energy basis (lb/MMBtu), divide by a heating value of 150 $MMBtu/10^3gal$ for Nos. 4, 5, 6, and residual fuel oil, and 140 $MMBtu/10^3gal$ for No. 2 and distillate fuel oil. Table 1.3-2 presents emission factors for condensible particulate matter. Tables 1.3-4, 1.3-5, 1.3-6, and 1.3-7 present cumulative size distribution data and size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Figures 1.3-1, 1.3-2, 1.3-3, and 1.3-4 present size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Emission factors for N_2O, POM, and formaldehyde are presented in Table 1.3-8. Emission factors for speciated organic compounds are presented in Table 1.3-9. Emission factors for trace elements in distillate oil are given in Table 1.3-10. Emission factors for trace metals residual oil are given in Table 1.3-11. Default emission factors for CO_2 are presented in Table 1.3-12. A summary of various SO_2 and NO_x controls for fuel-oil-fired boilers is presented in Table 1.3-13 and 1.3-14, respectively. Emission factors for CO, NO_x, and PM from burning No. 6 oil/water emulsion fuel are presented in Table 1.3-15.

1.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF web site (http://www.epa.gov/ttn/chief/).

Supplement A, February 1996

- The formulas presented in the footnotes for filterable PM were moved into the table.
- For SO_2 and SO_3 emission factors, text was added to the table footnotes to clarify that “S” is a weight percent and not a fraction. A similar clarification was made to the CO and NO_x footnotes. SCC A2104004/A2104011 was provided for residential furnaces.
- For industrial boilers firing No. 6 and No. 5 oil, the methane emission factor was changed from 1 to 1.0 to show two significant figures.
- For SO_2 and SO_3 factors, text was added to the table footnotes to clarify that “S” is a weight percent and not a fraction.
- The N_2O, POM, and formaldehyde factors were corrected.
- Table 1.3-10 was incorrectly labeled 1.1-10. This was corrected.

Supplement B, October 1996

- Text was added concerning firing practices.
- Factors for N_2O, POM, and formaldehyde were added.
- New data for filterable PM were used to create a new PM factor for residential oil-fired furnaces.
- Many new factors were added for toxic organics, toxic metals from distillate oil, and toxic metals from residual oil.
- A table was added for new CO_2 emission factors.

Supplement E, September 1998

- Table 1.3-1, the sub-heading for "Industrial Boilers" was added to the first column.
- Table 1.3-3, the emission factor for uncontrolled PM less than 0.625 micron was corrected to 1.7A, the emission factor for scrubber controlled PM less than 10 micron was corrected to 0.50A, and the relationships for each content in various fuel oils was corrected in footnote C.
- Table 1.3-4 and 1.3-6, the relationship for ash content in various fuel oils was corrected in the footnote C of each table.

- Table 1.3-9, the emission factors for trace metals in distillate oil were updated with newer data where available.

- 1.3-10, the title of the table was changed to clarify these factors apply to uncontrolled fuel oil boilers.

- Text and emission factors were added pertaining to No. 6 oil/water emulsion fuel.

- Table 1.3-1 was revised to include new NO_x emission factors.

- Emission factors for condensable particulate matter were added (Table 1.3-2).

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	10	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/10^3 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO_2/10^3 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[g] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 1b/10^3 gal.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.

[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.

[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.

[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.

[e] References: 76-78.

[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor (lb/10^3 gal)	Methane[b] Emission Factor (lb/10^3 gal)	NMTOC[b] Emission Factor (lb/10^3 gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL[a]

	Cumulative Mass % ≤ Stated Size			Cumulative Emission Factor lb/10^3 gal)					
		Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
Particle Size[b] (μm)	Uncon-trolled	ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.7A	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

[a] Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/10^3 gal to kg/m^3, multiply by 0.120. ESP = electrostatic precipitator.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84

[d] Estimated control efficiency for ESP is 99.2%.

[e] Estimated control efficiency for scrubber is 94%

Table 1.3-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] (lb/10^3 gal)			
			Uncontrolled		Multiple Cyclone Controlled[d]	
	Uncontrolled	Multiple Cyclone Controlled	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	91	100	7.59A	D	1.67A	E
10	86	95	7.17A	D	1.58A	E
6	77	72	6.42A	D	1.17A	E
2.5	56	22	4.67A	D	0.33A	E
1.25	39	21	3.25A	D	0.33A	E
1.00	36	21	3.00A	D	0.33A	E
0.625	30	—[e]	2.50A	D	—[e]	NA
TOTAL	100	100	8.34A	D	1.67A	E

[a] Reference 26. Source Classification Codes 1-02-004-01/02/03/04 and 1-02-005-04. To convert lb/10^3 gal to kg/10^3 L, multiply by 0.120. NA = not applicable.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37
No. 5 oil: A = 1.2
No. 4 oil: A = 0.84

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

[e] Insufficient data.

Table 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size	Cumulative Emission Factor ($lb/10^3$ gal)
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

[a] Reference 26. Source Classification Codes 1-02-005-01/02/03. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.

[b] Expressed as aerodynamic equivalent diameter.

Table 1.3-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL OR DISTILLATE OIL[a]

EMISSION FACTOR RATING: D

	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)	
Particle Size[b] (μm)	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil
15	78	60	6.50A	1.17
10	62	55	5.17A	1.08
6	44	49	3.67A	1.00
2.5	23	42	1.92A	0.83
1.25	16	38	1.33A	0.75
1.00	14	37	1.17A	0.75
0.625	13	35	1.08A	0.67
TOTAL	100	100	8.34A	2.00

[a] Reference 26. Source Classification Codes: 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the fuel. For example, if the fuel is 1.0% sulfur, then S = 1.

No. 6 oil: A = 1.12(S) + 0.37

No. 5 oil: A = 1.2

No. 4 oil: A = 0.84

No. 2 oil: A = 0.24

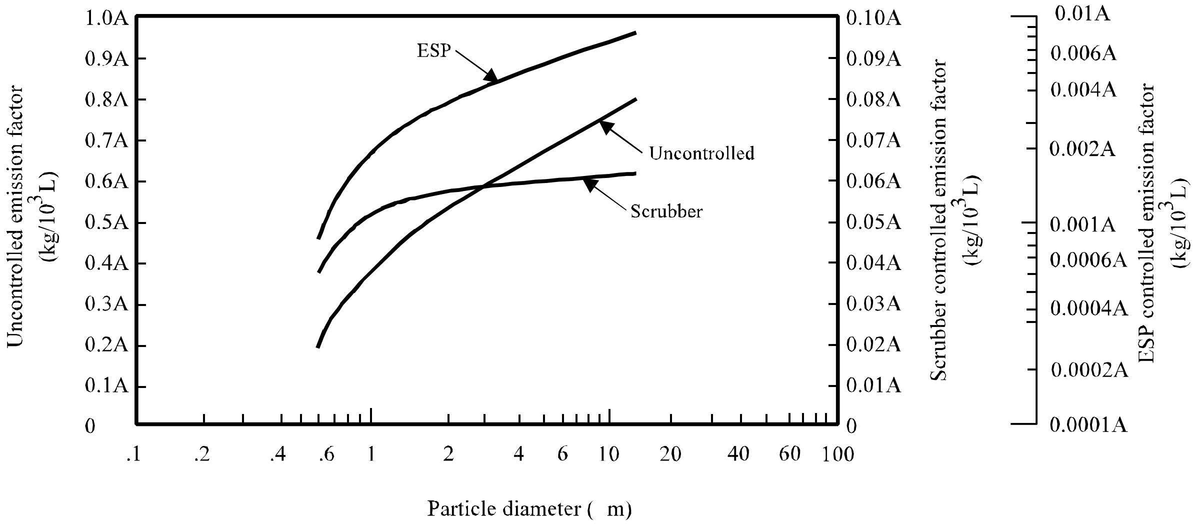

Figure 1.3-1. Cumulative size-specific emission factors for utility boilers firing residual oil.

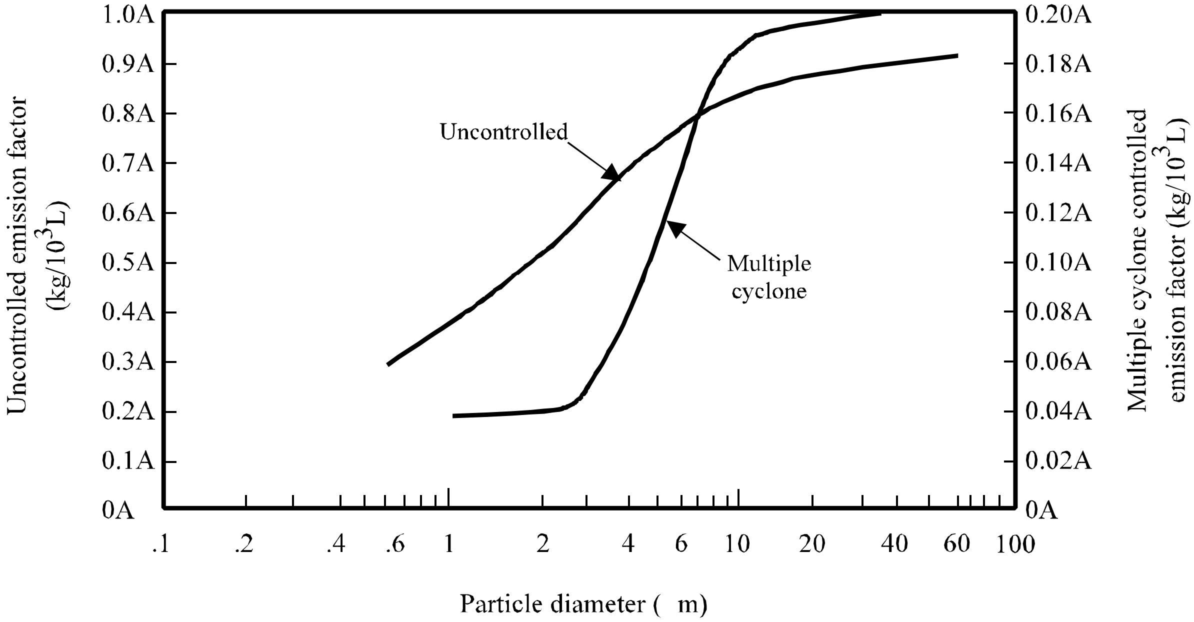

Figure 1.3-2. Cumulative size-specific emission factors for industrial boilers firing residual oil.

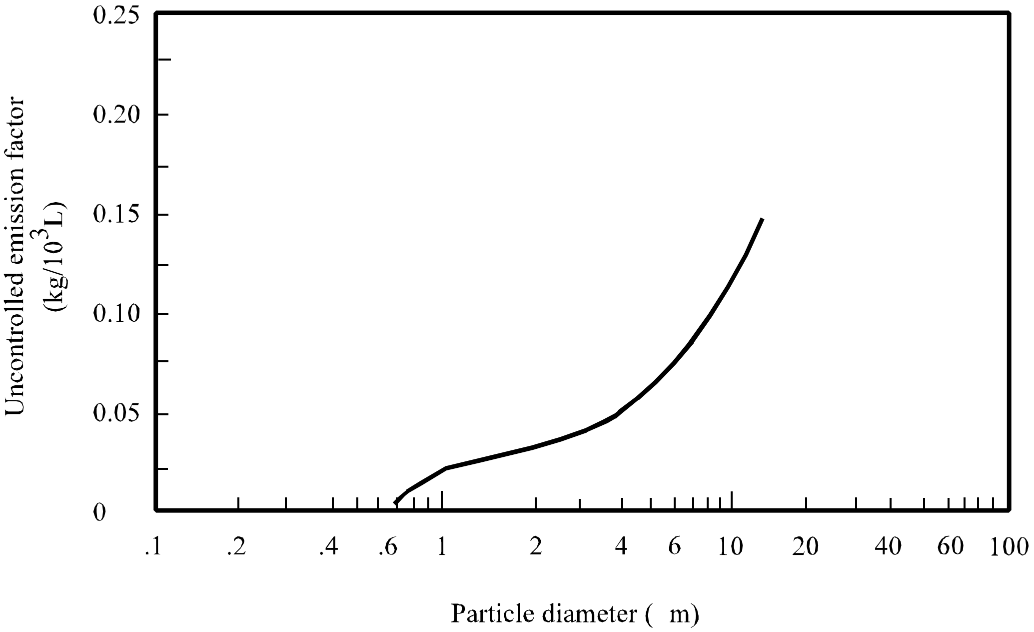

Figure 1.3-3. Cumulative size-specific emission factors for uncontrolled industrial boilers firing distillate oil.

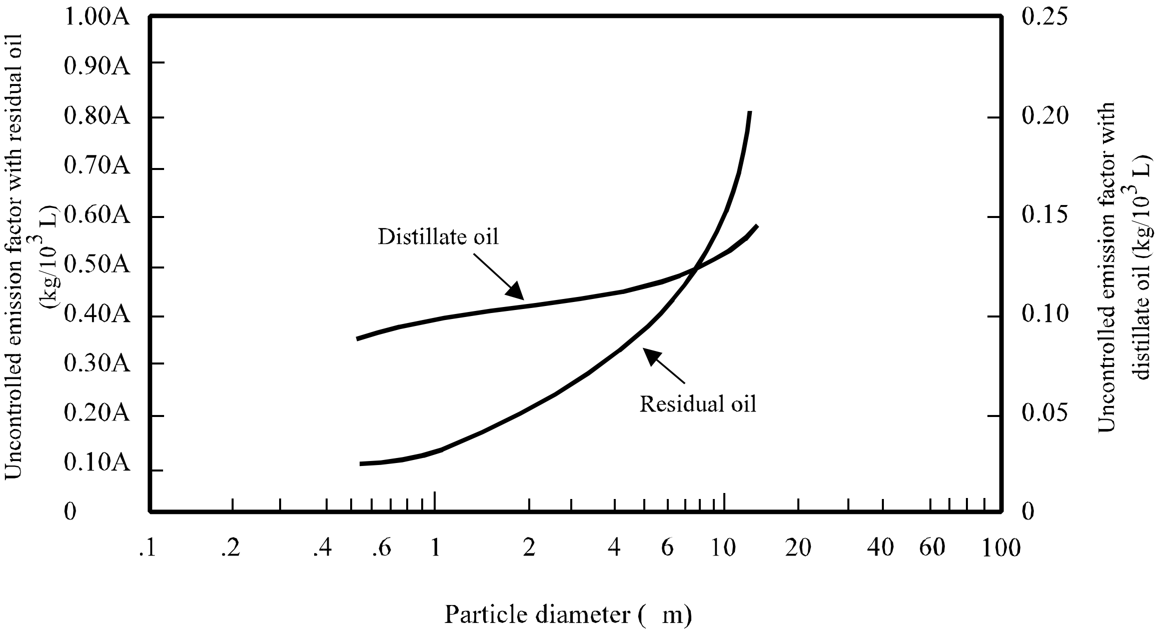

Figure 1.3-4. Cumulative size-specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

Table 1.3-8. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code. ND = no data.
[b] References 45-46. EMISSION FACTOR RATING = B.
[c] References 29-32.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

Table 1.3-9. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM FUEL OIL COMBUSTION[a]

Organic Compound	Average Emission Factor[b] (lb/10^3 Gal)	EMISSION FACTOR RATING
Benzene	2.14E-04	C
Ethylbenzene	6.36E-05[c]	E
Formaldehyde[d]	3.30E-02	C
Naphthalene	1.13E-03	C
1,1,1-Trichloroethane	2.36E-04[c]	E
Toluene	6.20E-03	D
o-Xylene	1.09E-04[c]	E
Acenaphthene	2.11E-05	C
Acenaphthylene	2.53E-07	D
Anthracene	1.22E-06	C
Benz(a)anthracene	4.01E-06	C
Benzo(b,k)fluoranthene	1.48E-06	C
Benzo(g,h,i)perylene	2.26E-06	C
Chrysene	2.38E-06	C
Dibenzo(a,h) anthracene	1.67E-06	D
Fluoranthene	4.84E-06	C
Fluorene	4.47E-06	C
Indo(1,2,3-cd)pyrene	2.14E-06	C
Phenanthrene	1.05E-05	C
Pyrene	4.25E-06	C
OCDD	3.10E-09[c]	E

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12.

[c] Based on data from one source test (Reference 67).

[d] The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43.

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b, d] ($lb/10^3$ Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.

[c] References 29-32,40-44.

[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

Table 1.3-12. DEFAULT CO_2 EMISSION FACTORS FOR LIQUID FUELS[a]

EMISSION FACTOR RATING: B

Fuel Type	%C[b]	Density[c] (lb/gal)	Emission Factor (lb/10^3 gal)
No. 1 (kerosene)	86.25	6.88	21,500
No. 2	87.25	7.05	22,300
Low Sulfur No. 6	87.26	7.88	25,000
High Sulfur No. 6	85.14	7.88	24,400

[a] Based on 99% conversion of fuel carbon content to CO_2. To convert from lb/gal to gram/cm^3, multiply by 0.12. To convert from lb/10^3 gal to kg/m^3, multiply by 0.12.

[b] Based on an average of fuel carbon contents given in references 73-74.

[c] References 73, 75.

Table 1.3-13. POSTCOMBUSTION SO_2 CONTROLS FOR FUEL OIL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80-95+%	Applicable to high-sulfur fuels, Wet sludge product
	Sodium carbonate	80-98%	5-430 MMBtu/hr typical application range, High reagent costs
	Magnesium oxide/hydroxide	80-95+%	Can be regenerated
	Dual alkali	90-96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70-90%	Applicable to low-and medium-sulfur fuels, Produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25-50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25-50+%	Several R&D and demonstration projects underway, Not yet Commercially available in the U.S.

Table 1.3-14. NO_x CONTROL OPTIONS FOR OIL-FIRED BOILERS[a]

Control Technique	Description Of Technique	NO_x Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	0 to 28	0 to 24	Generally excess O_2 can be reduced to 2.5% representing a 3% drop from baseline	Available for boilers with sufficient operational flexibility.	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	20 to 50	17 to 44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on packaged and field-erected units. However, not commercially available for all design types.	Best implemented on new units. Retrofit is probably not feasible for most units, especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder of burners firing fuel-rich	10 to 30	ND	Most effective on boilers with 4 or more burners in a square pattern.	Available.	Requires careful selection of BOOS pattern and control of air flow. May result in boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on most design types.	Available. Best suited for new units.	Requires extensive modifications to the burner and windbox. Possible flame instability at high FGR rates.
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	25 to 53	73 to 77	Maximum FGR rates set at 25% for distillate oil and 20% for residual oil.	Available for boilers with sufficient operational flexibility.	May not be feasible on all existing boiler types. Best implemented on new units.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO$_x$ Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	33% decrease to 25% increase in No$_x$	31% decrease to 17% increase in NO$_x$	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available in retrofit applications.	Technique not effective when it necessitates an increase in excess O$_2$ levels. LR possibly implemented in new designs as reduced combustion intensity (i. e., enlarged furnace plan area).
Low NO$_x$ Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	20 to 50	20 to 50	New burners described generally applicable to all boilers.	Commercially available.	Specific emissions data from industrial boilers equipped with LNB are lacking.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	5 to 16	ND	Combustion air temperature can be reduced to ambient conditions.	Available.	Application of this technique on new boilers requires installation of alternate heat recovery system (e. g., an economizer).
Selective Noncatalytic Reduction (SNCR)	Injection of NH$_3$ or urea as a reducing agent in the flue gas	40 to 70	40 to 70	Applicable for large packaged and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not widely demonstrated on large boilers.	Elaborate reagent injection, monitoring, and control system required. Possible load restrictions on boilers and air preheater fouling when burning high sulfur oil. Must have sufficient residence time at correct temperature.
Conventional Selective Catalytic Reduction (SCR)	Injections of NH$_3$ in the presence of a catalyst (usually upstream of air heater).	Up to 90% (estimated)	Up to 90% (estimated)	Typically large boiler designs	Commercially offered but not widely demonstrated.	Applicable to most boiler designs as a retrofit technology or for new boilers.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO_x Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Air Heater (SCR)	Catalyst-coated baskets in the air heater.	40-65 (estimated)	40-65 (estimated)	Boilers with rotating-basket air heaters	Available but not widely demonstrated	Design must address pressure drop and maintain heat transfer.
Duct SCR	A smaller version of conventional SCR is placed in existing ductwork	30 (estimated)	30 (estimated)	Typically large boiler designs	Available but not widely demonstrated.	Location of SCR in duct is temperature dependent.
Activated Carbon SCR	Activated carbon catalyst, installed downstream of air heater.	ND	ND	Typically large boiler designs	Available but not widely demonstrated.	High pressure drop.
Oil/Water Emulsified Fuel[a,b]	Oil/water fuel with emulsifying agent	41	ND	Firetube boilers	Available but not widely demonstrated	Thermal efficiency reduced due to water content

[a] ND = no data.

[b] Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at 2 x 10^6 Btu/hr.

Table 1.3-15. EMISSION FACTORS FOR NO. 6 OIL/WATER EMULSION IN INDUSTRIAL/COMMERCIAL/INSTITUTIONAL BOILERS[a]

Pollutant	Emission Factor ($lb/10^3$ gal)	Factor Rating	Comments
CO	1.90	C	33% Reduction from plain oil
NO_x	38.0	C	41% Reduction
PM	14.9	C	45% Reduction

[a] Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at 2×10^6 Btu/hr.

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1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

1.4.3 Emissions$^{3-4}$

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how “good” the factor is, with “A” being excellent and “E” being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

- Text was revised concerning Firing Practices, Emissions, and Controls.

- All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

- Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds.
VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)$ (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

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1.6 Wood Residue Combustion In Boilers

1.6.1 General[1-6]

The burning of wood residue in boilers is mostly confined to those industries where it is available as a byproduct. It is burned both to obtain heat energy and to alleviate possible solid residue disposal problems. In boilers, wood residue is normally burned in the form of hogged wood, bark, sawdust, shavings, chips, mill rejects, sanderdust, or wood trim. Heating values for this residue range from about 4,500 British thermal units/pound (Btu/lb) of fuel on a wet, as-fired basis, to about 8,000 Btu/lb for dry wood. The moisture content of as-fired wood is typically near 50 weight percent for the pulp, paper and lumber industries and is typically 10 to 15 percent for the furniture industry. However, moisture contents may vary from 5 to 75 weight percent depending on the residue type and storage operations. Generally, bark is the major type of residue burned in pulp mills; either a mixture of wood and bark residue or wood residue alone is burned most frequently in the lumber, furniture, and plywood industries.

1.6.2 Firing Practices[5, 7, 8]

Various boiler firing configurations are used for burning wood residue. One common type of boiler used in smaller operations is the Dutch oven. This unit is widely used because it can burn fuels with very high moisture content. Fuel is fed into the oven through an opening in the top of a refractory-lined furnace. The fuel accumulates in a cone-shaped pile on a flat or sloping grate. Combustion is accomplished in two stages: (1) drying and gasification, and (2) combustion of gaseous products. The first stage takes place in the primary furnace, which is separated from the secondary furnace chamber by a bridge wall. Combustion is completed in the secondary chamber before gases enter the boiler section. The large mass of refractory helps to stabilize combustion rates but also causes a slow response to fluctuating steam demand.

In another boiler type, the fuel cell oven, fuel is dropped onto suspended fixed grates and is fired in a pile. Unlike the Dutch oven, the refractory-lined fuel cell also uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Because of their overall design and operating similarities, however, fuel cell and Dutch oven boilers have many comparable emission characteristics.

The firing method most commonly employed for wood-fired boilers with a steam generation rate larger than 100,000 lb/hr is the spreader stoker. In this boiler type, wood enters the furnace through a fuel chute and is spread either pneumatically or mechanically across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The burning is accomplished in three stages in a single chamber: (1) moisture evaporation; (2) distillation and burning of volatile matter; and (3) burning of fixed carbon. This type of boiler has a fast response to load changes, has improved combustion control, and can be operated with multiple fuels. Natural gas, oil, and/or coal, are often fired in spreader stoker boilers as auxiliary fuels. The fossil fuels are fired to maintain constant steam production when the wood residue moisture content or mass rate fluctuates and/or to provide more steam than can be generated from the residue supply alone. Although spreader stokers are the most common stokers among larger wood-fired boilers, overfeed and underfeed stokers are also utilized for smaller units.

Another boiler type sometimes used for wood combustion is the suspension-fired boiler. This boiler differs from a spreader stoker in that small-sized fuel (normally less than 2 mm and normally low moisture) is blown into the boiler and combusted by supporting it in air rather than on fixed grates. Rapid changes in combustion rate and, therefore, steam generation rate are possible because the finely divided fuel particles burn very quickly.

A later innovation in wood firing is the fluidized bed combustion (FBC) boiler. A fluidized bed consists of inert particles through which air is blown so that the bed behaves as a fluid. Wood residue enters in the space above the bed and burns both in suspension and in the bed. Because of the large thermal mass represented by the hot inert bed particles, fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis). Fluidized beds can also handle dirty fuels (up to 30 percent inert material). Wood fuel is pyrolyzed faster in a fluidized bed than on a grate due to its immediate contact with hot bed material. As a result, combustion is rapid and results in nearly complete combustion of the organic matter, thereby minimizing the emissions of unburned organic compounds.

1.6.3 Emissions And Controls[7-12]

The major emission of concern from wood boilers is particulate matter (PM). These emissions depend primarily on the composition of the residue fuel burned, and the particle control device. Oxides of nitrogen (NO_x) may also be emitted in significant quantities when certain types of wood residue are combusted or when operating conditions are poor.

1.6.3.1 Criteria Pollutants

The composition of wood residue and the characteristics of the resulting emissions depend largely on the industry from which the wood residue originates. Pulping operations, for example, produce great quantities of bark that may contain more than 70 weight percent moisture, sand, and other non-combustibles. As a result, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are controlled. On the other hand, some operations, such as furniture manufacturing, generate a clean, dry wood residue (2 to 20 weight percent moisture) which produces relatively low particulate emission levels when properly burned. Still other operations, such as sawmills, burn a varying mixture of bark and wood residue that results in PM emissions somewhere between these two extremes. Additionally, NO_x emissions from wet bark and wood boilers are typically lower (approximately one-half) in comparison to NO_x emissions from dry wood-fired boilers.

Furnace operating conditions are particularly important when firing wood residue. For example, because of the high moisture content that may be present in wood residue, a larger than usual area of refractory surface is often necessary to dry the fuel before combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the residue. When proper drying conditions do not exist, or when secondary combustion is incomplete, the combustion temperature is lowered, and increased PM, CO, and organic compound emissions may result from any boiler type. Significant variations in fuel moisture content can cause short-term emissions to fluctuate.

1.6.3.2 Greenhouse Gases[13-18]

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during wood residue combustion. Nearly all of the fuel carbon (99 percent) in wood residue is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2, due to incomplete combustion, is entrained in the bottom ash. CO_2 emitted from this source is generally not counted as greenhouse gas emissions because it is considered part of the short-term CO_2 cycle of the biosphere.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475ºF) and excess air is kept to a minimum (less than 1 percent).

Methane emissions are highest during periods of low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.6.4 Controls

Currently, the four most common control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors, wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. The use of multitube cyclone (or multiclone) mechanical collectors provides particulate control for many wood-fired boilers. Often, two multiclones are used in series, allowing the first collector to remove the bulk of the dust and the second to remove smaller particles. The efficiency of this arrangement varies from 25 to 65 percent. The most widely used wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 85 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

ESPs are employed when collection efficiencies above 90 percent are required. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collector precleaners which remove larger-sized particles. Collection efficiencies of 90 to 99 percent for PM have been observed for ESPs operating on wood-fired boilers.

A variation of the ESP is the electrostatic gravel bed filter. In this device, PM in flue gases is removed by impaction with gravel media inside a packed bed; collection is augmented by an electrically charged grid within the bed. Particulate collection efficiencies are typically over 80 percent.

Fabric filters (i. e., baghouses) have had limited applications to wood-fired boilers. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. Steps can be taken to reduce this hazard, including the installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash (i. e., "sparklers"). Despite complications, fabric filters are generally preferred for boilers firing salt-laden wood. This fuel produces fine particulates with a high salt content having a quenching effect, thereby reducing fire hazards. Particle collection efficiencies are typically 80% or higher.

For stoker and FBC boilers, overfire air ports may be used to lower NO_x emissions by staging the combustion process. In those areas of the U. S. where NO_x emissions must be reduced to their lowest levels, the application of selective noncatalytic reduction (SNCR) to residue wood-fired boilers has been accomplished; the application of selective catalytic reduction (SCR) is being contemplated. Both systems are postcombustion NO_x reduction techniques in which ammonia (or urea) is injected into the flue gas to selectively reduce NO_x to nitrogen and water. In one application of SNCR to an industrial wood-fired boiler, NO_x reduction efficiencies varied between 35 and 75 percent as the ammonia-to-NO_x ratio increased from 0.4 to 3.2.

Emission factors and emission factor ratings for wood residue boilers are summarized in Tables 1.6-1, 1.6-2, 1.6-3, 1.6-4. The factors are presented on an energy basis (pound of pollutant per million Btu of heat input). Factors for wet wood represent facilities that burn wood residue with a moisture content of 20 percent or greater. Factors for dry wood represent wood residue with less than 20 percent moisture content. Cumulative particle size distribution data and associated emission factors are presented in Table 1.6-5. Uncontrolled and controlled size-specific emission factors are plotted in Figure 1.6-1.

1.6.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the background report for this section. This and other documents can be found on the CHIEF Web Site at http://www.epa.gov/ttn/chief/, or by calling the Info CHIEF Help Desk at (919)541-1000.

Supplement A, February 1996

- Significant figures were added to some PM and PM-10 emission factors.
- In the table with NO_x and CO emission factors, text was added in the footnotes to clarify meaning.

Supplement B, October 1996

- SO_x, CH_4, N_2O, CO_2, speciated organics, and trace elements emission factors were corrected.
- Several HAP emission factors were updated.

Supplement D, February 1998

- Table 1.6-1, the PM-10 and one PM emission factors were revised to present two significant figures and the PM-10 emission factor for wood-fired boilers with mechanical collectors without flyash reinjection was revised to 2.6 lb/ton to reflect that these values are based on wood with 50% moisture. A typographical error in the wet scrubber emission factor for PM-10 was corrected.
- Table 1.6-2, the SO_x emission factors for all boiler categories were revised to 0.075 lb/ton to reflect that these factors are based on wood with 50% moisture.
- Tables 1.6-4 and 1.6-5 were re-titled to reflect that the speciated organic and trace element analysis presented in these tables are compiled from wood-fired boilers equipped with a variety of PM control technologies.

Supplement D, August 1998

- Table 1.6-4, the emission factor for trichlorotrifluoroethane was removed. The phenol emission factor was corrected to 1.47E-04; the phenanthrene factor was corrected to 5.02E-05; the chrysene factor was corrected to 4.52E-07; and, the polychlorinated dibenzo-p-furans factor was corrected to 2.9E-08.

Supplement E, February 1999

- In the footnotes of tables 1.6-1, 2, 3, 4, 5, 6, 7, some text was removed that described how to adjust the factors when burning wood with moisture and thermal content significantly different from 50% or 4500 Btu/lb, respectively. The EPA is revising Section 1.6 and, in the interim, consistent with EPA's recommendations regarding proper use of AP-42, the EPA encourages users of the wood combustion emission factors to account for the specific assumptions included in the factors and to convert the factors to a thermal content basis (i.e., lb/MMBtu) to estimate emissions when burning wood that differs significantly from 4500 Btu/lb or 50% moisture.

July 2001

- All emission factors were revised and new factors were added. In some cases separate factors were developed for wet wood (greater than or equal to 20 percent moisture content) and dry wood (less than 20 percent moisture).

- Separate PM and NOx emission factors are provided for dry wood combustion.

- All emission factors have been converted to units of lb/MMBtu.

- PM emission factors are specified by fuel type and control device type but not by boiler type.

- NOx, SOx and CO emission factors are specified by fuel type and not by boiler type.

- Additional toxic emission factors have been added.

- The general quality rating for PM factors are higher than before.

- TOC and CO2 emission factors are specified by all wood types and not by boiler type.

- New Source Classification Codes (SCC) were assigned for dry wood.

March 2002

- The VOC and TOC emission factors in Table 1.6-3 were calculated incorrectly. This has been corrected. The correct factors are 0.013 and 0.039, respectively.

September 2003

- The VOC emission factor in Table 1.6-3 was calculated incorrectly. This has been corrected. The correct factor is 0.017.

Table 1.6-1. EMISSION FACTORS FOR PM FROM WOOD RESIDUE COMBUSTION[a]

Fuel	PM Control Device	Filterable PM		Filterable PM-10[b]		Filterable PM-2.5[b]	
		Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING
Bark/Bark and Wet Wood	No Control[c]	0.56[d]	C	0.50[e]	D	0.43[e]	D
Dry Wood	No Control[c]	0.40[f]	A	0.36[e]	D	0.31[e]	D
Wet Wood	No Control[c]	0.33[g]	A	0.29[e]	D	0.25[e]	D
Bark	Mechanical Collector	0.54[h]	D	0.49[e]	D	0.29[e]	D
Bark and Wet Wood	Mechanical Collector	0.35[i]	C	0.32[e]	D	0.19[e]	D
Dry Wood	Mechanical Collector	0.30[j]	A	0.27[e]	D	0.16[e]	D
Wet Wood	Mechanical Collector	0.22[k]	A	0.20[e]	D	0.12[e]	D
All Fuels[m]	Electrolyzed Gravel Bed	0.1[m]	D	0.074[e]	D	0.065[e]	D
All Fuels[m]	Wet Scrubber	0.066[n]	A	0.065[e]	D	0.065[e]	D
All Fuels[m]	Fabric Filter	0.1[o]	C	0.074[e]	D	0.065[e]	
All Fuels[m]	Electrostatic Precipitator	0.054[p]	B	0.04[e]	D	0.035[e]	
		Condensible PM					
All Fuels[m]	All Controls/No Controls	0.017[q]	A				

Table 1.6-1. (cont.)

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. CPM = Condensible Particulate Matter. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] PM-10 = particulate matter less than or equal to 10 microns in aerodynamic diameter. PM-2.5 = particulate matter less than or equal to 2.5 microns in aerodynamic diameter. Filterable PM = PM captured and measured on the filter in an EPA Method 5 (or equivalent) sampling train. Condensible PM = PM captured and measured in an EPA Method 202 (or equivalent) sampling train.

[c] Factor represents boilers with no controls, Breslove separators, Breslove separators with reinjection, and mechanical collectors with reinjection. Mechanical collectors include cyclones and multiclones.

[d] References 19-21, 88.

[e] Cumulative mass % provided in Table 1.6-6 for Bark and Wet Wood-fired boilers multiplied by the Filterable PM factor.

[f] References 22-32, 88.

[g] References 26, 33-36, 88.

[h] References 37, 38, 88.

[i] References 26, 39-41, 88.

[j] References 26, 27, 34, 42-54, 88.

[k] Reference 55-57, 88.

[l] All fuels = Bark, Bark and Wet Wood, Dry Wood, and Wet Wood.

[m] References 27, 58, 88.

[n] References 26, 59-66, 88.

[o] References 26, 67-70, 88.

[p] References 26, 71-74, 88.

[q] References 19-21, 25, 28, 29, 31, 32, 36-41, 46, 51, 53-60, 62 - 65, 67-69, 72-75, 88.

Table 1.6-2. EMISSION FACTORS FOR NO_x, SO_2, AND CO FROM WOOD RESIDUE COMBUSTION[a]

Source Category[c]	NO_x[b]		SO_2[b]		CO[b]	
	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING
Bark/bark and wet wood/wet wood-fired boiler	0.22[d]	A	0.025[e]	A	0.60[f,g,i,j]	A
Dry wood-fired boilers	0.49[h]	C	0.025[e]	A	0.60[f,g,i,j]	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. NO_x = Nitrogen oxides, SO_2 = Sulfur dioxide, CO = Carbon monoxide.

[b] Factors represent boilers with no controls or with particulate matter controls.

[c] These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[d] References 19, 33, 34, 39, 40, 41, 55, 62-64, 67, 70, 72, 78, 79, 88-89.

[e] References 26, 45, 50, 72, 88-89.

[f] References 26, 59, 88-89.

[g] References 19, 26, 39-41, 60-64, 67, 68, 70, 75, 79, 88-89.

[h] References 30, 34, 45, 50, 80, 81, 88-89.

[i] References 26, 30, 45-51, 80-82, 88-89.

[j] Emission factor is for stokers and dutch ovens/fuel cells. References 26, 34, 36, 55, 60, 65, 71, 72, 75. **CO Factor for fluidized bed combustors is 0.17 lb/MMbtu.** References 26, 72, 88-89.

Table 1.6-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS, TOC, VOC, NITROUS OXIDE, AND CARBON DIOXIDE FROM WOOD RESIDUE COMBUSTION[a]

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Acenaphthene	**9.1 E-07**[c]	B
Acenaphthylene	**5.0 E-06**[d]	A
Acetaldehyde	**8.3 E-04**[e]	A
Acetone	**1.9 E-04**[f]	D
Acetophenone	**3.2 E-09**[g]	D
Acrolein	**4.0 E-03**[h]	C
Anthracene	**3.0 E-06**[i]	A
Benzaldehyde	**<8.5 E-07**[j]	D
Benzene	**4.2 E-03**[k]	A
Benzo(a)anthracene	**6.5 E-08**[l]	B
Benzo(a)pyrene	**2.6 E-06**[m]	A
Benzo(b)fluoranthene	**1.0 E-07**[l]	B
Benzo(e)pyrene	**2.6 E-09**[f]	D
Benzo(g,h,i)perylene	**9.3 E-08**[n]	B
Benzo(j,k)fluoranthene	**1.6 E-07**[o]	D
Benzo(k)fluoranthene	**3.6 E-08**[p]	B
Benzoic acid	**4.7 E-08**[q]	D
bis(2-Ethylhexyl)phthalate	**4.7 E-08**[g]	D
Bromomethane	**1.5 E-05**[f]	D
2-Butanone (MEK)	**5.4 E-06**[f]	D
Carbazole	**1.8 E-06**[f]	D
Carbon tetrachloride	**4.5 E-05**[r]	D
Chlorine	**7.9 E-04**[s]	D
Chlorobenzene	**3.3 E-05**[f]	D
Chloroform	**2.8 E-05**[f]	D
Chloromethane	**2.3 E-05**[f]	D
2-Chloronaphthalene	**2.4 E-09**[f]	D
2-Chlorophenol	**2.4 E-08**[u]	C
Chrysene	**3.8 E-08**[c]	B
Crotonaldehyde	**9.9 E-06**[j]	D
Decachlorobiphenyl	**2.7 E-10**[r]	D
Dibenzo(a,h)anthracene	**9.1 E-09**[l]	B
1,2-Dibromoethene	**5.5 E-05**[f]	D
Dichlorobiphenyl	**7.4 E-10**[r]	C
1,2-Dichloroethane	**2.9 E-05**[r]	D
Dichloromethane	**2.9 E-04**[v]	D
1,2-Dichloropropane	**3.3 E-05**[f]	D
2,4-Dinitrophenol	**1.8 E-07**[w]	C
Ethylbenzene	**3.1 E-05**[f]	D
Fluoranthene	**1.6 E-06**[x]	B
Fluorene	**3.4 E-06**[i]	A
Formaldehyde	**4.4 E-03**[y]	A
Heptachlorobiphenyl	**6.6E-11**[r]	D

Table 1.6-3. (cont.)

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Hexachlorobiphenyl	**5.5 E-10**[r]	D
Hexanal	**7.0 E-06**[z]	D
Heptachlorodibenzo-p-dioxins	**2.0 E-09**[aa]	C
Heptachlorodibenzo-p-furans	**2.4 E-10**[aa]	C
Hexachlorodibenzo-p-dioxins	**1.6 E-06**[aa]	C
Hexachlorodibenzo-p-furans	**2.8 E-10**[aa]	C
Hydrogen chloride	**1.9 E-02**[j]	C
Indeno(1,2,3,c,d)pyrene	**8.7 E-08**[l]	B
Isobutyraldehyde	**1.2 E-05**[z]	D
Methane	**2.1 E-02**[f]	C
2-Methylnaphthalene	**1.6 E-07**[z]	D
Monochlorobiphenyl	**2.2 E-10**[r]	D
Naphthalene	**9.7 E-05**[ab]	A
2-Nitrophenol	**2.4 E-07**[w]	C
4-Nitrophenol	**1.1 E-07**[w]	C
Octachlorodibenzo-p-dioxins	**6.6 E-08**[aa]	B
Octachlorodibenzo-p-furans	**8.8 E-11**[aa]	C
Pentachlorodibenzo-p-dioxins	**1.5 E-09**[aa]	B
Pentachlorodibenzo-p-furans	**4.2 E-10**[aa]	C
Pentachlorobiphenyl	**1.2 E-09**[r]	D
Pentachlorophenol	**5.1 E-08**[ac]	C
Perylene	**5.2 E-10**[f]	D
Phenanthrene	**7.0 E-06**[ad]	B
Phenol	**5.1 E-05**[ae]	C
Propanal	**3.2 E-06**[z]	D
Propionaldehyde	**6.1 E-05**[f]	D
Pyrene	**3.7 E-06**[af]	A
Styrene	**1.9 E-03**[f]	D
2,3,7,8-Tetrachlorodibenzo-p-dioxins	**8.6 E-12**[aa]	C
Tetrachlorodibenzo-p-dioxins	**4.7 E-10**[ag]	C
2,3,7,8-Tetrachlorodibenzo-p-furans	**9.0 E-11**[aa]	C
Tetrachlorodibenzo-p-furans	**7.5 E-10**[aa]	C
Tetrachlorobiphenyl	**2.5 E-09**[r]	D
Tetrachloroethene	**3.8 E-05**[t]	D
o-Tolualdehyde	**7.2 E-06**[j]	D
p-Tolualdehyde	**1.1 E-05**[z]	D
Toluene	**9.2 E-04**[v]	C
Trichlorobiphenyl	**2.6 E-09**[r]	C
1,1,1-Trichloroethane	**3.1 E-05**[t]	D
Trichloroethene	**3.0 E-05**[t]	D
Trichlorofluoromethane	**4.1 E-05**	D
2,4,6-Trichlorophenol	**<2.2 E-08**[ak]	C

Table 1.6-3. (cont.)

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Vinyl Chloride	**1.8 E-05**[r]	D
o-Xylene	**2.5 E-05**[v]	D
Total organic compounds (TOC)	**0.039**[ai]	D
Volatile organic compounds (VOC)	**0.017**[aj]	D
Nitrous Oxide (N_2O)	**0.013**[ak]	D
Carbon Dioxide (CO_2)	**195**[al]	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] Factors are for boilers with no controls or with particulate matter controls.

[c] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[d] References 26, 33, 34, 36, 59, 60, 65, 71-73, 75.

[e] References, 26, 35, 36, 46, 50, 59, 60, 65, 71-75.

[f] Reference 26.

[g] Reference 33.

[h] Reference 26, 50, 83.

[i] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[j] References 26, 50.

[k] References 26, 35, 36, 46, 59, 60, 65, 70, 71-75.

[l] References 26, 36, 59, 60, 65, 70-75.

[m] References 26, 33, 36, 59, 60, 65, 70-73, 75.

[n] References 26, 33, 36, 59, 60, 65, 71-73, 75.

[o] Reference 34.

[p] References 26, 36, 60, 65, 71-75.

[q] References 26, 33.

[r] References 26.

[s] Reference 83.

[t] References 26, 72.

[u] References 35, 60, 65, 71, 72.

[v] References 26, 72.

[w] References 35, 60, 65, 71, 72.

[x] References 26, 33, 34, 59, 60, 65, 71-75.

[y] References 26, 28, 35, 36, 46 - 51, 59, 60, 65, 70, 71-75, 79, 81, 82.

[z] Reference 50.

[aa] Reference 26, 45.

[ab] References 26, 33, 34, 36, 59, 60, 65, 71-75, 83.

[ac] References 26, 35, 60, 65, 71, 72.

[ad] References 26, 33, 34, 36, 59, 60, 65, 71 - 73.

[ae] References 26, 33, 34, 35, 60, 65, 70, 71, 72.

[af] References 26, 33, 34, 36, 59, 60, 65, 71 - 73, 83.

[ag] References 26, 45.

[ah] References 26, 35, 60, 65, 71.

[ai] TOC = total organic compounds. Factor is the sum of all factors in table except nitrous oxide and carbon dioxide.

[aj] VOC volatile organic compounds. Factor is the sum of all factors in table except hydrogen chloride, chlorine, formaldehyde, tetrachloroethene, 1,1,1,-trichloroethane, dichloromethane, acetone, nitrous oxide, methane, and carbon dioxide.

[ak] Reference 83.

[al] References 19 - 26, 33 - 49, 51- 57, 77, 79 - 82, 84 - 86.

Table 1.6-4. EMISSION FACTORS FOR TRACE ELEMENTS FROM WOOD RESIDUE COMBUSTION[a]

Trace Element	Average Emission Factor (lb/MMBtu)[b]	EMISSION FACTOR RATING
Antimony	**7.9 E-06**[c]	C
Arsenic	**2.2 E-05**[d]	A
Barium	**1.7 E-04**[c]	C
Beryllium	**1.1 E-06**[e]	B
Cadmium	**4.1 E-06**[f]	A
Chromium, total	**2.1 E-05**[g]	A
Chromium, hexavalent	**3.5 E-06**[h]	C
Cobalt	**6.5 E-06**[i]	C
Copper	**4.9 E-05**[g]	A
Iron	**9.9 E-04**[k]	C
Lead	**4.8 E-05**[l]	A
Manganese	**1.6 E-03**[d]	A
Mercury	**3.5 E-06**[m]	A
Molybdenum	**2.1 E-06**[c]	D
Nickel	**3.3 E-05**[n]	A
Phosphorus	**2.7 E-05**[c]	D
Potassium	**3.9 E-02**[c]	D
Selenium	**2.8 E-06**[o]	A
Silver	**1.7 E-03**[p]	D
Sodium	**3.6 E-04**[c]	D
Strontium	**1.0 E-05**[c]	D
Tin	**2.3 E-05**[c]	D
Titanium	**2.0 E-05**[c]	D
Vanadium	**9.8 E-07**[c]	D
Yttrium	**3.0 E-07**[c]	D
Zinc	**4.2 E-04**[o]	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] Factors are for boilers with no controls or with particulate matter controls.

[c] Reference 26.

[d] References 26, 33, 36, 46, 59, 60, 65, 71-73, 75, 81.

[e] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75.

[f] References 26, 35, 36, 42, 46, 59, 60, 65, 71-73, 75, 81.

[g] References 26, 34, 35, 36, 42, 59, 60, 65, 71-73, 75, 81.

[h] References 26, 36, 46, 59, 60, 71, 72, 73, 75.

[i] References 26, 34, 83.

[j] References 26, 33-36, 46, 59, 60, 65, 71-73, 75, 81.

[k] References 26, 71, 72, 81.

[l] References 26, 33-36, 46, 59, 60, 65, 71-73, 75.

[m] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75, 81.

[n] References 26, 33 - 36, 46, 59, 60, 65, 71-73, 75, 81.

[o] References 26, 33, 35, 46, 59, 60, 65, 71-73, 75, 81.

[p] Reference 34.

Table 1.6-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR WOOD/BARK-FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size				
		Controlled			
	Uncontrolled[c]	Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]	Dry Electrostatic Granular Filter (DEGF)
15	94	96	35	98	77
10	90	91	32	98	74
6	86	80	27	98	69
2.5	76	54	16	98	65
1.25	69	30	8	96	61
1.00	67	24	6	95	58
0.625	ND	16	3	ND	51
Total	100	100	100	100	100

[a] Reference 89.
[b] Expressed as aerodynamic equivalent diameter.
[c] From data on underfeed stokers. May also be used as size distribution for wood-fired boilers.
[d] From data on spreader stokers with flyash reinjection.
[e] From data on spreader stokers without flyash reinjection.
[f] From data on Dutch ovens. Assumed control efficiency is 94%.

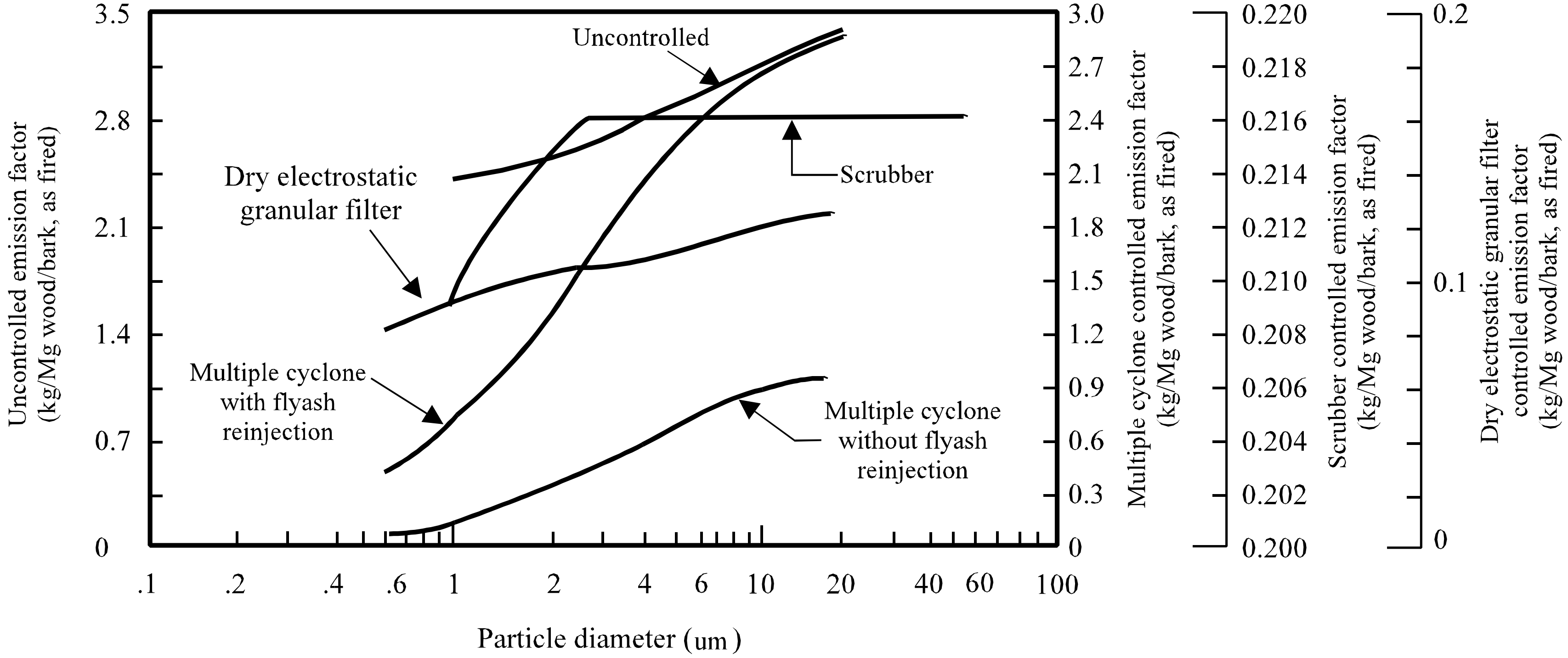

Figure 1.6-1. Cumulative size-specific particulate matter emission factors for wood/bark-fired boilers.

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1.7 Lignite Combustion

1.7.1 General[1-5]

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen, although no one parameter defines rank. Typically coal rank increases as the amount of fixed carbon increases and the amount of volatile matter decreases.

Lignite is a coal in the early stages of coalification, with properties intermediate to those of bituminous coal and peat. The two geographical areas of the U. S. with extensive lignite deposits are centered in the States of North Dakota and Texas. The lignite in both areas has a high moisture content (20 to 40 weight percent) and a low heating value (5,000 to 7,500 British thermal units per pound [Btu/lb], on a wet basis). Due to high moisture content and low Btu value, shipping the lignite would not be feasible; consequently, lignite is burned near where it is mined. A small amount is used in industrial and domestic situations, but lignite is mainly used for steam/electric production in power plants. Lignite combustion has advanced from small stokers to large pulverized coal (PC) and cyclone-fired units (greater than 500 megawatt).

The major advantages of firing lignite are that it is relatively abundant (in the North Dakota and Texas regions), relatively low in cost since it is surface mined, and low in sulfur content which can reduce the need for postcombustion sulfur emission control devices. The disadvantages are that more fuel and larger, more capital-intensive facilities are necessary to generate a unit of power with lignite than is the case with bituminous coal. The disadvantages arise because: (1) lignite's lower heating value means more fuel must be handled to produce a given amount of power; (2) the energy and maintenance costs of coal handling equipment are higher; (3) the high inherent moisture content of lignite decreases boiler efficiency; and (4) the ash characteristics of lignite require more attention to sootblowing and boiler operation to maintain high availability and reliability.

1.7.2 Firing Practices[3]

In a pulverized lignite-fired boiler, the fuel is fed from the stock pile into bunkers adjacent to the boiler. From there, the fuel is metered into several pulverizers which grind it to approximately 200-mesh particle size. A stream of hot air from the air preheater begins the fuel-drying process and conveys the fuel pneumatically to the burner nozzle where it is injected into the burner zone of the boiler. Firing configurations of boilers that fire pulverized lignite include tangential, horizontally opposed, front wall, cyclone, stoker, and fluidized bed combustor.

In the tangential firing method, the pulverized lignite is introduced from the corners of the boiler in vertical rows of burner nozzles. Such a firing mechanism produces a vortexing flame pattern which essentially uses the entire furnace enclosure as a burner. In front-wall firing and horizontally opposed firing boilers, the pulverized coal is introduced into the burner zone through a horizontal row of burners. This type of firing mechanism produces a more intense combustion pattern than the tangential design and has a slightly higher heat release rate in the burner zone itself.

In these methods of firing pulverized lignite, the ash is removed from the furnace both as fly ash and bottom ash. The bottom of the furnace is often characterized as either wet or dry, depending on whether the ash is removed as a liquid slag or as a solid. Pulverized coal units have been designed for both wet and dry bottoms, but the current practice is to design only dry bottom furnaces.

Another type of boiler firing lignite is the cyclone burner, which is a slag-lined high-temperature vortex burner. The coal is fed from the storage area to a crusher that reduces the lignite into particles of approximately 0.25 inch in diameter or less. Crushed lignite is partially dried in the crusher and is then fired in a tangential or vortex pattern into the cyclone burner. The temperature within the burner is hot enough to melt the ash to form a slag. Centrifugal force from the vortex flow forces the melted slag to the outside of the burner where it coats the burner walls with a thin layer of slag. As the solid lignite particles are fed into the burner, they are forced to the outside of the burner and are imbedded in the slag layer. The solid lignite particles are trapped there until complete burnout is attained. The ash from the burner is continuously removed through a slag tap which is flush with the furnace floor.

In a stoker furnace, the lignite is spread across a grate to form a bed which burns until the lignite is completely burned out. In such a mechanism, the lignite is broken up into approximately 2-inch pieces and is fed into the furnace by one of several feed mechanisms: underfeed, overfeed, or spreading. In most stoker units, the grate on which the lignite is burned gradually moves from one end of the furnace to the other. The lignite is spread on the grate in such a fashion that at the end of the grate only ash remains (i.e., all of the lignite has been burned to the final ash product). When the ash reaches the end of the grate, it falls into an ash collection hopper and is removed from the furnace. Stoker furnaces are dry-bottom furnaces and, as such, generally have lower heat release rates and lower temperature profiles than the corresponding pulverized or cyclone units.

There are two major categories of fluidized bed combustors (FBCs): (1) atmospheric FBCs, operating at or near ambient pressures, and (2) pressurized FBCs, operating between 4 and 30 atmospheres (60 to 450 pounds per square inch gauge). Pressurized FBC systems are not considered a demonstrated technology for lignite combustion. The two principal types of atmospheric FBCs are bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ high fluidization velocities to promote the carryover or circulation of the solids. High temperature cyclones are used in circulating bed FBCs and in some bubbling bed FBCs to capture the unburned solid fuel and bed material for return to the primary combustion chamber for more efficient fuel utilization.

1.7.3 Emissions [2-4,6-13]

The emissions generated from firing lignite, as with any coal, include the criteria pollutants particulate matter (PM), PM less than, or equal to, 10 micrometers in diameter (PM-10), condensable particulate matter (CPM), sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), and total organic compounds (TOC). The other pollutants generated include greenhouse gases, organics, trace elements, and acid gases.

Particulate Matter Emissions -

Emission levels for PM from lignite combustion are directly related to the ash content of the lignite and the firing configuration of the boiler. Pulverized coal-fired units fire much or all of the lignite in suspension. Cyclone furnaces collect much of the ash as molten slag in the furnace itself. Stokers (other than spreader) retain a large fraction of the ash in the fuel bed and bottom ash. Spreader stokers fire about 15 percent of the coal in suspension and the remainder in a bed.

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particules that are trapped by the glass fiber filter in the front half of a

Reference Method 5 or Method 17 sampling train. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosal particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

Sulfur Oxides Emissions -

The SO_x emissions from lignite combustion are a function of the sulfur content of the lignite and the lignite composition (i.e., sulfur content, heating value, and alkali concentration). The conversion of lignite sulfur to SO_x is generally inversely proportional to the concentration of alkali constituents in the lignite. The alkali content is known to have a great effect on sulfur conversion and acts as a built-in sorbent for SO_x removal.

Nitrogen Oxides Emissions -

The NO_x emissions from lignite combustion are mainly a function of the boiler design, firing configuration, and excess air level. Tangential units, stoker boilers, and FBCs typically produce lower NO_x levels than wall-fired units and cyclones. The boilers constructed since implementation of the 1971 and 1979 New Source Performance Standards (40 Code of Federal Regulations, Part 60, Subparts D and Da, respectively) have NO_x controls integrated into the boiler design and have NO_x emission levels that are comparable to emission levels from small stokers. In most boilers, regardless of firing configuration, lower excess combustion air results in lower NO_x emissions. However, lowering the amount of excess air in a lignite-fired boiler can also affect the potential for ash fouling.

Carbon Monoxide Emissions[14] -

The CO emission rate from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude.

Greenhouse Gases [15-20] -

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during lignite combustion. Nearly all of the fuel carbon (99 percent) in lignite is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion and is entrained in the bottom ash.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent). N_2O emissions for lignite combustion are not significant except for fluidized bed combustion, where localized areas of lower temperatures in the fuel bed produce N_2O emissions significantly higher than emissions from stokers.

Methane emissions vary with the type of coal being fired and firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

Organic Compounds -

Trace amounts of organic compounds are emitted during lignite combustion. As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase concentrations of organic compounds in the flue gas.

Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the lignite or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).

Polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) are formed during the combustion of lignite. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH).

Trace Metals-

Trace metals are also emitted during lignite combustion. The quantity of any given metal emitted, in general, depends on:

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

Acid Gases-

In addition to SO_x and NO_x emissions, combustion of lignite also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

1.7.4 Controls[2-4,6-13]

Particulate Matter -

The primary PM control systems for lignite-fired utility boilers are electrostatic precipitators (ESPs) and fabric filters (baghouses) with collection efficiencies as high as 99.5 percent. Older and smaller ESPs can have lower collection efficiencies of approximately 95 percent for total PM. Multiple cyclone collectors and scrubbers are typically used alone, or in series, with an ESP or baghouse on small industrial stoker boilers and normally achieve 60 to 80 percent collection efficiency for total PM.

Sulfur Oxides[14] -

Table 1.7-2 presents the techniques most frequently used to reduce SO_x emissions from coal combustion. Flue gas desulfurization (FGD) systems are in current operation on several lignite-fired utility boilers. Flue gases can be treated through wet, semi-dry, or dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery (regenerable) type (in which the SO_x absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove in excess of 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, spray drying, and dual alkali scrubbing are among the commercially proven FGD techniques.

Spray drying is a dry scrubbing approach in which a solution or slurry of alkaline material is sprayed into a reaction vessel as a fine mist and mixes with the flue gas. The SO_2 reacts with the alkali solution or slurry to form liquid-phase salts. The slurry is dried by the latent heat of the flue gas to about 1 percent free moisture. The dried alkali continues to react with SO_2 in the flue gas to form sulfite and sulfate salts. The spray dryer solids are entrained in the flue gas and carried out of the dryer to a particulate control device such as an ESP or baghouse.

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

Nitrogen Oxides[21] -

The most common NO_x control technique for lignite-fired boilers is overfire air (OFA) which involves diverting a portion of the total combustion air (5 to 20 percent) from the burners and injecting it through dedicated air ports above the top level of burners. OFA can be applied to tangential-fired, wall-fired, and stoker boilers; however, it cannot be used on cyclone boilers or other slag-tapping furnaces because it can alter the heat release profile of the boiler which can change the slagging characteristics of the boiler. Depending on the design of the existing furnace, OFA can be a retrofit technology that may achieve 20 to 30 percent NO_x reduction from uncontrolled levels. It is a typical NO_x control technique used in new Subpart D and Subpart Da boilers.

Another NO_x control technique used on lignite-fired boilers is low NO_x burners (LNB) which limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion process. LNBs can be retrofit in existing tangential- and wall-fired boilers or installed in new boilers; however, they are not applicable to cyclone boilers since the fuel is fired in cylindrical chambers in the cyclone boiler rather than with conventional burners. Depending on boiler design and the desired NO_x level, OFA and LNB can be applied separately, or in combination, to achieve as much as 50-60 percent reduction from uncontrolled levels.

1.7.5 Emission Factors

Uncontrolled emission factors for SO_x, NO_x, CO, CO_2, and total non-methane organic compounds (TNMOC) are presented in Table 1.7-1. Controlled emission factors for NO_x and CO in Table 1.7-3.

Table 1.7-4 presents uncontrolled emission factors for filterable PM and N_2O, and controlled emission factors for filterable PM are shown in Table 1.7-5. Condensable PM emission factors are presented in Table 1.7-6. Cumulative particle size distributions and particle size-specific emission factors are provided in Tables 1.7-7 and 1.7-8. In addition, particle size-specific emission factors are presented graphically in Figures 1.7-1 and 1.7-2.

Tables 1.7-9 through 1.7-11 present emission factors for polynuclear organic matter (POM), polynuclear aromatic hydrocarbons (PAH), and various organic compounds, respectively. Table 1.7-15 presents emission factors for hydrogen chloride and hydrogen fluoride.

Table 1.7-12 presents emission factor equations that may be used to estimate controlled and uncontrolled emissions of nine trace metals. Table 1.7-13 presents uncontrolled emission factors for trace metals, and Table 1.7-14 presents controlled emission factors. The emission factor equations are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate emissions. Because these are the major parameters affecting trace metals emissions, it is recommended that the emission factor equations be used to estimate uncontrolled and controlled emissions when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant and there is an emission factor in Table 1.7-13 or Table 1.7-14, then the emission factor(s) could be used to estimate emissions.

Tables in this section present emission factors on both a weight basis (lb/ton) and an energy basis (lb/10^{12}Btu). Emission factors in units of lb/ton can be converted to units of lb/MMBtu by multiplying the emission factor by 0.077, assuming a heating value for lignite of 6500 Btu/lb.

1.7.6 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

- In the table for SO_x emission factors, the footnote "f" was moved into the header of the SO_x column, and “other stoker” was clarified as a traveling grate (overfeed) stoke. Text was added to the same table to clarify that “S” is a weight percent and not a fraction.

- In the tables for PM factors, text was added to the footnotes to clarify that “A” is a weight percent and not a fraction.

Supplement B, October 1996

- Text was enhanced concerning lignite coal characteristics.

- Text was updated and enhanced concerning firing practices, emissions, and controls.

- The SO_x emission factor was updated and a CO_2 emission factor was added for all categories.

- The table containing NO_x and CO factors from controlled sources was revised to present data by appropriate categories.

- New factors for controlled SO_x were added.

- All POM factors were revised.

- New tables were added with new HAP emission factors.

- References were editorially corrected.

Supplement E, September 1998

- Table 1.7-1, the emission factor for sulfur emissions from AFBC with limestone bed material was moved to Table 1.7-2 and no data is available for AFBC using inert bed material.

- Tables 1.7-4 and -5, it was clarified that the FBC emissions factors are applicable to all AFBC.

- Text was inserted to define filterable and condensable particulate matter.

- NO_x emission factors were updated for pc-fired and cyclone boilers.

- Table 1.7-2 was revised to present the techniques most frequently used to reduce SO_x emissions from coal combustion.

- The title of Table 1.7-3 was revised to specify NO_x controls.

- Emission factors for condensable particulate matter were added (Table 1.7-6).

- Conversion factor for lb/ton to lb/MMBtu was added to the footnotes of Tables 1.7-1, 1.7-3, 1.7-4, 1.7-5, 1.7-7, 1.7-8, 1.7-10, 1.7-11, 1.7-14 and 1.7-15.

- The term “Filterable” was inserted in the title and header rows of Tables 1.7-4 and 1.7-5.

- TNMOC data from bituminous coal were added to Table 1.7-1 in the absence of lignite data.

Table 1.7-1. EMISSION FACTORS FOR SO_x, NO_x, CO, AND CO_2 FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: C (except as noted)

Firing Configuration	SO_x Emission Factor[b] (lb/ton)	NO_x Emission Factor[c] (lb/ton)	CO Emission Factor[d] (lb/ton)	CO_2 Emission Factor[g] (lb/ton)	TNMOC[j,k] Emission Factor (lb/ton)
Pulverized coal, dry bottom, tangential (SCC 1-01-003-02)	30S	7.1[i]	ND	72.6C	0.04
Pulverized coal, dry bottom, wall fired[e], Pre-NSPS[f] (SCC 1-01-003-01)	30S	13	0.25	72.6C	0.04
Pulverized coal, dry bottom, wall fired[e], NSPS[f] (SCC 1-01-003-01)	30S	6.3	0.25	72.6C	0.04
Cyclone (SCC 1-01-003-03)	30S	15	ND	72.6C	0.07
Spreader stoker (SCC 1-01-003-06)	30S	5.8	ND	72.6C	0.03
Traveling Grate Overfeed stoker (SCC 1-01-003-04)	30S	ND	ND	72.6C	0.03
Atmospheric fluidized bed combustor (SCC 1-01-003-17/18)	10S[l]	3.6	0.15[h]	72.6C	0.03

[a] To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. SCC = Source Classification Code. ND = no data.

[b] Reference 2. S = Weight % sulfur content of lignite, wet basis. For example, if the sulfur content equals 3.4%, then S = 3.4. For high sodium ash (Na_2O > 8%), use 22S. For low sodium ash (Na_2O < 2%), use 34S. If ash sodium content is unknown, use 30S.

[c] References 2-3, 8-9, 22-23.

[d] References 8, 23.

[e] Wall-fired includes front and rear all-fired units, as well as opposed wall-fired units.

[f] Pre-NSPS boilers are not subject to an NSPS. NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are boilers constructed after August 17, 1971 and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978 and with a heat input rate greater than 250 MMBtu/hr.

Table 1.7-1. EMISSION FACTORS FOR SO_x, NO_x, CO, AND CO_2 FROM UNCONTROLLED LIGNITE COMBUSTION[a] (CONTINUED)

EMISSION FACTOR RATING: C (except as noted)

[g] EMISSION FACTOR RATING: B. C = Weight % carbon of lignite, as-fired basis. For example, if carbon content equals 63%, then C = 63. If the %C value is not known, a default CO_2 emission value of 4600 lb/ton may be used.

[h] Emission factor is for circulating fluidized bed only SCC = 1-01-003-18.

[i] EMISSION FACTOR RATING: A

[j] TNMOC: Total non-methane organic compounds. Emission factors were derived from bituminous coal data in the absence of lignite data assuming emissions are proportional to coal heating value. TNMOC are expressed as C_2 to C_{16} alkane equivalents. Because of limited data, the effects of firing configuration on TNMOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal, cyclones, spreaders, and overfeed stokers.

[k] Reference 61. Nominal values achievable under normal operating conditions; values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

[l] Using limestone bed material.

Table 1.7-2. POSTCOMBUSTION SO_2 CONTROLS FOR COAL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet Scrubber	Lime/limestone	80 - 95+%	Applicable to high sulfur fuels, wet sludge product
	Sodium carbonate	80 - 98%	5-430 million Btu/hr typical application range, high reagent costs
	Magnesium oxide/hydroxide	80 - 95+%	Can be regenerated
	Dual alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, several U.S. demonstration projects are completed
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several research and development, and demonstration projects underway, not yet commercially available in the United States

Source: Reference 60.

Table 1.7-3. EMISSION FACTORS FOR NO_x AND CO FROM LIGNITE COMBUSTION WITH NO_x CONTROLS[a]

Firing Configuration	Control Device	NO_x[b]		CO[c]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Subpart D boilers:[d] Pulverized coal, tangential-fired (SCC 1-01-003-02)	Overfire Air	6.8	C	ND	NA
Pulverized coal, wall-fired (SCC 1-01-003-01)	Overfire air and low NO_x burners	4.6	C	0.48	D
Subpart Da boilers:[d] Pulverized coal, tangential-fired (SCC 1-01-003-02)	Overfire Air	6.0	C	0.1	D

[a] To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] References 22-23.

[c] Reference 22.

[d] Subpart D boilers are boilers constructed after August 17, 1971 and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978 and with a heat input rate greater than 250 MMBtu/hr.

Table 1.7-4. EMISSION FACTORS FOR FILTERABLE PM AND N_2O FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E (except as noted)

Firing Configuration	Filterable PM Emission Factor[b] (lb/ton)	N_2O Emission Factor[c] (lb/ton)
Pulverized coal, dry bottom, tangential (SCC 1-01-003-02)	6.5A	ND
Pulverized coal, dry bottom, wall fired (SCC 1-01-003-01)	5.1A	ND
Cyclone (SCC 1-01-003-03)	6.7A[d]	ND
Spreader stoker (SCC 1-01-003-06)	8.0A	ND
Other stoker (SCC 1-01-003-04)	3.4A	ND
Atmospheric fluidized bed combustor (SCC 1-01-003-17/18)	ND	2.5

[a] To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. SCC = Source Classification Code.
ND = no data.

[b] References 6-7, 24-25. A = weight % ash content of lignite, wet basis. For example, if the ash content is 5%, then A = 5.

[c] Reference 26.

[d] EMISSION FACTOR RATING: C

Table 1.7-5. EMISSION FACTORS FOR FILTERABLE PM EMISSIONS FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: C (except as noted)

Firing Configuration	Control Device	Filterable PM Emission Factor (lb/ton)
Subpart D Boilers[b] (SCC 1-01-003-01/-02)	Baghouse Wet scrubber	0.08A 0.05A
Subpart Da Boilers[b] (SCC 1-01-003-01/-02)	Wet scrubber	0.01A
Atmospheric fluidized bed combustor (SCC 1-01-003-17/18)[b,c]	ESP	0.07A

[a] References 22-23. A = weight % ash content of lignite, wet basis. For example, if lignite is 2.3% ash, then A = 2.3. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. SCC = Source Classification Code.

[b] Subpart D boilers are boilers constructed before August 17, 1971, and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978, and with a heat input rate greater than 250 MMBtu/hr.

[c] EMISSION FACTOR RATING: D.

Table 1.7-6. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR LIGNITE COMBUSTION[a]

Firing Configuration[b]	Controls[c]	SCC	CPM - TOT[d, e]		CPM - IOR[d, e]		CPM - ORG[d, e]	
			lb/MMBtu	Rating	lb/MMBtu	Rating	lb/MMBtu	Rating
All pulverized coal-fired boilers	All PM controls (without FGD controls)	1-01-003-01/02 1-02-003-01/02 1-03-003-05/06	0.1S -0.03[f,g]	C	80% of CPM-TOT emission factor[e]	E	20% of CPM-TOT emission factor[e]	E
All pulverized coal-fired boilers	All PM controls combined with an FGD control	1-01-003-01/02 1-02-003-01/02 1-03-003-05/06	0.02[f]	E	ND		ND	
Traveling grate overfeed stoker, spreader stoker	All PM controls, or Uncontrolled	1-01-003-04/06 1-02-003-04/06 1-03-003-07/09	0.04[g]	D	80% of CPM-TOT emission factor[g]	E	20% of CPM-TOT emission factor[g]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.

[b] No data are available for cyclone boilers (SCCs 1-01-003-03, 1-02-003-03). For cyclone boilers, use the factors provided for pulverized coal-fired boilers and applicable controls.

[c] FGD = flue gas desulfurization..

[d] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
ND= no data.

[e] Factors should be multiplied by fuel rate on a heat input basis (MMBtu), as fired. To convert to lb/ton of lignite, multiply by 16 MMBtu/ton.

[f] S = coal sulfur percent by weight, as fired. For example, if the sulfur percent is 1.04, then S = 1.04. If the coal sulfur percent is 0.4 or less, use a default emission factor of 0.01 lb/MMBtu rather than the emission equation.

[g] References 62-78

[h] References 79 and 80.

[i] References 81-88.

Table 1.7-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR BOILERS FIRING PULVERIZED LIGNITE[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] (lb/ton)	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	51	77	3.4A	1.0A
10	35	67	2.3A	0.88A
6	26	57	1.7A	0.75A
2.5	10	27	0.66A	0.36A
1.25	7	16	0.47A	0.21A
1.00	6	14	0.40A	0.19A
0.625	3	8	0.19A	0.11A
TOTAL			6.6A	1.3A

[a] Reference 27. Based on tangential-fired units (Source Classification Code 1-01-003-02). For wall-fired units (Source Classification Code 1-01-003-01), multiply emission factors in the table by 0.79.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = weight % ash content of lignite, wet basis. For example, if lignite is 3.4% ash, then A = 3.4. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625.

[d] Estimated control efficiency for multiple cyclone is 80%, averaged over all particle sizes.

Table 1.7-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR LIGNITE-FIRED SPREADER STOKERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size		Cumulative Emission Factor[c] (lb/ton)	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	28	55	2.2A	0.88A
10	20	41	1.6A	0.66A
6	14	31	1.1A	0.50A
2.5	7	26	0.56A	0.42A
1.25	5	23	0.40A	0.37A
1.00	5	22	0.40A	0.35A
0.625	4	—[e]	0.33A	—[e]
TOTAL			8.0A	1.6A

[a] Reference 27. Source Classification Code 1-01-003-06.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = weight % ash content of lignite, wet basis. For example, if the lignite is 5% ash, then A = 5. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625.

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

[e] Insufficient data.

Table 1.7-9. EMISSION FACTORS FOR POM FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration	Control Device	Emission Factor ($lb/10^{12}$ Btu)
		POM
Pulverized coal (SCC 1-01-003-01)	High efficiency cold-side ESP	2.3
Pulverized dry bottom (no SCC)	Multi-cyclones	1.8 - 18[b]
	ESP	2.6[b]
Cyclone furnace (SCC 1-01-003-03)	ESP	0.11[c] - 1.6[b]
Spreader stoker (SCC 1-01-003-06)	Multi-cyclones	15[c]

[a] References 28-29. To convert from $lb/10^{12}$ Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

[b] Primarily trimethyl propenyl naphthalene.

[c] Primarily biphenyl.

Table 1.7-10 EMISSION FACTORS FOR POLYNUCLEAR AROMATIC HYDROCARBONS (PAH) FROM CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor[b] (lb/ton)	EMISSION FACTOR RATING
Biphenyl	1.7E-06	D
Acenaphthene	5.1E-07	B
Acenaphthylene	2.5E-07	B
Anthracene	2.1E-07	B
Benzo(a)anthracene	8.0E-08	B
Benzo(a)pyrene	3.8E-08	D
Benzo(b,j,k)fluoranthene	1.1E-07	B
Benzo(g,h,i)perylene	2.7E-08	D
Chrysene	1.0E-07	C
Fluoranthene	7.1E-07	B
Fluorene	9.1E-07	B
Indeno(1,2,3-cd)pyrene	6.1E-08	C
Naphthalene	1.3E-05	C
Phenanthrene	2.7E-06	B
Pyrene	3.3E-07	B
5-Methyl chrysene	2.2E-08	D

[a] References 30-40. Factors were developed from emissions data from six sites firing bituminous coal, four sites firing subbituminous coal, and from one site firing lignite. Factors apply to boilers utilizing both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers utilizing only an ESP or FF. SCCs = pulverized coal-fired boilers, 1-01-003-01, 1-02-003-01, 1-03-003-05; pulverized coal tangentially-fired boilers, 1-01-003-02, 1-02-003-02, 1-03-003-06; and cyclone boilers, 1-01-003-03, and 1-02-003-03.

[b] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

Table 1.7-11 EMISSION FACTORS FOR VARIOUS ORGANIC COMPOUNDS FROM CONTROLLED COAL COMBUSTION[a]

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Acetaldehyde	5.7E-04	C
Acetophenone	1.5E-05	D
Acrolein	2.9E-04	D
Benzene	1.3E-03	A
Benzyl chloride	7.0E-04	D
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	D
Bromoform	3.9E-05	E
Carbon disulfide	1.3E-04	D
2-Chloroacetophenone	7.0E-06	E
Chlorobenzene	2.2E-05	D
Chloroform	5.9E-05	D
Cumene	5.3E-06	E
Cyanide	2.5E-03	D
2,4-Dinitrotoluene	2.8E-07	D
Dimethyl sulfate	4.8E-05	E
Ethyl benzene	9.4E-05	D
Ethyl chloride	4.2E-05	D
Ethylene dichloride	4.0E-05	E
Ethylene dibromide	1.2E-06	E
Formaldehyde	2.4E-04	A
Hexane	6.7E-05	D
Isophorone	5.8E-04	D
Methyl bromide	1.6E-04	D
Methyl chloride	5.3E-04	D
Methyl ethyl ketone	3.9E-04	D
Methyl hydrazine	1.7E-04	E
Methyl methacrylate	2.0E-05	E
Methyl tert butyl ether	3.5E-05	E
Methylene chloride	2.9E-04	D

Table 1.7-11 (continued)

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Phenol	1.6E-05	D
Propionaldehyde	3.8E-04	D
Tetrachloroethylene	4.3E-05	D
Toluene	2.4E-04	A
1,1,1-Trichloroethane	2.0E-05	E
Styrene	2.5E-05	D
Xylenes	3.7E-05	C
Vinyl acetate	7.6E-06	E

[a] References 30-48. Factors were developed from emissions data from ten sites firing bituminous coal, eight sites firing subbituminous coal, and from one site firing lignite. The emission factors are applicable to boilers using both wet limestone scrubbers or spray dryers and an electrostatic precipitator (ESP) or fabric filter (FF). In addition, the factors apply to boilers utilizing only an ESP or FF. SCCs = pulverized coal-fired boilers, 1-01-003-01, 1-02-003-01, 1-03-003-05; pulverized coal tangentially-fired boilers, 1-01-003-02, 1-02-003-02, 1-03-003-06; cyclone boilers, 1-01-003-03, 1-02-003-03; and atmospheric fluidized bed combustor, circulating bed, 1-01-003-18. This table is similar to Table 1.1-13 and is reproduced here for the convenience of the reader.

[b] Pollutants sampled for but not detected in any sampling run include: Carbon tetrachloride- 2 sites; 1,3-Dichloropropylene- 2 sites; N-nitrosodimethylamine- 2 sites; Ethylidene dichloride- 2 sites; Hexachlorobutadiene- 1 site; Hexachloroethane- 1 site; Propylene dichloride- 2 sites; 1,1,2,2-Tetrachloroethane- 2 sites; 1,1,2-Trichloroethane- 2 sites; Vinyl chloride- 2 sites; and, Hexachlorobenzene- 2 sites.

[c] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625.

Table 1.7-12. TRACE METAL EMISSION FACTOR EQUATIONS FOR FROM COAL COMBUSTION[a]

EMISSION FACTOR EQUATION RATING: A[b]

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

[a] Reference 49. The equations were developed from emissions data from bituminous coal combustion, subbituminous coal combustion, and from lignite combustion. The equations should be used to generate factors for controlled boilers when the necessary input information is available. The emission factor equations are applicable to all typical firing configurations and PM controls for electric generation (utility), industrial, and commercial/industrial boilers firing bituminous coal, subbituminous coal, or lignite. Thus, all SCCs for these boilers are assigned to the equations.

[b] AP-42 criteria for rating emission factors were used to rate the equations.

[c] The factors produced by the equations should be applied to heat input. To convert from $lb/10^{12}$ Btu to kg/joules multiply by 4.31×10^{-16}.

C = concentration of metal in the coal, parts per million by weight (ppmwt).
A = weight fraction of ash in the coal. For example, 10% ash is 0.1 ash fraction.
PM = Site-specific emission factor for total particulate matter, $lb/10^6$ Btu.

Table 1.7-13. EMISSION FACTORS FOR TRACE ELEMENTS FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration	Emission Factor ($lb/10^{12}Btu$)						
	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized, wet bottom (no SCC)	2730	131	49 - 77	1220 - 1880	4410 - 16,250	21	154 - 1160
Pulverized, dry bottom (no SCC)	1390	131	49	1500 - 1880	16,200	21	928 - 1160
Cyclone furnace (SCC 1-01-003-03)	235 - 632	131	31	253 - 1880	3,760	21	157 - 1160
Stoker configuration unknown (no SCC)	ND	118	ND	ND	11,800	21	ND
Spreader stoker (SCC 1-01-003-06)	538 - 1100	ND	23 - 47	1130 - 1880	ND	ND	696 - 1160
Traveling grate (overfed) stoker (SCC 1-01-003-04)	1100 - 2100	ND	47 - 90	ND	ND	ND	ND

[a] References 28-29. To convert from $lb/10^{12}$ Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

Table 1.7-14 EMISSION FACTORS FOR TRACE METALS FROM CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor (lb/ton)[b]	EMISSION FACTOR RATING
Antimony	1.8E-05	A
Arsenic	4.1E-04	A
Beryllium	2.1E-05	A
Cadmium	5.1E-05	A
Chromium	2.6E-04	A
Chromium (VI)	7.9E-05	D
Cobalt	1.0E-04	A
Lead	4.2E-04	A
Magnesium	1.1E-02	A
Manganese	4.9E-04	A
Mercury	8.3E-05	A
Nickel	2.8E-04	A
Selenium	1.3E-03	A

[a] References 30-48, 50-58. The emission factors were developed from emissions data at eleven facilities firing bituminous coal, fifteen facilities firing subbituminous coal, and from two facilities firing lignite. The factors apply to boilers utilizing either venturi scrubbers, spray dryer absorbers, or wet limestone scrubbers with an electrostatic precipitator (ESP) or Fabric Filter (FF). In addition, the factors apply to boilers using only an ESP, FF, or venturi scrubber. SCCs = pulverized coal-fired boilers, 1-01-003-01, 1-02-003-01, 1-03-003-05; pulverized coal tangentially-fired boilers, 1-01-003-02, 1-02-003-02, 1-03-003-06; cyclone boilers, 1-01-003-03, 1-02-003-03; and atmospheric fluidized bed combustor, circulating bed, 1-01-003-18.

[b] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625.

Table 1.7-15. EMISSION FACTORS FOR HYDROGEN CHLORIDE (HCI) AND HYDROGEN FLUORIDE (HF) FROM COAL COMBUSTION[a]

EMISSION FACTOR RATING: B

Firing Configuration	SCC	HCl Emission Factor (lb/ton)	HF Emission Factor (lb/ton)
PC-fired	1-01-003-01 1-02-003-01 1-03-003-05	1.2	0.15
PC-fired, tangential	1-01-003-02 1-02-003-02 1-03-003-06	1.2	0.15
Cyclone Furnace	1-01-003-03 1-02-003-03	1.2	0.15
Traveling Grate (overfeed stoker)	1-01-003-04 1-02-003-04 1-03-003-07	1.2	0.15
Spreader Stoker	1-01-003-06 1-02-003-06 1-03-003-09	1.2	0.15
FBC, Circulating Bed	1-01-003-18	1.2	0.15

[a] Reference 59. The emission factors were developed from bituminous coal, subbituminous coal, and lignite emissions data. To convert from lb/ton to kg/Mg, multiply by 0.5. To convert from lb/ton to lb/MMBtu, multiply by 0.0625. The factors apply to both controlled and uncontrolled sources.

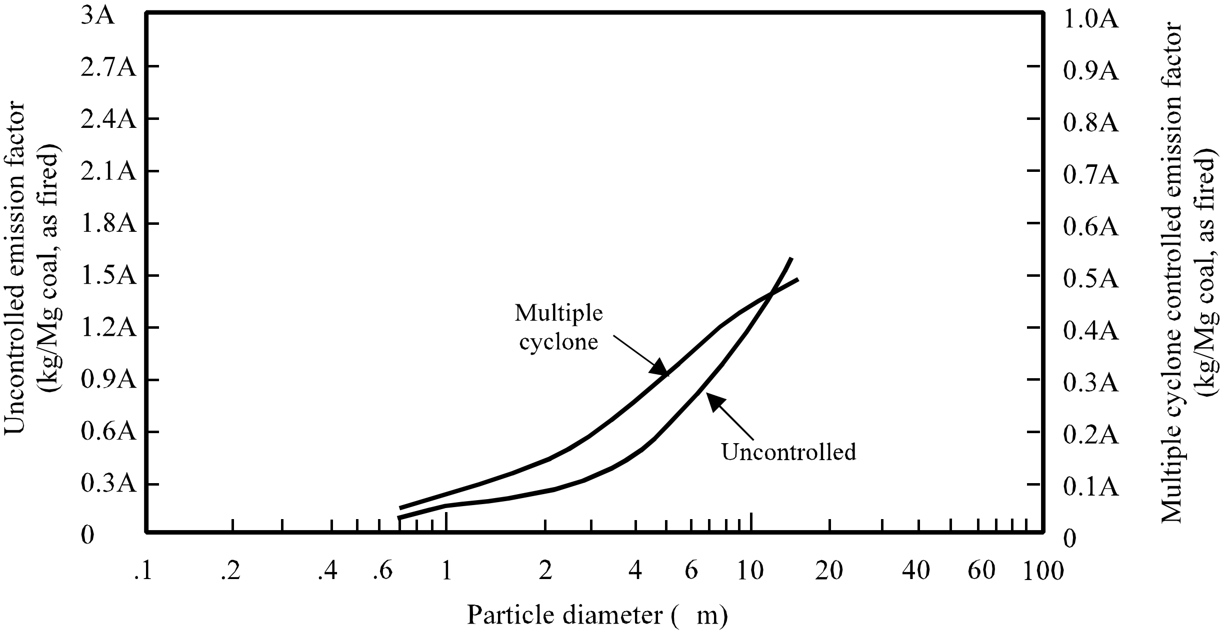

Figure 1.7-1. Cumulative size-specific emission factors for boilers firing pulverized lignite.

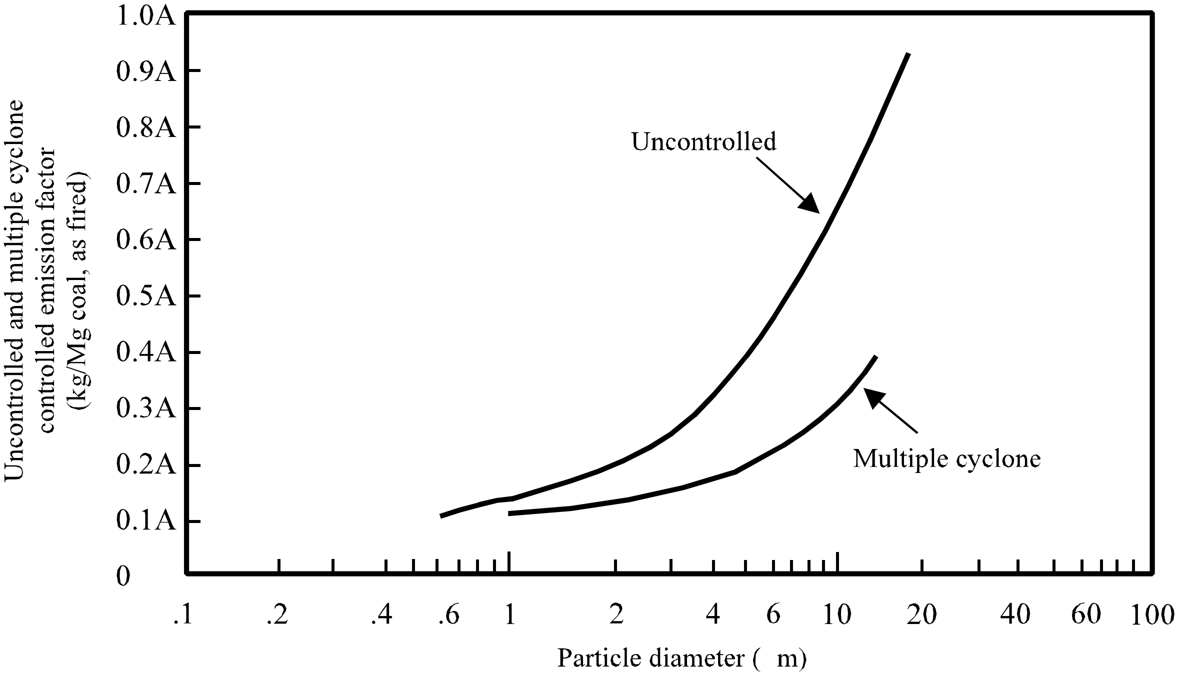

Figure 1.7-2. Cumulative size-specific emission factors for lignite-fired spreader stokers.

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1.8 Bagasse Combustion In Sugar Mills

1.8.1 Process Description[1-5]

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Previously, bagasse was burned as a means of solid waste disposal. However, as the cost of fuel oil, natural gas, and electricity has increased, bagasse has come to be regarded as a fuel rather than refuse. Bagasse is a fuel of varying composition, consistency, and heating value. These characteristics depend on the climate, type of soil upon which the cane is grown, variety of cane, harvesting method, amount of cane washing, and the efficiency of the milling plant. In general, bagasse has a heating value between 3,000 and 4,000 British thermal units per pound (Btu/lb) on a wet, as-fired basis. Most bagasse has a moisture content between 45 and 55 percent by weight.

The U. S. sugar cane industry is located in the tropical and subtropical regions of Florida, Texas, Louisiana, Hawaii, and Puerto Rico. Except for Hawaii, where sugar cane production takes place year round, sugar mills operate seasonally from 2 to 5 months per year.

Sugar cane is a large grass with a bamboo-like stalk that grows 8 to 15 feet tall. Only the stalk contains sufficient sucrose for processing into sugar. All other parts of the sugar cane (i. e., leaves, top growth, and roots) are termed "trash". The objective of harvesting is to deliver the sugar cane to the mill with a minimum of trash or other extraneous material. The cane is normally burned in the field to remove a major portion of the trash and to control insects and rodents. (See Section 13.1 for methods to estimate these emissions.) The three most common methods of harvesting are hand cutting, machine cutting, and mechanical raking. The cane that is delivered to a particular sugar mill will vary in trash and dirt content depending on the harvesting method and weather conditions. Inside the mill, cane preparation for extraction usually involves washing the cane to remove trash and dirt, chopping, and then crushing. Juice is extracted in the milling portion of the plant by passing the chopped and crushed cane through a series of grooved rolls. The cane remaining after milling is bagasse.

1.8.2 Firing Practices

Fuel cells, horseshoe boilers, and spreader stoker boilers are used to burn bagasse. Horseshoe boilers and fuel cells differ in the shapes of their furnace area but in other respects are similar in design and operation. In these boilers (most common among older plants), bagasse is gravity-fed through chutes and piles onto a refractory hearth. Primary and overfire combustion air flows through ports in the furnace walls; burning begins on the surface pile. Many of these units have dumping hearths that permit ash removal while the unit is operating.

In more recently built sugar mills, bagasse is burned in spreader stoker boilers. Bagasse fed to these boilers enters the furnace through a fuel chute and is spread pneumatically or mechanically across the furnace, where part of the fuel burns while in suspension. Simultaneously, large pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The flame over the grate radiates heat back to the fuel to aid combustion. The combustion area of the furnace is lined with heat exchange tubes (waterwalls).

1.8.3 Emissions[1-3]

The most significant pollutant emitted by bagasse-fired boilers is particulate matter, caused by the turbulent movement of combustion gases with respect to the burning bagasse and resultant ash. Emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) are lower than conventional fossil fuels due to the characteristically low levels of sulfur and nitrogen associated with bagasse.

Auxiliary fuels (typically fuel oil or natural gas) may be used during startup of the boiler or when the moisture content of the bagasse is too high to support combustion; if fuel oil is used during these periods, SO_2 and NO_x emissions will increase. Soil characteristics such as particle size can affect the magnitude of particulate matter (PM) emissions from the boiler. Cane that is improperly washed or incorrectly prepared can also influence the bagasse ash content. Upsets in combustion conditions can cause increased emissions of carbon monoxide (CO) and unburned organics, typically measured as volatile organic compounds (VOCs) and total organic compounds (TOCs).

1.8.4 Controls

Mechanical collectors and wet scrubbers are commonly used to control particulate emissions from bagasse-fired boilers. Mechanical collectors may be installed in single cyclone, double cyclone, or multiple cyclone (i. e., multiclone) arrangements. The reported PM collection efficiency for mechanical collectors is 20 to 60 percent. Due to the abrasive nature of bagasse fly ash, mechanical collector performance may deteriorate over time due to erosion if the system is not well maintained.

The most widely used wet scrubbers for bagasse-fired boilers are impingement and venturi scrubbers. Impingement scrubbers normally operate at gas-side pressure drops of 5 to 15 inches of water; typical pressure drops for venturi scrubbers are over 15 inches of water. Impingement scrubbers are in greater use due to their lower energy requirements and fewer operating and maintenance problems. Reported PM collection efficiencies for both scrubber types are 90 percent or greater.

Fabric filters and electrostatic precipitators have not been used to a significant extent for controlling PM from bagasse-fired boilers because both are relatively costly compared to other control options. Fabric filters also pose a potential fire hazard.

Gaseous emissions (e. g., SO_2, NO_x, CO, and organics) may also be absorbed to a significant extent in a wet scrubber. Alkali compounds are sometimes utilized in the scrubber to prevent low pH conditions. If carbon dioxide (CO_2)-generating compounds (such as sodium carbonate or calcium carbonate) are used, CO_2 emissions will increase.

Fugitive dust may be generated by truck traffic and cane handling operations at the sugar mill. PM emissions from these sources may be estimated by consulting Section 13.2.

Emission factors and emission factor ratings for bagasse-fired boilers are shown in Table 1.8-1. Table 1.8-1 presents emission factors on a weight basis (lb/ton). To convert to an energy basis (lb/MMBtu), divide by a heating value of 7.0 MMBtu/ton.

1.8.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- PM emission factors were revised for boilers controlled with wet scrubbers.

Table 1.8-1. EMISSION FACTORS FOR BAGASSE-FIRED BOILERS[a]

Pollutant	Emission Factor (lb/ton)[b]	EMISSION FACTOR RATING
PM[c]		
Uncontrolled[d]	15.6	C
Controlled		
Mechanical collector[e]	8.4	D
Wet scrubber[f]	1.4	A
PM-10		
Controlled		
Wet scrubber[g]	1.36	D
CO_2		
Uncontrolled[h]	1,560	A
NO_x		
Uncontrolled[j]	1.2	C
Polycyclic organic matter		
Uncontrolled[k]	0.001	D

[a] Source Classification Code is 1-02-011-01.

[b] Units are lb of pollutant/ton of wet, as-fired bagasse containing approximately 50% moisture, by weight. If lbs of steam produced is monitored, assume 1 lb of bagasse produces 2 lb of steam, in lieu of any site-specific conversion data. To convert from lb/ton to kg/Mg, multiply by 0.5.

[c] Includes only filterable PM (i. e., that particulate collected on or prior to the filter of an EPA Method 5 [or equivalent] sampling train).

[d] Reference 2.

[e] References 6-7.

[f] References 6,8-65.

[g] Reference 13.

[h] References 6-13,66. CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used.

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[k] Reference 7. Based on measurements collected downstream of PM control devices which may have provided some removal of polycyclic organic matter condensed on PM.

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1.9 Residential Fireplaces

1.9.1 General[1-2]

Fireplaces are used primarily for aesthetic effects and secondarily as supplemental heating sources in houses and other dwellings. Wood is the most common fuel for fireplaces, but coal and densified wood "logs" may also be burned. The user intermittently adds fuel to the fire by hand. Fireplaces can be divided into 2 broad categories: (1) masonry (generally brick and/or stone, assembled on site, and integral to a structure) and (2) prefabricated (usually metal, installed on site as a package with appropriate duct work).

Masonry fireplaces typically have large fixed openings to the fire bed and have dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection, heated, and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace, the most common of which consists of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy-gauge steel firebox lined inside with firebrick and surrounded by multiple steel walls with spaces for air circulation. Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, and thus are sometimes called "inserts". Some of these units are equipped with close-fitting doors and have operating and combustion characteristics similar to wood stoves. (See Section 1.10, Residential Wood Stoves.)

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases and through fireplace walls. Moreover, some of the radiant heat entering the room goes toward warming the air that is pulled into the residence to make up for that drawn up the chimney. The net effect is that masonry fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence using a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer back into the residence some of the heat that would normally be lost in the exhaust gases or through fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions And Controls[1-13]

Fireplace emissions, caused mainly by incomplete combustion, include particulate matter (PM) (mainly PM less than 10 micrometers in diameter [PM-10]), carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), and volatile organic compounds (VOC). Significant quantities of unburnt combustibles are produced because fireplaces are inefficient combustion devices, with high uncontrolled excess air rates and without any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent by dry weight.

Hazardous air pollutants (HAPs) are a minor, but potentially important, component of wood smoke. A group of HAPs known as polycyclic organic matter (POM) includes potential carcinogens such as benzo(a)pyrene (BaP). POM results from the combination of free radical species formed in the flame zone, primarily as a consequence of incomplete combustion. Under reducing conditions, radical chain propagation is enhanced, allowing the buildup of complex organic material such as POM. The POM is generally found in or on smoke particles, although some sublimation into the vapor phase is probable.

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during wood combustion in residential fireplaces. Most of the fuel carbon in wood is converted to CO_2 during the combustion process, but because of ineffecient combustion, low combustion temperatures, and large amounts of excess air, a much higher ratio of carbon monoxide to CO_2 is produced than for combustion of wood in airtight wood stoves or wood-fired boilers. This formation of carbon monoxide coupled with incomplete combustion acts to slightly reduce CO_2 emissions compared to other types of wood combustion.[14-19] CO_2 emitted from this source may not increase total atmospheric CO_2, however, because emissions may be offset by the uptake of CO_2 by regrowing biomass.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Although no test data were available, it is assumed that N_2O emissions from residential fireplaces would be significantly higher than either wood stoves or commercial wood-fired boilers because of the combination of low combustion temperatures and high amounts of excess air.[14-19]

Methane emissions are highest during periods of low-temperature combustion or incomplete combustion, both of which occur often in residential fireplaces. VOC emissions for residential fireplaces are high compared to other wood combustion sources. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.[14-19]

Another important constituent of wood smoke is creosote. This tar-like substance will burn if the fire is hot enough, but at insufficient temperatures, it may deposit on surfaces in the exhaust system. Creosote deposits are a fire hazard in the flue, but they can be reduced if the chimney is insulated to prevent creosote condensation or if the chimney is cleaned regularly to remove any buildup.

In order to decrease PM and CO emissions from fireplaces, combustion must be improved. Combustion efficiency improves as burn rate and flame intensity increase. Noncatalytic fireplace inserts reduce emissions by directing unburned hydrocarbons and CO into an insulated secondary chamber, where mixing with fresh, preheated makeup air occurs and combustion is enhanced.[20]

Fireplace emissions are highly variable and are a function of many wood characteristics and operating practices. In general, conditions which promote a fast burn rate and a higher flame intensity enhance secondary combustion and thereby lower emissions. Conversely, higher emissions will result from a slow burn rate and a lower flame intensity. Such generalizations apply particularly to the earlier stages of the burning cycle, when significant quantities of combustible volatile matter are being driven out of the wood. Later in the burning cycle, when all volatile matter has been driven out of the wood, the charcoal that remains burns with relatively few emissions.

Emission factors and their ratings for wood combustion in residential fireplaces are given in Table 1.9-1. Table 1.9-1 presents emission factors on a weight basis (lb/ton). To convert from lb/ton to lb/MMBtu, divide by a heating value of 17.3 MMBtu/ton.

1.9.3 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- References for tables were editorially corrected.
- Text was added concerning controls.
- An emission factor was added for N_2O.

Table 1.9-1. EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES[a]
(SCC 21-04-008-001)

Device	Pollutant	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Fireplace	PM-10[b]	34.6	B
	CO[c]	252.6	B
	SO_x[d]	0.4	A
	NO_x[e]	2.6	C
	N_2O[f]	0.3	E
	CO_2[g]	3400	C
	Total VOC[h]	229.0	D
	POM[j]	16 E-03	E
	Aldehydes[k,m]	2.4	E

[a] Units are in lb of pollutant/ton of dry wood burned. To convert lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

[b] References 2, 5, 7, 13; contains filterable and condensable PM; PM emissions are considered to be 100% PM-10.

[c] References 2, 4-6, 9, 11, 13.

[d] References 1, 8.

[e] References 4, 6, 9, 11; expressed as NO_2.

[f] Reference 21.

[g] References 5, 13.

[h] References 1, 4, 5. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, factors may not be accurate for individual sources.

[j] Reference 2.

[k] Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.

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1.10 Residential Wood Stoves

1.10.1 General[1-2]

Wood stoves are enclosed wood heaters that control burning or burn time by restricting the amount of air that can be used for combustion; they are commonly used in residences as space heaters. They are used both as the primary source of residential heat and to supplement conventional heating systems. Based on known variations in construction, combustion, and emission characteristics, there are five different categories of residential wood burning devices: (1) the conventional wood stove; (2) the noncatalytic wood stove; (3) the catalytic wood stove; (4) the pellet stove; and (5) the masonry heater.

The conventional stove category comprises all stoves without catalytic combustors not included in the other noncatalytic categories (i. e., noncatalytic and pellet). Conventional stoves do not have any emission reduction technology or design features and, in most cases, were manufactured before July 1, 1986. Stoves with various airflow designs may be in this category, such as updraft, downdraft, crossdraft, and S-flow.

Noncatalytic wood stoves are those units that do not employ catalysts but that do have emission reducing technology or features. Typical noncatalytic design includes baffles and secondary combustion chambers.

Catalytic stoves are equipped with a ceramic or metal honeycomb device, called a combustor or converter, that is coated with a noble metal such as platinum or palladium. The catalyst material reduces the ignition temperature of the unburned volatile organic compounds (VOC) and carbon monoxide (CO) in the exhaust gases, thus augmenting their ignition and combustion at normal stove operating temperatures. As these components of the gases burn, the temperature inside the catalyst increases to a point at which the ignition of the gases is essentially self-sustaining.

Pellet stoves are those fueled with pellets of sawdust, wood products, and other biomass materials pressed into manageable shapes and sizes. These stoves have active air flow systems and unique grate design to accommodate this type of fuel. Some pellet stove models are subject to the 1988 New Source Performance Standards (NSPS), while others are exempt due to a high air-to-fuel ratio (i. e., greater than 35-to-1).

Masonry heaters are large, enclosed chambers made of masonry products or a combination of masonry products and ceramic materials. These devices are exempt from the 1988 NSPS due to their weight (i. e., greater than 1764 lb). Masonry heaters are gaining popularity as a cleaner-burning, heat-efficient form of primary and supplemental heat, relative to some other types of wood heaters. In a masonry heater, a complete charge of wood is burned in a relatively short period of time. The use of masonry materials promotes heat transfer. Thus, radiant heat from the heater warms the surrounding area for many hours after the fire has burned out.

1.10.2 Emissions

The combustion and pyrolysis of wood in wood stoves produce atmospheric emissions of particulate matter (PM), CO, nitrogen oxides (NO_x), VOC, mineral residues, and to a lesser extent, sulfur oxides (SO_x). The quantities and types of emissions are highly variable, depending on a number of factors, including stage of the combustion cycle. During initial burning stages, after a new wood charge is introduced, emissions (primarily VOCs) increase dramatically. After the initial period of high burn rate, there is a charcoal stage of the burn cycle characterized by a slower burn rate and decreased emissions. Emission rates during this stage are cyclical, characterized by relatively long periods of low emissions and shorter episodes of emission spikes.

Particulate emissions are defined in this discussion as the total catch measured by the EPA Method 5H (Oregon Method 7) sampling train.[1] A small portion of wood stove particulate emissions includes "solid" particles of elemental carbon and wood. The vast majority of particulate emissions are condensed organic products of incomplete combustion equal to or less than 10 micrometers in aerodynamic diameter (PM-10). Although reported particle size data are scarce, one reference states that 95 percent of the particles emitted from a wood stove were less than 0.4 micrometers in size.[3]

SO_x are formed by oxidation of sulfur in the wood. NO_x are formed by oxidation of fuel and atmospheric nitrogen. Mineral constituents, such as potassium and sodium compounds, are released from the wood matrix during combustion.

The high levels of organic compounds and CO emissions result from incomplete combustion of the wood. Organic constituents of wood smoke vary considerably in both type and volatility. These constituents include simple hydrocarbons of carbon numbers 1 through 7 (C1 - C7) (which exist as gases or which volatilize at ambient conditions) and complex low-volatility substances that condense at ambient conditions. These low volatility condensable materials generally are considered to have boiling points below 572°F.

Polycyclic organic matter (POM) is an important component of the condensable fraction of wood smoke. POM contains a wide range of compounds, including organic compounds formed through incomplete combustion by the combination of free radical species in the flame zone. These compounds are classified as hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments, which contains the sub-group of hydrocarbons called polycyclic aromatic hydrocarbons (PAH).

1.10.3 Controls[4]

To decrease PM and CO emissions from wood stoves, combustion efficiency must increase. Both catalytic and noncatalytic control techniques increase efficiency and decrease emissions. Catalytic combustors reduce emissions by using a ceramic catalyst coated with a noble metal (e. g., palladium or platinum) which allows organics and other combustibles to burn at temperatures much lower than required in a noncatalytic firebox.

Older, noncatalytic wood stoves reduce emissions by directing unburned hydrocarbons (HCs) and CO into a secondary chamber, where mixing with fresh, preheated makeup air enhances further combustion. Current noncatalytic wood stoves inject fresh secondary air into the top of the primary combustion chamber, allowing ignition of the HCs. Multiple air channels, some with their own controls, coupled with baffles which trap and retain heat in the top of the firebox facilitate this combustion.

Emission factors and their ratings for wood combustion in residential wood stoves, pellet stoves, and masonry heaters are presented in Tables 1.10-1, 1.10-2, 1.10-3, 1.10-4, 1.10-5, 1.10-6, and 1.10-7. Tables in this section present emission factors on a weight basis (lb/ton). To convert to an energy basis (lb/MMBtu), divide by a heating value of 17.3 MMBtu/ton. The analysis leading to the revision of these emission factors is contained in the emission factor documentation.[4] These tables include emission factors for criteria pollutants (PM-10, CO, NO_x, SO_x), carbon dioxide (CO_2), total organic compounds (TOC), speciated organic compounds, PAH, and some elements. The emission factors are presented by wood heater type. PM-10 and CO emission factors are further classified by stove certification category. Phase II stoves are those certified to meet the July 1, 1990, EPA standards; Phase I stoves meet only the July 1, 1988, EPA standards; and Pre-Phase I stoves do not meet any of the EPA standards but in most cases do necessarily meet the Oregon 1986 certification standards.[1]

The emission factors for PM and CO in Tables 1.10-1 and 1.10-2 are averages, derived entirely from field test data obtained under actual operating conditions. Still, there is a potential for higher emissions from some wood stove, pellet stove, and masonry heater models. Particulate emissions are presented as the total PM emissions equivalent to that collected by EPA Method 5H. This method employs a heated filter followed by three impingers, an unheated filter, and a final impinger. Conversions are employed, as appropriate, for data collected with other methods.

Table 1.10-5 shows net efficiency by device type, determined entirely from field test data. Net or overall efficiency is the product of combustion efficiency multiplied by heat transfer efficiency. Wood heater efficiency is an important parameter that is used, along with emission factors and percent degradation, to calculate PM-10 emission reduction credits. Percent degradation is related to the loss in effectiveness of a wood stove control device or catalyst over a period of operation. Control degradation for any stove, including noncatalytic wood stoves, may also occur as a result of deteriorated seals and gaskets, misaligned baffles and bypass mechanisms, broken refractories, or other damaged functional components. The increase in emissions which can result from control degradation has not been quantified.

1.10.4 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- Text was added concerning controls.
- Reference 15 was corrected.
- The emission factor for phenanthrene was corrected.
- Information was incorporated concerning methane and nonmethane-HC.

Table 1.10-1. EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]

Pollutant/EPA Certification[b]	EMISSION FACTOR RATING	Wood Stove Type Emission Factor (lb/ton)			Pellet Stove Type,[c] Emission Factor (lb/ton) (SCC 21-04-008-053)		Masonry Heater, Emission Factor (lb/ton) (SCC 21-04-008-055)
		Conventional (SCC 21-04-008-051)	Noncatalytic (SCC 21-04-008-050)	Catalytic (SCC 21-04-008-030)	Certified	Exempt	Exempt[d]
PM-10[e]							
Pre-Phase I	B	30.6	25.8	24.2	ND	ND	ND
Phase I	B	ND	20.0	19.6	ND	ND	ND
Phase II	B	ND	14.6	16.2	4.2	ND	ND
All	B	30.6	19.6	20.4	4.2	8.8	5.6
CO							
Pre-Phase I	B	230.8	ND	ND	ND	ND	ND
Phase I	B	ND	ND	104.4	ND	ND	ND
Phase II	B	ND	140.8	107.0	39.4	ND	ND
All	B	230.8	140.8	104.4	39.4	52.2	149.0
NO_x		2.8[f]	ND	2.0[g]	13.8[g]	ND	ND
SO_x	B	0.4	0.4	0.4	0.4	ND	ND
CO_2[j]	C	ND	ND	ND	2952	3671	3849
TOC[k]	C	83	28	26.6	ND	ND	ND
Methane	C	30	16	11.6	ND	ND	ND
TNMOC	C	53	12	15	ND	ND	ND

[a] To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data. TNMOC = total nonmethane organic compounds.

[b] Pre-Phase I = Not certified to 1988 EPA emission standards; Phase I = Certified to 1988 EPA emission standards; Phase II = Certified to 1990 EPA emission standards; All = Average of emission factors for all devices.

[c] Certified = Certified pursuant to 1988 NSPS; Exempt = Exempt from 1988 NSPS (i. e., air-to-fuel ratio > 35:1).

[d] Exempt = Exempt from 1988 NSPS (i. e., device weight >800 kg).

[e] References 5-18. PM-10 is defined as equivalent to total catch by EPA method 5H train.

[f] EMISSION FACTOR RATING: C.

[g] EMISSION FACTOR RATING: E.

[h] References 12, 15-18.

[j] CO_2 emitted from this source may not increase total atmospheric CO_2 because the emissions may be offset by the uptake of CO_2 by regrowing biomass.

[k] References 12, 19-22. Data show a high degree of variability within the source population. Factors may not be accurate for individual sources.

Table 1.10-2. ORGANIC COMPOUND EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a,b]

EMISSION FACTOR RATING: E

Compounds	Wood Stove Type Emission Factor (lb/ton)	
	Conventional (SCC 21-04-008-051)	Catalytic (SCC 21-04-008-030)
Ethane	1.470	1.376
Ethylene	4.490	3.482
Acetylene	1.124	0.564
Propane	0.358	0.158
Propene	1.244	0.734
i-Butane	0.028	0.010
n-Butane	0.056	0.014
Butenes[c]	1.192	0.714
Pentenes[d]	0.616	0.150
Benzene	1.938	1.464
Toluene	0.730	0.520
Furan	0.342	0.124
Methyl Ethyl Ketone	0.290	0.062
2-Methyl Furan	0.656	0.084
2,5-Dimethyl Furan	0.162	0.002
Furfural	0.486	0.146
o-Xylene	0.202	0.186

[a] Reference 19. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

[b] Data show a high degree of variability within the source population. Factors may not be accurate for individual sources.

[c] 1-butene, i-butene, t-2-butene, c-2-butene, 2-me-1-butene, 2-me-butene are reported as butenes.

[d] 1-pentene, t-2-pentene, and c-2-pentene are reported as pentenes.

Table 1.10-3. PAH EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a,b]

EMISSION FACTOR RATING: E

Pollutant	Stove Type Emission Factor (lb/ton)			
	Conventional[c] (SCC 21-04-008-051)	Noncatalytic[d] (SCC 21-04-008-050)	Catalytic[e] (SCC 21-04-008-030)	Exempt Pellet[f] (SCC 21-04-008-053)
PAH				
Acenaphthene	0.010	0.010	0.006	ND
Acenaphthylene	0.212	0.032	0.068	ND
Anthracene	0.014	0.009	0.008	ND
Benzo(a)Anthracene	0.020	<0.001	0.024	ND
Benzo(b)Fluoranthene	0.006	0.004	0.004	2.60 E-05
Benzo(g,h,i)Fluoranthene	ND	0.028	0.006	ND
Benzo(k)Fluoranthene	0.002	<0.001	0.002	ND
Benzo(g,h,i)Perylene	0.004	0.020	0.002	ND
Benzo(a)Pyrene	0.004	0.006	0.004	ND
Benzo(e)Pyrene	0.012	0.002	0.004	ND
Biphenyl	ND	0.022	ND	ND
Chrysene	0.012	0.010	0.010	7.52 E-05
Dibenzo(a,h)Anthracene	BDL	0.004	0.002	ND
7,12-Dimethylbenz(a)Anthracene	ND	0.004	ND	ND
Fluoranthene	0.020	0.008	0.012	5.48 E-05
Fluorene	0.024	0.014	0.014	ND
Indeno(1,2,3,cd)Pyrene	BDL	0.020	0.004	ND
9-Methylanthracene	ND	0.004	ND	ND
12-Methylbenz(a)Anthracene	ND	0.002	ND	ND
3-Methylchlolanthrene	ND	<0.001	ND	ND
1-Methylphenanthrene	ND	0.030	ND	ND
Naphthalene	0.288	0.144	0.186	ND
Nitronaphthalene	ND	BDL	ND	ND
Perylene	ND	0.002	ND	ND
Phenanthrene	0.078	0.118	0.048	3.32 E-05
Phenanthrol	ND	BDL	ND	ND
Phenol	ND	<0.001	ND	ND
Pyrene	0.024	0.008	0.010	4.84 E-05
PAH Total	0.730	<0.500	0.414	2.38 E-04

[a] To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. ND = no data. BDL = below detection limit. < = values are below this detection limit.

[b] Data show a high degree of variability within the source population and/or came from a small number of sources. Factors may not be accurate for individual sources.

[c] Reference 19.

[d] References 20,23-25.

[e] References 13,19-20,23,26.

[f] Reference 18. Exempt = Exempt from 1988 NSPS (i. e., air-to-fuel ratio > 35:1).

Table 1.10-4. TRACE ELEMENT EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a,b]

EMISSION FACTOR RATING: E

Element	Wood Stove Type Emission Factor (lb/ton)		
	Conventional (SCC 21-04-008-051)	Noncatalytic (SCC 21-04-008-050)	Catalytic (SCC 21-04-008-030)
Cadmium (Cd)	2.2 E-05	2.0 E-05	4.6 E-05
Chromium (Cr)	<1.0 E-06	<1.0 E-06	<1.0 E-06
Manganese (Mn)	1.7 E-04	1.4 E-04	2.2 E-04
Nickel (Ni)	1.4 E-05	2.0 E-05	2.2 E-06

[a] References 19,25. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code. < = values are below this detection limit.
[b] The data used to develop these emission factors showed a high degree of variability within the source population. Factors may not be accurate for individual sources.

Table 1.10-5. SUMMARY OF WOOD STOVE NET EFFICIENCIES[a]

Wood Heater Type	Source Classification Code	Net Efficiency (%)	Reference
Wood Stoves			
Conventional	21-04-008-051	54	16
Noncatalytic	21-04-008-050	68	7,10,16
Catalytic	21-04-008-030	68	16,27
Pellet Stoves			
Certified[b]	21-04-008-053	68	9
Exempt[c]		56	17
Masonry Heaters			
All	21-04-008-055	58	18

[a] Net efficiency is a function of both combustion efficiency and heat transfer efficiency. The percentages shown here are based on data collected from in-home testing. References 5,8,10-11,17-18,28.
[b] Certified = Certified pursuant to 1988 NSPS.
[c] Exempt = Exempt from 1988 NSPS (i. e., air-to-fuel ratio >35:1).

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1.11 Waste Oil Combustion

1.11.1 General[1]

Waste oil includes used crankcase oils from automobiles and trucks, used industrial lubricating oils (such as metal working oils), and other used industrial oils (such as heat transfer fluids). When discarded, these oils become waste oils due to a breakdown of physical properties and contamination by the materials they come in contact with. The different types of waste oils may be burned as mixtures or as single fuels where supplies allow. Waste, or used, oil can be burned in a variety of combustion systems including industrial boilers; commercial/institutional boilers; space heaters; asphalt plants; cement and lime kilns; other types of dryers and calciners; and steel production blast furnaces. Boilers and space heaters consume the bulk of the waste oil burned. Space heaters are small combustion units (generally less than 250,000 British thermal units per hour [Btu/hr] input) that are common in automobile service stations and automotive repair shops where supplies of waste crankcase oil are available.

Boilers designed to burn No. 6 (residual) fuel oils or one of the distillate fuel oils can be used to burn waste oil, with or without modifications for optimizing combustion. As an alternative to boiler modification, the properties of waste oil can be modified by blending it with fuel oil, to the extent required to achieve a clean-burning fuel mixture.

1.11.2 Emissions[1]

The emissions from burning waste oils reflect the compositional variations of the waste oils. Potential pollutants include carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), particulate matter (PM), particles less than 10 micrometers in size (PM-10), toxic metals, organic compounds, hydrogen chloride, and global warming gases (carbon dioxide [CO_2], methane [CH_4]).

Particulate Matter[1] -

Ash levels in waste oils are normally much higher than ash levels in either distillate oils or residual oils. Waste oils have substantially higher concentrations of most of the trace elements reported relative to those concentrations found in virgin fuel oils. Without air pollution controls, higher concentrations of ash and trace metals in the waste fuel translate to higher emission levels of PM and trace metals than is the case for virgin fuel oils.

Sulfur Oxides[1] -

Emissions of SO_x are a function of the sulfur content of the fuel. The sulfur content varies but some data suggest that uncontrolled SO_x emissions will increase when waste oil is substituted for a distillate oil but will decrease when residual oil is replaced.

Chlorinated Organics[1] -

Constituent chlorine in waste oils typically exceeds the concentration of chlorine in virgin distillate and residual oils. High levels of halogenated solvents are often found in waste oil as a result of inadvertent or deliberate addition of contaminant solvents to the waste oils. Many efficient combustors can destroy more than 99.99 percent of the chlorinated solvents present in the fuel. However, given the wide array of combustor types which burn waste oils, the presence of these compounds in the emission stream cannot be ruled out.

Other Organics[1] -

The flue gases from waste oil combustion often contain organic compounds other than chlorinated solvents. At ppmw levels, several hazardous organic compounds have been found in waste oils. Benzene, toluene, polychlorinated biphenyls (PCBs), and polychlorinated dibenzo-d-dioxins are a few of the hazardous compounds that have been detected in waste oil samples. Additionally, these hazardous compounds may be formed in the combustion process as products of incomplete combustion.

1.11.3 Controls[1]

Emissions can be controlled by the pretreatment of the waste oil to remove the pollutant precursors or with emission controls to remove the air pollutants. Reduction of emission levels is not the only purpose of pretreatment of the waste oil. Improvement in combustion efficiency and reduction of erosion and corrosion of the combustor internal surfaces are important considerations. The most common pretreatment scheme uses sedimentation followed by filtration. Water and large particles (greater than 10 microns in diameter) are removed without having much effect on sulfur, nitrogen, or chlorine contents. Other methods of pretreatment involve clay contacting; demetallization by acid, solvent, or chemical contacting; and thermal processing to remove residual water and light ends. These latter processes might be attractive as waste reduction schemes or to recycle the waste oil, but the added costs probably hinder their use as part of a combustion process.

Blending of waste oil with a virgin fuel oil is practiced frequently and has the same effect as some of the other pretreatment processes. However, for the purpose of developing emission factors, blending by itself was assumed to be in the uncontrolled category.

Waste oil serves as a substitute fuel for combustors designed to burn distillate or residual oils. Therefore, the emission controls are usually those in place when waste oil is first burned. For small boilers and space heaters, all of the sources having acceptable test data for determining emission factors were uncontrolled. For an asphalt plant, PM emissions, which included the dust from drying of the aggregate, were controlled with a fabric filter.

Emission factors and emission factor ratings for waste oil combustion are shown in Tables 1.11-1, 1.11-2, 1.11-3, 1.11-4, and 1.11-5. Emission factors have been determined for emissions from uncontrolled small boilers and space heaters combusting waste oil. These factors apply to both blended and unblended waste oil fuels when waste oil comprises the majority of the fuel combusted. If virgin oil comprises the majority of the fuel combusted, the emission factors presented in Section 1.3, Fuel Oil Combustion, should be used.

Evaporative emissions from waste oil used as a diluent in batch asphalt plants may be estimated using the procedures outlined in Section 4.5.

Tables in this section present emission factors on a volume basis ($lb/10^3gal$). To convert to an energy basis (lb/MMBtu), divide by the heating value of the oil in units of $MMBtu/10^3gal$, if known. If the heating value is not known, and the waste oil is blended with residual oil, divide by a heating value of 150 $MMBtu/10^3gal$. If the waste oil is blended with distillate oil, divide by a heating value of 140 $MMBtu/10^3gal$.

1.11.4 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

- An earlier transcription error was corrected and the TOC emission factor was changed from 0.1 to 1.0 lb/1000 gal.

Supplement B, October 1996

- Math errors were corrected and factors for As, Be, Cd, Cr, Co, and speciated organics were changed.

- The CO_2 factors were revised based on a review of existing information.

Table 1.11-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM), PARTICULATE MATTER LESS THAN 10 MICROMETERS (PM-10), AND LEAD (Pb) FROM WASTE OIL COMBUSTORS[a]

Source Category (SCC)	PM[b]		PM-10[c]		Pb[d]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Small boilers (1-03-013-02)	64A[d]	C	51A	C	55L[f]	D
Space heaters Vaporizing burner (1-05-001-14, 1-05-002-14)	2.8A	D	ND	NA	0.41L	D
Atomizing burner (1-05-001-13, 1-05-002-13)	66A	D	57A	E	50L	D

[a] Units are lb of pollutant/10^3 gallons of blended waste oil burned. To convert from lb/10^3 gallons to kg/m^3, multiply by 0.12. SCC = Source Classification Code. ND = no data. NA = not applicable.
[b] References 2-5.
[c] Reference 1.
[d] References 4-6.
[e] A = weight % ash in fuel. Multiply numeric value by A to obtain emission factor. For example, if ash content is 5%, then A = 5.
[f] L = weight % lead in fuel. Multiply numeric value by L to obtain emission factor. For example, if lead content is 5%, then L = 5.

Table 1.11-2. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), SULFUR OXIDES (SO_x), AND CARBON MONOXIDE (CO) FROM WASTE OIL COMBUSTORS[a]

Source Category (SCC)	NO_x[b]		SO_x[b]		CO[c]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Small boilers (1-03-013-02)	19	C	147S[d]	C	5	D
Space heaters Vaporizing burner (1-05-001-14, 1-05-002-14)	11	D	100S[d]	D	1.7	D
Atomizing burner (1-05-001-13, 1-05-002-13)	16	D	107S[d]	D	2.1	D

[a] Units are lb of pollutant/10^3 gallons of blended waste oil burned. To convert from lb/10^3 gallons to kg/m^3, multiply by 0.12. SCC = Source Classification Code.

[b] References 4, 7.

[c] References 2, 5.

[d] S = weight % sulfur in fuel. Multiply numeric value by S to obtain emission factor. For example, if sulfur content is 3.4%, then S = 3.4.

Table 1.11-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), HYDROGEN CHLORIDE (HCl), AND CARBON DIOXIDE (CO_2) FROM WASTE OIL COMBUSTORS[a]

Source Category (SCC)	TOC[b]		HCl[b]		CO_2[c]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Small boilers (1-03-013-02)	1.0	D	66Cl[d]	C	22,000	C
Space heaters Vaporizing burner (1-05-001-14, 1-05-002-14)	1.0	D	ND	NA	22,000	D
Atomizing burner (1-05-001-13, 1-05-002-13)	1.0	D	ND	NA	22,000	D

[a] Units are lb of pollutant/10^3 gallons of blended waste oil burned. To convert from $lb/10^3$ gallons to kg/m^3, multiply by 0.12. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Reference 1.

[c] References 2-4. Ranges from 18,000 to 25,000 lb of $CO_2/10^3$gal, depending on carbon content.

[d] Cl = weight % chlorine in fuel. Multiply numeric value by Cl to obtain emission factor. For example, if chlorine content is 3%, Cl = 3.

Table 1.11-4. EMISSION FACTORS FOR SPECIATED METALS FROM WASTE OIL COMBUSTORS[a]

EMISSION FACTOR RATING: D

Pollutant	Small Boilers Emission Factor (lb/10^3 gal)[b] (SCC 1-03-013-02)	Space Heaters: Vaporizing Burner Emission Factor (lb/10^3 gal)[c] (SCC 1-05-001-14, 1-05-002-14)	Space Heaters: Atomizing Burner Emission Factor (lb/10^3 gal)[c] (SCC 1-05-001-13, 1-05-002-13)
Antimony	BDL	3.4 E-04	4.5 E-03
Arsenic	1.1 E-01	2.5 E-03	6.0 E-02
Beryllium	BDL	BDL	1.8 E-03
Cadmium	9.3 E-03	1.5 E-04	1.2 E-02
Chromium	2.0 E-02	1.9 E-01	1.8 E-01
Cobalt	2.1 E-04	5.7 E-03	5.2 E-03
Manganese	6.8 E-02	2.2 E-03	5.0 E-02
Nickel	1.1 E-02	5.0 E-02	1.6 E-01
Selenium	BDL	BDL	BDL
Phosphorous	ND	3.6 E-02	ND

[a] Pollutants in this table represent metal species measured for waste oil combustors. Other metal species may also have been emitted but were either not measured or were present at concentrations below analytical detection limits. Units are lb of pollutant/10^3 gallons of waste oil burned. To convert from lb/10^3 gallons to kg/m^3, multiply by 0.12. BDL = below detection limit. SCC = Source Classification Code. ND = no data.

[b] Reference 4.

[c] References 4-5.

Table 1.11-5. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WASTE OIL COMBUSTORS[a]

EMISSION FACTOR RATING: D

Pollutant	Space Heaters: Vaporizing Burner (SCC 1-05-001-14, 1-05-002-14) Emission Factor (lb/10^3 gal)	Space Heaters: Atomizing Burner (SCC 1-05-001-13, 1-05-002-13) Emission Factor (lb/10^3 gal)
Phenol	2.4 E-03	2.8 E-05
Dichlorobenzene	8.0 E-07	ND
Naphthalene	1.3 E-02	9.2 E-05
Phenanthrene/anthracene	1.1 E-02	1.0 E-04
Dibutylphthalate	ND	3.4 E-05
Butylbenzylphthalate	5.1 E-04	ND
Bis(2-ethylhexyl)phthalate	2.2 E-03	ND
Pyrene	7.1 E-03	8.3 E-06
Benz(a)anthracene/chrysene	4.0 E-03	ND
Benzo(a)pyrene	4.0 E-03	ND
Trichloroethylene	ND	ND

[a] Reference 4. Pollutants in this table represent organic species measured for waste oil combustors. Other organic species may also have been emitted but were either not measured or were present at concentrations below analytical detection limits. Units are lb of pollutant/10^3 gallons of waste oil burned. To convert from lb/10^3 gallons to kg/m^3, multiply by 0.12. SCC = Source Classification Code. ND = no data.

References For Section 1.11

1. *Emission Factor Documentation For AP-42 Section 1.11, Waste Oil Combustion (Draft)*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

2. *Environmental Characterization Of Disposal Of Waste Oils In Small Combustors*, EPA-600/2-84-150, U. S. Environmental Protection Agency, Cincinnati, OH, September 1984.

3. *Used Oil Burned As A Fuel*, EPA-SW-892, U. S. Environmental Protection Agency, Washington, DC, August 1980.

4. *The Fate Of Hazardous And Nonhazardous Wastes In Used Oil Disposal And Recycling*, DOE/BC/10375-6, U. S. Department of Energy, Bartlesville, OK, October 1983.

5. "Comparisons of Air Pollutant Emissions from Vaporizing and Air Atomizing Waste Oil Heaters", *Journal Of The Air Pollution Control Association*, 33(7), July 1983.

6. "Waste Oil Combustion: An Environmental Case Study", Presented at the 75th Annual Meeting of the Air Pollution Control Association, June 1982.

7. *Chemical Analysis Of Waste Crankcase Oil Combustion Samples*, EPA600/7-83-026, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1983.

APPENDIX A

MISCELLANEOUS DATA AND CONVERSION FACTORS

SOME USEFUL WEIGHTS AND MEASURES

Unit Of Measure	Equivalent	
grain	0.002	ounces
gram	0.04	ounces
ounce	28.35	grams
kilogram	2.21	pounds
pound	0.45	kilograms
pound (troy)	12	ounces
ton (short)	2000	pounds
ton (long)	2240	pounds
ton (metric)	2200	pounds
ton (shipping)	40	feet^3
centimeter	0.39	inches
inch	2.54	centimeters
foot	30.48	centimeters
meter	1.09	yards
yard	0.91	meters
mile	1.61	kilometers
centimeter^2	0.16	inches^2
inch^2	6.45	centimeters^2
foot^2	0.09	meters^2
meter^2	1.2	yards^2
yard^2	0.84	meters^2
mile^2	2.59	kilometers^2
centimeter^3	0.061	inches^3
inch^3	16.39	centimeters^3
foot^3	283.17	centimeters^3
foot^3	1728	inches^3

SOME USEFUL WEIGHTS AND MEASURES (cont.)

Unit Of Measure	Equivalent	
meter^3	1.31	yeads^3
yard^3	0.77	meters^3
cord	128	feet^3
cord	4	meters^3
peck	8	quarts
bushel (dry)	4	pecks
bushel	2150.4	inches^3
gallon (U. S.)	231	inches^3
barrel	31.5	gallons
hogshead	2	barrels
township	36	miles^2
hectare	2.5	acres

MISCELLANEOUS DATA

One cubic foot of anthracite coal weighs about 53 pounds.

One cubic foot of bituminous coal weighs from 47 to 50 pounds.

One ton of coal is equivalent to two cords of wood for steam purposes.

A gallon of water (U. S. Standard) weighs 8.33 pounds and contains 231 cubic inches.

There are 9 square feet of heating surface to each square foot of grate surface.

A cubic foot of water contains 7.5 gallons and 1728 cubic inches, and weighs 62.5 lbs.

Each nominal horsepower of a boiler requires 30 to 35 pounds of water per hour.

A horsepower is equivalent to raising 33,000 pounds one foot per minute, or 550 pounds one foot per second.

To find the pressure in pounds per square inch of a column of water, multiply the height of the column in feet by 0.434.

TYPICAL PARAMETERS OF VARIOUS FUELS[a]

Type Of Fuel	Heating Value		Sulfur % (by weight)	Ash % (by weight)
	kcal	Btu		
Solid Fuels				
Bituminous Coal	7,200/kg	13,000/lb	0.6-5.4	4-20
Anthracite Coal	6,810/kg	12,300/lb	0.5-1.0	7.0-16.0
Lignite (@ 35% moisture)	3,990/kg	7,200/lb	0.7	6.2
Wood (@ 40% moisture)	2,880/kg	5,200/lb	N	1-3
Bagasse (@ 50% moisture)	2,220/kg	4,000/lb	N	1-2
Bark (@ 50% moisture)	2,492/kg	4,500/lb	N	1-3[b]
Coke, Byproduct	7,380/kg	13,300/lb	0.5-1.0	0.5-5.0
Liquid Fuels				
Residual Oil	$9.98 \times 10^6/m^3$	150,000/gal	0.5-4.0	0.05-0.1
Distillate Oil	$9.30 \times 10^6/m^3$	140,000/gal	0.2-1.0	N
Diesel	$9.12 \times 10^6/m^3$	137,000/gal	0.4	N
Gasoline	$8.62 \times 10^6/m^3$	130,000/gal	0.03-0.04	N
Kerosene	$8.32 \times 10^6/m^3$	135,000/gal	0.02-0.05	N
Liquid Petroleum Gas	$6.25 \times 10^6/m^3$	94,000/gal	N	N
Gaseous Fuels				
Natural Gas	$9,341/m^3$	1,050/SCF	N	N
Coke Oven Gas	$5,249/m^3$	590/SCF	0.5-2.0	N
Blast Furnace Gas	$890/m^3$	100/SCF	N	N

[a] N = negligible.

[b] Ash content may be considerably higher when sand, dirt, etc., are present.

THERMAL EQUIVALENTS FOR VARIOUS FUELS

Type Of Fuel	kcal	Btu (gross)
Solid fuels		
Bituminous coal	(5.8 to 7.8) x 10^6/Mg	(21.0 to 28.0) x 10^6/ton
Anthracite coal	7.03 x 10^6/Mg	25.3 x 10^6/ton
Lignite	4.45 x 10^6/Mg	16.0 x 10^6/ton
Wood	1.47 x 10^6/m^3	21.0 x 10^6/cord
Liquid fuels		
Residual fuel oil	10 x 10^3/liter	6.3 x 10^6/bbl
Distillate fuel oil	9.35 x 10^3/liter	5.9 x 10^6/bbl
Gaseous fuels		
Natural gas	9,350/m^3	1,050/ft^3
Liquefied petroleum gas		
Butane	6,480/liter	97,400/gal
Propane	6,030/liter	90,500/gal

WEIGHTS OF SELECTED SUBSTANCES

Type Of Substance	g/liter	lb/gal
Asphalt	1030	8.57
Butane, liquid at 60°F	579	4.84
Crude oil	850	7.08
Distillate oil	845	7.05
Gasoline	739	6.17
Propane, liquid at 60°F	507	4.24
Residual oil	944	7.88
Water	1000	8.4

DENSITIES OF SELECTED SUBSTANCES

Substance	Density	
Fuels		
Crude Oil	874 kg/m^3	7.3 lb/gal
Residual Oil	944 kg/m^3	7.88 lb/gal
Distillate Oil	845 kg/m^3	7.05 lb/gal
Gasoline	739 kg/m^3	6.17 lb/gal
Natural Gas	673 kg/m^3	1 lb/23.8 ft^3
Butane	579 kg/m^3	4.84 lb/gal (liquid)
Propane	507 kg/m^3	4.24 lb/gal (liquid)
Wood (Air dried)		
Elm	561 kg/m^3	35 lb/ft^3
Fir, Douglas	513 kg/m^3	32 lb/ft^3
Fir, Balsam	400 kg/m^3	25 lb/ft^3
Hemlock	465 kg/m^3	29 lb/ft^3
Hickory	769 kg/m^3	48 lb/ft^3
Maple, Sugar	689 kg/m^3	43 lb/ft^3
Maple, White	529 kg/m^3	33 lb/ft^3
Oak, Red	673 kg/m^3	42 lb/ft^3
Oak, White	769 kg/m^3	48 lb/ft^3
Pine, Southern	641 kg/m^3	40 lb/ft^3
Agricultural Products		
Corn	25.4 kg/bu	56 lb/bu
Milo	25.4 kg/bu	56 lb/bu
Oats	14.5 kg/bu	32 lb/bu
Barley	21.8 kg/bu	48 lb/bu
Wheat	27.2 kg/bu	60 lb/bu
Cotton	226 kg/bale	500 lb/bale
Mineral Products		
Brick	2.95 kg/brick	6.5 lb/brick
Cement	170 kg/bbl	375 lb/bbl
Cement	1483 kg/m^3	2500 lb/yd^3

DENSITIES OF SELECTED SUBSTANCES (cont.).

Substance	Density	
Concrete	2373 kg/m^3	4000 lb/yd^3
Glass, Common	2595 kg/m^3	162 lb/ft^3
Gravel, Dry Packed	1600 - 1920 kg/m^3	100 - 120 lb/ft^3
Gravel, Wet	2020 kg/m^3	126 lb/ft^3
Gypsum, Calcined	880 - 960 kg/m^3	55 - 60 lb/ft^3
Lime, Pebble	850 - 1025 kg/m^3	53 - 64 lb/ft^3
Sand, Gravel (Dry, loose)	1440 - 1680 kg/m^3	90 - 105 lb/ft^3

CONVERSION FACTORS

The table of conversion factors on the following pages contains factors for converting English to metric units and metric to English units as well as factors to manipulate units within the same system. The factors are arranged alphabetically by unit within the following property groups.

- Area
- Density
- Energy
- Force
- Length
- Mass
- Pressure
- Velocity
- Volume
- Volumetric Rate

To convert a number from one unit to another:

1. Locate the unit in which the number is currently expressed in the left-hand column of the table;

2. Find the desired unit in the center column; and

3. Multiply the number by the corresponding conversion factor in the right-hand column.

CONVERSION FACTORS[a]

To Convert From	To	Multiply By
Area		
Acres	Sq feet	4.356×10^{4}
Acres	Sq kilometers	4.0469×10^{-3}
Acres	Sq meters	4.0469×10^{3}
Acres	Sq miles (statute)	1.5625×10^{-3}
Acres	Sq yards	4.84×10^{3}
Sq feet	Acres	2.2957×10^{-5}
Sq feet	Sq cm	929.03
Sq feet	Sq inches	144.0
Sq feet	Sq meters	0.092903
Sq feet	Sq miles	3.587×10^{-8}
Sq feet	Sq yards	0.111111
Sq inches	Sq feet	6.9444×10^{-3}
Sq inches	Sq meters	6.4516×10^{-4}
Sq inches	Sq mm	645.16
Sq kilometers	Acres	247.1
Sq kilometers	Sq feet	1.0764×10^{7}
Sq kilometers	Sq meters	1.0×10^{6}
Sq kilometers	Sq miles	0.386102
Sq kilometers	Sq yards	1.196×10^{6}
Sq meters	Sq cm	1.0×10^{4}
Sq meters	Sq feet	10.764
Sq meters	Sq inches	1.55×10^{3}
Sq meters	Sq kilometers	1.0×10^{-6}
Sq meters	Sq miles	3.861×10^{-7}
Sq meters	Sq mm	1.0×10^{6}
Sq meters	Sq yards	1.196
Sq miles	Acres	640.0
Sq miles	Sq feet	2.7878×10^{7}
Sq miles	Sq kilometers	2.590

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Sq miles	Sq meters	2.59×10^{6}
Sq miles	Sq yards	3.0976×10^{6}
Sq yards	Acres	2.0661×10^{-4}
Sq yards	Sq cm	8.3613×10^{3}
Sq yards	Sq ft	9.0
Sq yards	Sq inches	1.296×10^{3}
Sq yards	Sq meters	0.83613
Sq yards	Sq miles	3.2283×10^{-7}
Density		
Dynes/cu cm	Grams/cu cm	1.0197×10^{-3}
Grains/cu foot	Grams/cu meter	2.28835
Grams/cu cm	Dynes/cu cm	980.665
Grams/cu cm	Grains/milliliter	15.433
Grams/cu cm	Grams/milliliter	1.0
Grams/cu cm	Pounds/cu inch	1.162
Grams/cu cm	Pounds/cu foot	62.428
Grams/cu cm	Pounds/cu inch	0.036127
Grams/cu cm	Pounds/gal (Brit.)	10.022
Grams/cu cm	Pounds/gal (U. S., dry)	9.7111
Grams/cu cm	Pounds/gal (U. S., liq.)	8.3454
Grams/cu meter	Grains/cu foot	0.4370
Grams/liter	Pounds/gal (U. S.)	8.345×10^{-3}
Kilograms/cu meter	Grams/cu cm	0.001
Kilograms/cu meter	Pounds/cu ft	0.0624
Kilograms/cu meter	Pounds/cu in	3.613×10^{-5}
Pounds/cu foot	Grams/cu cm	0.016018
Pounds/cu foot	kg/cu meter	16.018
Pounds/cu inch	Grams/cu cm	27.68
Pounds/cu inch	Grams/liter	27.681
Pounds/cu inch	kg/cu meter	2.768×10^{4}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Pounds/gal (U. S., liq.)	Grams/cu cm	0.1198
Pounds/gal (U. S., liq.)	Pounds/cu ft	7.4805
Energy		
Btu	Cal. gm (IST.)	251.83
Btu	Ergs	1.05435×10^{10}
Btu	Foot-pounds	777.65
Btu	Hp-hours	3.9275×10^{-4}
Btu	Joules (Int.)	1054.2
Btu	kg-meters	107.51
Btu	kW-hours (Int.)	2.9283×10^{-4}
Btu/hr	Cal. kg/hr	0.252
Btu/hr	Ergs/sec	2.929×10^{6}
Btu/hr	Foot-pounds/hr	777.65
Btu/hr	Horsepower (mechanical)	3.9275×10^{-4}
Btu/hr	Horsepower (boiler)	2.9856×10^{-5}
Btu/hr	Horsepower (electric)	3.926×10^{-4}
Btu/hr	Horsepower (metric)	3.982×10^{-4}
Btu/hr	Kilowatts	2.929×10^{-4}
Btu/lb	Foot-pounds/lb	777.65
Btu/lb	Hp-hr/lb	3.9275×10^{-4}
Btu/lb	Joules/gram	2.3244
Calories, kg (mean)	Btu (IST.)	3.9714
Calories, kg (mean)	Ergs	4.190×10^{10}
Calories, kg (mean)	Foot-pounds	3.0904×10^{3}
Calories, kg (mean)	Hp-hours	1.561×10^{-3}
Calories, kg (mean)	Joules	4.190×10^{3}
Calories, kg (mean)	kg-meters	427.26
Calories, kg (mean)	kW-hours (Int.)	1.1637×10^{-3}
Ergs	Btu	9.4845×10^{-11}
Ergs	Foot-poundals	2.373×10^{-6}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Ergs	Foot-pounds	7.3756×10^{-8}
Ergs	Joules (Int.)	9.99835×10^{-8}
Ergs	kW-hours	2.7778×10^{-14}
Ergs	kg-meters	1.0197×10^{-8}
Foot-pounds	Btu (IST.)	1.2851×10^{-3}
Foot-pounds	Cal. kg (IST.)	3.2384×10^{-4}
Foot-pounds	Ergs	1.3558×10^{7}
Foot-pounds	Foot-poundals	32.174
Foot-pounds	Hp-hours	5.0505×10^{-7}
Foot-pounds	Joules	1.3558
Foot-pounds	kg-meters	0.138255
Foot-pounds	kW-hours (Int.)	3.76554×10^{-7}
Foot-pounds	Newton-meters	1.3558
Foot-pounds/hr	Btu/min	2.1432×10^{-5}
Foot-pounds/hr	Ergs/min	2.2597×10^{5}
Foot-pounds/hr	Horsepower (mechanical)	5.0505×10^{-7}
Foot-pounds/hr	Horsepower (metric)	5.121×10^{-7}
Foot-pounds/hr	Kilowatts	3.766×10^{-7}
Horsepower (mechanical)	Btu (mean)/hr	2.5425×10^{3}
Horsepower (mechanical)	Ergs/sec	7.457×10^{9}
Horsepower (mechanical)	Foot-pounds/hr	1.980×10^{6}
Horsepower (mechanical)	Horsepower (boiler)	0.07602
Horsepower (mechanical)	Horsepower (electric)	0.9996
Horsepower (mechanical)	Horsepower (metric)	1.0139
Horsepower (mechanical)	Joules/sec	745.70
Horsepower (mechanical)	Kilowatts (Int.)	0.74558
Horsepower (boiler)	Btu (mean)/hr	3.3446×10^{4}
Horsepower (boiler)	Ergs/sec	9.8095×10^{10}
Horsepower (boiler)	Foot-pounds/min	4.341×10^{5}
Horsepower (boiler)	Horsepower (mechanical)	13.155

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Horsepower (boiler)	Horsepower (electric)	13.15
Horsepower (boiler)	Horsepower (metric)	13.337
Horsepower (boiler)	Joules/sec	9.8095×10^3
Horsepower (boiler)	Kilowatts	9.8095
Horsepower (electric)	Btu (mean)/hr	2.5435×10^3
Horsepower (electric)	Cal. kg/hr	641.87
Horsepower (electric)	Ergs/sec	7.46×10^9
Horsepower (electric)	Foot-pounds/min	3.3013×10^4
Horsepower (electric)	Horsepower (boiler)	0.07605
Horsepower (electric)	Horsepower (metric)	1.0143
Horsepower (electric)	Joules/sec	746.0
Horsepower (electric)	Kilowatts	0.746
Horsepower (metric)	Btu (mean)/hr	2.5077×10^3
Horsepower (metric)	Ergs/sec	7.355×10^9
Horsepower (metric)	Foot-pounds/min	3.255×10^4
Horsepower (metric)	Horsepower (mechanical)	0.98632
Horsepower (metric)	Horsepower (boiler)	0.07498
Horsepower (metric)	Horsepower (electric)	0.9859
Horsepower (metric)	kg-meters/sec	75.0
Horsepower (metric)	Kilowatts	0.7355
Horsepower-hours	Btu (mean)	2.5425×10^3
Horsepower-hours	Foot-pounds	1.98×10^6
Horsepower-hours	Joules	2.6845×10^6
Horsepower-hours	kg-meters	2.73745×10^5
Horsepower-hours	kW-hours	0.7457
Joules (Int.)	Btu (IST.)	9.4799×10^{-4}
Joules (Int.)	Ergs	1.0002×10^7
Joules (Int.)	Foot-poundals	12.734
Joules (Int.)	Foot-pounds	0.73768
Joules (Int.)	kW-hours	2.778×10^{-7}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Joules (Int.)/sec	Btu (mean)/min	0.05683
Joules (Int.)/sec	Cal. kg/min	0.01434
Joules (Int.)/sec	Horsepower	1.341×10^{-3}
Kilogram-meters	Btu (mean)	9.2878×10^{-3}
Kilogram-meters	Cal. kg (mean)	2.3405×10^{-3}
Kilogram-meters	Ergs	9.80665×10^{7}
Kilogram-meters	Foot-poundals	232.715
Kilogram-meters	Foot-pounds	7.233
Kilogram-meters	Hp-hours	3.653×10^{-6}
Kilogram-meters	Joules (Int.)	9.805
Kilogram-meters	kW-hours	2.724×10^{-6}
Kilogram-meters/sec	Watts	9.80665
Kilowatts (Int.)	Btu (IST.)/hr	3.413×10^{3}
Kilowatts (Int.)	Cal. kg (IST.)/hr	860.0
Kilowatts (Int.)	Ergs/sec	1.0002×10^{10}
Kilowatts (Int.)	Foot-poundals/min	1.424×10^{6}
Kilowatts (Int.)	Foot-pounds/min	4.4261×10^{4}
Kilowatts (Int.)	Horsepower (mechanical)	1.341
Kilowatts (Int.)	Horsepower (boiler)	0.10196
Kilowatts (Int.)	Horsepower (electric)	1.3407
Kilowatts (Int.)	Horsepower (metric)	1.3599
Kilowatts (Int.)	Joules (Int.)/hr	3.6×10^{6}
Kilowatts (Int.)	kg-meters/hr	3.6716×10^{5}
Kilowatt-hours (Int.)	Btu (mean)	3.41×10^{3}
Kilowatt-hours (Int.)	Foot-pounds	2.6557×10^{6}
Kilowatt-hours (Int.)	Hp-hours	1.341
Kilowatt-hours (Int.)	Joules (Int.)	3.6×10^{6}
Kilowatt-hours (Int.)	kg-meters	3.6716×10^{5}
Newton-meters	Gram-cm	1.01972×10^{4}
Newton-meters	kg-meters	0.101972

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Newton-meters	Pound-feet	0.73756
Force		
Dynes	Newtons	1.0×10^{-5}
Dynes	Poundals	7.233×10^{-5}
Dynes	Pounds	2.248×10^{-6}
Newtons	Dynes	1.0×10^{-5}
Newtons	Pounds (avdp.)	0.22481
Poundals	Dynes	1.383×10^{4}
Poundals	Newtons	0.1383
Poundals	Pounds (avdp.)	0.03108
Pounds (avdp.)	Dynes	4.448×10^{5}
Pounds (avdp.)	Newtons	4.448
Pounds (avdp.)	Poundals	32.174
Length		
Feet	Centimeters	30.48
Feet	Inches	12
Feet	Kilometers	3.048×10^{-4}
Feet	Meters	0.3048
Feet	Miles (statute)	1.894×10^{-4}
Inches	Centimeters	2.540
Inches	Feet	0.08333
Inches	Kilometers	2.54×10^{-5}
Inches	Meters	0.0254
Kilometers	Feet	3.2808×10^{3}
Kilometers	Meters	1000
Kilometers	Miles (statute)	0.62137
Kilometers	Yards	1.0936×10^{3}
Meters	Feet	3.2808
Meters	Inches	39.370
Micrometers	Angstrom units	1.0×10^{4}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Micrometers	Centimeters	1.0×10^{-3}
Micrometers	Feet	3.2808×10^{-6}
Micrometers	Inches	3.9370×10^{-5}
Micrometers	Meters	1.0×10^{-6}
Micrometers	Millimeters	0.001
Micrometers	Nanometers	1000
Miles (statute)	Feet	5280
Miles (statute)	Kilometers	1.6093
Miles (statute)	Meters	1.6093×10^{3}
Miles (statute)	Yards	1760
Millimeters	Angstrom units	1.0×10^{7}
Millimeters	Centimeters	0.1
Millimeters	Inches	0.03937
Millimeters	Meters	0.001
Millimeters	Micrometers	1000
Millimeters	Mils	39.37
Nanometers	Angstrom units	10
Nanometers	Centimeters	1.0×10^{-7}
Nanometers	Inches	3.937×10^{-8}
Nanometers	Micrometers	0.001
Nanometers	Millimeters	1.0×10^{-6}
Yards	Centimeters	91.44
Yards	Meters	0.9144
Mass		
Grains	Grams	0.064799
Grains	Milligrams	64.799
Grains	Pounds (apoth. or troy)	1.7361×10^{-4}
Grains	Pounds (avdp.)	1.4286×10^{-4}
Grains	Tons (metric)	6.4799×10^{-8}
Grams	Dynes	980.67

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Grams	Grains	15.432
Grams	Kilograms	0.001
Grams	Micrograms	1×10^{6}
Grams	Pounds (avdp.)	2.205×10^{-3}
Grams	Tons, metric (megagrams)	1×10^{-6}
Kilograms	Grains	1.5432×10^{4}
Kilograms	Poundals	70.932
Kilograms	Pounds (apoth. or troy)	2.679
Kilograms	Pounds (avdp.)	2.2046
Kilograms	Tons (long)	9.842×10^{-4}
Kilograms	Tons (metric)	0.001
Kilograms	Tons (short)	1.1023×10^{-3}
Megagrams	Tons (metric)	1.0
Milligrams	Grains	0.01543
Milligrams	Grams	1.0×10^{-3}
Milligrams	Ounces (apoth. or troy)	3.215×10^{-5}
Milligrams	Ounces (avdp.)	3.527×10^{-5}
Milligrams	Pounds (apoth. or troy)	2.679×10^{-6}
Milligrams	Pounds (avdp.)	2.2046×10^{-6}
Ounces (apoth. or troy)	Grains	480
Ounces (apoth. or troy)	Grams	31.103
Ounces (apoth. or troy)	Ounces (avdp.)	1.097
Ounces (avdp.)	Grains	437.5
Ounces (avdp.)	Grams	28.350
Ounces (avdp.)	Ounces (apoth. or troy)	0.9115
Ounces (avdp.)	Pounds (apoth. or troy)	0.075955
Ounces (avdp.)	Pounds (avdp.)	0.0625
Pounds (avdp.)	Poundals	32.174
Pounds (avdp.)	Pounds (apoth. or troy)	1.2153
Pounds (avdp.)	Tons (long)	4.4643×10^{-4}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Pounds (avdp.)	Tons (metric)	4.5359×10^{-4}
Pounds (avdp.)	Tons (short)	5.0×10^{-4}
Pounds (avdp.)	Grains	7000
Pounds (avdp.)	Grams	453.59
Pounds (avdp.)	Ounces (apoth. or troy)	14.583
Pounds (avdp.)	Ounces (avdp.)	16
Tons (long)	Kilograms	1.016×10^{3}
Tons (long)	Pounds (apoth. or troy)	2.722×10^{3}
Tons (long)	Pounds (avdp.)	2.240×10^{3}
Tons (long)	Tons (metric)	1.016
Tons (long)	Tons (short)	1.12
Tons (metric)	Grams	1.0×10^{6}
Tons (metric)	Megagrams	1.0
Tons (metric)	Pounds (apoth. or troy)	2.6792×10^{3}
Tons (metric)	Pounds (avdp.)	2.2046×10^{3}
Tons (metric)	Tons (long)	0.9842
Tons (metric)	Tons (short)	1.1023
Tons (short)	Kilograms	907.18
Tons (short)	Pounds (apoth. or troy)	2.4301×10^{3}
Tons (short)	Pounds (avdp.)	2000
Tons (short)	Tons (long)	0.8929
Tons (short)	Tons (metric)	0.9072
Pressure		
Atmospheres	cm of H_2O (4°C)	1.033×10^{3}
Atmospheres	Ft of H_2O (39.2°F)	33.8995
Atmospheres	In. of Hg (32°F)	29.9213
Atmospheres	kg/sq cm	1.033
Atmospheres	mm of Hg (0°C)	760
Atmospheres	Pounds/sq inch	14.696
Inches of Hg (60°F)	Atmospheres	0.03333

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Inches of Hg (60°F)	Grams/sq cm	34.434
Inches of Hg (60°F)	mm of Hg (60°F)	25.4
Inches of Hg (60°F)	Pounds/sq ft	70.527
Inches of H_2O (4°C)	Atmospheres	2.458×10^{-3}
Inches of H_2O (4°C)	In. of Hg (32°F)	0.07355
Inches of H_2O (4°C)	kg/sq meter	25.399
Inches of H_2O (4°C)	Pounds/sq ft	5.2022
Inches of H_2O (4°C)	Pounds/sq inch	0.036126
Kilograms/sq cm	Atmospheres	0.96784
Kilograms/sq cm	cm of Hg (0°C)	73.556
Kilograms/sq cm	Ft of H_2O (39.2°F)	32.809
Kilograms/sq cm	In. of Hg (32°F)	28.959
Kilograms/sq cm	Pounds/sq inch	14.223
Millimeters of Hg (0°C)	Atmospheres	1.3158×10^{-3}
Millimeters of Hg (0°C)	Grams/sq cm	1.3595
Millimeters of Hg (0°C)	Pounds/sq inch	0.019337
Pounds/sq inch	Atmospheres	0.06805
Pounds/sq inch	cm of Hg (0°C)	5.1715
Pounds/sq inch	cm of H_2O (4°C)	70.309
Pounds/sq inch	In. of Hg (32°F)	2.036
Pounds/sq inch	In. of H_2O (39.2°F)	27.681
Pounds/sq inch	kg/sq cm	0.07031
Pounds/sq inch	mm of Hg (0°C)	51.715
Velocity		
Centimeters/sec	Feet/min	1.9685
Centimeters/sec	Feet/sec	0.0328
Centimeters/sec	Kilometers/hr	0.036
Centimeters/sec	Meters/min	0.6
Centimeters/sec	Miles/hr	0.02237

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Feet/minute	cm/sec	0.508
Feet/minute	Kilometers/hr	0.01829
Feet/minute	Meters/min	0.3048
Feet/minute	Meters/sec	5.08×10^{-3}
Feet/minute	Miles/hr	0.01136
Feet/sec	cm/sec	30.48
Feet/sec	Kilometers/hr	1.0973
Feet/sec	Meters/min	18.288
Feet/sec	Miles/hr	0.6818
Kilometers/hr	cm/sec	27.778
Kilometers/hr	Feet/hr	3.2808×10^{3}
Kilometers/hr	Feet/min	54.681
Kilometers/hr	Meters/sec	0.27778
Kilometers/hr	Miles (statute)/hr	0.62137
Meters/min	cm/sec	1.6667
Meters/min	Feet/min	3.2808
Meters/min	Feet/sec	0.05468
Meters/min	Kilometers/hr	0.06
Miles/hr	cm/sec	44.704
Miles/hr	Feet/hr	5280
Miles/hr	Feet/min	88
Miles/hr	Feet/sec	1.4667
Miles/hr	Kilometers/hr	1.6093
Miles/hr	Meters/min	26.822
Volume		
Barrels (petroleum, U. S.)	Cu feet	5.6146
Barrels (petroleum, U. S.)	Gallons (U. S.)	42
Barrels (petroleum, U. S.)	Liters	158.98
Barrels (U. S., liq.)	Cu feet	4.2109
Barrels (U. S., liq.)	Cu inches	7.2765×10^{3}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Barrels (U. S., liq.)	Cu meters	0.1192
Barrels (U. S., liq.)	Gallons (U. S., liq.)	31.5
Barrels (U. S., liq.)	Liters	119.24
Cubic centimeters	Cu feet	3.5315×10^{-5}
Cubic centimeters	Cu inches	0.06102
Cubic centimeters	Cu meters	1.0×10^{-6}
Cubic centimeters	Cu yards	1.308×10^{-6}
Cubic centimeters	Gallons (U. S., liq.)	2.642×10^{-4}
Cubic centimeters	Quarts (U. S., liq.)	1.0567×10^{-3}
Cubic feet	Cu centimeters	2.8317×10^{4}
Cubic feet	Cu meters	0.028317
Cubic feet	Gallons (U. S., liq.)	7.4805
Cubic feet	Liters	28.317
Cubic inches	Cu cm	16.387
Cubic inches	Cu feet	5.787×10^{-4}
Cubic inches	Cu meters	1.6387×10^{-5}
Cubic inches	Cu yards	2.1433×10^{-5}
Cubic inches	Gallons (U. S., liq.)	4.329×10^{-3}
Cubic inches	Liters	0.01639
Cubic inches	Quarts (U. S., liq.)	0.01732
Cubic meters	Barrels (U. S., liq.)	8.3864
Cubic meters	Cu cm	1.0×10^{6}
Cubic meters	Cu feet	35.315
Cubic meters	Cu inches	6.1024×10^{4}
Cubic meters	Cu yards	1.308
Cubic meters	Gallons (U. S., liq.)	264.17
Cubic meters	Liters	1000
Cubic yards	Bushels (Brit.)	21.022
Cubic yards	Bushels (U. S.)	21.696
Cubic yards	Cu cm	7.6455×10^{5}

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Cubic yards	Cu feet	27
Cubic yards	Cu inches	4.6656×10^4
Cubic yards	Cu meters	0.76455
Cubic yards	Gallons	168.18
Cubic yards	Gallons	173.57
Cubic yards	Gallons	201.97
Cubic yards	Liters	764.55
Cubic yards	Quarts	672.71
Cubic yards	Quarts	694.28
Cubic yards	Quarts	807.90
Gallons (U. S., liq.)	Barrels (U. S., liq.)	0.03175
Gallons (U. S., liq.)	Barrels (petroleum, U. S.)	0.02381
Gallons (U. S., liq.)	Bushels (U. S.)	0.10742
Gallons (U. S., liq.)	Cu centimeters	3.7854×10^3
Gallons (U. S., liq.)	Cu feet	0.13368
Gallons (U. S., liq.)	Cu inches	231
Gallons (U. S., liq.)	Cu meters	3.7854×10^{-3}
Gallons (U. S., liq.)	Cu yards	4.951×10^{-3}
Gallons (U. S., liq.)	Gallons (wine)	1.0
Gallons (U. S., liq.)	Liters	3.7854
Gallons (U. S., liq.)	Ounces (U. S., fluid)	128.0
Gallons (U. S., liq.)	Pints (U. S., liq.)	8.0
Gallons (U. S., liq.)	Quarts (U. S., liq.)	4.0
Liters	Cu centimeters	1000
Liters	Cu feet	0.035315
Liters	Cu inches	61.024
Liters	Cu meters	0.001
Liters	Gallons (U. S., liq.)	0.2642
Liters	Ounces (U. S., fluid)	33.814

CONVERSION FACTORS (cont.).

To Convert From	To	Multiply By
Volumetric Rate		
Cu ft/min	Cu cm/sec	471.95
Cu ft/min	Cu ft /hr	60. 0
Cu ft/min	Gal (U. S.)/min	7.4805
Cu ft/min	Liters/sec	0.47193
Cu meters/min	Gal (U. S.)/min	264.17
Cu meters/min	Liters/min	999.97
Gallons (U. S.)/hr	Cu ft/hr	0.13368
Gallons (U. S.)/hr	Cu meters/min	6.309×10^{-5}
Gallons (U. S.)/hr	Cu yd/min	8.2519×10^{-5}
Gallons (U. S.)/hr	Liters/hr	3.7854
Liters/min	Cu ft/min	0.0353
Liters/min	Gal (U. S., liq.)/min	0.2642

[a] Where appropriate, the conversion factors appearing in this table have been rounded to four to six significant figures for ease in use. The accuracy of these numbers is considered suitable for use with emissions data; if a more accurate number is required, tables containing exact factors should be consulted.

CONVERSION FACTORS FOR COMMON AIR POLLUTION MEASUREMENTS

AIRBORNE PARTICULATE MATTER

To Convert From	To	Multiply By
Milligrams/cu m	Grams/cu ft	283.2×10^{-6}
	Grams/cu m	0.001
	Micrograms/cu m	1000.0
	Micrograms/cu ft	28.32
	Pounds/1000 cu ft	62.43×10^{-6}
Grams/cu ft	Milligrams/cu m	35.3145×10^{3}
	Grams/cu m	35.314
	Micrograms/cu m	35.314×10^{6}
	Micrograms/cu ft	1.0×10^{6}
	Pounds/1000 cu ft	2.2046
Grams/cu m	Milligrams/cu m	1000.0
	Grams/cu ft	0.02832
	Micrograms/cu m	1.0×10^{6}
	Micrograms/cu ft	28.317×10^{3}
	Pounds/1000 cu ft	0.06243
Micrograms/cu m	Milligrams/cu m	0.001
	Grams/cu ft	28.317×10^{-9}
	Grams/cu m	1.0×10^{-6}
	Micrograms/cu ft	0.02832
	Pounds/1000 cu ft	62.43×10^{-9}
Micrograms/cu ft	Milligrams/cu m	35.314×10^{-3}
	Grams/cu ft	1.0×10^{-6}
	Grams/cu m	35.314×10^{-6}
	Micrograms/cu m	35.314
	Pounds/1000 cu ft	2.2046×10^{-6}
Pounds/1000 cu ft	Milligrams/cu m	16.018×10^{3}
	Grams/cu ft	0.35314
	Micrograms/cu m	16.018×10^{6}
	Grams/cu m	16.018
	Micrograms/cu ft	353.14×10^{3}

CONVERSION FACTORS FOR COMMON AIR POLLUTION MEASUREMENTS (cont.).

SAMPLING PRESSURE

To Convert From	To	Multiply By
Millimeters of mercury (0°C)	Inches of water (60°F)	0.5358
Inches of mercury (0°C)	Inches of water (60°F)	13.609
	Millimeters of mercury (0°C)	1.8663
Inches of water (60°F)	Inches of mercury (0°C)	73.48×10^{-3}

CONVERSION FACTORS FOR COMMON AIR POLLUTION MEASUREMENTS (cont.).

ATMOSPHERIC GASES

To Convert From	To	Multiply By
Milligrams/cu m	Micrograms/cu m	1000.0
	Micrograms/liter	1.0
	ppm by volume (20°C)	24.04/M
	ppm by weight	0.8347
	Pounds/cu ft	62.43×10^{-9}
Micrograms/cu m	Milligrams/cu m	0.001
	Micrograms/liter	0.001
	ppm by volume (20°C)	0.02404/M
	ppm by weight	834.7×10^{-6}
	Pounds/cu ft	62.43×10^{-12}
Micrograms/liter	Milligrams/cu m	1.0
	Micrograms/cu m	1000.0
	ppm by volume (20°C)	24.04/M
	ppm by weight	0.8347
	Pounds/cu ft	62.43×10^{-9}
ppm by volume (20°C)	Milligrams/cu m	M/24.04
	Micrograms/cu m	M/0.02404
	Micrograms/liter	M/24.04
	ppm by weight	M/28.8
	Pounds/cu ft	$M/385.1 \times 10^{6}$
ppm by weight	Milligrams/cu m	1.198
	Micrograms/cu m	1.198×10^{-3}
	Micrograms/liter	1.198
	ppm by volume (20°C)	28.8/M
	Pounds/cu ft	7.48×10^{-6}
Pounds/cu ft	Milligrams/cu m	16.018×10^{6}
	Micrograms/cu m	16.018×10^{9}
	Micrograms/liter	16.018×10^{6}
	ppm by volume (20°C)	$385.1 \times 10^{6}/M$
	ppm by weight	133.7×10^{3}

M = Molecular weight of gas.

CONVERSION FACTORS FOR COMMON AIR POLLUTION MEASUREMENTS (cont.).

VELOCITY

To Convert From	To	Multiply By
Meters/sec	Kilometers/hr	3.6
	Feet/sec	3.281
	Miles/hr	2.237
Kilometers/hr	Meters/sec	0.2778
	Feet/sec	0.9113
	Miles/hr	0.6214
Feet/sec	Meters/sec	0.3048
	Kilometers/hr	1.09728
	Miles/hr	0.6818
Miles/hr	Meters/sec	0.4470
	Kilometers/hr	1.6093
	Feet/sec	1.4667

ATMOSPHERIC PRESSURE

To Convert From	To	Multiply By
Atmospheres	Millimeters of mercury	760.0
	Inches of mercury	29.92
	Millibars	1013.2
Millimeters of mercury	Atmospheres	1.316×10^{-3}
	Inches of mercury	39.37×10^{-3}
	Millibars	1.333
Inches of mercury	Atmospheres	0.03333
	Millimeters of mercury	25.4005
	Millibars	33.35
Millibars	Atmospheres	0.00987
	Millimeters of mercury	0.75
	Inches of mercury	0.30

VOLUME EMISSIONS

To Convert From	To	Multiply By
Cubic m/min	Cubic ft/min	35.314
Cubic ft/min	Cubic m/min	0.0283

BOILER CONVERSION FACTORS

1 Megawatt = 10.5 x 10^{6} Btu/hr
(8 to 14 x 10^{6} Btu/hr)

1 Megawatt = 8 x 10^{3} lb steam/hr
(6 to 11 x 10^{3} lb steam/hr)

1 BHP = 34.5 lb steam/hr

1 BHP = 45 x 10^{3} Btu/hr
(40 to 50 x 10^{3} Btu/hr)

1 lb steam/hr = 1.4 x 10^{3} Btu/hr
(1.2 to 1.7 x 10^{3} Btu/hr)

NOTES: In the relationships,

Megawatt is the net electric production of a steam electric power plant.

BHP is boiler horsepower.

lb steam/hr is the steam production rate of the boiler.

Btu/hr is the heat input rate to the boiler (based on the gross or high heating value of the fuel burned).

For less efficient (generally older and/or smaller) boiler operations, use the higher values expressed. For more efficient operations (generally newer and/or larger), use the lower values.

Volume	cu in	ml	liters	ounces (U. S. fl.)	gallons (U. S.)	barrels (U. S.)	cu ft
Cubic inches		16.3868	0.0163868	0.5541	4.3290x10^{-3}	1.37429x10^{-4}	5.78704x10^{-4}
Milliliters	0.061024		0.001	0.03381	2.6418x10^{-4}	8.387x10^{-6}	3.5316x10^{-5}
Liters	61.024	1000		33.8147	0.26418	8.387x10^{-3}	0.035316
Ounces (U. S. fl.)	1.80469	29.5729	0.029573		7.8125x10^{-3}	2.48x10^{-4}	1.0443x10^{-3}
Gallons (U. S.)[a]	231	3785.3	3.7853	128		0.031746	0.13368
Barrels (U. S.)	7276.5	1.1924x10^{5}	119.2369	4032.0	31.5		4.2109
Cubic feet	1728	2.8316x10^{4}	28.316	957.568	7.481	0.23743	

[a] U. S. gallon of water at 16.7°C (62°F) weighs 3.780 kg or 8.337 pounds (avoir.)

Mass	grams	kilograms	ounces (avoir.)	pounds (avoir.)	grains	tons (U. S.)	milligrams
Grams		0.001	3.527x10^{-2}	2.205x10^{-3}	15.432	1.102x10^{-6}	1000
Kilograms	1000		35.274	2.2046	15432	1.102x10^{-3}	1x10^{6}
Ounces (avoir.)	28.350	0.028350		0.0625	437.5	3.125x10^{-5}	2.8350x10^{4}
Pounds (avoir.)[a]	453.59	0.45359	16.0		7000	5.0x10^{-4}	4.5359x10^{5}
Grains	0.06480	6.480x10^{-5}	2.286x10^{-3}	1.429x10^{-4}		7.142x10^{-8}	64.799
Tons (U. S.)	9.072x10^{5}	907.19	3.200x10^{4}	2000	1.4x10^{7}		9.0718x10^{8}
Milligrams	0.001	1x10^{-6}	3.527x10^{-5}	2.205x10^{-6}	0.015432	1.102x10^{-9}	

[a] Mass of 27.692 cubic inches water weighed in air at 4.0°C, 760 mm mercury pressure.

Work and Energy	g cal.	kg cal.	ergs	joules	Btu	ft lb	kg meters	L-Atm	HP hours	ft poundals	kWh	Wh
Gram calories (mean)		0.001	4.186x10^{7}	4.186	3.9680x10^{-3}	3.0874	0.42685	0.041311	1.5593x10^{-6}	99.334	1.1628x10^{-6}	1.1628x10^{-3}
Kilogram calories	1000		4.186x10^{10}	4186	3.9680	3087.4	426.85	41.311	1.5593x10^{-3}	99334	1.1628x10^{-3}	1.1628
Ergs	2.3889x10^{-8}	2.3889x10^{-11}		1x10^{-7}	9.4805x10^{-11}	7.3756x10^{-8}	1.0197x10^{-8}	9.8689x10^{-10}	3.7251x10^{-14}	2.3730x10^{-6}	2.7778x10^{-14}	2.7778x10^{-11}
Joules	0.23889	2.3889x10^{-4}	1x10^{7}		9.4805x10^{-4}	0.73756	0.10197	9.8689x10^{-3}	3.7251x10^{-7}	23.730	2.7778x10^{-7}	2.7778x10^{-4}
Btu (mean)	251.98	0.25198	1.0548x10^{10}	1054.8		777.98	107.56	10.409	3.9292x10^{-4}	2.5030x10^{4}	2.930x10^{-4}	0.2930
Foot pounds	0.32389	3.2389x10^{-4}	1.35582x10^{7}	1.3558	1.2854x10^{-3}		0.13825	0.013381	5.0505x10^{-7}	32.174	3.7662x10^{-7}	3.7662x10^{-4}
Kilogram meters	2.3427	2.3427x10^{-3}	9.8066x10^{7}	9.8066	9.2967x10^{-3}	7.2330		0.096781	3.6529x10^{-6}	232.71	2.7241x10^{-6}	2.7241x10^{-3}
Liter atmospheres (normal)	24.206	2.4206x10^{-2}	1.0133x10^{9}	101.328	0.09606	74.735	10.333		3.7745x10^{-5}	2404.5	2.8164x10^{-5}	2.8164x10^{-2}
Horsepower hours	6.4130x10^{5}	641.30	2.6845x10^{13}	2.6845x10^{6}	2454.0	1.9800x10^{6}	2.7374x10^{5}	26494		6.3705x10^{7}	0.7457	745.7
Foot poundals	0.010067	10.067x10^{-6}	4.21402x10^{5}	0.04214	3.9952x10^{-5}	0.031081	4.2972x10^{-3}	4.1558x10^{-4}	1.5697x10^{-8}		1.17055x10^{-8}	1.17055x10^{-5}
Kilowatt hours	8.6001x10^{5}	860.01	3.6000x10^{13}	3.6000x10^{6}	3413.0	2.6552x10^{6}	3.6709x10^{-5}	3.5529x10^{6}	1.3440	8.5430x10^{7}		1000
Watt hours	860.01	0.86001	3.6000x10^{10}	3600	3.4130	2655.3	367.09	3.5529x10^{3}	1.3410x10^{-3}	8.5430x10^{1}	0.001	

Power	watts	kW	ft lb/sec	erg/sec	Btu/min	g cm/sec	kg cal/min	HP	lumens	joules/sec	Btu/hr
Watts		0.001	0.73756	$1x10^{7}$	0.056884	$1.0197x10^{4}$	0.01433	$1.341x10^{-3}$	668	1	3.41304
Kilowatts	1000		737.56	$1x10^{10}$	56.884	$1.0197x10^{7}$	14.3334	1.3410	$6.68x10^{5}$	1000	3413.04
Foot pounds per second	1.35582	$1.3558x10^{-3}$		$1.3558x10^{7}$	0.077124	$1.3826x10^{4}$	0.019433	$1.8182x10^{-3}$	906.28	1.3558	4.6274
Ergs per second	$1x10^{-7}$	$1x10^{-10}$	$7.3756x10^{-8}$		$5.688x10^{-9}$	$1.0197x10^{-3}$	$1.4333x10^{-9}$	$1.3410x10^{-10}$	$6.6845x10^{-5}$	$1x10^{-7}$	$3.4130x10^{-7}$
Btu[a] per minute	17.580	0.017580	12.9600	$1.7580x10^{8}$		$1.7926x10^{5}$	0.2520	0.023575	11751	17.580	60
Gram centimeters per second	$9.8067x10^{-5}$	$9.8067x10^{-8}$	$7.2330x10^{-5}$	980.665	$5.5783x10^{-6}$		$1.4056x10^{-6}$	$1.3151x10^{-7}$	0.065552	$9.8067x10^{-5}$	$3.3470x10^{-4}$
Kilogram calories per minute	69.767	0.069767	51.457	$6.9770x10^{8}$	3.9685	$7.1146x10^{5}$		0.093557	46636	69.769	238.11
Horsepower (U. S.)	745.7	0.7457	550	$7.457x10^{9}$	42.4176	$7.6042x10^{6}$	10.688		498129	745.7	2545.1
Lumens	$1.496x10^{-3}$	$1.496x10^{-6}$	$1.0034x10^{-3}$	$1.496x10^{4}$	$8.5096x10^{-5}$	15.254	$2.1437x10^{-5}$	$2.0061x10^{-6}$		$1.496x10^{-3}$	$5.1069x10^{-3}$
Joules per second	1	0.001	0.73756	$1x10^{7}$	0.056884	$1.0197x10^{4}$	0.01433	$1.341x10^{-3}$	668		3.41304
Btu[a] per hour	0.29299	$2.9299x10^{-4}$	0.21610	$2.9299x10^{6}$	0.01667	$2.9878x10^{3}$	$4.1997x10^{-3}$	$3.9291x10^{-4}$	195.80	0.29299	

[a] British Thermal Units (Mean)

CONVERSION FACTORS FOR VARIOUS SUBSTANCES[a]

Type Of Substance	Conversion Factors
Fuel	
Oil	1 bbl = 159 liters (42 gal)
Natural gas	1 therm = 100,000 Btu (approx.25000 kcal)
Gaseous Pollutants	
O_3	1 ppm, volume = 1960µg/m^3
NO_2	1 ppm, volume = 1880µg/m^3
SO_2	1 ppm, volume = 2610µg/m^3
H_2S	1 ppm, volume = 1390 µg/m^3
CO	1 ppm, volume = 1.14 mg/m^3
HC (as methane)	1 ppm, volume = 0.654 mg/m^3
Agricultural products	
Corn	1 bu = 25.4 kg = 56 lb
Milo	1 bu = 25.4 kg = 56 lb
Oats	1 bu = 14.5 kg = 32 lb
Barley	1 bu = 21.8 kg = 48 lb
Wheat	1 bu = 27.2 kg = 60 lb
Cotton	1 bale = 226 kg = 500 lb
Mineral products	
Brick	1 brick = 2.95 kg = 6.5 lb
Cement	1 bbl = 170 kg = 375 lb
Cement	1 yd^3 = 1130 kg = 2500 lb
Concrete	1 yd^3 = 1820 kg = 4000 lb
Mobile sources, fuel efficiency	
Motor vehicles	1.0 mi/gal = 0.426 km/liter
Waterborne vessels	1.0 gal/naut mi = 2.05 liters/km
Miscellaneous liquids	
Beer	1 bbl = 31.5 gal
Paint	1 gal = 4.5 to 6.82 kg = 10 to 15 lb
Varnish	1 gal = 3.18 kg = 7 lb
Whiskey	1 bbl = 190 liters = 50.2 gal
Water	1 gal = 3.81 kg = 8.3 lb

[a] Many of the conversion factors in this table represent average values and approximations and some of the values vary with temperature and pressure. These conversion factors should, however, be sufficiently accurate for general field use.

APPENDIX B.1

PARTICLE SIZE DISTRIBUTION DATA AND SIZED EMISSION FACTORS FOR SELECTED SOURCES

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APPENDIX B.1

PARTICLE SIZE DISTRIBUTION DATA AND SIZED EMISSION FACTORS FOR SELECTED SOURCES

Introduction

This appendix presents particle size distributions and emission factors for miscellaneous sources or processes for which documented emission data were available. Generally, the sources of data used to develop particle size distributions and emission factors for this appendix were:

1. Source test reports in the files of the Emissions Monitoring, and Analysis Division of EPA's Office Of Air Quality Planning And Standards.

2. Source test reports in the Fine Particle Emission Information System (FPEIS), a computerized data base maintained by EPA's Air And Energy Engineering Research Laboratory, Office Of Research And Development.

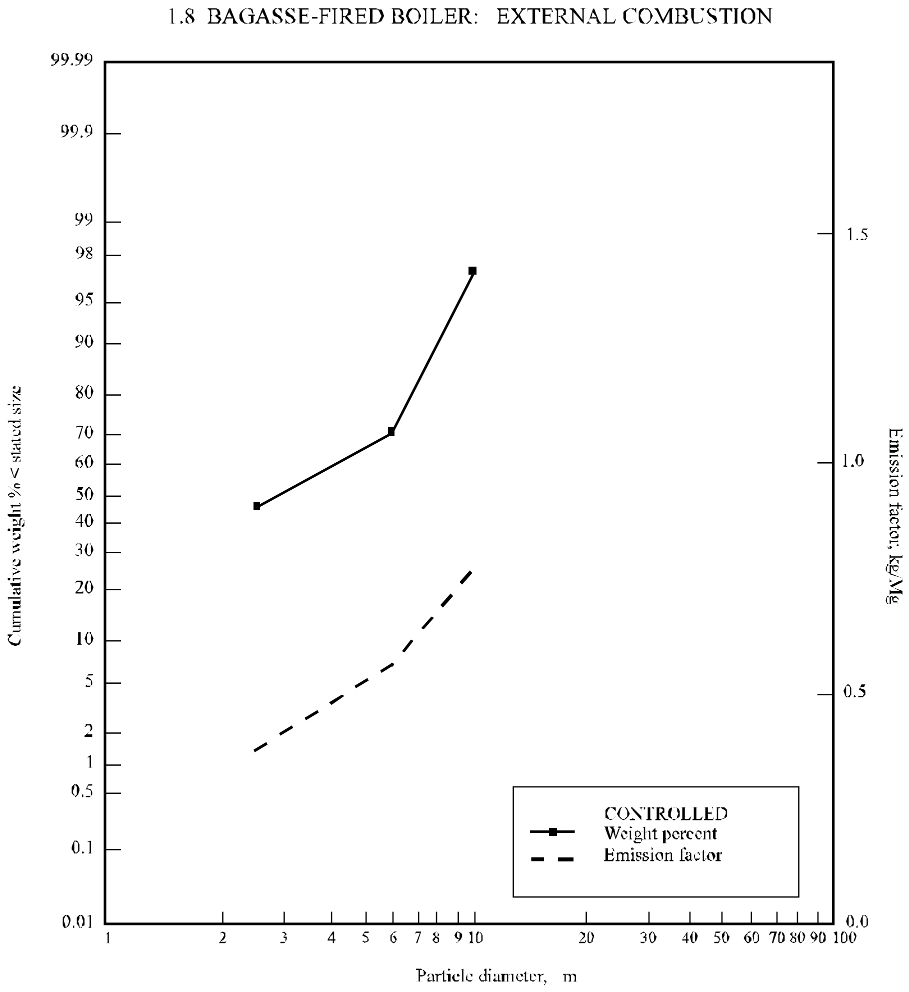
3. A series of source tests titled *Fine Particle Emissions From Stationary And Miscellaneous Sources In The South Coast Air Basin*, by H. J. Taback.

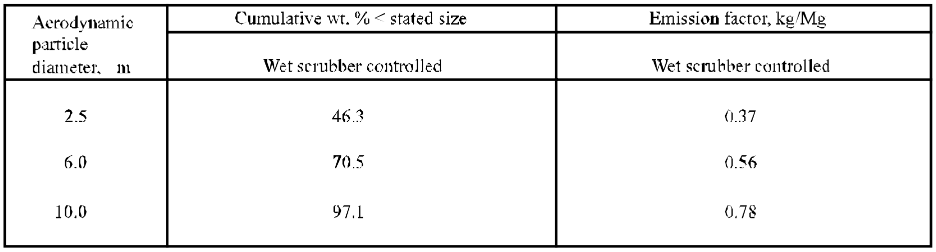
4. Particle size distribution data reported in the literature by various individuals and companies.

Particle size data from FPEIS were mathematically normalized into more uniform and consistent data. Where EMB tests and Taback report data were filed in FPEIS, the normalized data were used in developing this appendix.

Information on each source category in Appendix B.1 is presented in a 2-page format: For a source category, a graph provided on the first page presents a particle size distribution expressed as the cumulative weight percent of particles less than a specified aerodynamic diameter (cut point), in micrometers. A sized emission factor can be derived from the mathematical product of a mass emission factor and the cumulative weight percent of particles smaller than a specific cut point in the graph. At the bottom of the page is a table of numerical values for particle size distributions and sized emission factors, in micrometers, at selected values of aerodynamic particle diameter. The second page gives some information on the data used to derive the particle size distributions.

Portions of the appendix denoted TBA in the table of contents refer to information that will be added at a later date.





Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Wet scrubber controlled	Wet scrubber controlled
2.5	46.3	0.37
6.0	70.5	0.56
10.0	97.1	0.78

1.8 BAGASSE-FIRED BOILER: EXTERNAL COMBUSTION

NUMBER OF TESTS: 2, conducted after wet scrubber control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	46.3	70.5	97.1
	Standard deviation (Cum. %):	0.9	0.9	1.9
	Min (Cum. %):	45.4	69.6	95.2
	Max (Cum. %):	47.2	71.4	99.0

TOTAL PARTICULATE EMISSION FACTOR: Approximately 0.8 kg particulate/Mg bagasse charged to boiler. This factor is derived from AP-42, Section 1.8, 4/77, which states that the particulate emission factor from an uncontrolled bagasse-fired boiler is 8 kg/Mg and that wet scrubbers typically provide 90% particulate control.

SOURCE OPERATION: Source is a Riley Stoker Corp. vibrating grate spreader stoker boiler rated at 120,000 lb/hr but operated during this testing at 121% of rating. Average steam temperature and pressure were 579°F and 199 psig, respectively. Bagasse feed rate could not be measured, but was estimated to be about 41 (wet) tons/hr.

SAMPLING TECHNIQUE: Andersen Cascade Impactor

EMISSION FACTOR RATING: D

REFERENCE:

Emission Test Report, U. S. Sugar Company, Bryant, FL, EMB-80-WFB-6, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1980.

2.1 REFUSE INCINERATION: MUNICIPAL WASTE MASS BURN INCINERATOR

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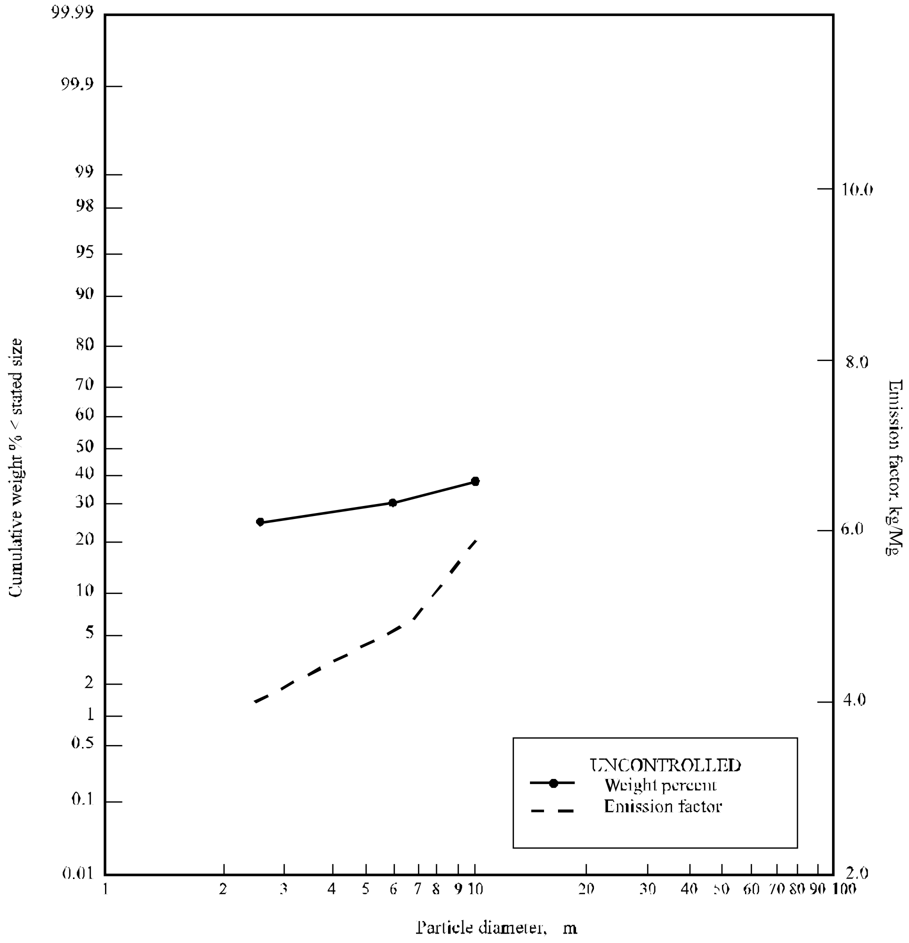

Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	26.0	3.9
6.0	30.6	4.6
10.0	38.0	5.7

2.1 REFUSE INCINERATION: MUNICIPAL WASTE MASS BURN INCINERATOR

NUMBER OF TESTS: 7, conducted before control

STATISTICS:	Aerodynamic Particle Diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	26.0	30.6	38.0
	Standard deviation (Cum. %):	9.5	13.0	14.0
	Min (Cum. %):	18	22	24
	Max (Cum. %):	40	49	54

TOTAL PARTICULATE EMISSION FACTOR: 15 kg of particulate/Mg of refuse charged. Emission factor from AP-42 Section 2.1.

SOURCE OPERATION: Municipal incinerators reflected in the data base include various mass burning facilities of typical design and operation.

SAMPLING TECHNIQUE: Unknown

EMISSION FACTOR RATING: D

REFERENCE:

Determination of Uncontrolled Emissions, Product 2B, Montgomery County, Maryland, Roy F. Weston, Inc., West Chester, PA, August 1984.

2.1 REFUSE INCINERATION: MUNICIPAL WASTE MODULAR INCINERATOR

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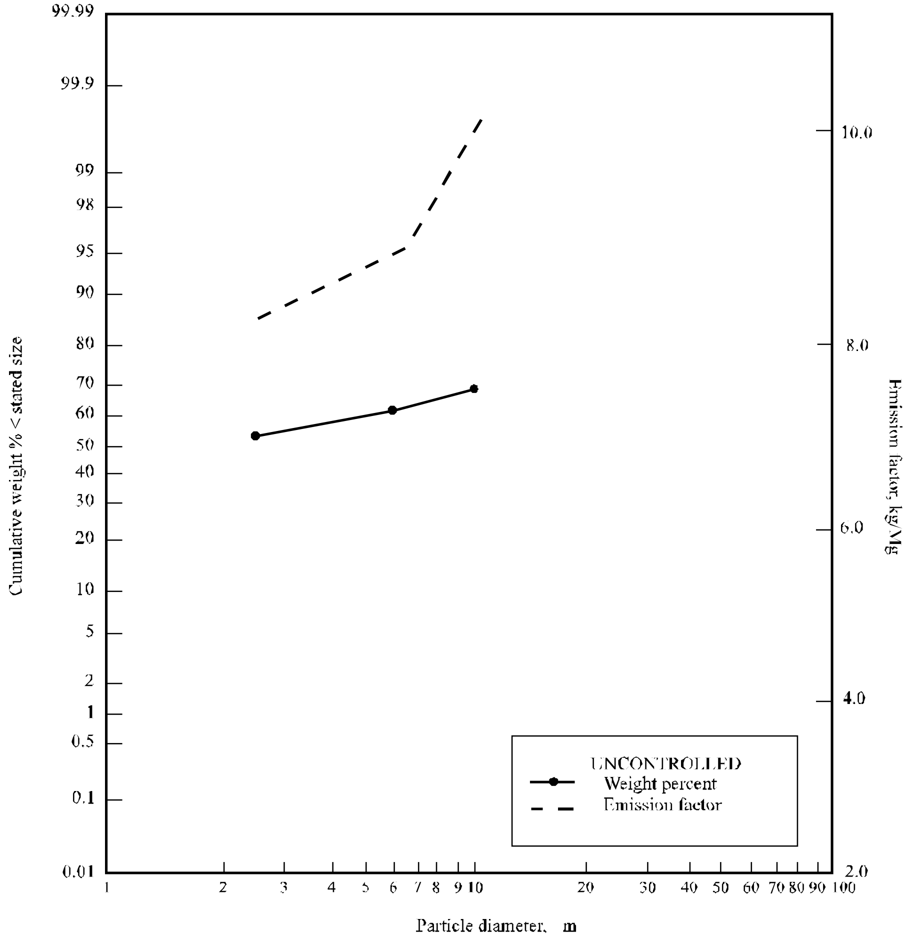


Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	54.0	8.1
6.0	60.1	9.0
10.0	67.1	10.1

2.1 REFUSE INCINERATION: MUNICIPAL WASTE MODULAR INCINERATOR

NUMBER OF TESTS: 3, conducted before control

STATISTICS:	Aerodynamic Particle Diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	54.0	60.1	67.1
	Standard deviation (Cum. %):	19.0	20.8	23.2
	Min (Cum. %):	34.5	35.9	37.5
	Max (Cum. %):	79.9	86.6	94.2

TOTAL PARTICULATE EMISSION FACTOR: 15 kg of particulate/Mg of refuse charged. Emission factor from AP-42 Section 2.1.

SOURCE OPERATION: Modular incinerator (2-chambered) operation was at 75.9% of the design process rate (10,000 lb/hr) and 101.2% of normal steam production rate. Natural gas is required to start the incinerator each week. Average waste charge rate was 1.983T/hr. Net heating value of garbage 4200-4800 Btu/lb garbage charged.

SAMPLING TECHNIQUE: Andersen Impactor

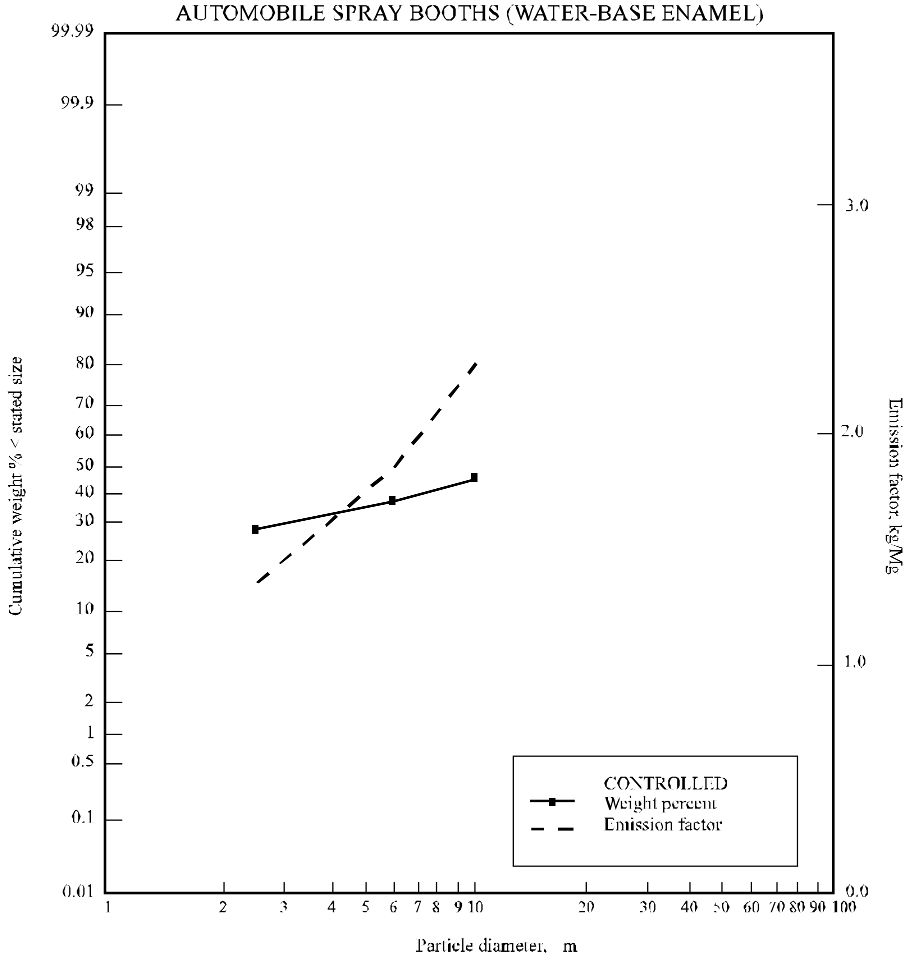
EMISSION FACTOR RATING: C

REFERENCE:

> *Emission Test Report, City of Salem, Salem, Va*, EMB-80-WFB-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1980.

4.2.2.8 AUTOMOBILE AND LIGHT-DUTY TRUCK SURFACE COATING OPERATIONS: AUTOMOBILE SPRAY BOOTHS (WATER-BASE ENAMEL)

4.2.2.8 AUTOMOBILE AND LIGHT-DUTY TRUCK SURFACE COATING OPERATIONS:
AUTOMOBILE SPRAY BOOTHS (WATER-BASE ENAMEL)



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Water curtain controlled	Water curtain controlled
2.5	28.6	1.39
6.0	38.2	1.85
10.0	46.7	2.26

4.2.2.8 AUTOMOBILE AND LIGHT-DUTY TRUCK SURFACE COATING OPERATIONS: AUTOMOBILE SPRAY BOOTHS (WATER-BASE ENAMEL)

NUMBER OF TESTS: 2, conducted after water curtain control

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	28.6	38.2	46.7
Standard deviation (Cum. %):	14.0	16.8	20.6
Min (Cum. %):	15.0	21.4	26.1
Max (Cum. %):	42.2	54.9	67.2

TOTAL PARTICULATE EMISSION FACTOR: 4.84 kg particulate/Mg of water-base enamel sprayed. From References a and b.

SOURCE OPERATION: Source is a water-base enamel spray booth in an automotive assembly plant. Enamel spray rate is 568 lb/hour, but spray gun type is not identified. The spray booth exhaust rate is 95,000 scfm. Water flow rate to the water curtain control device is 7181 gal/min. Source is operating at 84% of design rate.

SAMPLING TECHNIQUE: SASS and Joy trains with cyclones

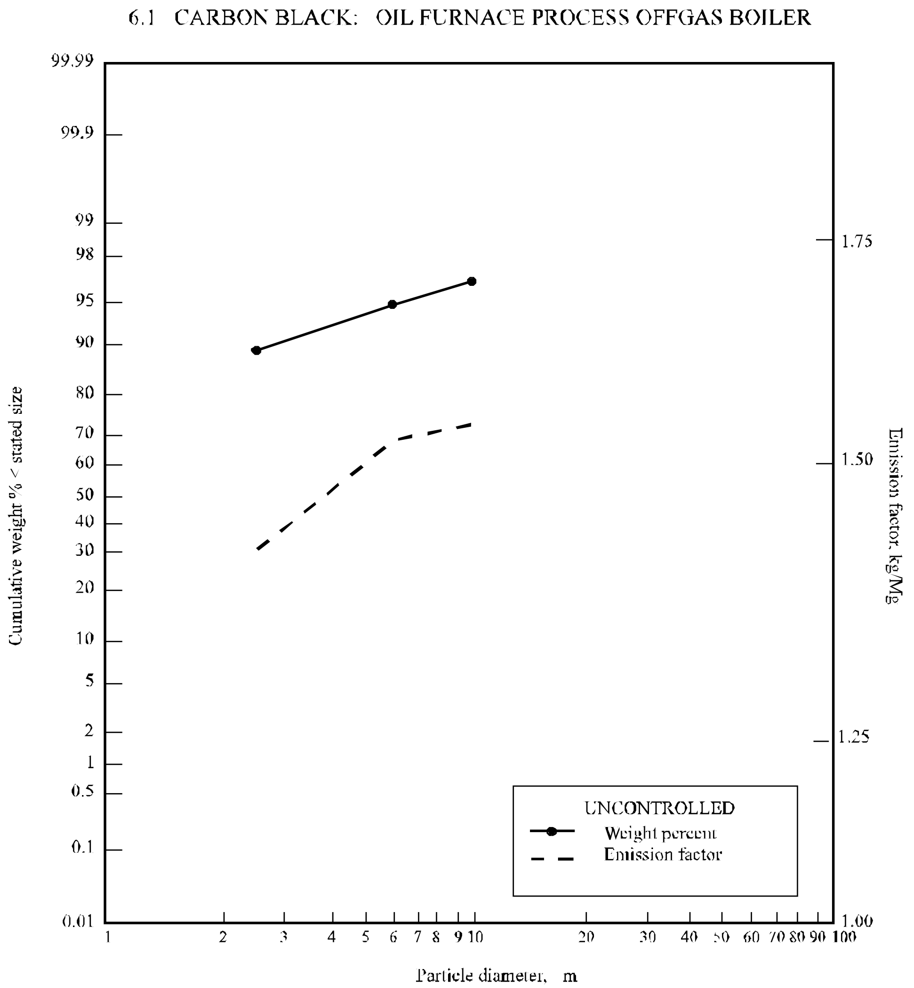
EMISSION FACTOR RATING: D

REFERENCES:

a. H. J. Taback, *Fine Particle Emissions from Stationary and Miscellaneous Sources in the South Coast Air Basin*, PB 293 923/AS, National Technical Information Service, Springfield, VA, February 1979.

b. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 234, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

6.1 CARBON BLACK: OIL FURNACE PROCESS OFFGAS BOILER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	87.3	1.40
6.0	95.0	1.52
10.0	97.0	1.55

6.1 CARBON BLACK: OIL FURNACE PROCESS OFFGAS BOILER

NUMBER OF TESTS: 3, conducted at offgas boiler outlet

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	87.3	95.0	97.0
Standard Deviation (Cum. %):	2.3	3.7	8.0
Min (Cum. %):	76.0	90.0	94.5
Max (Cum. %):	94.0	99	100

TOTAL PARTICULATE EMISSION FACTOR: 1.6 kg particulate/Mg carbon black produced, from reference.

SOURCE OPERATION: Process operation: "normal" (production rate = 1900 kg/hr). Product is collected in fabric filter, but the offgas boiler outlet is uncontrolled.

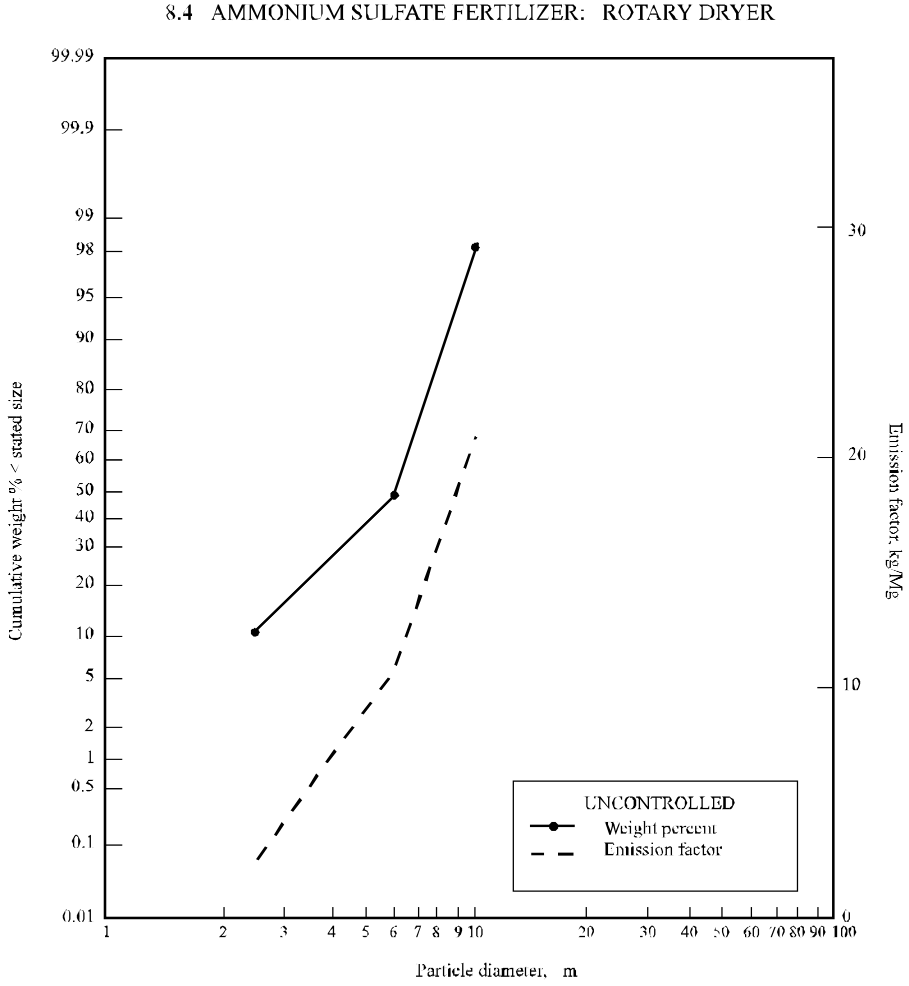
SAMPLING TECHNIQUE: Brink Cascade Impactor

EMISSION FACTOR RATING: D

REFERENCE:

> *Air Pollution Emission Test, Phillips Petroleum Company, Toledo, OH*, EMB-73-CBK-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1974.

8.4 AMMONIUM SULFATE FERTILIZER: ROTARY DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	10.8	2.5
6.0	49.1	11.3
10.0	98.6	22.7

8.4 AMMONIUM SULFATE FERTILIZER: ROTARY DRYER

NUMBER OF TESTS: 3, conducted before control

STATISTICS:	Aerodynamic particle diameter (μm):	2.5	6.0	10.0
	Mean (Cum. %):	10.8	49.1	98.6
	Standard Deviation (Cum. %):	5.1	21.5	1.8
	Min (Cum. %):	4.5	20.3	96.0
	Max (Cum. %):	17.0	72.0	100.0

TOTAL PARTICULATE EMISSION FACTOR: 23 kg particulate/Mg of ammonium sulfate produced. Factor from AP-42, Section 8.4.

SOURCE OPERATION: Testing was conducted at 3 ammonium sulfate plants operating rotary dryers within the following production parameters:

Plant	A	C	D
% of design process rate	100.6	40.1	100
production rate, Mg/hr	16.4	6.09	8.4

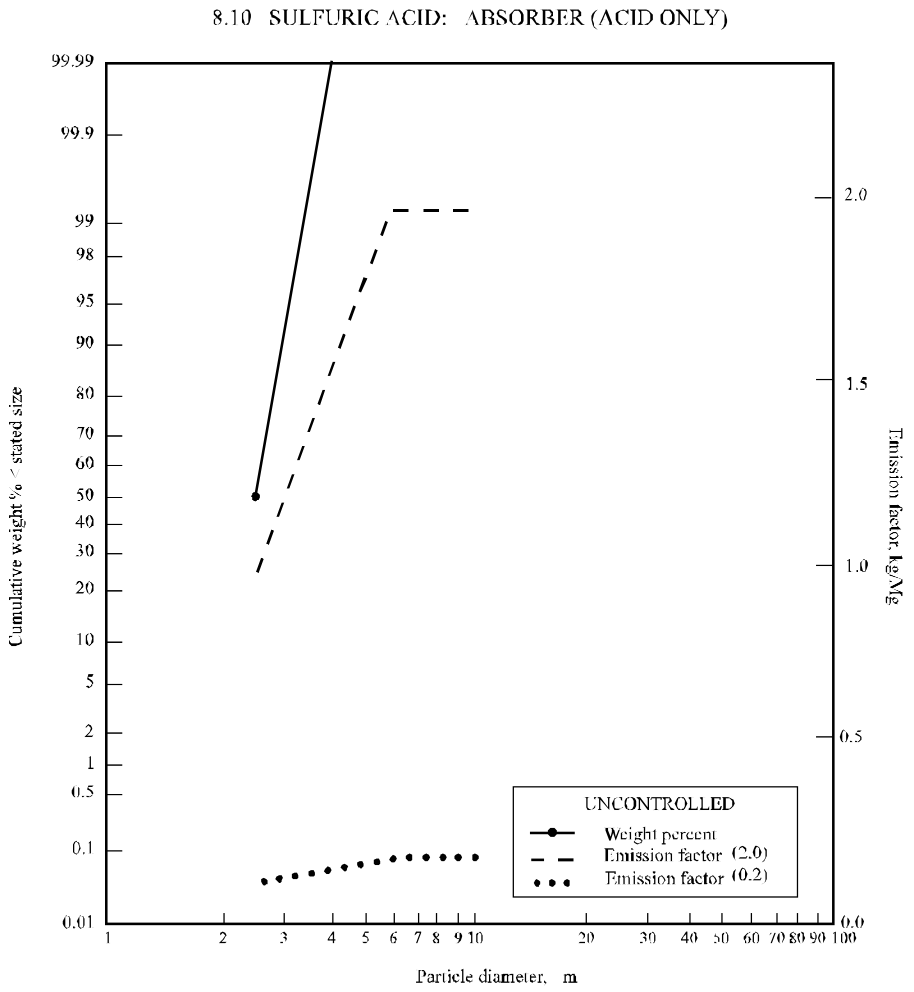
SAMPLING TECHNIQUE: Andersen Cascade Impactors

EMISSION FACTOR RATING: C

REFERENCE:

Ammonium Sulfate Manufacture — Background Information For Proposed Emission Standards, EPA-450/3-79-034a, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.

8.10 SULFURIC ACID: ABSORBER (ACID ONLY)



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg	
	Uncontrolled	Uncontrolled	
		(0.2)	(2.0)
2.5	51.2	0.10	1.0
6.0	100	0.20	2.0
10.0	100	0.20	2.0

8.10 SULFURIC ACID: ABSORBER (ACID ONLY)

NUMBER OF TESTS: Not available

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	51.2	100	100
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.2 to 2.0 kg acid mist/Mg sulfur charged, for uncontrolled 98% acid plants burning elemental sulfur. Emission factors are from AP-42 Section 8.10.

SOURCE OPERATION: Not available

SAMPLING TECHNIQUE: Brink Cascade Impactor

EMISSION FACTOR RATING: E

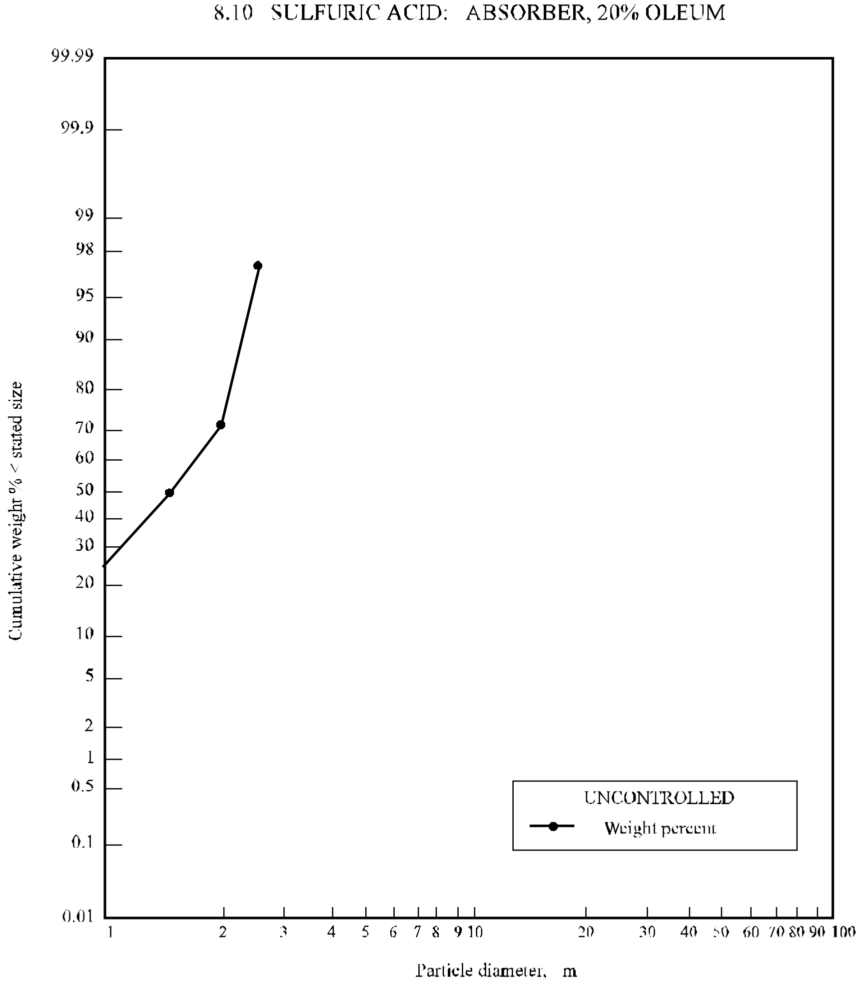
REFERENCES:

a. *Final Guideline Document: Control Of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units*, EPA-450/2-77-019, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

b. R. W. Kurek, *Special Report On EPA Guidelines For State Emission Standards For Sulfuric Acid Plant Mist*, E. I. du Pont de Nemours and Company, Wilmington, DE, June 1974.

c. J. A. Brink, Jr., "Cascade Impactor For Adiabatic Measurements", *Industrial and Engineering Chemistry*, *50*:647, April 1958.

8.10 SULFURIC ACID: ABSORBER, 20% OLEUM



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	97.5	See Table 8.10-2
6.0	100	
10.0	100	

8.10 SULFURIC ACID: ABSORBER, 20% OLEUM

NUMBER OF TESTS: Not available

STATISTICS:

Aerodynamic particle diameter (µm)*:	1.0	1.5	2.0
Mean (Cum. %):	26	50	73
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: Acid mist emissions from sulfuric acid plants are a function of type of feed as well as oleum content of product. See AP-42, Section 8.10, Tables 8.10-2 and 8.10-3.

SOURCE OPERATION: Not available

SAMPLING TECHNIQUE: Brink Cascade Impactor

EMISSION FACTOR RATING: E

REFERENCES:

a. *Final Guideline Document: Control Of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units*, EPA-450/2-77-019, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

b. R. W. Kurek, *Special Report On EPA Guidelines For State Emission Standards For Sulfuric Acid Plant Mist*, E. I. du Pont de Nemours and Company, Wilmington, DE, June 1974.

c. J. A. Brink, Jr., "Cascade Impactor For Adiabatic Measurements", *Industrial and Engineering Chemistry, 50*:647, April 1958.

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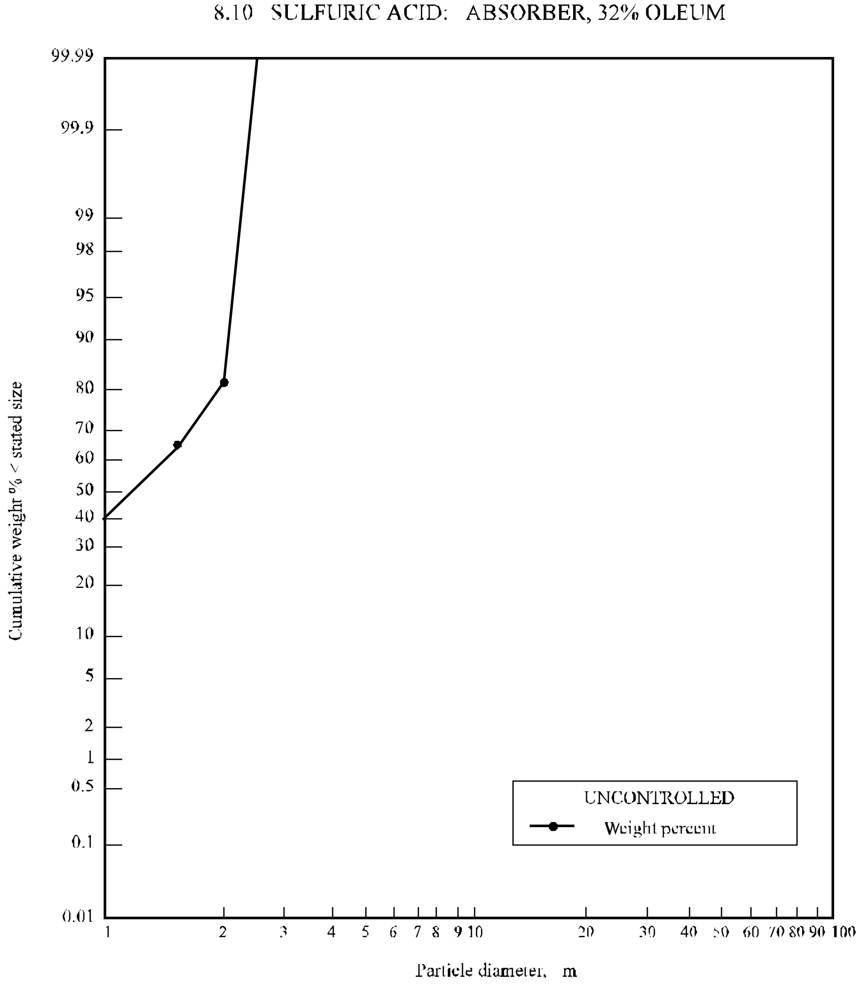
*100% of the particulate is less than 2.5 µm in diameter.

8.10 SULFURIC ACID: ABSORBER, 32% OLEUM



Aerodynamic particle diameter, µm	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	100	See Table 8.10-2
6.0	100	
10.0	100	

8.10 SULFURIC ACID: ABSORBER, 32% OLEUM

NUMBER OF TESTS: Not available

STATISTICS:				
	Aerodynamic particle diameter (µm)*:	1.0	1.5	2.0
	Mean (Cum. %):	41	63	84
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %);			

TOTAL PARTICULATE EMISSION FACTOR: Acid mist emissions from sulfuric acid plants are a function of type of feed as well as oleum content of product. See AP-42, Section 8.10, Table 8.10-2.

SOURCE OPERATION: Not available

SAMPLING TECHNIQUE: Brink Cascade Impactor

EMISSION FACTOR RATING: E

REFERENCES:

a. *Final Guideline Document: Control Of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units*, EPA-450/2-77-019, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

b. R. W. Kurek, *Special Report On EPA Guidelines For State Emission Standards For Sulfuric Acid Plant Mist*, E. I. du Pont de Nemours and Company, Wilmington, DE, June 1974.

c. J. A. Brink, Jr., "Cascade Impactor For Adiabatic Measurements", *Industrial and Engineering Chemistry*, *50*:647, April 1958.

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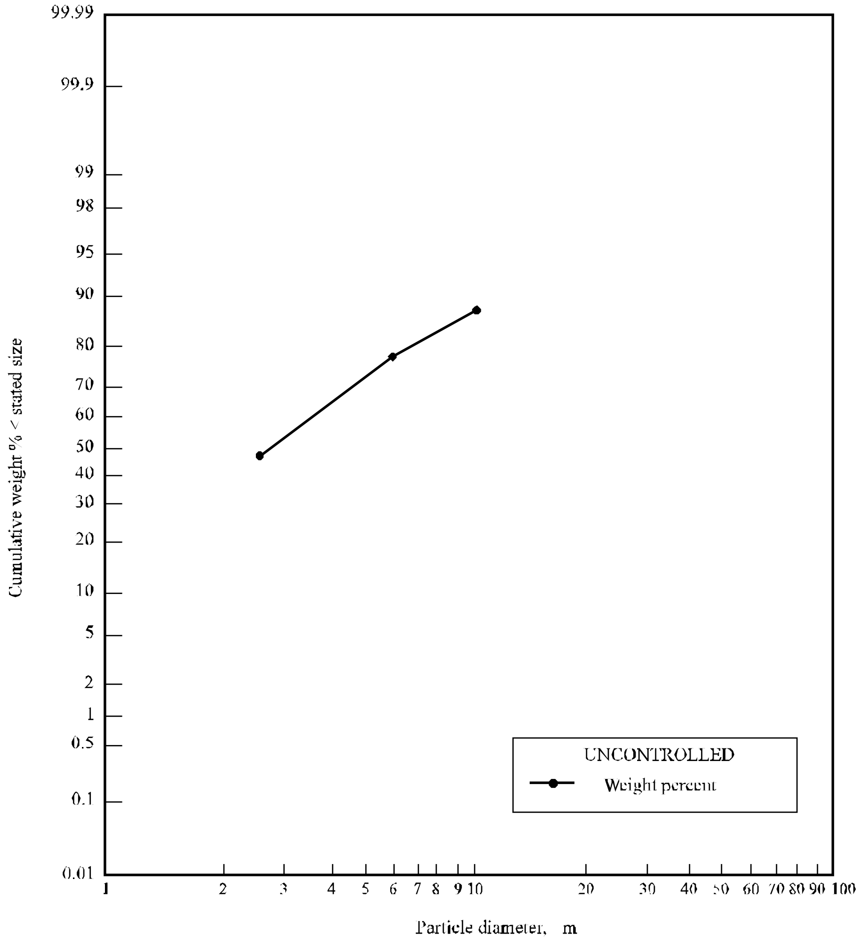
*100% of the particulate is less than 2.5 µm in diameter.

8.10 SULFURIC ACID: SECONDARY ABSORBER


8.10 SULFURIC ACID: SECONDARY ABSORBER

Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	48	Not Available
6.0	78	Not Available
10.0	87	Not Available

8.10 SULFURIC ACID: SECONDARY ABSORBER

NUMBER OF TESTS: Not available

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	48	78	87
	Standard Deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: Acid mist emission factors vary widely according to type of sulfur feedstock. See AP-42 Section 8.10 for guidance.

SOURCE OPERATION: Source is the second absorbing tower in a double absorption sulfuric acid plant. Acid mist loading is 175 - 350 mg/m^3.

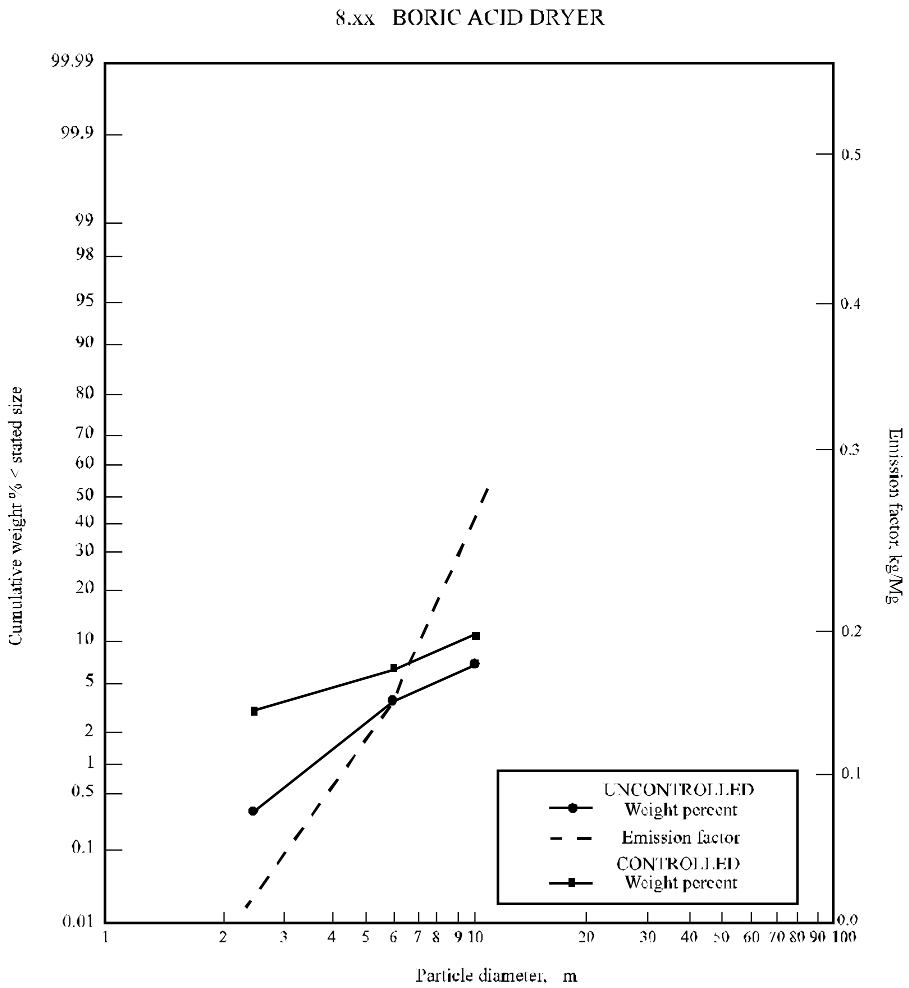
SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: E

REFERENCE:

G. E. Harris and L. A. Rohlack, "Particulate Emissions From Non-fired Sources In Petroleum Refineries: A Review Of Existing Data", Publication No. 4363, American Petroleum Institute, Washington, DC, December 1982.

8.xx BORIC ACID DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	Uncontrolled	Fabric filter	Uncontrolled	Fabric filter controlled
2.5	0.3	3.3	0.01	0.004
6.0	3.3	6.7	0.14	0.007
10.0	6.9	10.6	0.29	0.011

8.xx BORIC ACID DRYER

NUMBER OF TESTS: (a) 1, conducted before controls
(b) 1, conducted after fabric filter control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	0.3	3.3	6.9
Standard Deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	3.3	6.7	10.6
Standard Deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: Before control, 4.15 kg particulate/Mg boric acid dried. After fabric filter control, 0.11 kg particulate/Mg boric acid dried. Emission factors from Reference a.

SOURCE OPERATION: 100% of design process rate.

SAMPLING TECHNIQUE: (a) Joy train with cyclones
(b) SASS train with cyclones

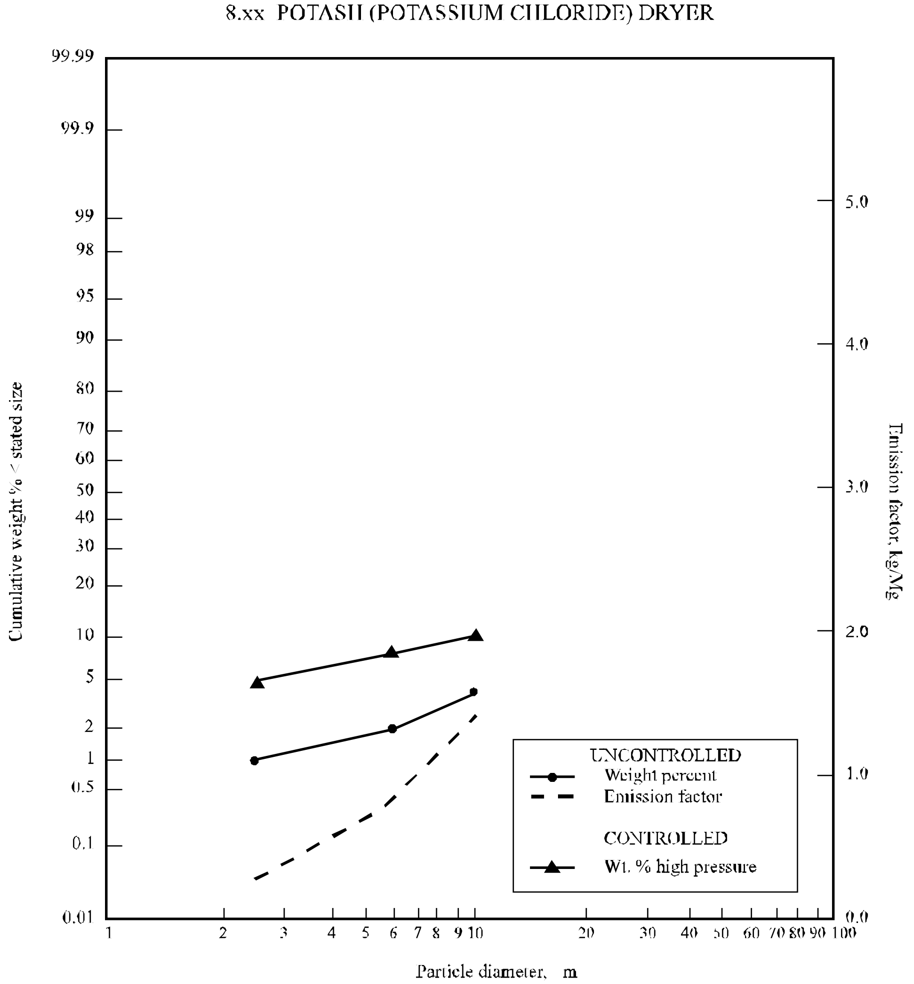
EMISSION FACTOR RATING: E

REFERENCES:

a. H. J. Taback, *Fine Particle Emissions From Stationary And Miscellaneous Sources In The South Coast Air Basin*, PB 293 923/AS, National Technical Information Service, Springfield, VA, February 1979.

b. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 236, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

8.xx POTASH (POTASSIUM CHLORIDE) DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg
	Uncontrolled	High pressure drop venturi scrubber	Uncontrolled
2.5	0.95	5.0	0.31
6.0	2.46	7.5	0.81
10.0	4.07	9.0	1.34

8.xx POTASH (POTASSIUM CHLORIDE) DRYER

NUMBER OF TESTS: (a) 7, before control
(b) 1, after cyclone and high pressure drop venturi scrubber control

STATISTICS:

(a)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	0.95	2.46	4.07
	Standard deviation (Cum. %):	0.68	2.37	4.34
	Min (Cum. %):	0.22	0.65	1.20
	Max (Cum. %):	2.20	7.50	13.50

(b)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	5.0	7.5	9.0
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: Uncontrolled emissions of 33 kg particulate/Mg of potassium chloride product from dryer, from AP-42. It is assumed that particulate emissions from rotary gas-fired dryers for potassium chloride are similar to particulate emissions from rotary steam tube dryers for sodium carbonate.

SOURCE OPERATION: Potassium chloride is dried in a rotary gas-fired dryer.

SAMPLING TECHNIQUE: (a) Andersen Impactor
(b) Andersen Impactor

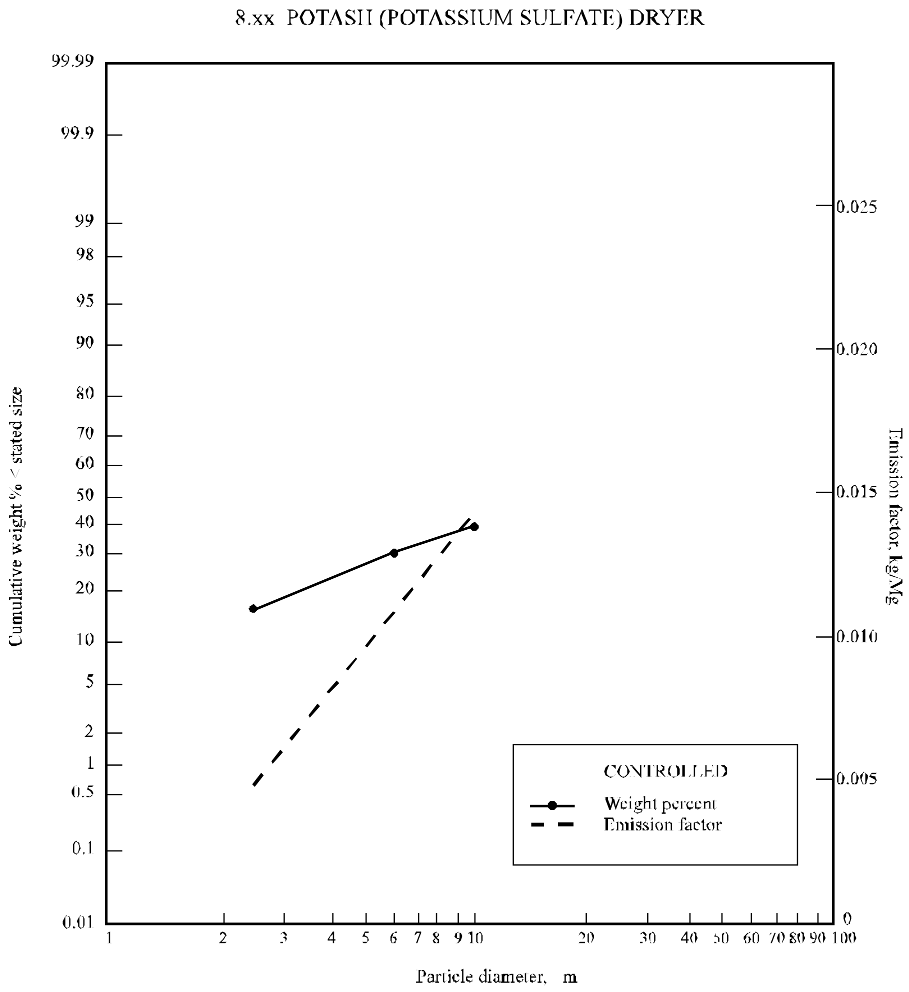
EMISSION FACTOR RATING: C

REFERENCES:

a. *Emission Test Report, Kerr-Magee, Trona, CA*, EMB-79-POT-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

b. *Emission Test Report, Kerr-Magee, Trona, CA*, EMB-79-POT-5, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

8.xx POTASH (POTASSIUM SULFATE) DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Controlled with fabric filter	Controlled with fabric filter
2.5	18.0	0.006
6.0	32.0	0.011
10.0	43.0	0.014

8.xx POTASH (POTASSIUM SULFATE) DRYER

NUMBER OF TESTS: 2, conducted after fabric filter

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	18.0	32.0	43.0
	Standard deviation (Cum. %):	7.5	11.5	14.0
	Min (Cum. %):	10.5	21.0	29.0
	Max (Cum. %):	24.5	44.0	14.0

TOTAL PARTICULATE EMISSION FACTOR: After fabric filter control, 0.033 kg of particulate per Mg of potassium sulfate product from the dryer. Calculated from an uncontrolled emission factor of 33 kg/Mg and control efficiency of 99.9%. From Reference a and AP-42, Section 8.12. It is assumed that particulate emissions from rotary gas-fired dryers are similar to those from rotary steam tube dryers.

SOURCE OPERATION: Potassium sulfate is dried in a rotary gas-fired dryer.

SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: E

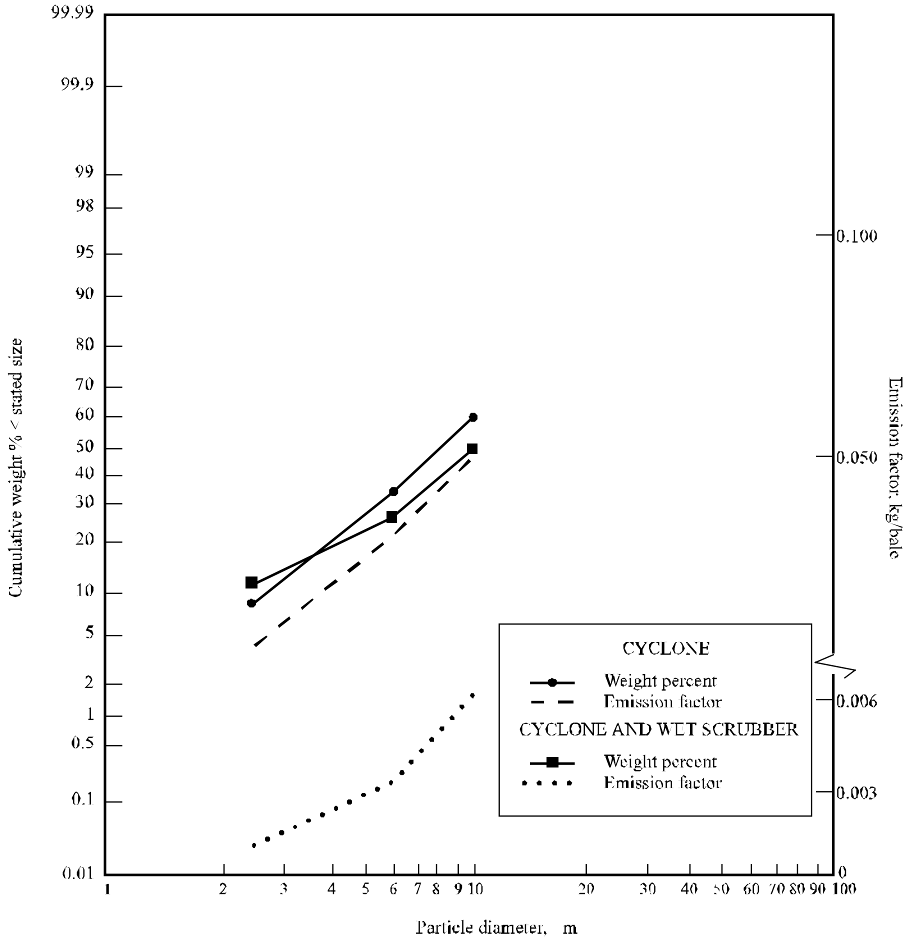
REFERENCES:

a. *Emission Test Report, Kerr-McGee, Trona, CA*, EMB-79-POT-4, Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

b. *Emission Test Report, Kerr-McGee, Trona, CA*, EMB-79-POT-5, Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

9.7 COTTON GINNING: BATTERY CONDENSER

9.7 COTTON GINNING: BATTERY CONDENSER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/bale	
	With cyclone	With cyclone & wet scrubber	With cyclone	With cyclone & wet scrubber
2.5	8	11	0.007	0.001
6.0	33	26	0.028	0.003
10.0	62	52	0.053	0.006

9.7 COTTON GINNING: BATTERY CONDENSER

NUMBER OF TESTS: (a) 2, after cyclone
(b) 3, after wet scrubber

STATISTICS:

(a) Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	8	33	62
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b) Aerodynamic particle diameter (µm)			
Mean (Cum. %.):	11	26	52
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: Particulate emission factor for battery condensers with typical controls is 0.09 kg (0.19 lb)/bale of cotton. Factor is from AP-42, Section 9.7. Factor with wet scrubber after cyclone is 0.012 kg (0.026 lb)/bale. Scrubber efficiency is 86%. From Reference b.

SOURCE OPERATION: During tests, source was operating at 100% of design capacity. No other information on source is available.

SAMPLING TECHNIQUE: UW Mark 3 Impactor

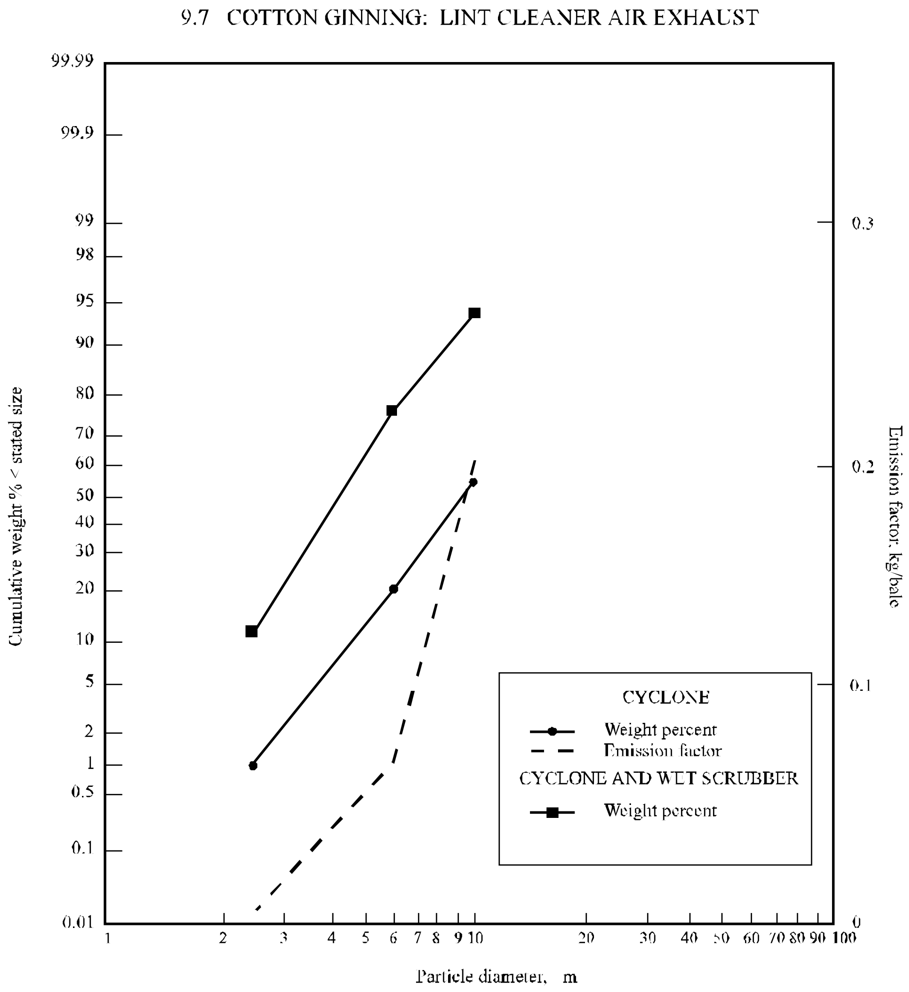
EMISSION FACTOR RATING: E

REFERENCES:

a. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System (FPEIS), Series Report No. 27, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

b. Robert E. Lee, Jr., *et al*., "Concentration And Size Of Trace Metal Emissions From A Power Plant, A Steel Plant, And A Cotton Gin", *Environmental Science And Technology*, *9*(7)643-7, July 1975.

9.7 COTTON GINNING: LINT CLEANER AIR EXHAUST



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/bale
	After cyclone	After cyclone & wet scrubber	Controlled with fabric filter
2.5	1	11	0.004
6.0	20	74	0.07
10.0	54	92	0.20

9.7 COTTON GINNING: LINT CLEANER AIR EXHAUST

NUMBER OF TESTS: (a) 4, after cyclone
(b) 4, after cyclone and wet scrubber

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	1	20	54
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	11	74	92
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.37 kg particulate/bale of cotton processed, with typical controls. Factor is from AP-42, Section 9.7.

SOURCE OPERATION: Testing was conducted while processing both machine-picked and ground-harvested upland cotton, at a production rate of about 6.8 bales/hr.

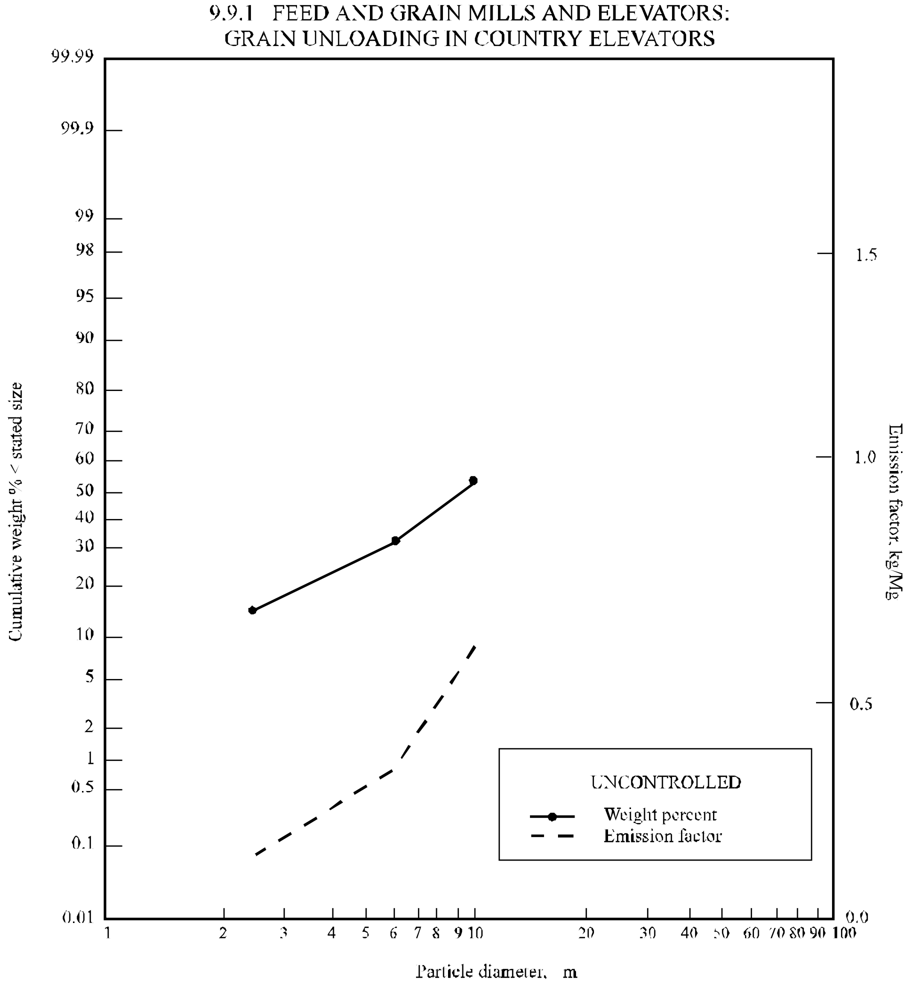
SAMPLING TECHNIQUE: Coulter counter

EMISSION FACTOR RATING: E

REFERENCE:

S. E. Hughs, *et al.*, "Collecting Particles From Gin Lint Cleaner Air Exhausts", presented at the 1981 Winter Meeting of the American Society Of Agricultural Engineers, Chicago, IL, December 1981.

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: GRAIN UNLOADING IN COUNTRY ELEVATORS



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	13.8	0.13
6.0	30.5	0.33
10.0	49.0	0.56

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: GRAIN UNLOADING IN COUNTRY ELEVATORS

NUMBER OF TESTS: 2, conducted before control

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	13.8	30.5	49.0
Standard deviation (Cum. %):	3.3	2.5	—
Min (Cum. %):	10.5	28.0	49.0
Max (Cum. %):	17.0	33.0	49.0

TOTAL PARTICULATE EMISSION FACTOR: 0.3 kg particulate/Mg of grain unloaded, without control. Emission factor from AP-42, Section 9.9.1.

SOURCE OPERATION: During testing, the facility was continuously receiving wheat of low dockage. The elevator is equipped with a dust collection system that serves the dump pit boot and leg.

SAMPLING TECHNIQUE: Nelson Cascade Impactor

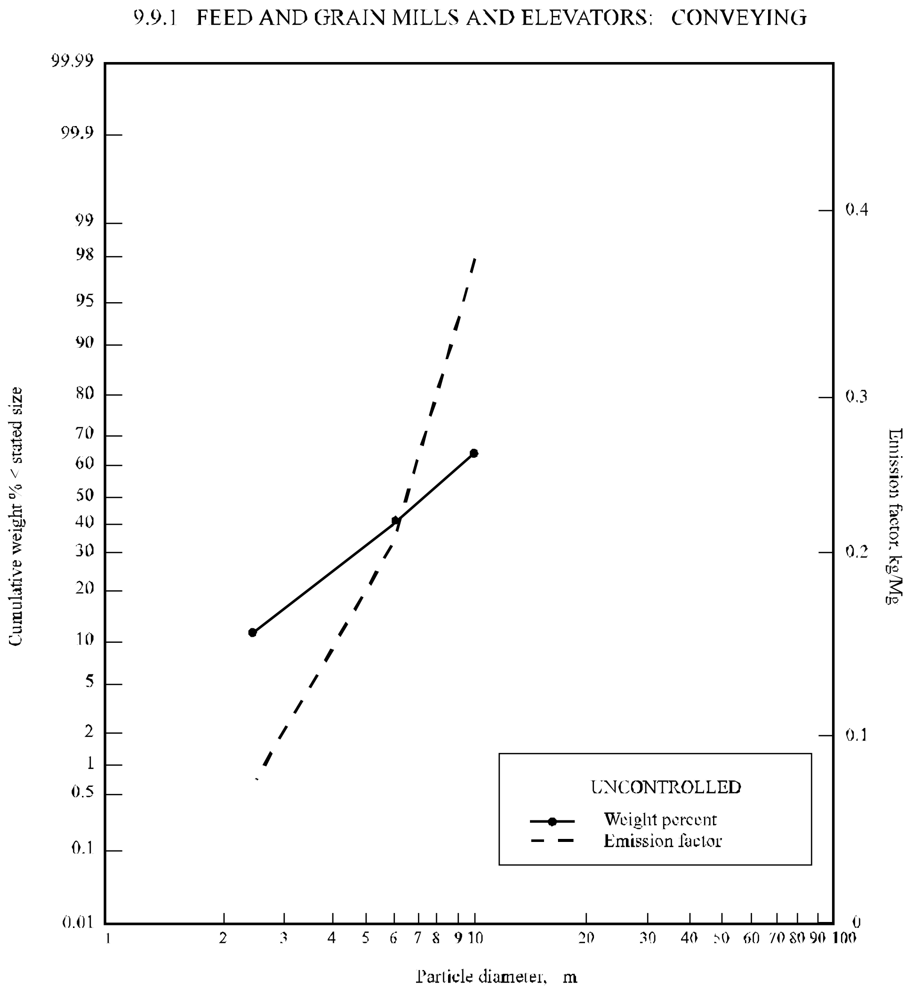
EMISSION FACTOR RATING: D

REFERENCES:

a. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System (FPEIS), Series Report No. 154, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

b. *Emission Test Report, Uniontown Co-op, Elevator No. 2, Uniontown, WA*, Report No. 75-34, Washington State Department Of Ecology, Olympia, WA, October 1975.

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: CONVEYING



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	16.8	0.08
6.0	41.3	0.21
10.0	69.4	0.35

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: CONVEYING

NUMBER OF TESTS: 2, conducted before control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	16.8	41.3	69.4
	Standard deviation (Cum. %):	6.9	16.3	27.3
	Min (Cum. %):	9.9	25.0	42.1
	Max (Cum. %):	23.7	57.7	96.6

TOTAL PARTICULATE EMISSION FACTOR: 0.5 kg particulate/Mg of grain processed, without control. Emission factor from AP-42, Section 9.9.1.

SOURCE OPERATION: Grain is unloaded from barges by "marine leg" buckets lifting the grain from the barges and discharging it onto an enclosed belt conveyer, which transfers the grain to the elevator. These tests measured the combined emissions from the "marine leg" bucket unloader and the conveyer transfer points. Emission rates averaged 1956 lb particulate/hour (0.67 kg/Mg grain unloaded). Grains are corn and soy beans.

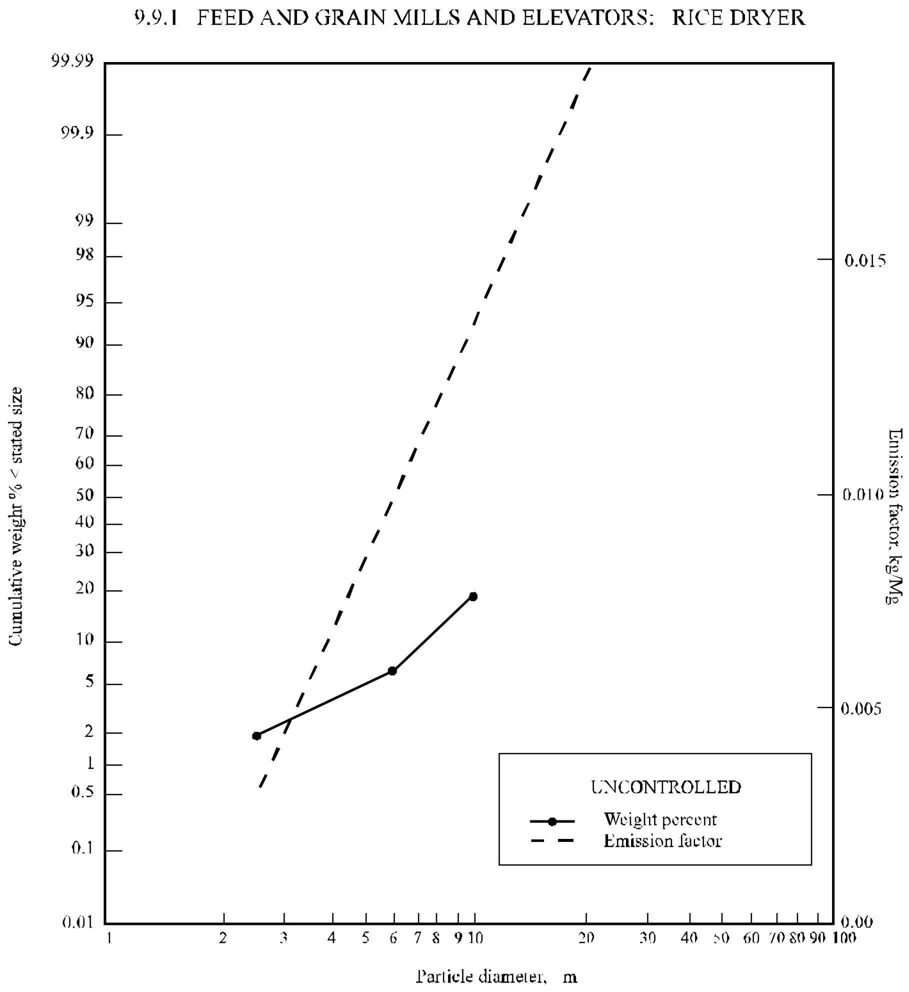
SAMPLING TECHNIQUE: Brink Model B Cascade Impactor

EMISSION FACTOR RATING: D

REFERENCE:

> *Air Pollution Emission Test, Bunge Corporation, Destrehan, LA*, EMB-74-GRN-7, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1974.

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: RICE DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	2.0	0.003
6.0	8.0	0.01
10.0	19.5	0.029

9.9.1 FEED AND GRAIN MILLS AND ELEVATORS: RICE DRYER

NUMBER OF TESTS: 2, conducted on uncontrolled source.

STATISTICS:	Aerodynamic Particle Diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	2.0	8.0	19.5
	Standard Deviation (Cum. %):	—	3.3	9.4
	Min (Cum. %):	2.0	3.1	10.1
	Max (Cum. %):	2.0	9.7	28.9

TOTAL PARTICULATE EMISSION FACTOR: 0.15 kg particulate/Mg of rice dried. Factor from AP-42, Section 9.9.1. Table 9.9.1-1, footnote b for column dryer.

SOURCE OPERATION: Source operated at 100% of rated capacity, drying 90.8 Mg rice/hr. The dryer is heated by 4 9.5-kg/hr burners.

SAMPLING TECHNIQUE: SASS train with cyclones

EMISSION FACTOR RATING: D

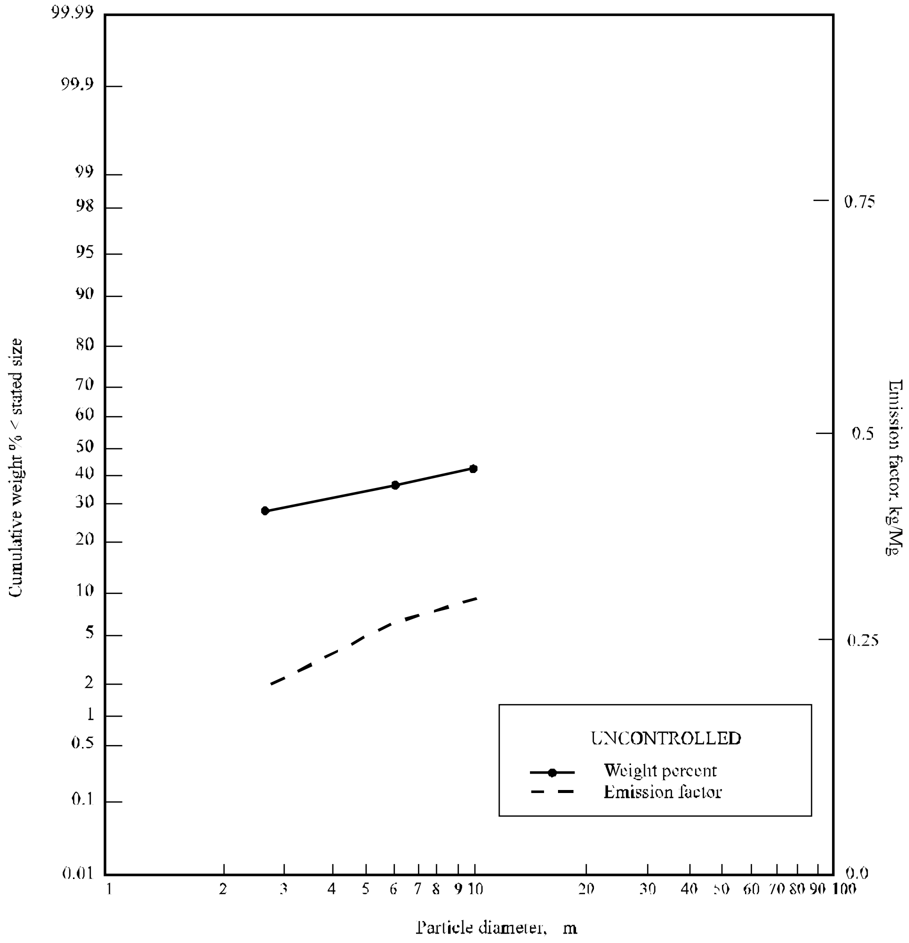
REFERENCES:

a. H. J. Taback, *Fine Particle Emissions From Stationary And Miscellaneous Sources In The South Coast Air Basin*, PB 293 923/AS, National Technical Information Service, Springfield, VA, February 1979.

b. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 228, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

9.9.2 FEED AND GRAIN MILLS AND ELEVATORS: CEREAL DRYER

9.9.2 FEED AND GRAIN MILLS AND ELEVATORS: CEREAL DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	27	0.20
6.0	37	0.28
10.0	44	0.33

9.9.2 FEED AND GRAIN MILLS AND ELEVATORS: CEREAL DRYER

NUMBER OF TESTS: 6, conducted before controls

STATISTICS: Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	27	37	44
Standard deviation (Cum. %):	17	18	20
Min (Cum. %):	13	20	22
Max (Cum. %):	47	56	58

TOTAL PARTICULATE EMISSION FACTOR: 0.75 kg particulate/Mg cereal dried. Factor taken from AP-42, Section 9.9.2.

SOURCE OPERATION: Confidential

SAMPLING TECHNIQUE: Andersen Mark III Impactor

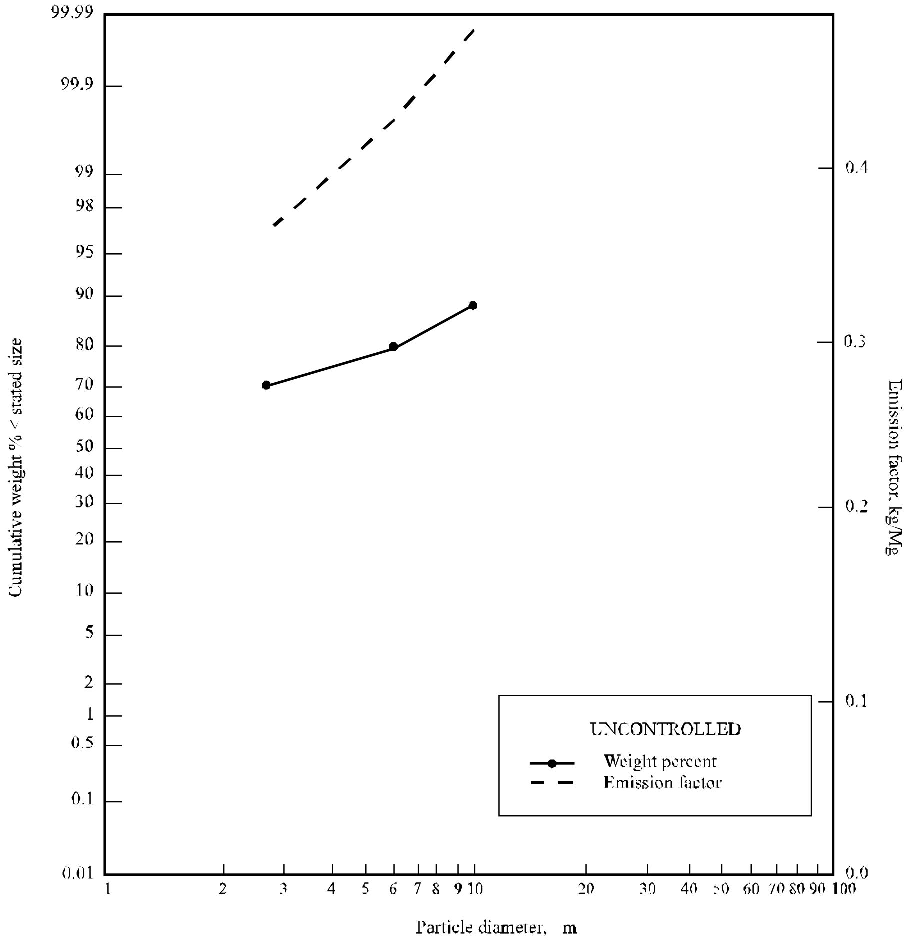
EMISSION FACTOR RATING: C

REFERENCE:

Confidential test data from a major grain processor, PEI Associates, Inc., Golden, CO, January 1985.

9.9.4 ALFALFA DEHYDRATING: DRUM DRYER PRIMARY CYCLONE

9.9.4 ALFALFA DEHYDRATING: DRUM DRYER PRIMARY CYCLONE



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	70.6	3.5
6.0	82.7	4.1
10.0	90.0	4.5

9.9.4 ALFALFA DEHYDRATING: DRUM DRYER PRIMARY CYCLONE

NUMBER OF TESTS: 1, conducted before control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	70.6	82.7	90.0
	Standard deviation (Cum. %)			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 5.0 kg particulate/Mg alfalfa pellets before control. Factor from AP-42, Section 9.9.4.

SOURCE OPERATION: During this test, source dried 10 tons of alfalfa/hour in a direct-fired rotary dryer.

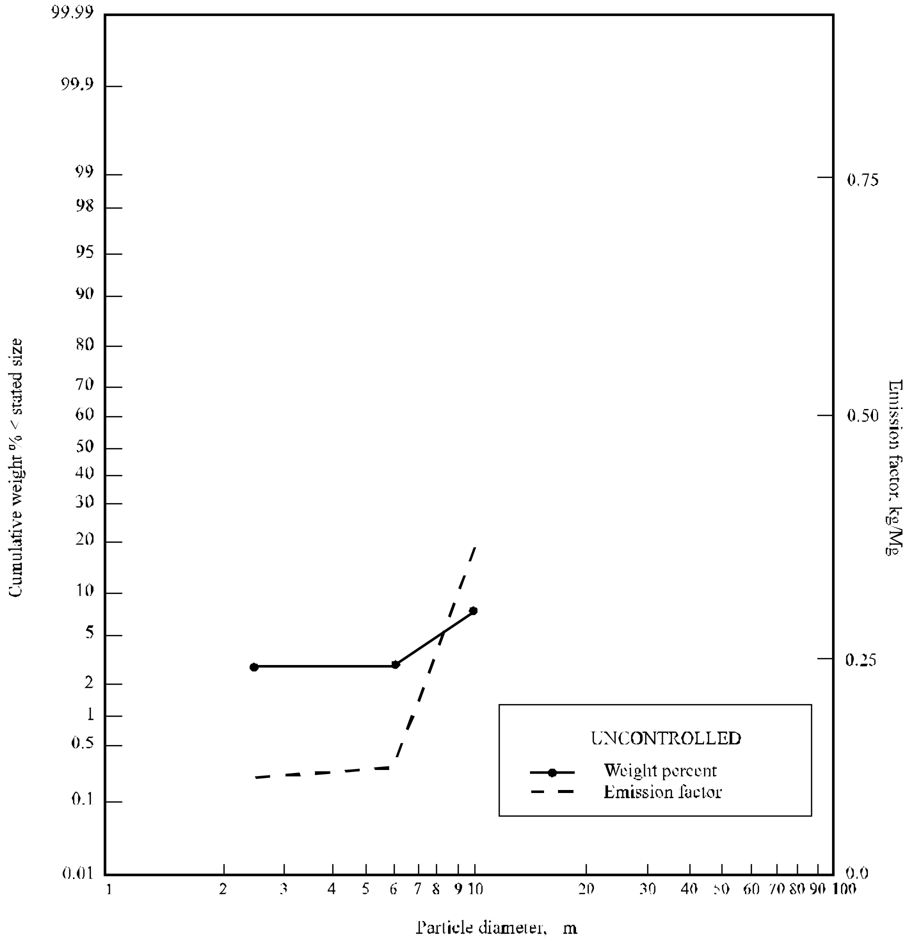
SAMPLING TECHNIQUE: Nelson Cascade Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 152, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

9.9.xx FEED AND GRAIN MILLS AND ELEVATORS: CAROB KIBBLE ROASTER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	3.0	0.11
6.0	3.2	0.12
10.0	9.6	0.36

9.9.xx FEED AND GRAIN MILLS AND ELEVATORS: CAROB KIBBLE ROASTER

NUMBER OF TESTS: 1, conducted before controls

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	3.0	3.2	9.6
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 3.8 kg/Mg carob kibble roasted. Factor from Reference a, p. 4-175.

SOURCE OPERATION: Source roasts 300 kg carob pods per hour, 100% of the design rate. Roaster heat input is 795 kJ/hr of natural gas.

SAMPLING TECHNIQUE: Joy train with 3 cyclones

EMISSION FACTOR RATING: E

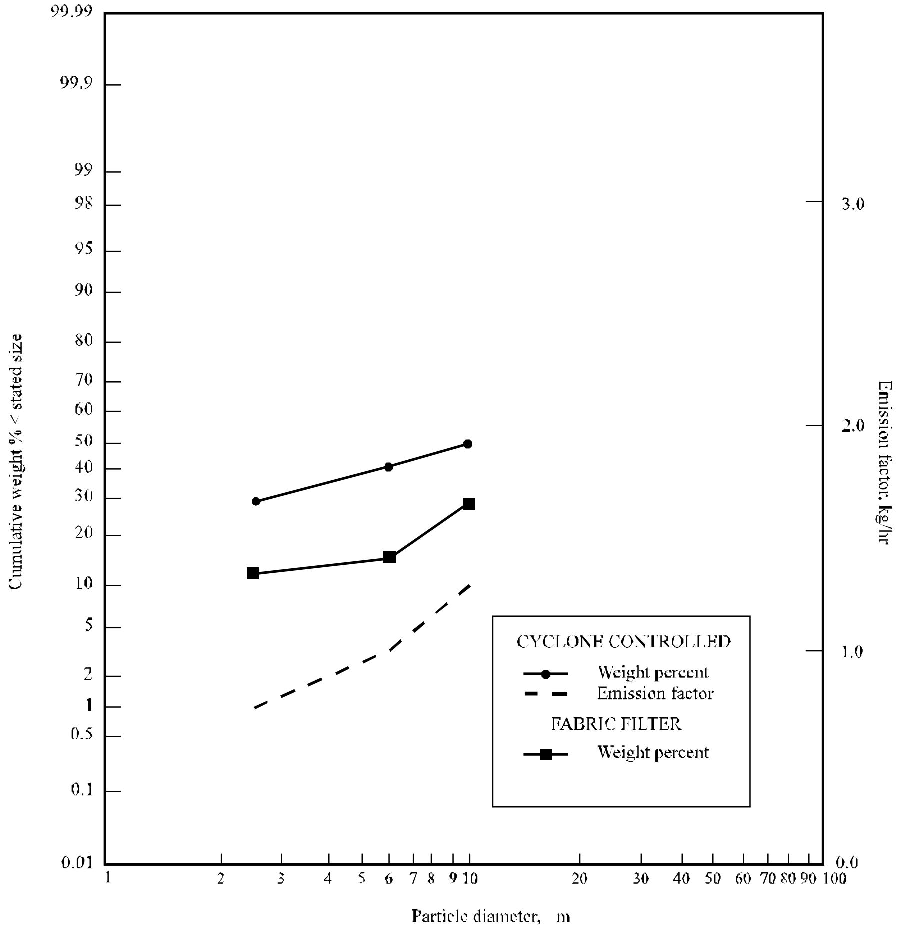
REFERENCES:

a. H. J. Taback, *Fine Particle Emissions From Stationary And Miscellaneous Sources In The South Coast Air Basin*, PB 293 923/AS, National Technical Information Service, Springfield, VA, February 1979.

b. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System Series, Report No. 229, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

10.5 WOODWORKING WASTE COLLECTION OPERATIONS: BELT SANDER HOOD EXHAUST CYCLONE

10.5 WOODWORKING WASTE COLLECTION OPERATIONS:
BELT SANDER HOOD EXHAUST CYCLONE



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/hr of cyclone operation
	Cyclone	After cyclone and fabric filter	After cyclone collector
2.5	29.5	14.3	0.68
6.0	42.7	17.3	0.98
10.0	52.9	32.1	1.22

10.5 WOODWORKING WASTE COLLECTION OPERATIONS: BELT SANDER HOOD EXHAUST CYCLONE

NUMBER OF TESTS: (a) 1, conducted after cyclone control
(b) 1, after cyclone and fabric filter control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	29.5	42.7	52.9
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %.):	14.3	17.3	32.1
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 2.3 kg particulate/hr of cyclone operation. For cyclone-controlled source, this emission factor applies to typical large diameter cyclones into which wood waste is fed directly, not to cyclones that handle waste previously collected in cyclones. If baghouses are used for waste collection, particulate emissions will be negligible. Accordingly, no emission factor is provided for the fabric filter-controlled source. Factors from AP-42.

SOURCE OPERATION: Source was sanding 2-ply panels of mahogany veneer, at 100% of design process rate of 1110 m^2/hr.

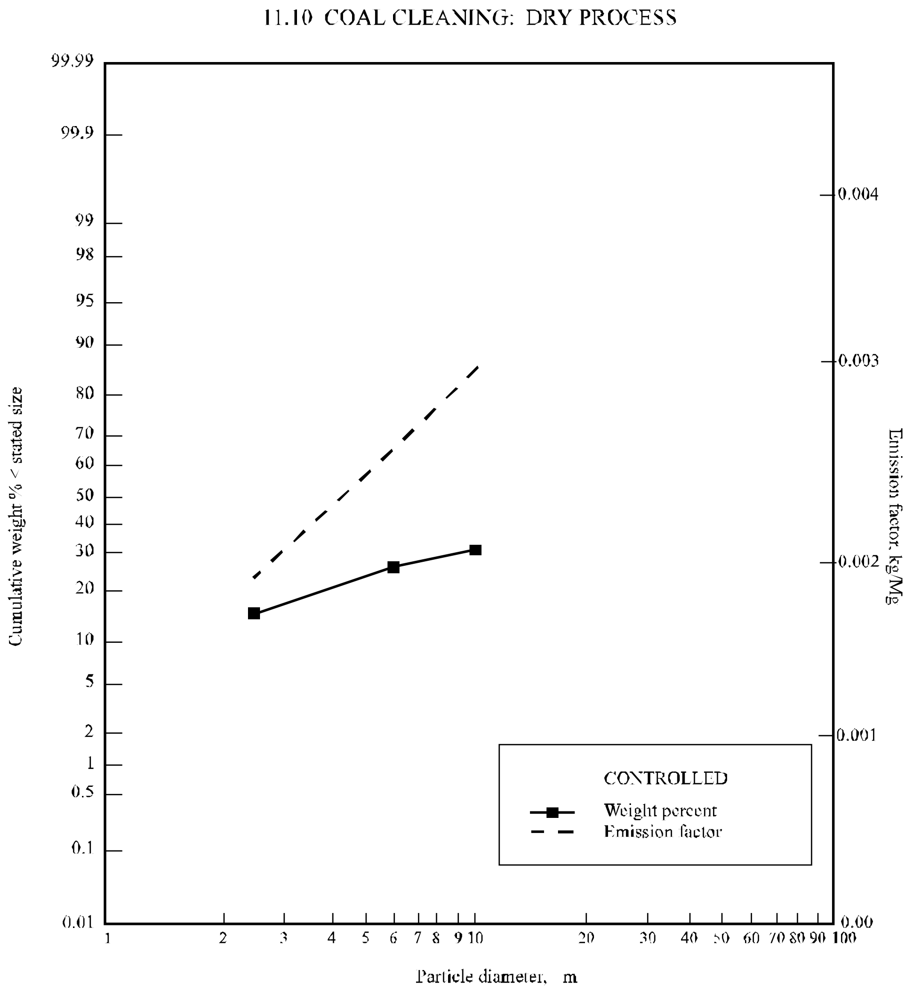
SAMPLING TECHNIQUE: (a) Joy train with 3 cyclones
(b) SASS train with cyclones

EMISSION FACTOR RATING: E

REFERENCE:

Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 238, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

11.10 COAL CLEANING: DRY PROCESS



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After fabric filter control	After fabric filter control
2.5	16	0.002
6.0	26	0.0025
10.0	31	0.003

11.10 COAL CLEANING: DRY PROCESS

NUMBER OF TESTS: 1, conducted after fabric filter control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	16	26	31
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.01 kg particulate/Mg of coal processed. Emission factor is calculated from data in AP-42, Section 11.10, assuming 99% particulate control by fabric filter.

SOURCE OPERATION: Source cleans coal with the dry (air table) process. Average coal feed rate during testing was 70 tons/hr/table.

SAMPLING TECHNIQUE: Coulter counter

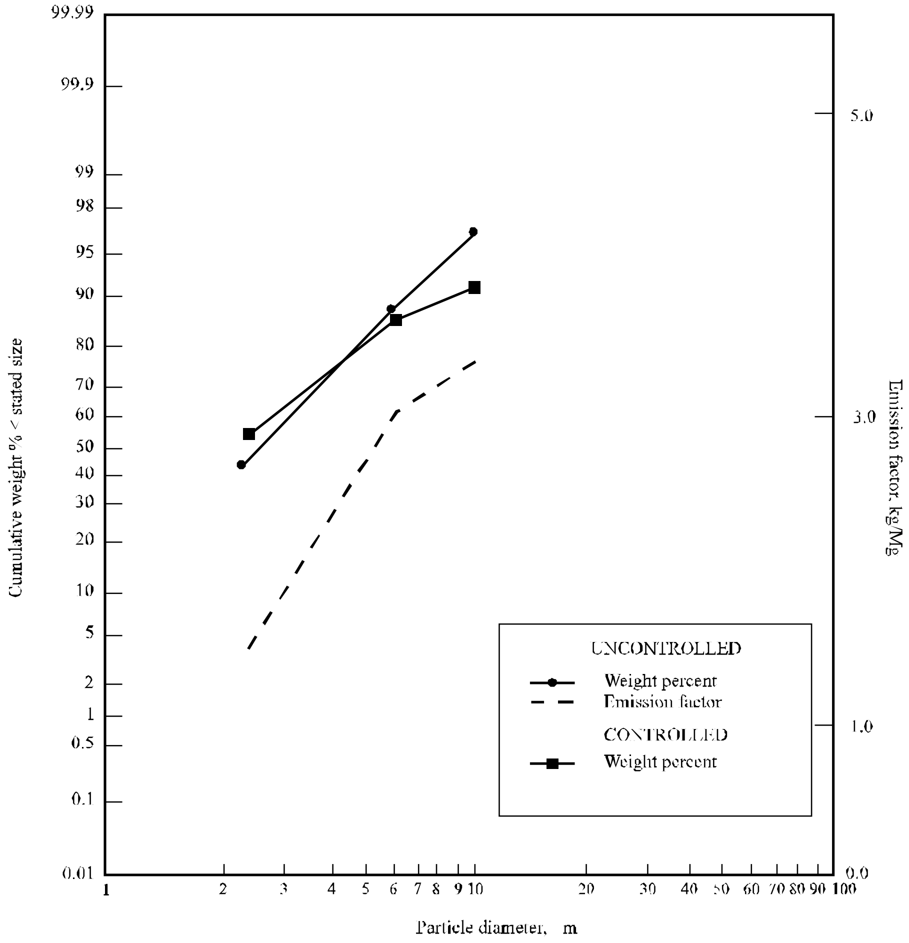
EMISSION FACTOR RATING: E

REFERENCE:

R. W. Kling, *Emissions From The Florence Mining Company Coal Processing Plant At Seward, PA*, Report No. 72-CI-4, York Research Corporation, Stamford, CT, February 1972.

11.10 COAL CLEANING: THERMAL DRYER

11.10 COAL CLEANING: THERMAL DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	Uncontrolled	After wet scrubber	Uncontrolled	After wet scrubber
2.5	42	53	1.47	0.016
6.0	86	85	3.01	0.026
10.0	96	91	3.36	0.027

11.10 COAL CLEANING: THERMAL DRYER

NUMBER OF TESTS: (a) 1, conducted before control
(b) 1, conducted after wet scrubber control

STATISTICS: (a)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	42	86	96
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			
(b)	Aerodynamic particle diamter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	53	85	91
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 3.5 kg particulate/Mg of coal processed (after cyclone) before wet scrubber control. After wet scrubber control, 0.03 kg/Mg. These are site-specific emission factors and are calculated from process data measured during source testing.

SOURCE OPERATION: Source operates a thermal dryer to dry coal cleaned by wet cleaning process. Combustion zone in the thermal dryer is about 1000°F, and the air temperature at the dryer exit is about 125°F. Coal processing rate is about 450 tons per hour. Product is collected in cyclones.

SAMPLING TECHNIQUE: (a) Coulter counter
(b) Each sample was dispersed with aerosol OT, and further dispersed using an ultrasonic bath. Isoton was the electrolyte used.

EMISSION FACTOR RATING: E

REFERENCE:

R. W. Kling, *Emission Test Report, Island Creek Coal Company Coal Processing Plant, Vansant, Virgina*, Report No. Y-7730-H, York Research Corporation, Stamford, CT, February 1972.

11.10 COAL PROCESSING: THERMAL INCINERATOR

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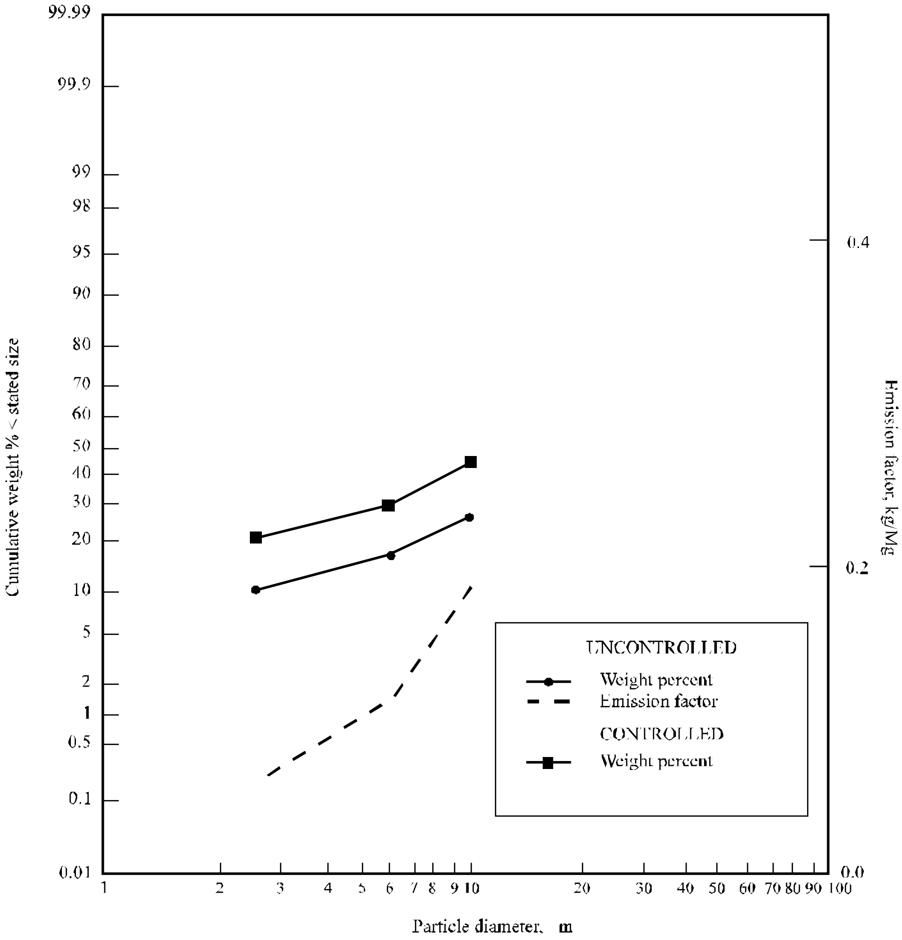


Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg
	Uncontrolled	Cyclone controlled	Uncontrolled
2.5	9.6	21.3	0.07
6.0	17.5	31.8	0.12
10.0	26.5	43.7	0.19

11.10 COAL PROCESSING: THERMAL INCINERATOR

NUMBER OF TESTS: (a) 2, conducted before controls
(b) 2, conducted after multicyclone control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	9.6	17.5	26.5
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diamter (µm):	2.5	6.0	10.0
Mean (Cum. %):	26.4	35.8	46.6
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.7 kg particulate/Mg coal dried, before multicyclone control. Factor from AP-42, Section 11.10.

SOURCE OPERATION: Source is a thermal incinerator controlling gaseous emissions from a rotary kiln drying coal. No additional operating data are available.

SAMPLING TECHNIQUE: Andersen Mark III Impactor

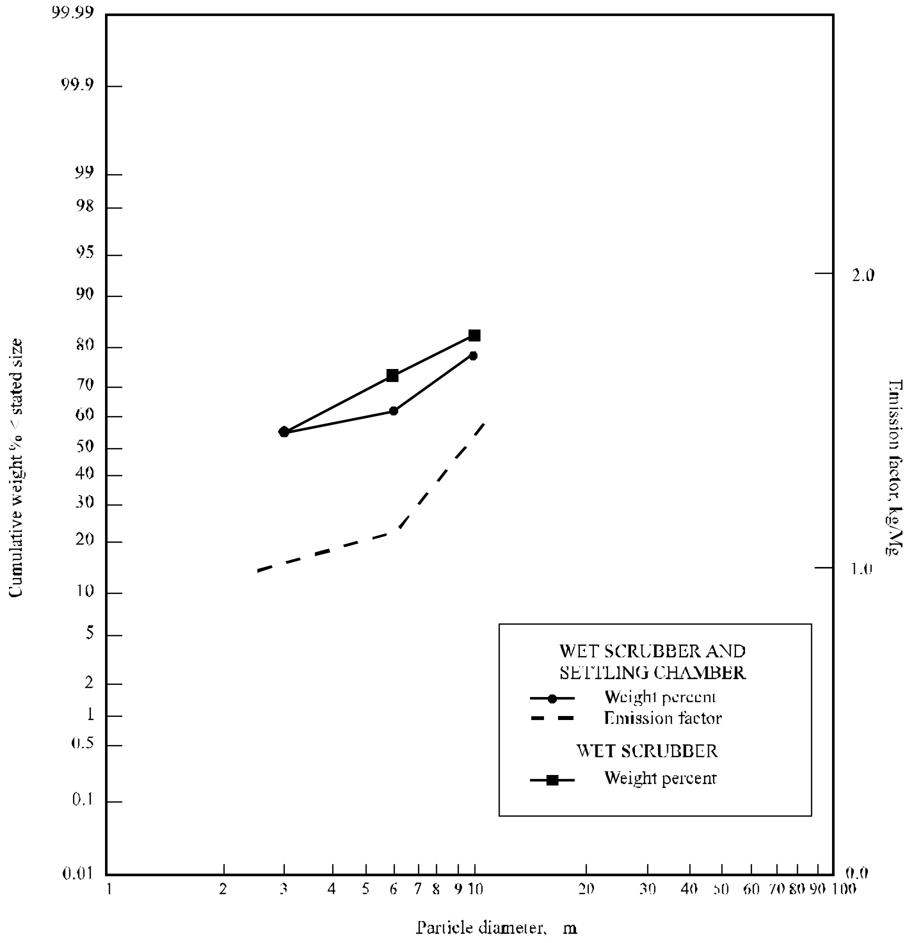
EMISSION FACTOR RATING: D

REFERENCE:

> Confidential test data from a major coal processor, PEI Associates, Inc., Golden, CO, January 1985.

11.20 LIGHTWEIGHT AGGREGATE (CLAY): COAL-FIRED ROTARY KILN

11.20 LIGHTWEIGHT AGGREGATE (CLAY): COAL-FIRED ROTARY KILN



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg
	Wet scrubber and settling chamber	Wet scrubber	Wet scrubber and settling chamber
2.5	55	55	0.97
6.0	65	75	1.15
10.0	81	84	1.43

11.20 LIGHTWEIGHT AGGREGATE (CLAY): COAL-FIRED ROTARY KILN

NUMBER OF TESTS: (a) 4, conducted after wet scrubber control
(b) 8, conducted after settling chamber and wet scrubber control

STATISTICS: (a)

Aerodynamic particle diameter, (µm):	2.5	6.0	10.0
Mean (Cum. %):	55	75	84
Standard Deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diameter, (µm):	2.5	6.0	10.0
Mean (Cum. %):	55	65	81
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 1.77 kg particulate/Mg of clay processed, after control by settling chamber and wet scrubber. Calculated from data in Reference c.

SOURCE OPERATION: Sources produce lightweight clay aggregate in pulverized coal-fired rotary kilns. Kiln capacity for Source b is 750 tons/day, and operation is continuous.

SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: C

REFERENCES:

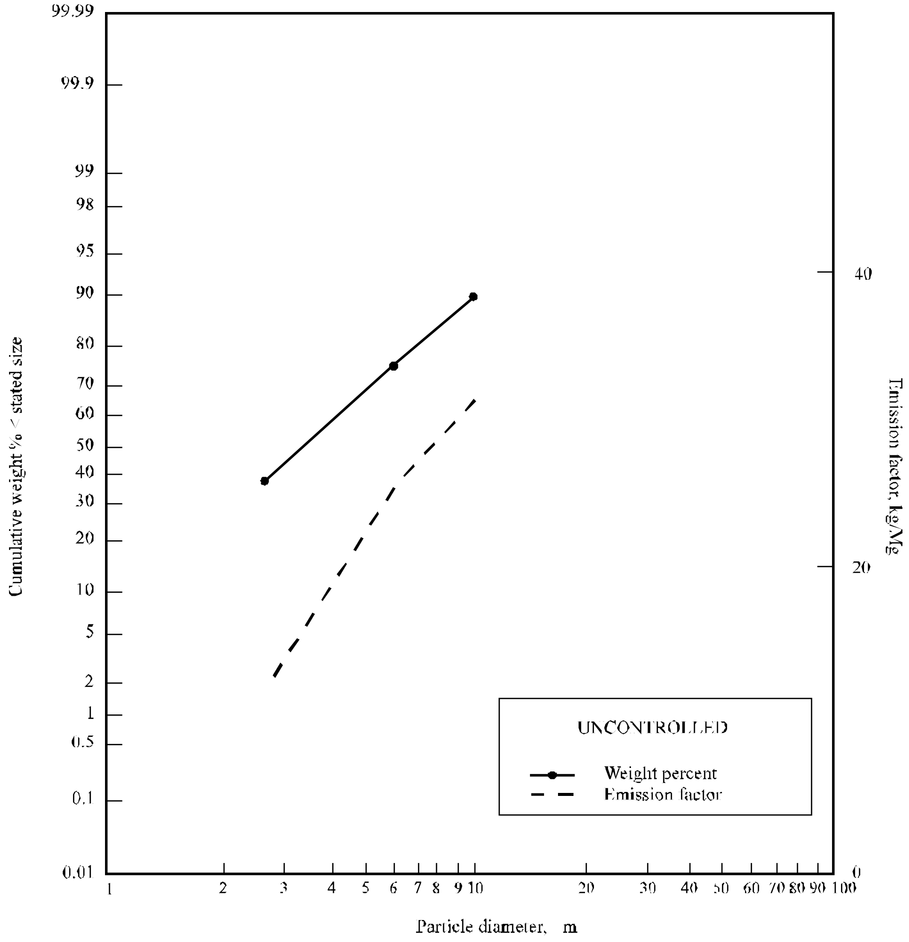
a. *Emission Test Report, Lightweight Aggregate Industry, Texas Industries, Inc.*, EMB-80-LWA-3, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

b. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 341, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

c. *Emission Test Report, Lightweight Aggregate Industry, Arkansas Lightweight Aggregate Corporation*, EMB-80-LWA-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

11.20 LIGHTWEIGHT AGGREGATE (CLAY): DRYER

11.20 LIGHTWEIGHT AGGREGATE (CLAY): DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	37.2	13.0
6.0	74.8	26.2
10.0	89.5	31.3

11.20 LIGHTWEIGHT AGGREGATE (CLAY): DRYER

NUMBER OF TESTS: 5, conducted before controls

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	37.2	74.8	89.5
Standard deviation (Cum. %):	3.4	5.6	3.6
Min (Cum. %):	32.3	68.9	85.5
Max (Cum. %):	41.0	80.8	92.7

TOTAL PARTICULATE EMISSION FACTOR: 65 kg/Mg clay feed to dryer. From AP-42, Section 11.20.

SOURCE OPERATION: No information on source operation is available

SAMPLING TECHNIQUE: Brink Impactor

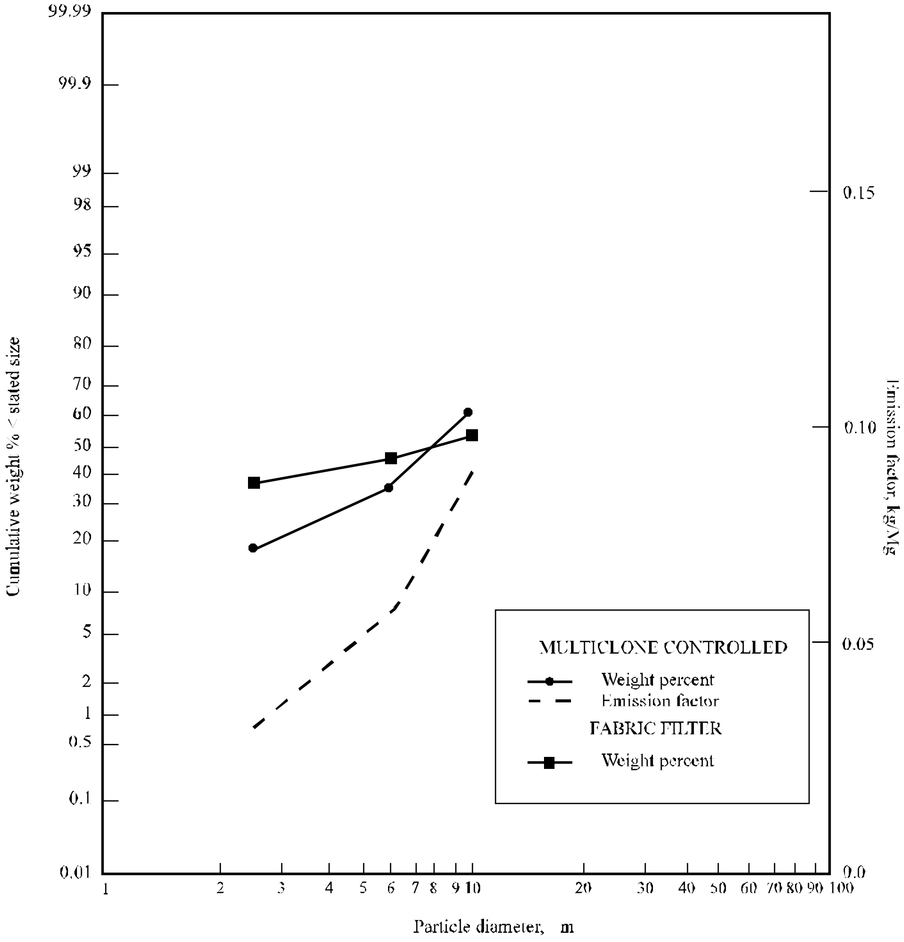
EMISSION FACTOR RATING: C

REFERENCE:

Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 88, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

11.20 LIGHTWEIGHT AGGREGATE (CLAY): RECIPROCATING GRATE CLINKER COOLER

11.20 LIGHTWEIGHT AGGREGATE (CLAY): RECIPROCATING GRATE CLINKER COOLER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg
	Multiclone	Fabric filter	Multiclone
2.5	19.3	39	0.03
6.0	38.1	48	0.06
10.0	56.1	54	0.09

11.20 LIGHTWEIGHT AGGREGATE (CLAY): RECIPROCATING GRATE CLINKER COOLER

NUMBER OF TESTS: (a) 12, conducted after Multicyclone control
(b) 4, conducted after Multicyclone and fabric filter control

STATISTICS:

(a)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	19.3	38.1	56.7
	Standard deviation (Cum. %):	7.9	14.9	17.9
	Min (Cum. %):	9.3	18.6	29.2
	Max (Cum. %):	34.6	61.4	76.6
(b)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	39	48	54
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.157 kg particulate/Mg clay processed, after multicyclone control. Factor calculated from data in Reference b. After fabric filter control, particulate emissions are negligible.

SOURCE OPERATION: Sources produce lightweight clay aggregate in a coal-fired rotary kiln and reciprocating grate clinker cooler.

SAMPLING TECHNIQUE: (a) Andersen Impactor
(b) Andersen Impactor

EMISSION FACTOR RATING: C

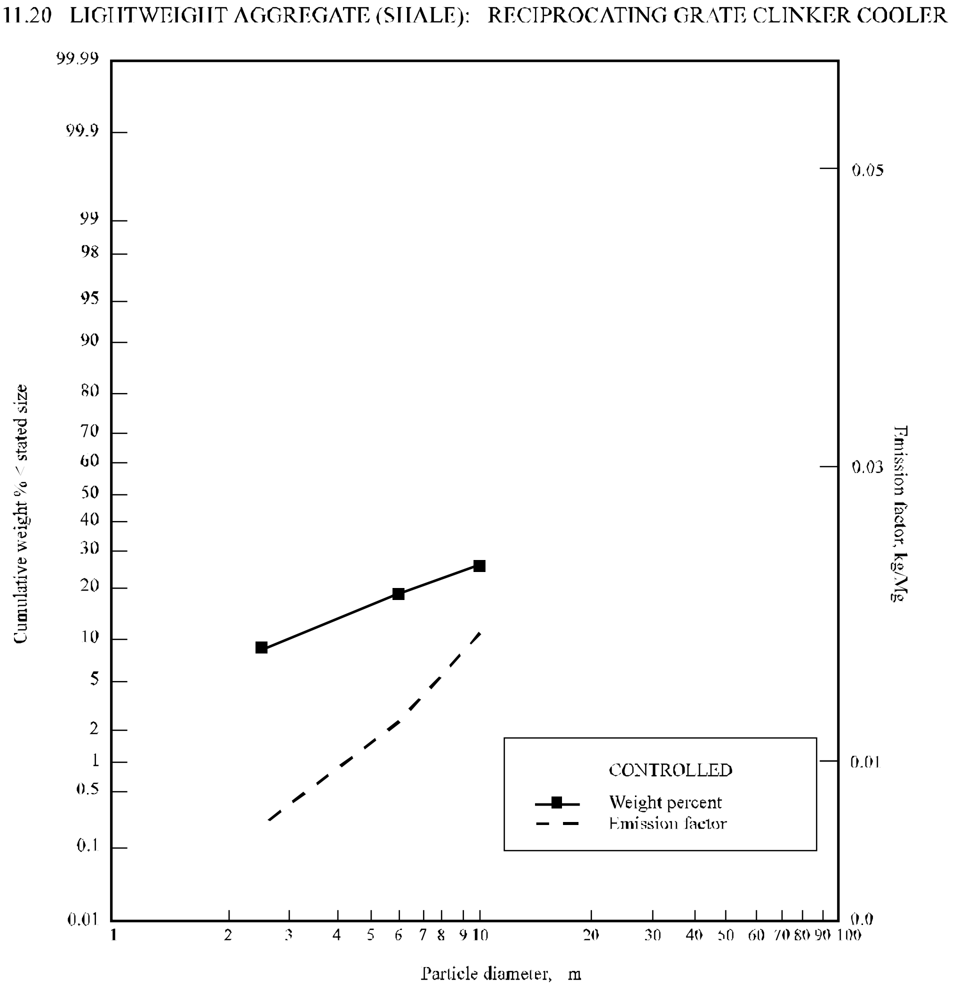
REFERENCES:

a. *Emission Test Report, Lightweight Aggregate Industry, Texas Industries, Inc.*, EMB-80-LWA-3, in U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

b. *Emission Test Report, Lightweight Aggregate Industry, Arkansas Lightweight Aggregate Corporation*, EMB-80-LWA-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

c. Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 342, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

11.20 LIGHTWEIGHT AGGREGATE (SHALE): RECIPROCATING GRATE CLINKER COOLER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Settling chamber control	Settling chamber control
2.5	8.2	0.007
6.0	17.6	0.014
10.0	25.6	0.020

11.20 LIGHTWEIGHT AGGREGATE (SHALE): RECIPROCATING GRATE CLINKER COOLER

NUMBER OF TESTS: 4, conducted after settling chamber control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	8.2	17.6	25.6
	Standard deviation (Cum. %):	4.3	2.8	1.7
	Min (Cum. %):	4.0	15.0	24.0
	Max (Cum. %):	14.0	21.0	28.0

TOTAL PARTICULATE EMISSION FACTOR: 0.08 kg particulate/Mg of aggregate produced. Factor calculated from data in reference.

SOURCE OPERATION: Source operates 2 kilns to produce lightweight shale aggregate, which is cooled and classified on a reciprocating grate clinker cooler. Normal production rate of the tested kiln is 23 tons/hr, about 66% of rated capacity. Kiln rotates at 2.8 rpm. Feed end temperature is 1100°F.

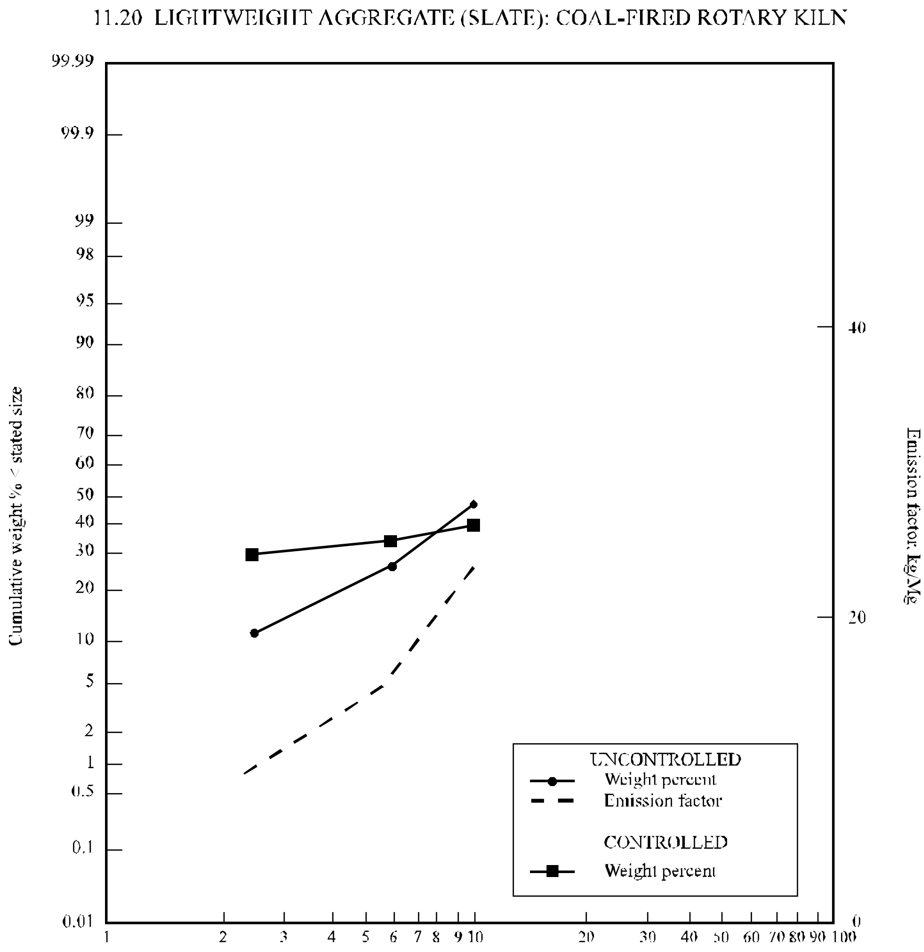
SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: B

REFERENCE:

Emission Test Report, Lightweight Aggregate Industry, Vulcan Materials Company, EMB-80-LWA-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

11.20 LIGHTWEIGHT AGGREGATE (SLATE): COAL-FIRED ROTARY KILN



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	Without controls	After wet scrubber control	Without controls	After wet scrubber control
2.5	13	33	7.3	0.59
6.0	29	36	16.2	0.65
10.0	42	39	23.5	0.70

11.20 LIGHTWEIGHT AGGREGATE (SLATE): COAL-FIRED ROTARY KILN

NUMBER OF TESTS: (a) 3, conducted before control
(b) 5, conducted after wet scrubber control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	13.0	29.0	42.0
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	33.0	36.0	39.0
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: For uncontrolled source, 56.0 kg particulate/Mg of feed. After wet scrubber control, 1.8 kg particulate/Mg of feed. Factors are calculated from data in reference.

SOURCE OPERATION: Source produces lightweight aggregate from slate in coal-fired rotary kiln and reciprocating grate clinker cooler. During testing source was operating at a feed rate of 33 tons/hr, 83% rated capacity. Firing zone temperatures are about 2125°F and kiln rotates at 3.25 rpm.

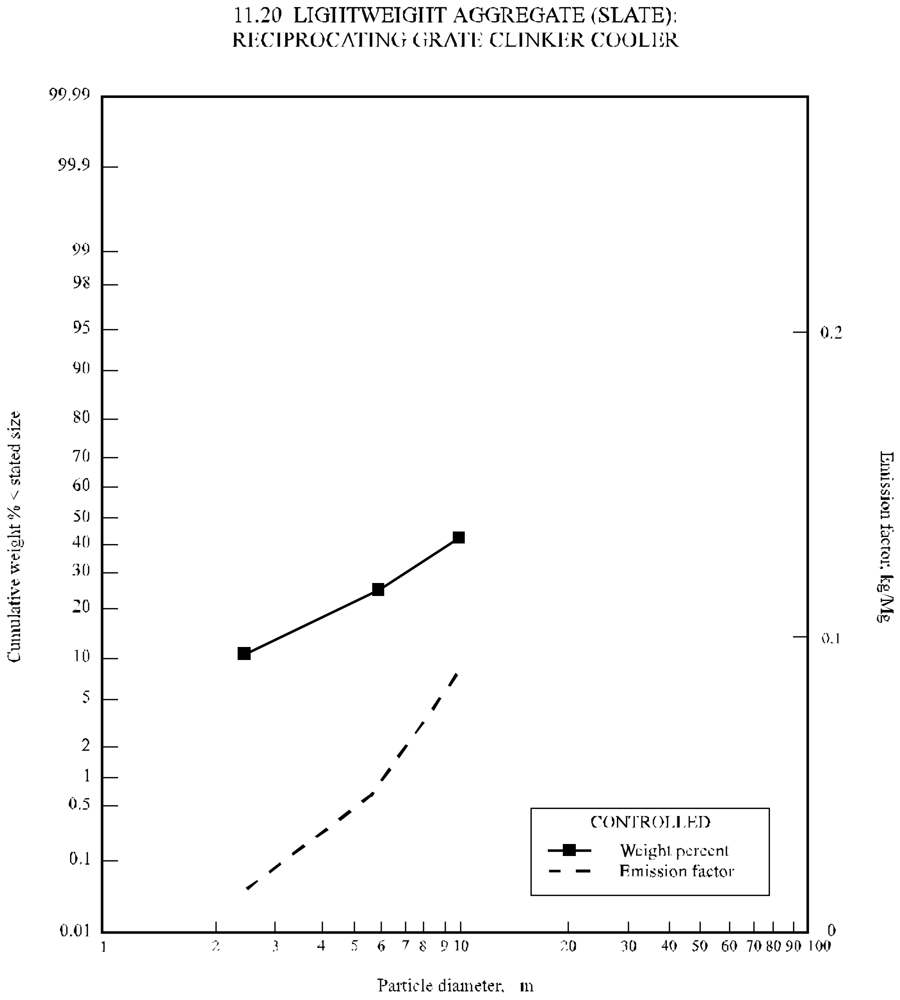
SAMPLING TECHNIQUE: (a) Bacho
(b) Andersen Impactor

EMISSION FACTOR RATING: C

REFERENCE:

Emission Test Report, Lightweight Aggregate Industry, Galite Corporation, EMB-80-LWA-6, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1982.

11.20 LIGHTWEIGHT AGGREGATE (SLATE): RECIPROCATING GRATE CLINKER COOLER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After settling chamber control	After settling chamber control
2.5	9.8	0.02
6.0	23.6	0.05
10.0	41.0	0.09

11.20 LIGHTWEIGHT AGGREGATE (SLATE): RECIPROCATING GRATE CLINKER COOLER

NUMBER OF TESTS: 5, conducted after settling chamber control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	9.8	23.6	41.0
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.22 kg particulate/Mg of raw material feed. Factor calculated from data in reference.

SOURCE OPERATION: Source produces lightweight slate aggregate in a coal-fired kiln and a reciprocating grate clinker cooler. During testing, source was operating at a feed rate of 33 tons/hr, 83% of rated capacity. Firing zone temperatures are about 2125°F, and kiln rotates at 3.25 rpm.

SAMPLING TECHNIQUE: Andersen Impactor

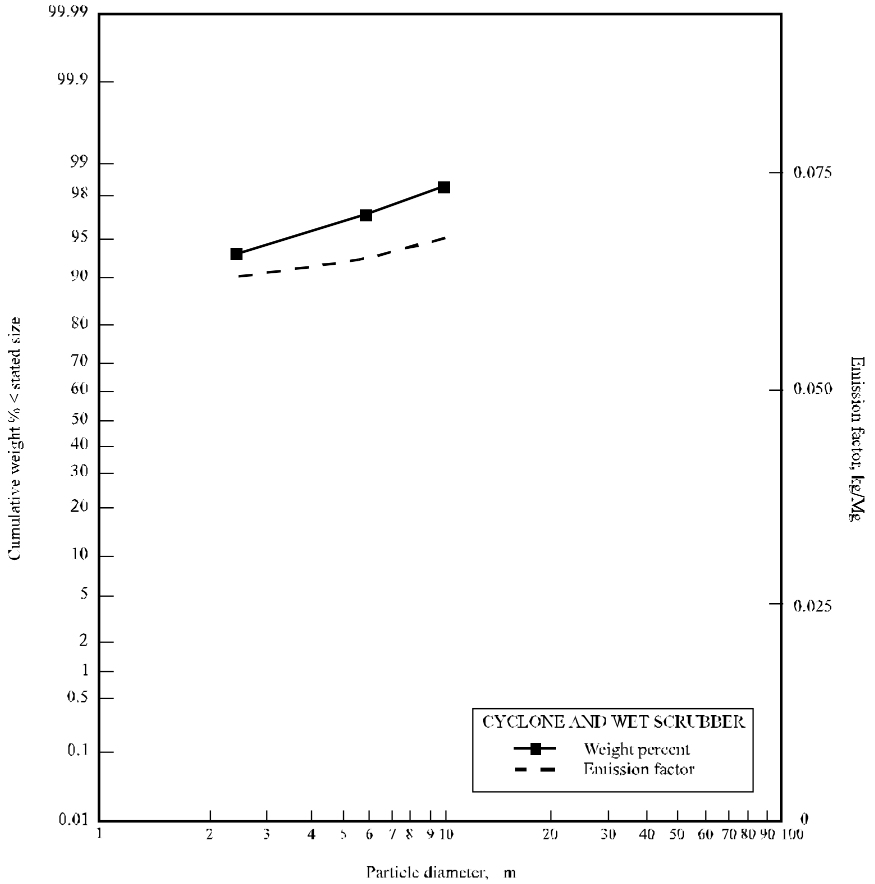
EMISSION FACTOR RATING: C

REFERENCE:

Emission Test Report, Lightweight Aggregate Industry, Galite Corporation, EMB-80-LWA-6, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1982.

11.21 PHOSPHATE ROCK PROCESSING: CALCINER

11.21 PHOSPHATE ROCK PROCESSING: CALCINER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After cyclone[a] and wet scrubber	After cyclone[a] and wet scrubber
2.5	94.0	0.064
6.0	97.0	0.066
10.0	98.0	0.067

[a] Cyclones are typically used in phosphate rock processing as product collectors. Uncontrolled emissions are emissions in the air exhausted from such cyclones.

11.21 PHOSPHATE ROCK PROCESSING: CALCINER

NUMBER OF TESTS: 6, conducted after wet scrubber control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	94.0	97.0	98.0
	Standard deviation (Cum. %):	2.5	1.6	1.5
	Min (Cum. %):	89.0	95.0	96.0
	Max (Cum. %):	98.0	99.2	99.7

TOTAL PARTICULATE EMISSION FACTOR: 0.0685 kg particulate/Mg of phosphate rock calcined, after collection of airborne product in a cyclone, and wet scrubber controls. Factor from reference cited below.

SOURCE OPERATION: Source is a phosphate rock calciner fired with No. 2 oil, with a rated capacity of 70 tons/hr. Feed to the calciner is beneficiated rock.

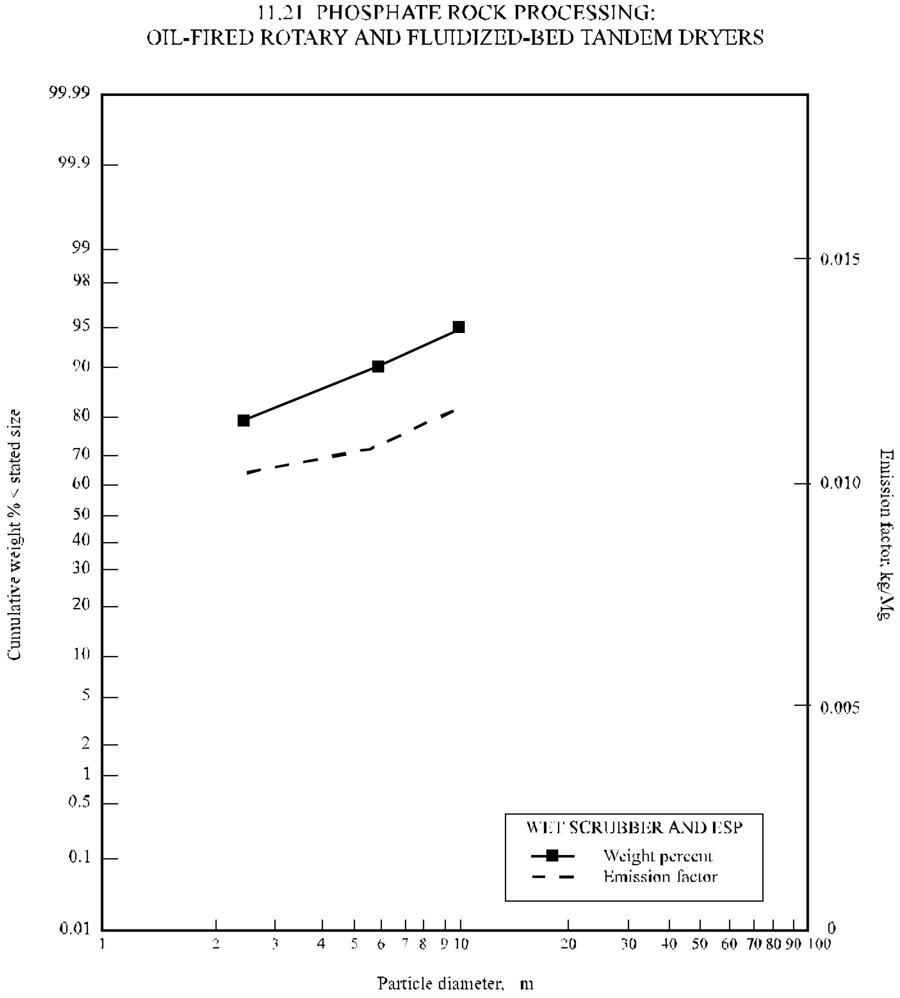
SAMPLING TECHNIQUE: Andersen Impactor.

EMISSION FACTOR RATING: C

REFERENCE:

Air Pollution Emission Test, Beker Industries, Inc., Conda, ID, EMB-75-PRP-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

11.21 PHOSPHATE ROCK PROCESSING: OIL-FIRED ROTARY AND FLUIDIZED-BED TANDEM DRYERS



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After wet scrubber and ESP control	After wet scrubber and ESP control
2.5	78.0	0.010
6.0	88.8	0.011
10.0	93.8	0.012

11.21 PHOSPHATE ROCK PROCESSING:
OIL-FIRED ROTARY AND FLUIDIZED-BED TANDEM DRYERS

NUMBER OF TESTS: 2, conducted after wet scrubber and electrostatic precipitator control

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	78.0	88.8	93.8
Standard deviation (Cum. %):	22.6	9.6	2.5
Min (Cum. %):	62	82	92
Max (Cum. %):	94	95	95

TOTAL PARTICULATE EMISSION FACTOR: 0.0125 kg particulate/Mg phosphate rock processed, after collection of airborne product in a cyclone and wet scrubber/ESP controls. Factor from reference cited below.

SOURCE OPERATION: Source operates a rotary and a fluidized bed dryer to dry various types of phosphate rock. Both dryers are fired with No. 5 fuel oil, and exhaust into a common duct. The rated capacity of the rotary dryer is 300 tons/hr, and that of the fluidized bed dryer is 150-200 tons/hr. During testing, source was operating at 67.7% of rated capacity.

SAMPLING TECHNIQUE: Andersen Impactor

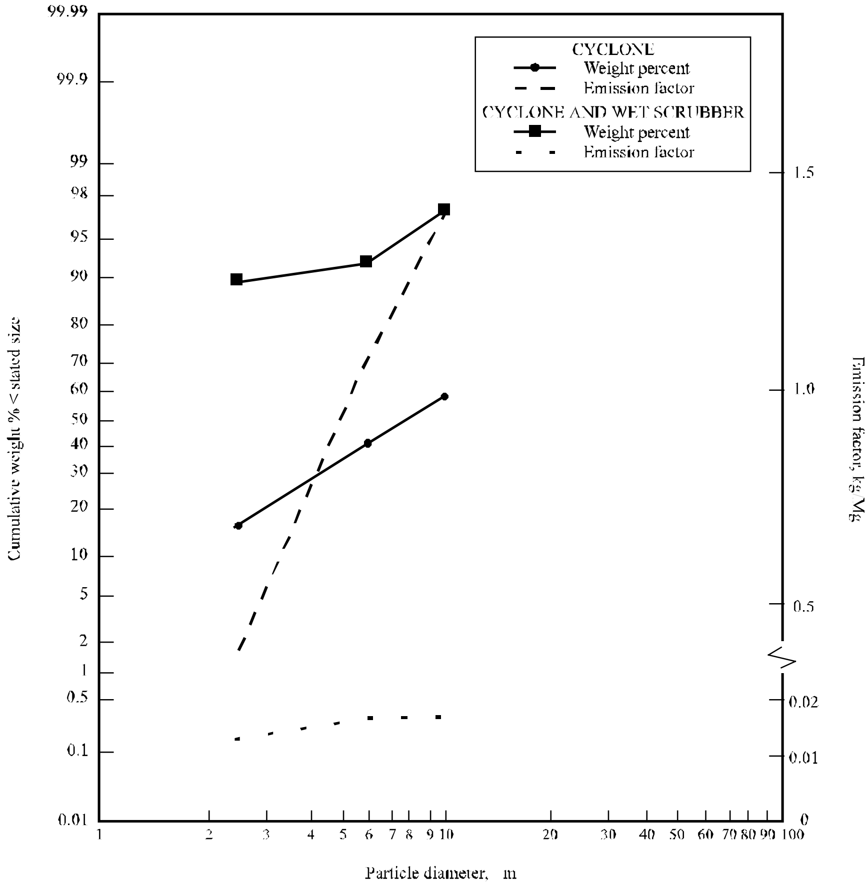
EMISSION FACTOR RATING: C

REFERENCE:

Air Pollution Emission Test, W. R. Grace Chemical Company, Bartow, FL, EMB-75-PRP-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1976.

11.21 PHOSPHATE ROCK PROCESSING: OIL-FIRED ROTARY DRYER

11.21 PHOSPHATE ROCK PROCESSING: OIL-FIRED ROTARY DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	After cyclone[a]	After wet scrubber	After cyclone[a]	After wet scrubber
2.5	15.7	89	0.38	0.017
6.0	41.3	92.3	1.00	0.018
10.0	58.3	96.6	1.41	0.018

[a] Cyclones are typically used in phosphate rock processing as product collectors. Uncontrolled emissions are emissions in the air exhausted from such cyclones.

11.21 PHOSPHATE ROCK PROCESSING: OIL-FIRED ROTARY DRYER

NUMBER OF TESTS: (a) 3, conducted after cyclone
(b) 2, conducted after wet scrubber control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	15.7	41.3	58.3
Standard deviation (Cum. %):	5.5	9.6	13.9
Min (Cum. %):	12	30	43
Max (Cum. %):	22	48	70

(b)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	89.0	92.3	96.6
Standard Deviation (Cum. %):	7.1	6.0	3.7
Min (Cum. %):	84	88	94
Max (Cum. %):	94	96	99

Impactor cut points for the tests conducted before control are small, and many of the data points are extrapolated. These particle size distributions are related to specific equipment and source operation, and are most applicable to particulate emissions from similar sources operating similar equipment. Table 11.21-2, Section 11.21, AP-42 presents particle size distributions for generic phosphate rock dryers.

TOTAL PARTICULATE EMISSION FACTORS: After cyclone, 2.419 kg particulate/Mg rock processed. After wet scrubber control, 0.019 kg/Mg. Factors from reference cited below.

SOURCE OPERATION: Source dries phosphate rock in #6 oil-fired rotary dryer. During these tests, source operated at 69% of rated dryer capacity of 350 tons/day, and processed coarse pebble rock.

SAMPLING TECHNIQUE: (a) Brinks Cascade Impactor
(b) Andersen Impactor

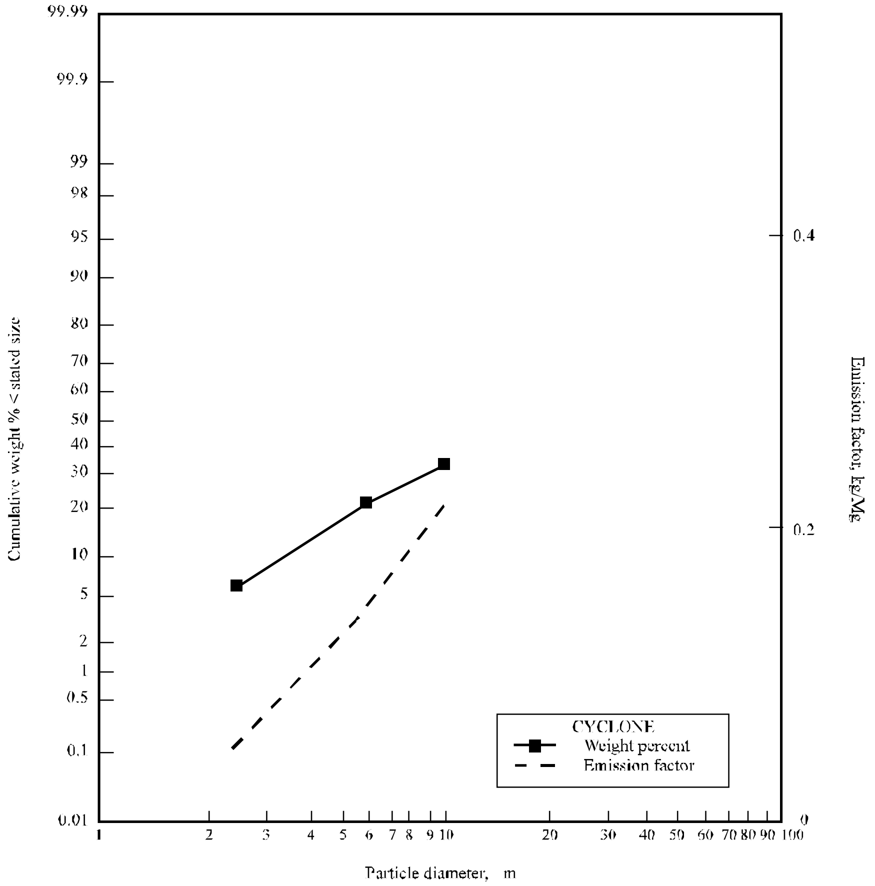
EMISSION FACTOR RATING: D

REFERENCE:

Air Pollution Emission Test, Mobil Chemical, Nichols, FL, EMB-75-PRP-3, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1976.

11.21 PHOSPHATE ROCK PROCESSING: BALL MILL

11.21 PHOSPHATE ROCK PROCESSING: BALL MILL



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After cyclone[a]	After cyclone[a]
2.5	6.5	0.05
6.0	19.0	0.14
10.0	30.8	0.22

[a] Cyclones are typically used in phosphate rock processing as product collectors. Uncontrolled emissions are emissions in the air exhausted from such cyclones.

11.21 PHOSPHATE ROCK PROCESSING: BALL MILL

NUMBER OF TESTS: 4, conducted after cyclone

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	6.5	19.0	30.8
	Standard deviation (Cum. %):	3.5	0.9	2.6
	Min (Cum. %):	3	18	28
	Max (Cum. %):	11	20	33

Impactor cutpoints were small, and most data points were extrapolated.

TOTAL PARTICULATE EMISSION FACTOR: 0.73 kg particulate/Mg of phosphate rock milled, after collection of airborne product in cyclone. Factor from reference cited below.

SOURCE OPERATION: Source mills western phosphate rock. During testing source was operating at 101% of rated capacity, producing 80 tons/hr.

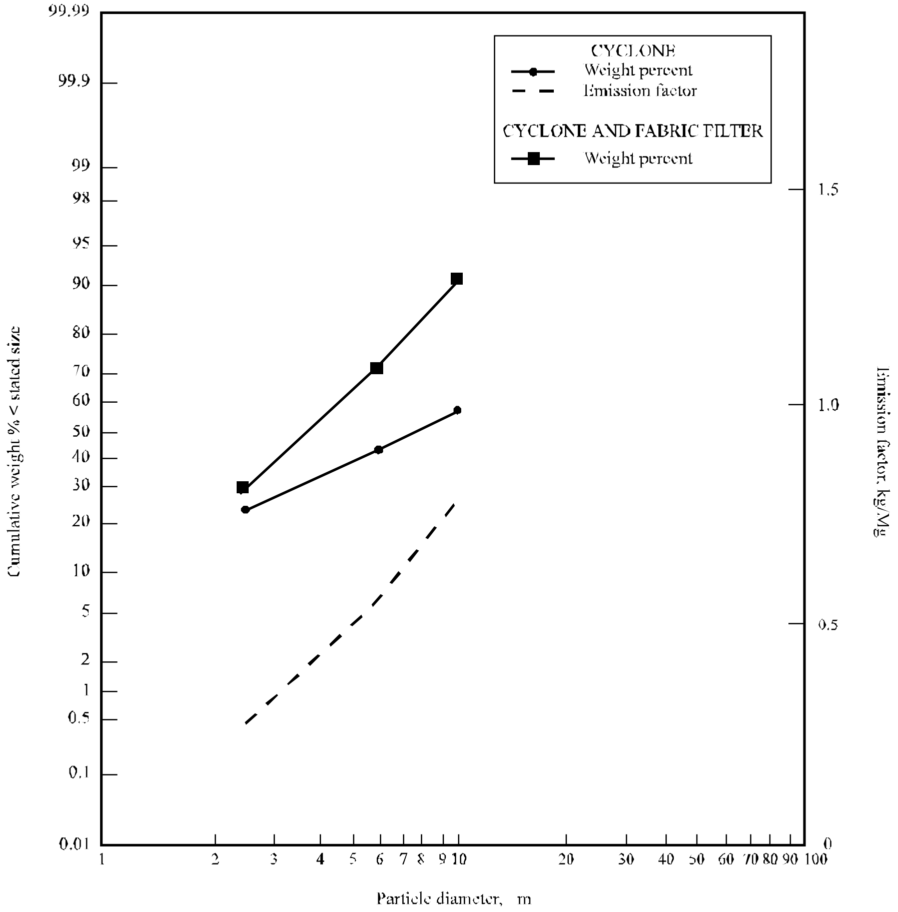
SAMPLING TECHNIQUE: Brink Impactor

EMISSION FACTOR RATING: C

REFERENCE:

Air Pollution Emission Test, Beker Industries, Inc., Conda, ID, EMB-75-PRP-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

11.21 PHOSPHATE ROCK PROCESSING: ROLLER MILL AND BOWL MILL GRINDING



Aerodynamic particle diameter, µm	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	After cyclone[a]	After fabric filter	After cyclone[a]	After fabric filter
2.5	21	25	0.27	Negligible
6.0	45	70	0.58	Negligible
10.0	62	90	0.79	Negligible

[a] Cyclones are typically used in phosphate rock processing as product collectors. Uncontrolled emissions are emissions in the air exhausted from such cyclones.

11.21 PHOSPHATE ROCK PROCESSING: ROLLER MILL AND BOWL MILL GRINDING

NUMBER OF TESTS: (a) 2, conducted after cyclone
(b) 1, conducted after fabric filter control

STATISTICS: (a)

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	21.0	45.0	62.0
Standard deviation (Cum. %):	1.0	1.0	0
Min (Cum. %):	20.0	44.0	62.0
Max (Cum. %):	22.0	46.0	62.0

(b)

Aerodynamic particle diamter (µm):	2.5	6.0	10.0
Mean (Cum. %):	25	70	90
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR. 0.73 kg particulate/Mg of rock processed, after collection of airborne product in a cyclone. After fabric filter control, 0.001 kg particulate/Mg rock processed. Factors calculated from data in reference cited below. See Table 11.21-3 for guidance.

SOURCE OPERATION: During testing, source was operating at 100% of design process rate. Source operates 1 roller mill with a rated capacity of 25 tons/hr of feed, and 1 bowl mill with a rated capacity of 50 tons/hr of feed. After product has been collected in cyclones, emissions from each mill are vented to a coin baghouse. Source operates 6 days/week, and processes Florida rock.

SAMPLING TECHNIQUE: (a) Brink Cascade Impactor
(b) Andersen Impactor

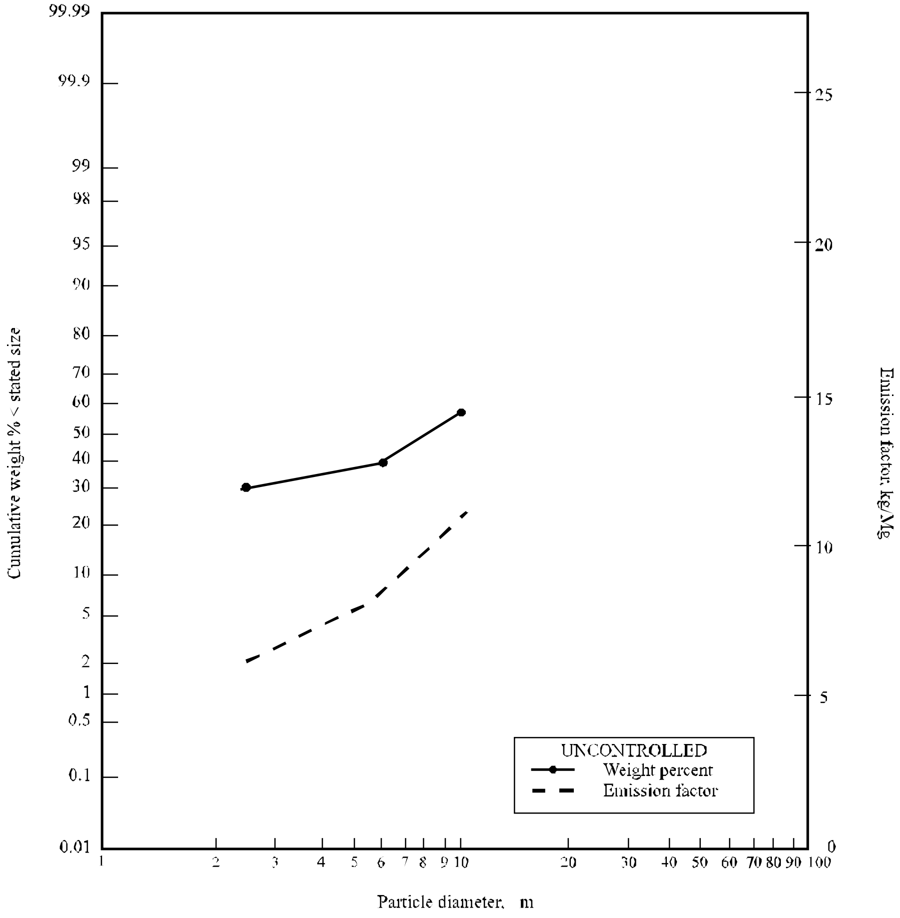
EMISSION FACTOR RATING: D

REFERENCE:

Air Pollution Emission Test, The Royster Company, Mulberry, FL, EMB-75-PRP-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1976.

11.26 NONMETALLIC MINERALS: TALC PEBBLE MILL

11.26 NONMETALLIC MINERALS: TALC PEBBLE MILL



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Before controls	Before controls
2.5	30.1	5.9
6.0	42.4	8.3
10.0	56.4	11.1

11.26 NONMETALLIC MINERALS: TALC PEBBLE MILL

NUMBER OF TESTS: 2, conducted before controls

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	30.1	42.4	56.4
	Standard deviation (Cum. %):	0.8	0.2	0.4
	Min (Cum. %):	29.5	42.2	56.1
	Max (Cum. %):	30.6	42.5	56.6

TOTAL PARTICULATE EMISSION FACTOR: 19.6 kg particulate/Mg ore processed. Calculated from data in reference.

SOURCE OPERATION: Source crushes talc ore then grinds crushed ore in a pebble mill. During testing, source operation was normal according to the operators. An addendum to the reference indicates throughput varied between 2.8 and 4.4 tons/hr during these tests.

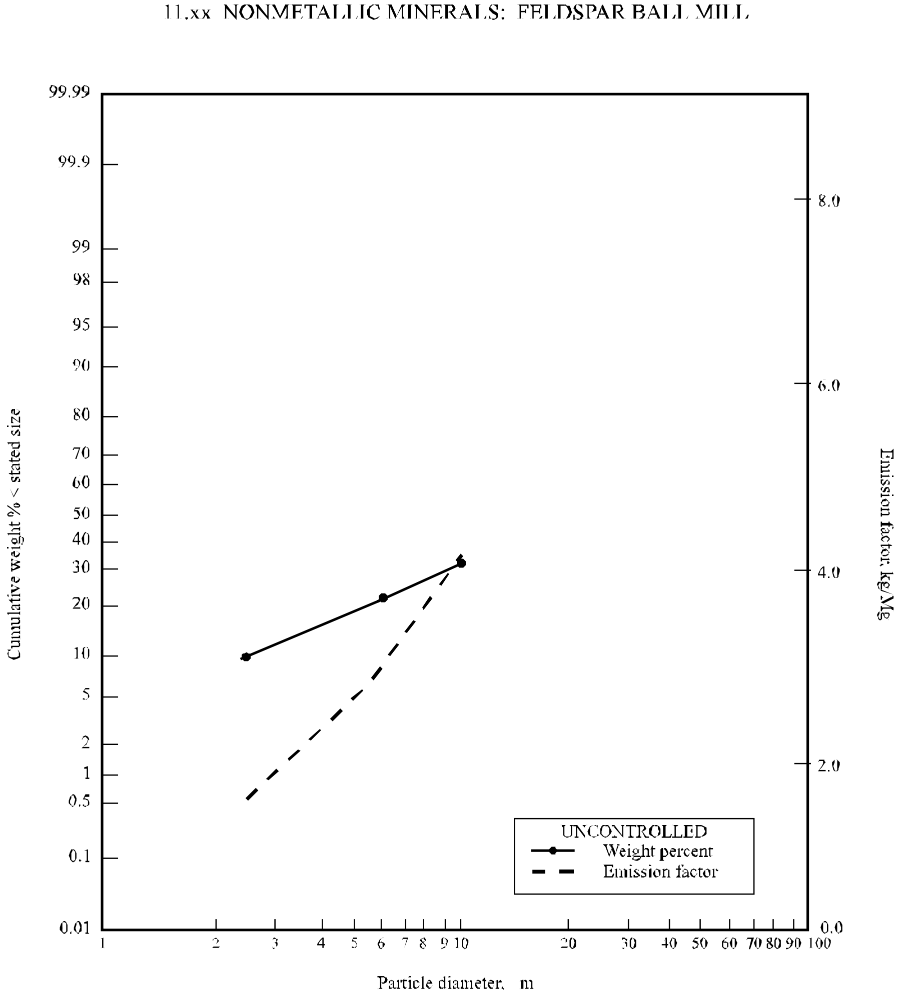
SAMPLING TECHNIQUE: Sample was collected in an alundum thimble and analyzed with a Spectrex Prototron Particle Counter Model ILI 1000.

EMISSION FACTOR RATING: E

REFERENCE:

> *Air Pollution Emission Test, Pfizer, Inc., Victorville, CA*, EMB-77-NMM-5, U. S. Environmental Protection Agency, Research Triangle Park, NC, July 1977.

11.xx NONMETALLIC MINERALS: FELDSPAR BALL MILL



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Before controls	Before controls
2.5	11.5	1.5
6.0	22.8	2.9
10.0	32.3	4.2

11.xx NONMETALLIC MINERALS: FELDSPAR BALL MILL

NUMBER OF TESTS: 2, conducted before controls

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	11.5	22.8	32.3
	Standard deviation (Cum. %):	6.4	7.4	6.7
	Min (Cum. %):	7.0	17.5	27.5
	Max (Cum. %):	16.0	28.0	37.0

TOTAL PARTICULATE EMISSION FACTOR: 12.9 kg particulate/Mg feldspar produced. Calculated from data in reference and related documents.

SOURCE OPERATION: After crushing and grinding of feldspar ore, source produces feldspar powder in a ball mill.

SAMPLING TECHNIQUE: Alundum thimble followed by 12-inch section of stainless steel probe followed by 47-mm type SGA filter contained in a stainless steel Gelman filter holder. Laboratory analysis methods: microsieve and electronic particle counter.

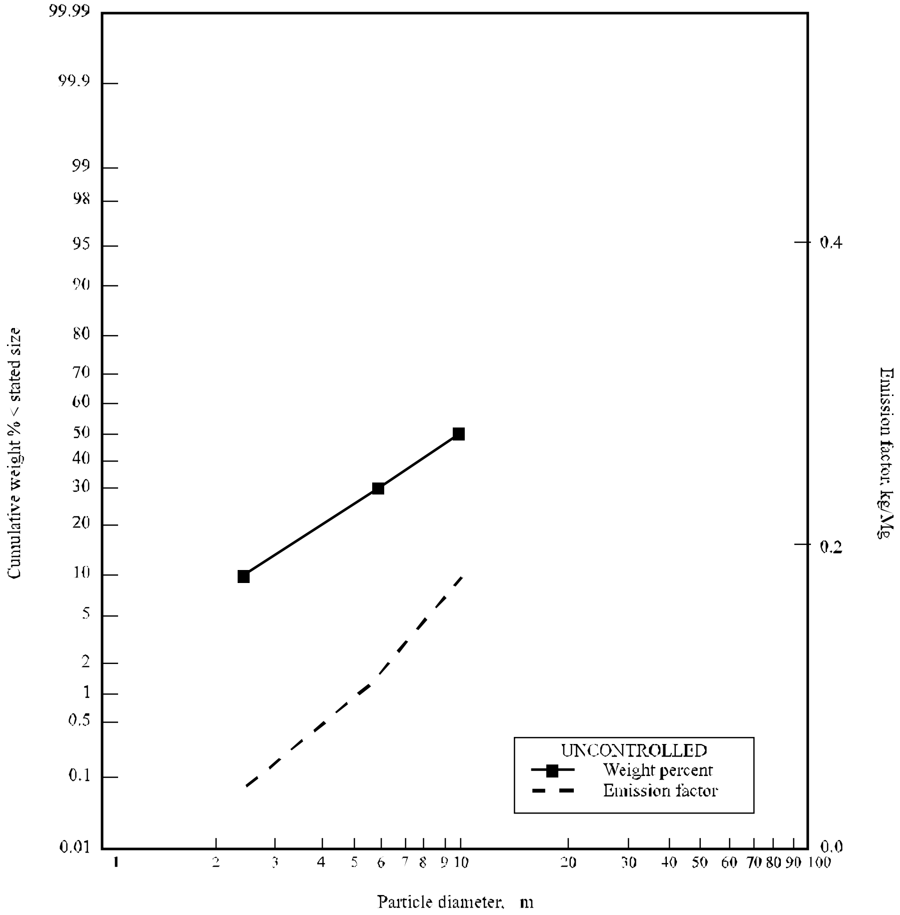
EMISSION FACTOR RATING: D

REFERENCE:

Air Pollution Emission Test, International Minerals and Chemical Company, Spruce Pine, NC, EMB-76-NMM-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1976.

11.xx NONMETALLIC MINERALS: FLUORSPAR ORE ROTARY DRUM DRYER

11.xx NONMETALLIC MINERALS: FLUORSPAR ORE ROTARY DRUM DRYER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	After fabric filter control	After fabric filter control
2.5	10	0.04
6.0	30	0.11
10.0	48	0.18

11.xx NONMETALLIC MINERALS: FLUORSPAR ORE ROTARY DRUM DRYER

NUMBER OF TESTS: 1, conducted after fabric filter control

STATISTICS:	Aerodynamic particle diameter (μm):	2.5	6.0	10.0
	Mean (Cum. %):	10	30	48
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.375 kg particulate/Mg ore dried, after fabric filter control. Factors from reference.

SOURCE OPERATION: Source dries fluorspar ore in a rotary drum dryer at a feed rate of 2 tons/hr.

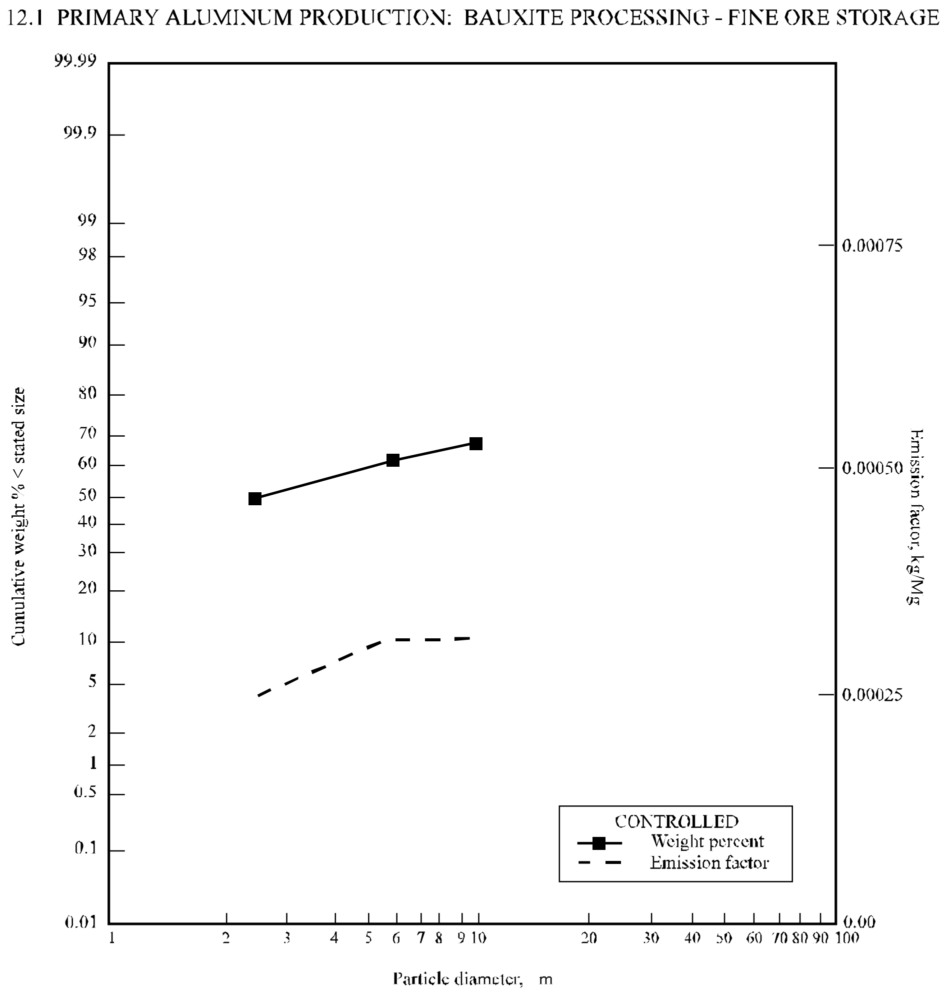
SAMPLING TECHNIQUE: Andersen Mark III Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Confidential test data from a major fluorspar ore processor, PEI Associates, Inc., Golden, CO, January 1985.

12.1 PRIMARY ALUMINUM PRODUCTION: BAUXITE PROCESSING - FINE ORE STORAGE



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Fabric filter controlled	Fabric filter controlled
2.5	50.0	0.00025
6.0	62.0	0.0003
10.0	68.0	0.0003

12.1 PRIMARY ALUMINUM PRODUCTION: BAUXITE PROCESSING - FINE ORE STORAGE

NUMBER OF TESTS: 2, after fabric filter control

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	50.0	62.0	68.0
Standard deviation (Cum. %):	15.0	19.0	20.0
Min (Cum. %):	35.0	43.0	48.0
Max (Cum. %):	65.0	81.0	88.0

TOTAL PARTICULATE EMISSION FACTOR: 0.0005 kg particulate/Mg of ore filled, with fabric filter control. Factor calculated from emission and process data in reference.

SOURCE OPERATION: The facility purifies bauxite to alumina. Bauxite ore, unloaded from ships, is conveyed to storage bins from which it is fed to the alumina refining process. These tests measured the emissions from the bauxite ore storage bin filling operation (the ore drop from the conveyer into the bin), after fabric filter control. Normal bin filling rate is between 425 and 475 tons per hour.

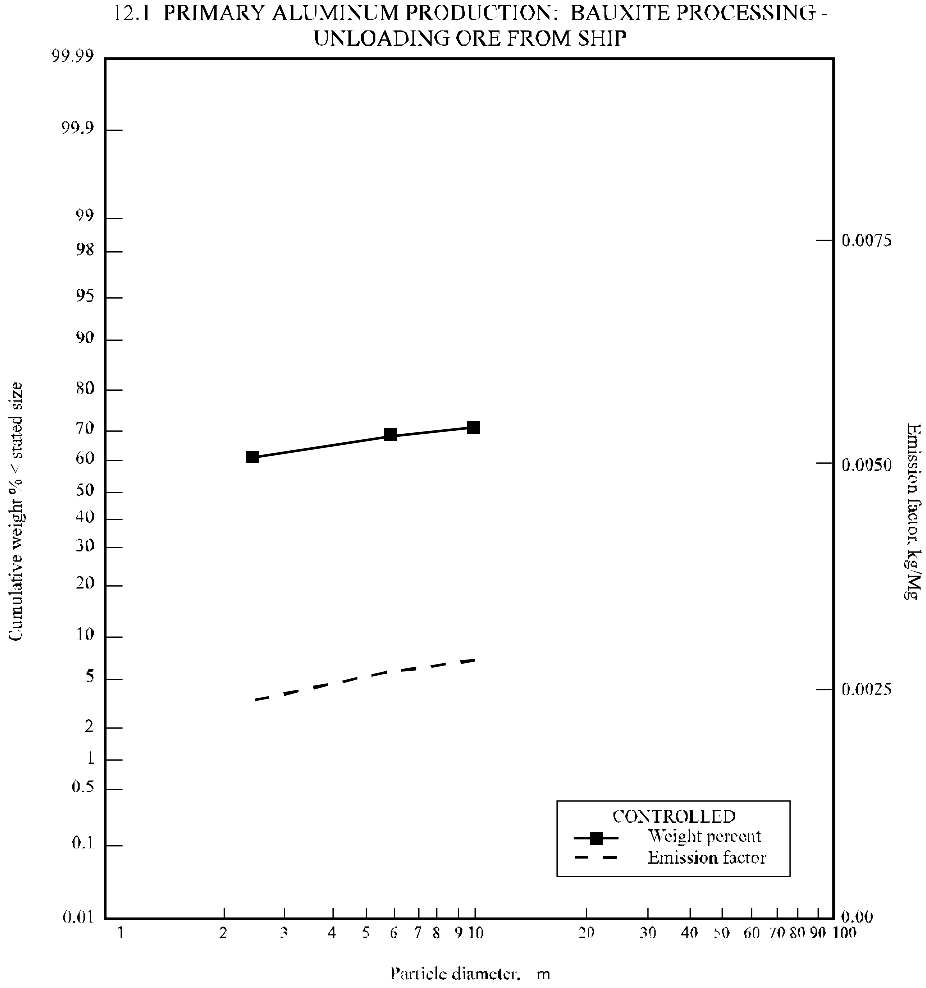
SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Emission Test Report, *Reynolds Metals Company*, *Corpus Christi*, *TX*, EMB-80-MET-9, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1980.

12.1 PRIMARY ALUMINUM PRODUCTION: BAUXITE PROCESSING - UNLOADING ORE FROM SHIP



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Wet scrubber controlled	Wet scrubber controlled
2.5	60.5	0.0024
6.0	67.0	0.0027
10.0	70.0	0.0028

12.1 PRIMARY ALUMINUM PRODUCTION: BAUXITE PROCESSING - UNLOADING ORE FROM SHIP

NUMBER OF TESTS: 1, after venturi scrubber control

STATISTICS: Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	60.5	67.0	70.0
Standard deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 0.004 kg particulate/Mg bauxite ore unloaded after scrubber control. Factor calculated from emission and process data contained in reference.

SOURCE OPERATION: The facility purifies bauxite to alumina. Ship unloading facility normally operates at 1500-1700 tons/hr, using a self-contained extendable boom conveyor that interfaces with a dockside conveyor belt through an accordion chute. The emissions originate at the point of transfer of the bauxite ore from the ship's boom conveyer as the ore drops through the chute onto the dockside conveyer. Emissions are ducted to a dry cyclone.and then to a Venturi scrubber. Design pressure drop across scrubber is 15 inches, and efficiency during test was 98.4%.

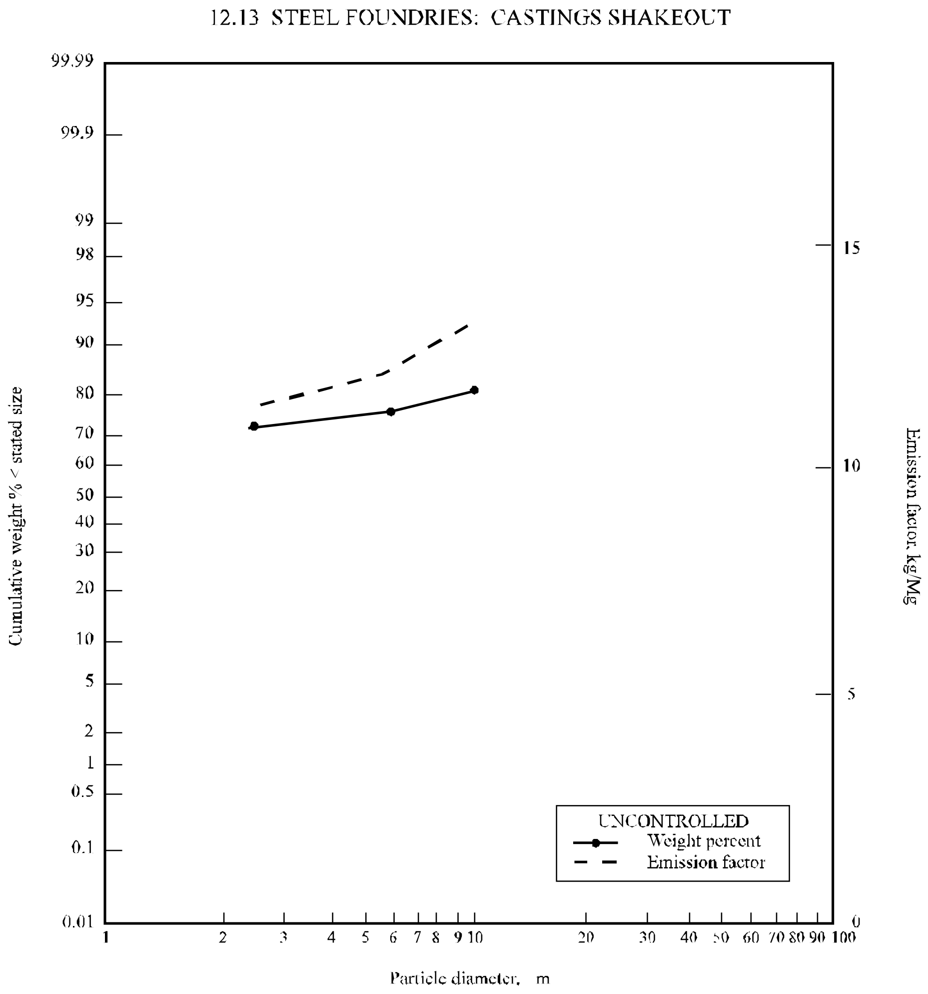
SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Emission Test Report, *Reynolds Metals Company*, *Corpus Christi*, *TX*, EMB-80-MET-9, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1980.

12.13 STEEL FOUNDRIES: CASTINGS SHAKEOUT



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	72.2	11.6
6.0	76.3	12.2
10.0	82.0	13.1

12.13 STEEL FOUNDRIES: CASTINGS SHAKEOUT

NUMBER OF TESTS: 2, conducted at castings shakeout exhaust hood before controls

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	72.2	76.3	82.0
	Standard deviation (Cum. %):	5.4	6.9	4.3
	Min (Cum. %):	66.7	69.5	77.7
	Max (Cum. %):	77.6	83.1	86.3

TOTAL PARTICULATE EMISSION FACTOR: 16 kg particulate/Mg metal melted, without controls. Although no nonfurnace emission factors are available for steel foundries, emissions are presumed to be similar to those in iron foundries. Nonfurnace emission factors for iron foundries are presented in AP-42, Section 12.13.

SOURCE OPERATION: Source is a steel foundry casting steel pipe. Pipe molds are broken up at the castings shakeout operation. No additional information is available.

SAMPLING TECHNIQUE: Brink Model BMS-11 Impactor

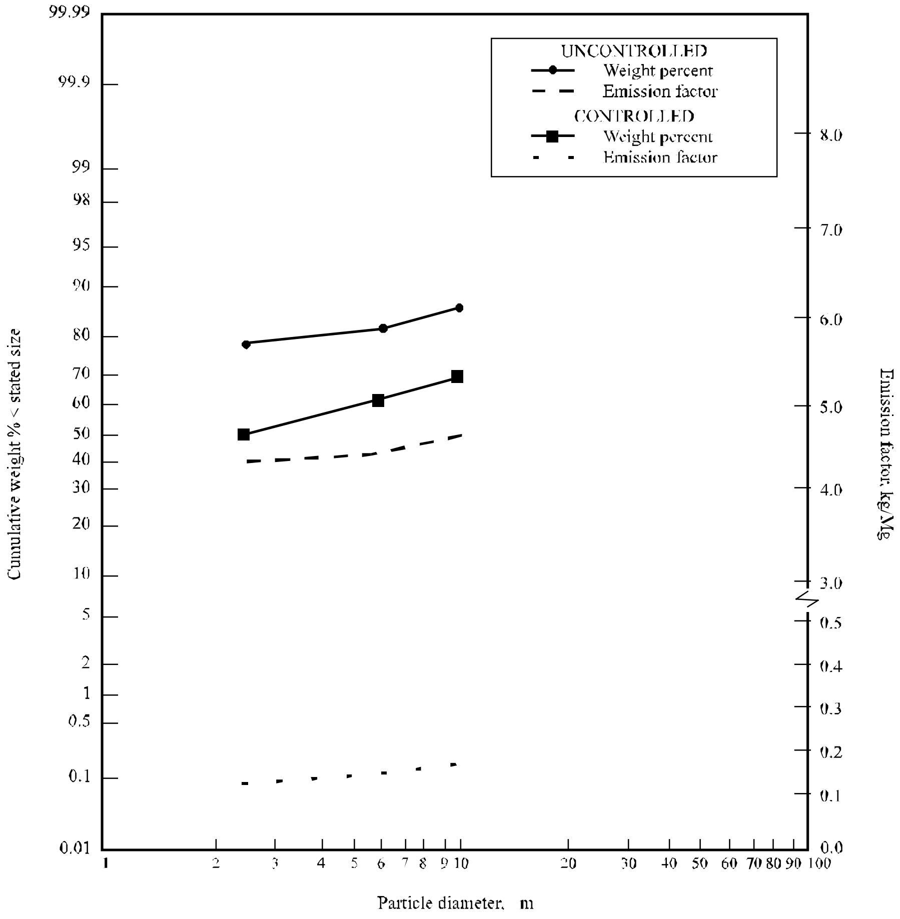
EMISSION FACTOR RATING: D

REFERENCE:

Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 117, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

12.13 STEEL FOUNDRIES: OPEN HEARTH EXHAUST

12.13 STEEL FOUNDRIES: OPEN HEARTH EXHAUST



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor, kg/Mg	
	Uncontrolled	ESP	Uncontrolled	ESP
2.5	79.6	49.3	4.4	0.14
6.0	82.8	58.6	4.5	0.16
10.0	85.4	66.8	4.7	0.18

12.13 STEEL FOUNDRIES: OPEN HEARTH EXHAUST

NUMBER OF TESTS: (a) 1, conducted before control
(b) 1, conducted after ESP control

STATISTICS:

(a) Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	79.6	82.8	85.4
Standard Deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

(b) Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	49.3	58.6	66.8
Standard Deviation (Cum. %):			
Min (Cum. %):			
Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 5.5 kg particulate/Mg metal processed, before control. Emission factor from AP-42, Section 12.13. AP-42 gives an ESP control efficiency of 95 to 98.5%. At 95% efficiency, factor after ESP control is 0.275 kg particulate/Mg metal processed.

SOURCE OPERATION: Source produces steel castings by melting, alloying, and casting pig iron and steel scrap. During these tests, source was operating at 100% of rated capacity of 8260 kg metal scrap feed/hour, fuel oil-fired, and 8-hour heats.

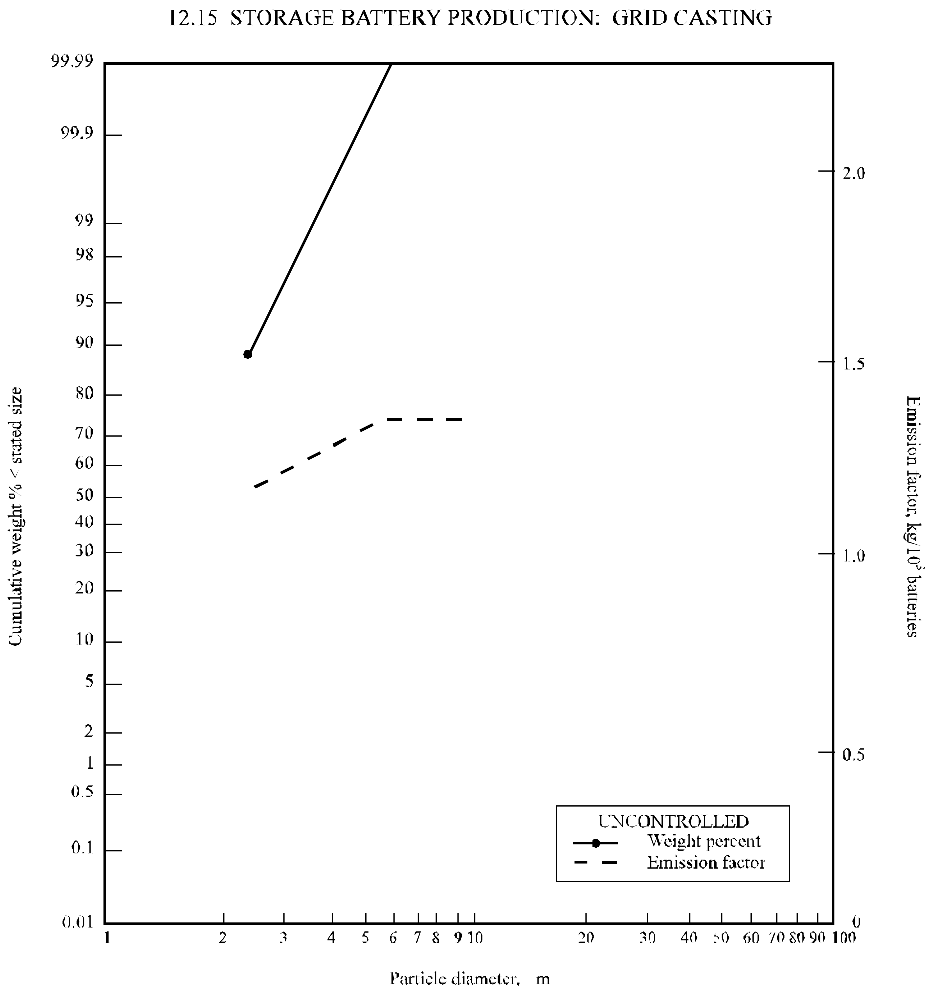
SAMPLING TECHNIQUE: (a) Joy train with 3 cyclones
(b) SASS train with cyclones

EMISSION FACTOR RATING: E

REFERENCE:

Emission test data from Environmental Assessment Data Systems, Fine Particle Emission Information System, Series Report No. 233, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1983.

12.15 STORAGE BATTERY PRODUCTION: GRID CASTING



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor (kg/10³ batteries)
	Uncontrolled	Uncontrolled
2.5	87.8	1.25
6.0	100	1.42
10.0	100	1.42

12.15 STORAGE BATTERY PRODUCTION: GRID CASTING

NUMBER OF TESTS: 3, conducted before control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	87.8	100	100
	Standard deviation (Cum. %):	10.3	—	—
	Min (Cum. %):	75.4	100	100
	Max (Cum. %):	100	100	100

Impactor cut points were so small that most data points had to be extrapolated.

TOTAL PARTICULATE EMISSION FACTOR: 1.42 kg particulate/10^3 batteries produced, without controls. Factor from AP-42, Section 12.15.

SOURCE OPERATION: During tests, plant was operated at 39% of design process rate. Six of nine of the grid casting machines were operating during the test. Typically, 26,500 to 30,000 pounds of lead per 24-hour day are charged to the grid casting operation.

SAMPLING TECHNIQUE: Brink Impactor

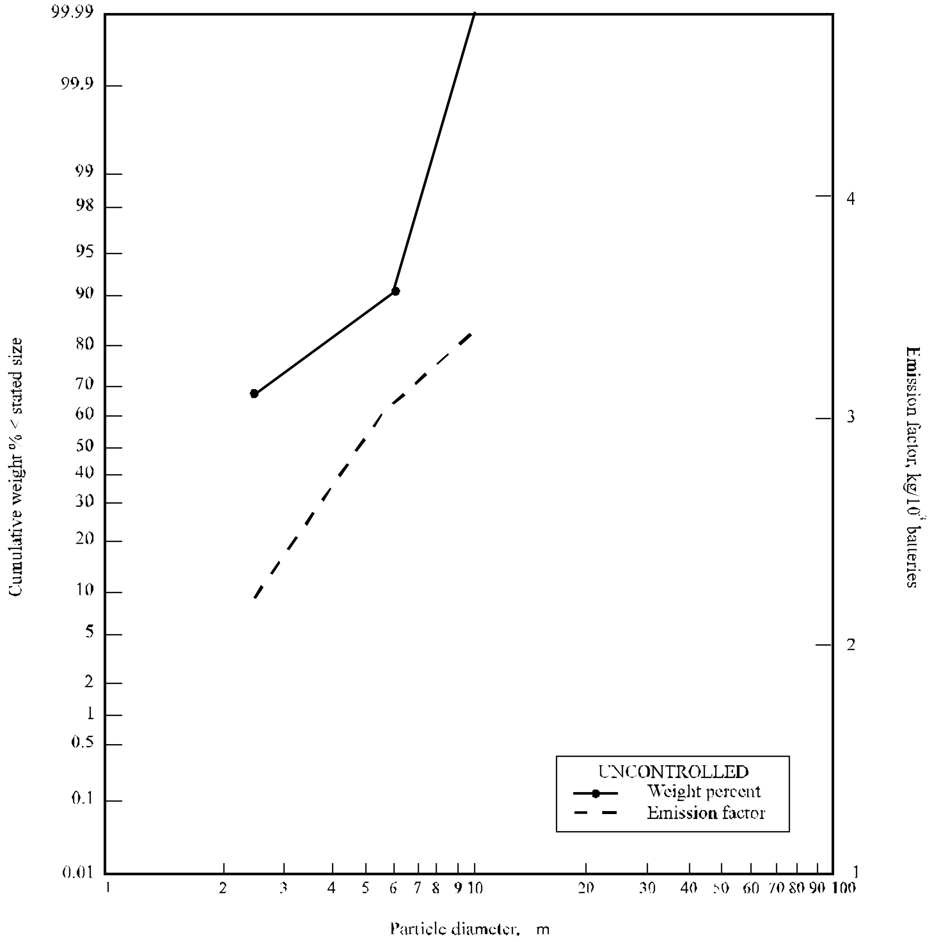
EMISSION FACTOR RATING: E

REFERENCE:

> *Air Pollution Emission Test, Globe Union, Inc., Canby, OR*, EMB-76-BAT-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1976.

12.15 STORAGE BATTERY PRODUCTION: GRID CASTING AND PASTE MIXING

12.15 STORAGE BATTERY PRODUCTION: GRID CASTING AND PASTE MIXING



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor (kg/10^3 batteries)
	Uncontrolled	Uncontrolled
2.5	65.1	2.20
6.0	90.4	3.05
10.0	100	3.38

12.15 STORAGE BATTERY PRODUCTION: GRID CASTING AND PASTE MIXING

NUMBER OF TESTS: 3, conducted before control

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	65.1	90.4	100
Standard deviation (Cum. %):	24.8	7.4	—
Min (Cum. %):	44.1	81.9	100
Max (Cum. %):	100	100	100

TOTAL PARTICULATE EMISSION FACTOR: 3.38 kg particulate/10^3 batteries, without controls. Factor is from AP-42, Section 12.15, and is the sum of the individual factors for grid casting and paste mixing.

SOURCE OPERATION: During tests, plant was operated at 39% of the design process rate. Grid casting operation consists of 4 machines. Each 2,000 lb/hr paste mixer is controlled for product recovery by a separate low-energy, impingement-type wet collector designed for an 8 - 10 inch w. g. pressure drop at 2,000 acfm.

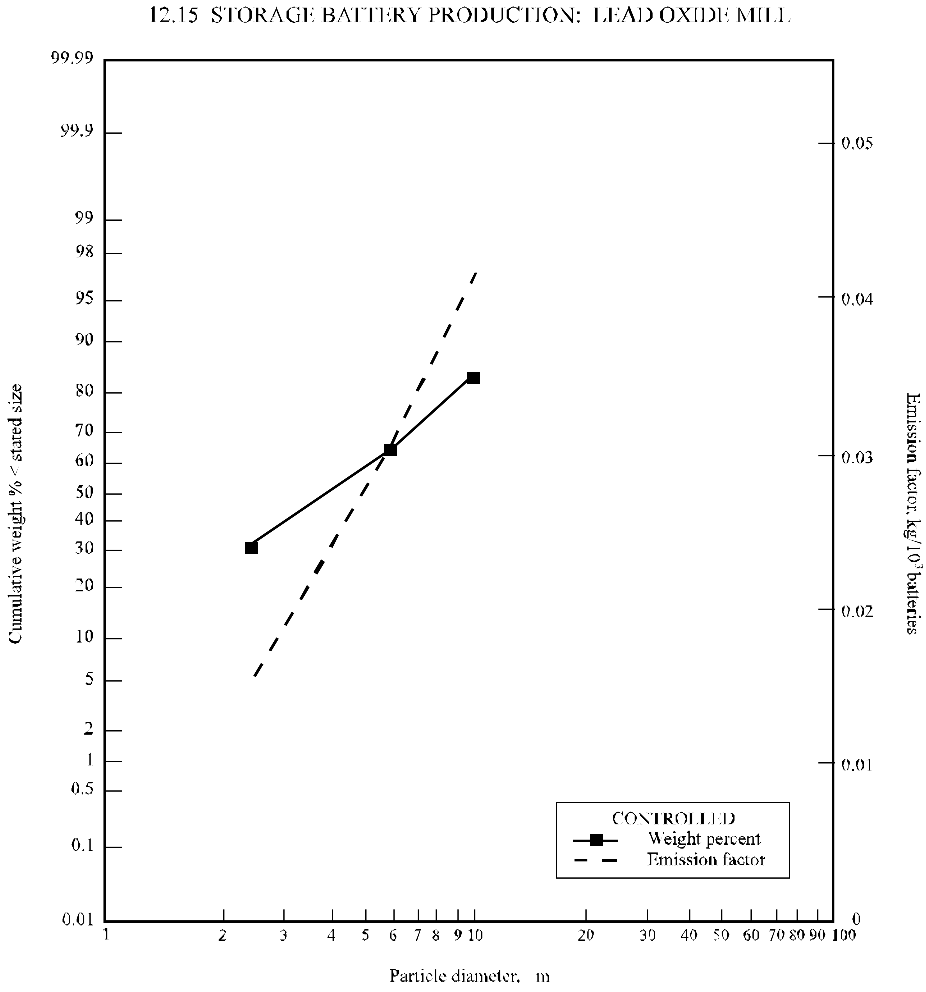
SAMPLING TECHNIQUE: Brink Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Air Pollution Emission Test, Globe Union, Inc., Canby, OR, EMB-76-BAT-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1976.

12.15 STORAGE BATTERY PRODUCTION: LEAD OXIDE MILL



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor (kg/10^3 batteries)
	After fabric filter	After fabric filter
2.5	32.8	0.016
6.0	64.7	0.032
10.0	83.8	0.042

12.15 STORAGE BATTERY PRODUCTION: LEAD OXIDE MILL

NUMBER OF TESTS: 3, conducted after fabric filter

STATISTICS:

Aerodynamic particle diameter (µm):	2.5	6.0	10.0
Mean (Cum. %):	32.8	64.7	83.8
Standard deviation (Cum. %):	14.1	29.8	19.5
Min (Cum. %):	17.8	38.2	61.6
Max (Cum. %):	45.9	97.0	100

TOTAL PARTICULATE EMISSION FACTOR: 0.05 kg particulate/10^3 batteries, after typical fabric filter control (oil-to-cloth ratio of 4:1). Emissions from a well-controlled facility (fabric filters with an average air-to-cloth ratio of 3:1) were 0.025 kg/10^3 batteries (Table 12.15-1 of AP-42).

SOURCE OPERATION: Plant receives metallic lead and manufactures lead oxide by the ball mill process. There are 2 lead oxide production lines, each with a typical feed rate of 15 100-pound lead pigs per hour. Product is collected with a cyclone and baghouses with 4:1 air-to-cloth ratios.

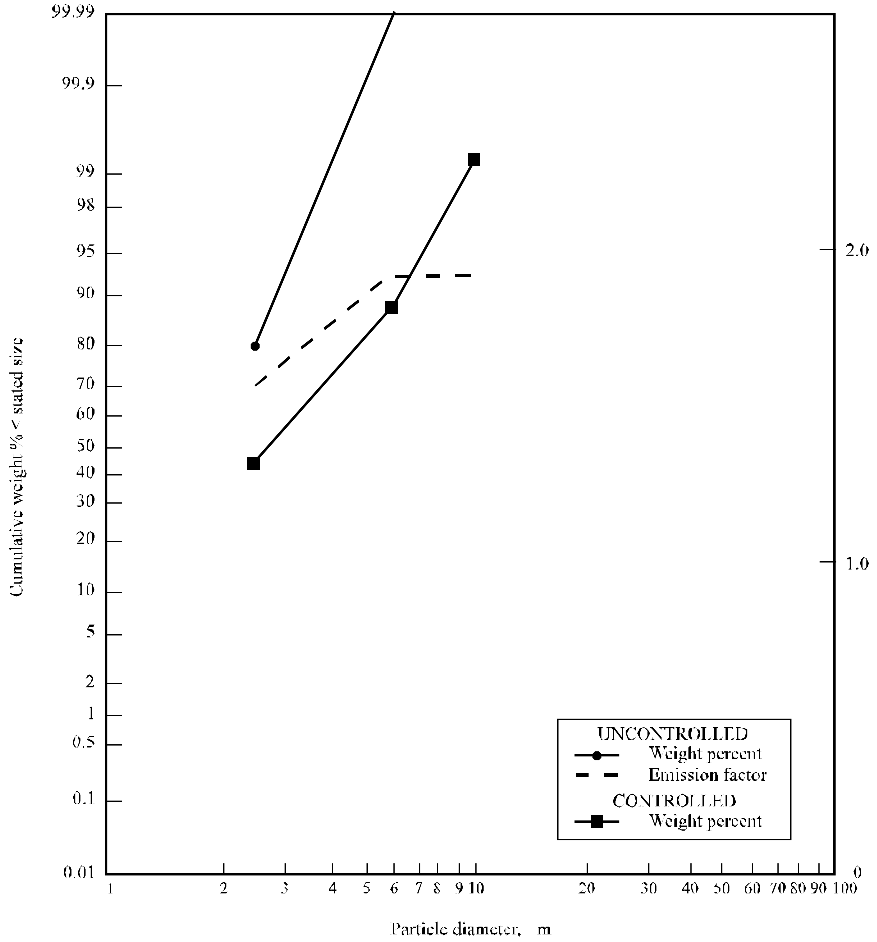
SAMPLING TECHNIQUE: Andersen Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Air Pollution Emission Test, ESB Canada Limited, Mississouga, Ontario, EMB-76-BAT-3, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1976.

12.15 STORAGE BATTERY PRODUCTION: PASTE MIXING AND LEAD OXIDE CHARGING



Aerodynamic particle diameter, m	Cumulative wt. % < stated size		Emission factor (kg/10^3 batteries)
	Uncontrolled	Fabric filter	Uncontrolled
2.5	80	47	1.58
6.0	100	87	1.96
10.0	100	99	1.96

12.15 STORAGE BATTERY PRODUCTION: PASTE MIXING AND LEAD OXIDE CHARGING

NUMBER OF TESTS: (a) 1, conducted before control
(b) 4, conducted after fabric filter control

STATISTICS:

(a)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	80	100	100
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

(b)	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %.):	47	87	99
	Standard deviation (Cum. %):	33.4	14.5	0.9
	Min (Cum. %):	36	65	98
	Max (Cum. %):	100	100	100

Impactor cut points were so small that many data points had to be extrapolated. Reliability of particle size distributions based on a single test is questionable.

TOTAL PARTICULATE EMISSION FACTOR: 1.96 kg. particulate/10^3 batteries, without controls. Factor from AP-42, Section 12.15.

SOURCE OPERATION: During test, plant was operated at 39% of the design process rate. Plant has normal production rate of 2,400 batteries per day and maximum capacity of 4,000 batteries per day. Typical amount of lead oxide charged to the mixer is 29,850 lb/8-hour shift. Plant produces wet batteries, except formation is carried out at another plant.

SAMPLING TECHNIQUE: (a) Brink Impactor
(b) Andersen Impactor

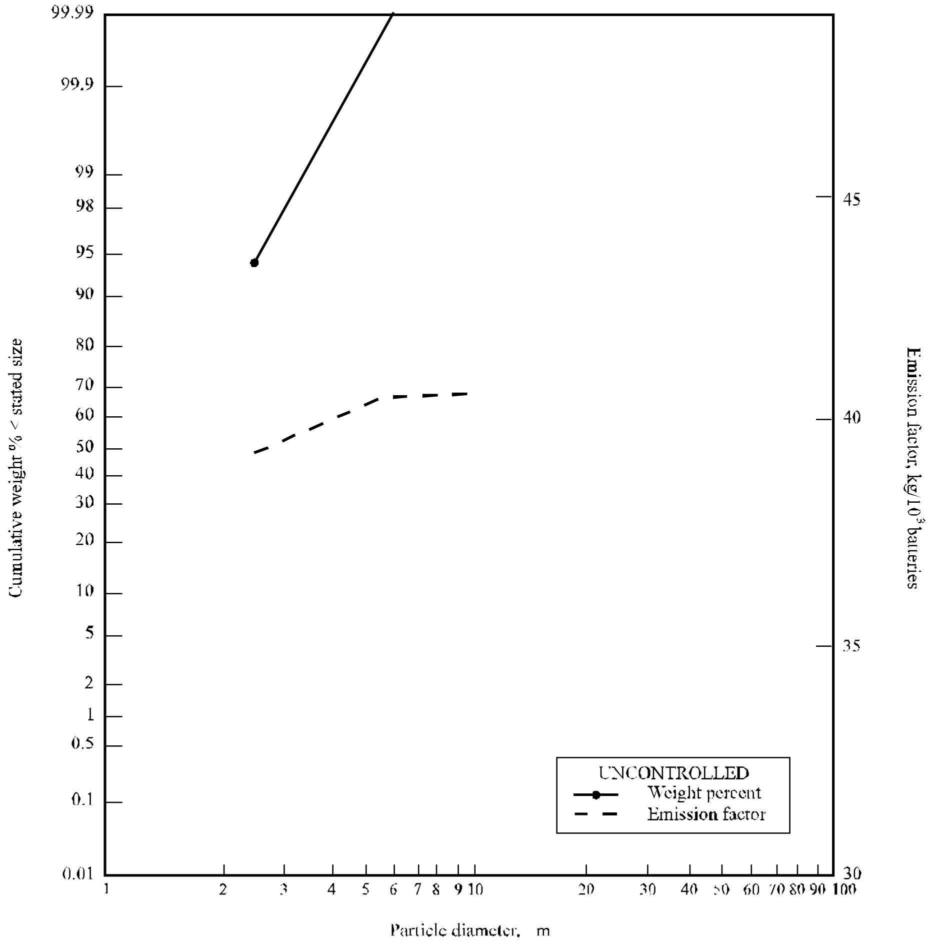
EMISSION FACTOR RATING: E

REFERENCE:

Air Pollution Emission Test, Globe Union, Inc., Canby, OR, EMB-76-BAT-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1976.

12.15 STORAGE BATTERY PRODUCTION: THREE-PROCESS OPERATION

12.15 STORAGE BATTERY PRODUCTION: THREE-PROCESS OPERATION



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor (kg/10^3 batteries)
	Uncontrolled	Uncontrolled
2.5	93.4	39.3
6.0	100	42
10.0	100	42

12.15 STORAGE BATTERY PRODUCTION: THREE-PROCESS OPERATION

NUMBER OF TESTS: 3, conducted before control

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	93.4	100	100
	Standard deviation (Cum. %):	6.43		
	Min (Cum. %):	84.7		
	Max (Cum. %):	100		

Impactor cut points were so small that data points had to be extrapolated.

TOTAL PARTICULATE EMISSION FACTOR: 42 kg particulate/10^3 batteries, before controls. Factor from AP-42, Section 12.15.

SOURCE OPERATION: Plant representative stated that the plant usually operated at 35% of design capacity. Typical production rate is 3,500 batteries per day (dry and wet), but up to 4,500 batteries per day can be produced. This is equivalent to normal and maximum daily element production of 21,000 and 27,000 battery elements, respectively.

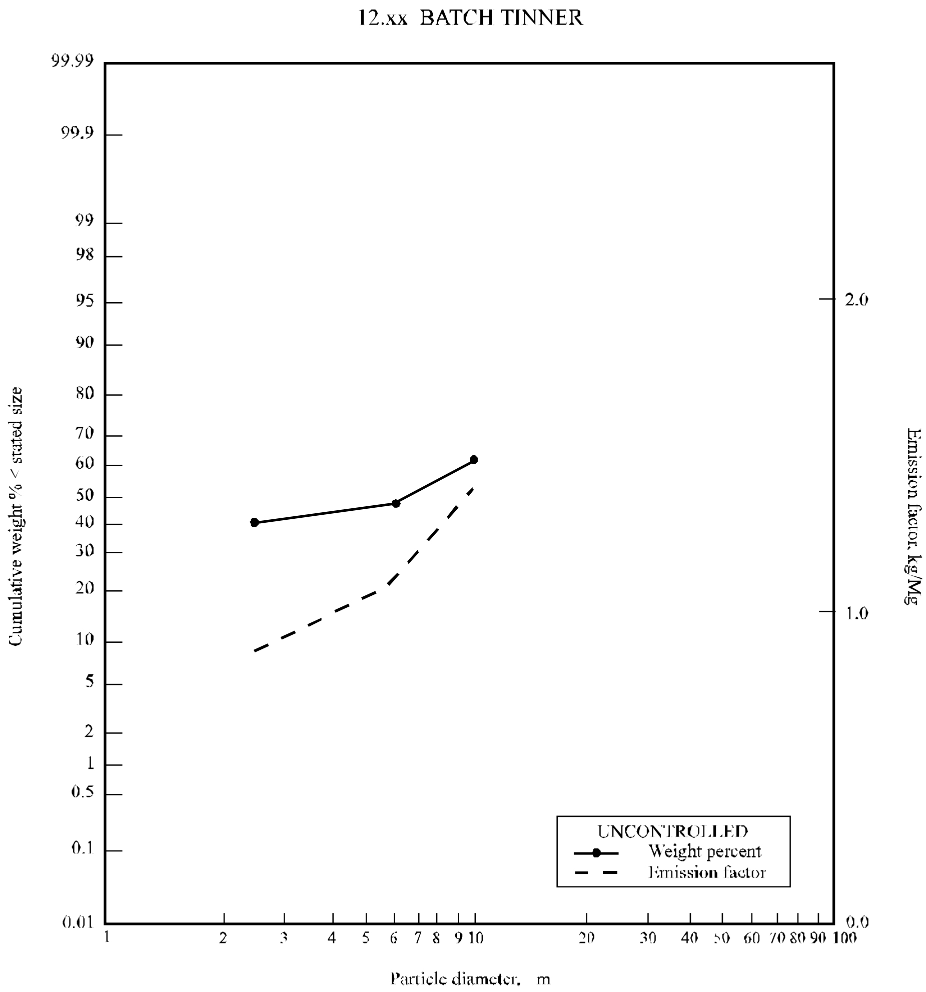
SAMPLING TECHNIQUE: Brink Impactor

EMISSION FACTOR RATING: E

REFERENCE:

Air Pollution Emission Test, ESB Canada Limited, Mississouga, Ontario, EMB-76-BAT-3, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1976.

12.xx BATCH TINNER



Aerodynamic particle diameter, m	Cumulative wt. % < stated size	Emission factor, kg/Mg
	Uncontrolled	Uncontrolled
2.5	37.2	0.93
6.0	45.9	1.15
10.0	55.9	1.40

12.xx BATCH TINNER

NUMBER OF TESTS: 2, conducted before controls

STATISTICS:	Aerodynamic particle diameter (µm):	2.5	6.0	10.0
	Mean (Cum. %):	37.2	45.9	55.9
	Standard deviation (Cum. %):			
	Min (Cum. %):			
	Max (Cum. %):			

TOTAL PARTICULATE EMISSION FACTOR: 2.5 kg particulate/Mg tin consumed, without controls. Factor from AP-42, Section 12.14.

SOURCE OPERATION: Source is a batch operation applying a lead/tin coating to tubing. No further source operating information is available.

SAMPLING TECHNIQUE: Andersen Mark III Impactor

EMISSION FACTOR RATING: D

REFERENCE:

Confidential test data, PEI Associates, Inc., Golden, CO, January 1985.

APPENDIX B.2

GENERALIZED PARTICLE SIZE DISTRIBUTIONS

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Appendix B.2

Generalized Particle Size Distributions

B.2.1 Rationale For Developing Generalized Particle Size Distributions

The preparation of size-specific particulate emission inventories requires size distribution information for each process. Particle size distributions for many processes are contained in appropriate industry sections of this document. Because particle size information for many processes of local impact and concern are unavailable, this appendix provides "generic" particle size distributions applicable to these processes. The concept of the "generic" particle size distribution is based on categorizing measured particle size data from similar processes generating emissions from similar materials. These generic distributions have been developed from sampled size distributions from about 200 sources.

Generic particle size distributions are approximations. They should be used only in the absence of source-specific particle size distributions for areawide emission inventories.

B.2.2 How To Use The Generalized Particle Size Distributions For Uncontrolled Processes

Figure B.2-1 provides an example calculation to assist the analyst in preparing particle size-specific emission estimates using generic size distributions.

The following instructions for the calculation apply to each particulate emission source for which a particle size distribution is desired and for which no source specific particle size information is given elsewhere in this document:

1. Identify and review the AP-42 section dealing with that process.
2. Obtain the uncontrolled particulate emission factor for the process from the main text of AP-42, and calculate uncontrolled total particulate emissions.
3. Obtain the category number of the appropriate generic particle size distribution from Table B.2-1.
4. Obtain the particle size distribution for the appropriate category from Table B.2-2. Apply the particle size distribution to the uncontrolled particulate emissions.

Instructions for calculating the controlled size-specific emissions are given in Table B.2-3 and illustrated in Figure B.2-1.

Figure B.2-1. Example calculation for determining uncontrolled and controlled particle size-specific emissions.

SOURCE IDENTIFICATION

Source name and address: ABC Brick Manufacturing
24 Dusty Way
Anywhere, USA

Process description: Dryers/Grinders
AP-42 Section: 8.3, Bricks And Related Clay Products
Uncontrolled AP-42 emission factor: 96 lbs/ton (units)
Activity parameter: 63,700 tons/year (units)
Uncontrolled emissions: 3057.6 tons/year (units)

UNCONTROLLED SIZE EMISSIONS

Category name: Mechanically Generated/Aggregated, Unprocessed Ores
Category number: 3

	Particle size (µm)		
	≤ 2.5	≤ 6	≤ 10
Generic distribution, Cumulative percent equal to or less than the size:	15	34	51
Cumulative mass ≤ particle size emissions (tons/year):	458.6	1039.6	1559.4

CONTROLLED SIZE EMISSIONS*

Type of control device: Fabric Filter

	Particle size (µm)		
	0 - 2.5	2.5 - 6	6 - 10
Collection efficiency (Table B.2-3):	99.0	99.5	99.5
Mass in size range** before control (tons/year):	458.6	581.0	519.8
Mass in size range after control (tons/year):	4.59	2.91	2.60
Cumulative mass (tons/year):	4.59	7.50	10.10

* These data do not include results for the greater than 10 µm particle size range.

** Uncontrolled size data are cumulative percent equal to or less than the size. Control efficiency data apply only to size range and are not cumulative.

Table B.2-1. PARTICLE SIZE CATEGORY BY AP-42 SECTION

AP-42 Section	Source Category	Category Number*
	External combustion	
1.1	Bituminous and subbituminous coal combustion	a
1.2	Anthracite coal combustion	a
1.3	Fuel oil combustion	
	Residual oil	
	Utility	a
	Commercial	a
	Distillate oil	
	Utility	a
	Commercial	a
	Residential	a
1.4	Natural gas combustion	a
1.5	Liquefied petroleum gas	a
1.6	Wood waste combustion in boilers	a
1.7	Lignite combustion	a
1.8	Bagasse combustion	b
1.9	Residential fireplaces	a
1.10	Residential wood stoves	a
1.11	Waste oil combustion	a
	Solid waste disposal	
2.1	Refuse combustion	a
2.2	Sewage sludge incineration	a
2.7	Conical burners (wood waste)	2
	Internal combustion engines	
	Highway vehicles	c
3.2	Off highway vehicles	1
	Organic chemical processes	
6.4	Paint and varnish	4
6.5	Phthalic anhydride	9
6.8	Soap and detergents	a
	Inorganic chemical processes	
8.2	Urea	a
8.3	Ammonium nitrate fertilizers	a
8.4	Ammonium sulfate	
	Rotary dryer	b
	Fluidized bed dryer	b
8.5	Phosphate fertilizers	3
8.5.3	Ammonium phosphates	
	Reactor/ammoniator-granulator	4
	Dryer/cooler	4
8.7	Hydrofluoric acid	
	Spar drying	3
	Spar handling	3
	Transfer	3
8.9	Phosphoric acid (thermal process)	a
8.10	Sulfuric acid	b
8.12	Sodium carbonate	a
	Food and agricultural	
9.3.1	Defoliation and harvesting of cotton	
	Trailer loading	6
	Transport	6
9.3.2	Harvesting of grain	
	Harvesting machine	6
	Truck loading	6
	Field transport	6
9.5.2	Meat smokehouses	9
9.7	Cotton ginning	b
9.9.1	Grain elevators and processing plants	a
9.9.4	Alfalfa dehydrating	
	Primary cyclone	b
	Meal collector cyclone	7
	Pellet cooler cyclone	7
	Pellet regrind cyclone	7
9.9.7	Starch manufacturing	7
9.12	Fermentation	6,7
9.13.2	Coffee roasting	6
	Wood products	
10.2	Chemical wood pulping	a
10.7	Charcoal	9
	Mineral products	
11.1	Hot mix asphalt plants	a
11.3	Bricks and related clay products	
	Raw materials handling	
	Dryers, grinders, etc.	b

Table B.2-1 (cont.).

AP-42 Section	Source Category	Category Number*
	Tunnel/periodic kilns	
	Gas fired	a
	Oil fired	a
	Coal fired	a
11.5	Refractory manufacturing	
	Raw material dryer	3
	Raw material crushing and screening	3
	Electric arc melting	8
	Curing oven	3
11.6	Portland cement manufacturing	
	Dry process	
	Kilns	a
	Dryers, grinders, etc.	4
	Wet process	
	Kilns	a
	Dryers, grinders, etc.	4
11.7	Ceramic clay manufacturing	
	Drying	3
	Grinding	4
	Storage	3
11.8	Clay and fly ash sintering	
	Fly ash sintering, crushing, screening, yard storage	5
	Clay mixed with coke	
	Crushing, screening, yard storage	3
11.9	Western surface coal mining	a
11.10	Coal cleaning	3
11.12	Concrete batching	3
11.13	Glass fiber manufacturing	
	Unloading and conveying	3
	Storage bins	3
	Mixing and weighing	3
	Glass furnace - wool	a
	Glass furnace - textile	a
11.15	Glass manufacturing	a
11.16	Gypsum manufacturing	
	Rotary ore dryer	a
	Roller mill	4
	Impact mill	4
	Flash calciner	a
	Continuous kettle calciner	a
11.17	Lime manufacturing	a
11.18	Mineral wool manufacturing	
	Cupola	8
	Reverberatory furnace	8
	Blow chamber	8
	Curing oven	9
	Cooler	9
11.19.1	Sand and gravel processing	
	Continuous drop	
	Transfer station	a
	Pile formation - stacker	a
	Batch drop	a
	Active storage piles	a
	Vehicle traffic on unpaved road	a
11.19.2	Crushed stone processing	
	Dry crushing	
	Primary crushing	a
	Secondary crushing and screening	a
	Tertiary crushing and screening	3
	Recrushing and screening	4
	Fines mill	4
	Screening, conveying, handling	a
11.21	Phosphate rock processing	
	Drying	a
	Calcining	a
	Grinding	b
	Transfer and storage	3
11.23	Taconite ore processing	
	Fine crushing	4

Table B.2-1 (cont.).

AP-42 Section	Source Category	Category Number*
	Waste gas	a
	Pellet handling	4
	Grate discharge	5
	Grate feed	4
	Bentonite blending	4
	Coarse crushing	3
	Ore transfer	3
	Bentonite transfer	4
	Unpaved roads	a
11.24	Metallic minerals processing	a
	<u>Metallurgical</u>	
12.1	Primary aluminum production	
	Bauxite grinding	4
	Aluminum hydroxide calcining	5
	Anode baking furnace	9
	Prebake cell	a
	Vertical Soderberg	8
	Horizontal Soderberg	a
12.2	Coke manufacturing	a
12.3	Primary copper smelting	a
12.4	Ferroalloy production	a
12.5	Iron and steel production	
	Blast furnace	
	Slips	a
	Cast house	a
	Sintering	
	Windbox	a
	Sinter discharge	a
	Basic oxygen furnace	a
	Electric arc furnace	a
12.6	Primary lead smelting	a
12.7	Zinc smelting	8
12.8	Secondary aluminum operations	
	Sweating furnace	8
	Smelting	
	Crucible furnace	8
	Reverberatory furnace	a
12.9	Secondary copper smelting and alloying	8
12.10	Gray iron foundries	a
12.11	Secondary lead processing	a
12.12	Secondary magnesium smelting	8
12.13	Steel foundries - melting	b
12.14	Secondary zinc processing	8
12.15	Storage battery production	b
12.18	Leadbearing ore crushing and grinding	4
	<u>Miscellaneous sources</u>	
13.1	Wildfires and prescribed burning	a
13.2	Fugitive dust	a

[*] Data for numbered categories are given Table B.2-2. Particle size data on "a" categories are found in the AP-42 text; for "b" categories, in Appendix B.1; and for "c" categories, in AP-42 *Volume II: Mobile Sources*.

Figure B.2-2. CALCULATION SHEET

SOURCE IDENTIFICATION
Source name and address: ____________________
____
____

Process description: ____________________
AP-42 Section: ____________________
Uncontrolled AP-42 emission factor: ____________________ (units)
Activity parameter: ____________________ (units)
Uncontrolled emissions: ____________________ (units)

UNCONTROLLED SIZE EMISSIONS
Category name: ____________________
Category number: _____

	Particle size (µm)		
	≤ 2.5	≤ 6	≤ 10
Generic distribution, Cumulative percent equal to or less than the size:			
Cumulative mass ≤ particle size emissions (tons/year):			

CONTROLLED SIZE EMISSIONS*
Type of control device: ____________________

	Particle size (µm)		
	0 - 2.5	2.5 - 6	6 - 10
Collection efficiency (Table B.2-3):			
Mass in size range** before control (tons/year):			
Mass in size range after control (tons/year):			
Cumulative mass (tons/year):			

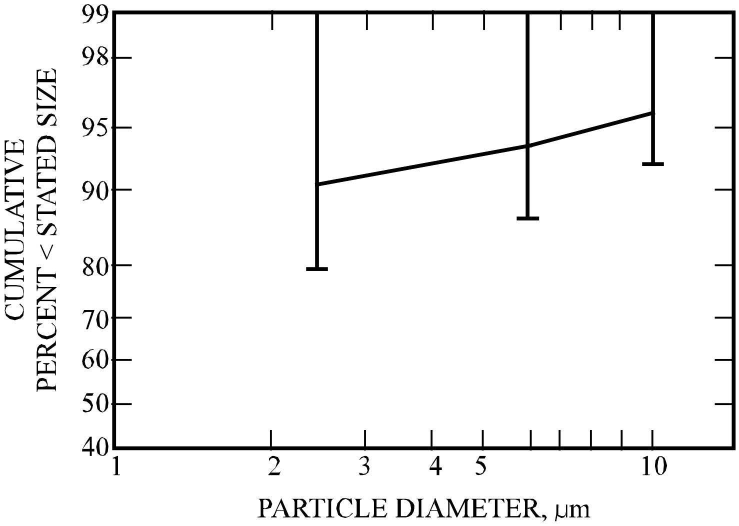
* These data do not include results for the greater than 10 µm particle size range.
** Uncontrolled size data are cumulative percent equal to or less than the size. Control efficiency data apply only to size range and are not cumulative.

Table B.2-2. DESCRIPTION OF PARTICLE SIZE CATEGORIES

Category: 1
Process: Stationary Internal Combustion Engines
Material: Gasoline and Diesel Fuel

Category 1 covers size-specific emissions from stationary internal combustion engines. The particulate emissions are generated from fuel combustion.

REFERENCES: 1,9



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	82			
2.0[a]	88			
2.5	90	78	99	11
3.0[a]	90			
4.0[a]	92			
5.0[a]	93			
6.0	93	86	99	7
10.0	96	92	99	4

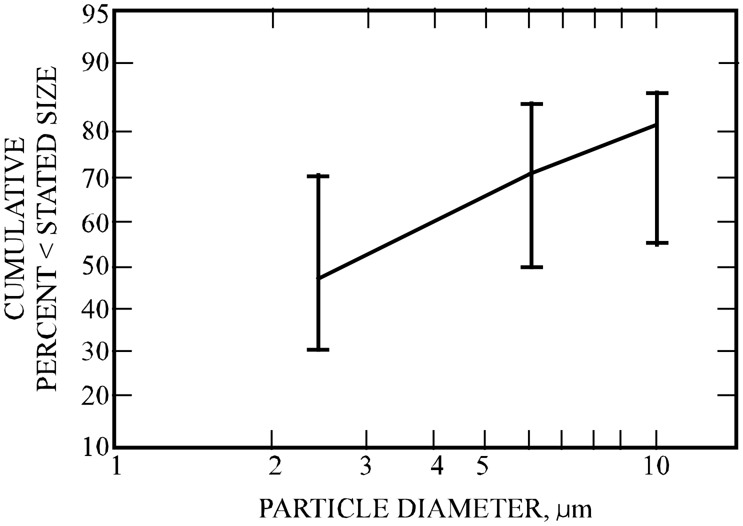
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 2
Process: Combustion
Material: Mixed Fuels

Category 2 covers boilers firing a mixture of fuels, regardless of the fuel combination. The fuels include gas, coal, coke, and petroleum. Particulate emissions are generated by firing these miscellaneous fuels.

REFERENCE: 1



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	23			
2.0[a]	40			
2.5	45	32	70	17
3.0[a]	50			
4.0[a]	58			
5.0[a]	64			
6.0	70	49	84	14
10.0	79	56	87	12

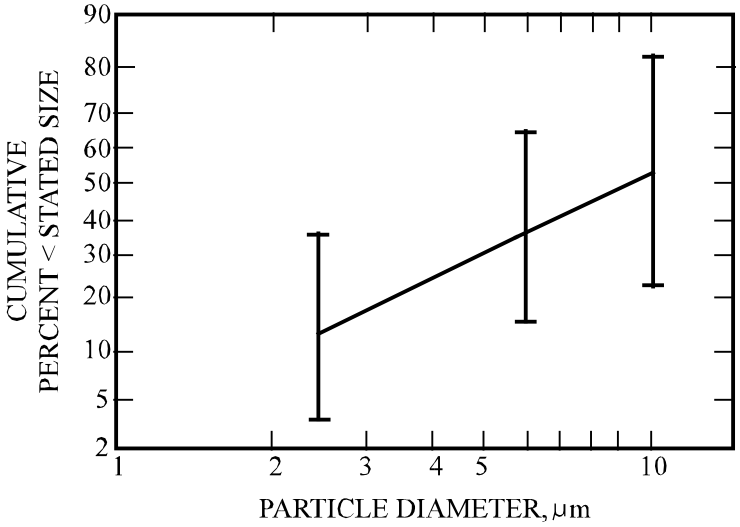
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 3
Process: Mechanically Generated
Material: Aggregate, Unprocessed Ores

Category 3 covers material handling and processing of aggregate and unprocessed ore. This broad category includes emissions from milling, grinding, crushing, screening, conveying, cooling, and drying of material. Emissions are generated through either the movement of the material or the interaction of the material with mechanical devices.

REFERENCES: 1-2,4,7



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	4			
2.0[a]	11			
2.5	15	3	35	7
3.0[a]	18			
4.0[a]	25			
5.0[a]	30			
6.0	34	15	65	13
10.0	51	23	81	14

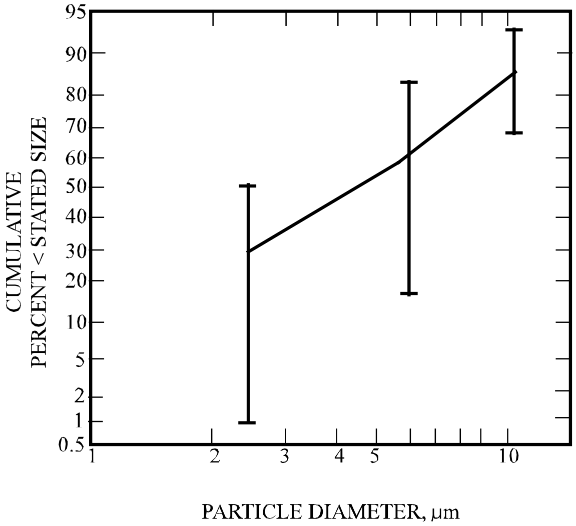
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category:	4
Process:	Mechanically Generated
Material:	Processed Ores and Nonmetallic Minerals

Category 4 covers material handling and processing of processed ores and minerals. While similar to Category 3, processed ores can be expected to have a greater size consistency than unprocessed ores. Particulate emissions are a result of agitating the materials by screening or transfer during size reduction and beneficiation of the materials by grinding and fine milling and by drying.

REFERENCE: 1



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	6			
2.0[a]	21			
2.5	30	1	51	19
3.0[a]	36			
4.0[a]	48			
5.0[a]	58			
6.0	62	17	83	17
10.0	85	70	93	7

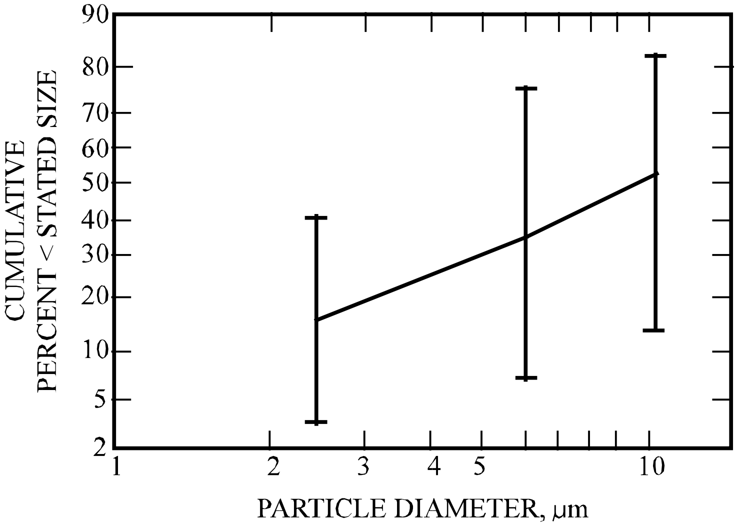
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 5
Process: Calcining and Other Heat Reaction Processes
Material: Aggregate, Unprocessed Ores

Category 5 covers the use of calciners and kilns in processing a variety of aggregates and unprocessed ores. Emissions are a result of these high temperature operations.

REFERENCES: 1-2,8



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	6			
2.0[a]	13			
2.5	18	3	42	11
3.0[a]	21			
4.0[a]	28			
5.0[a]	33			
6.0	37	13	74	19
10.0	53	25	84	19

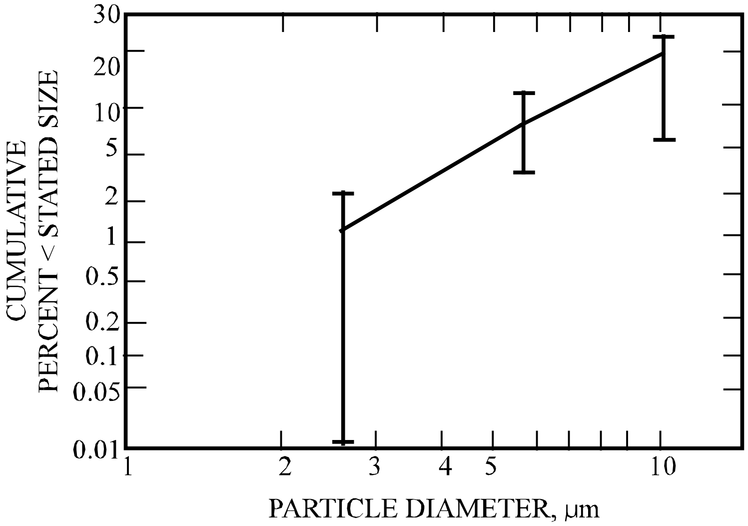
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 6
Process: Grain Handling
Material: Grain

Category 6 covers various grain handling (versus grain processing) operations. These processes could include material transfer, ginning and other miscellaneous handling of grain. Emissions are generated by mechanical agitation of the material.

REFERENCES: 1,5



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	0.07			
2.0[a]	0.60			
2.5	1	0	2	1
3.0[a]	2			
4.0[a]	3			
5.0[a]	5			
6.0	7	3	12	3
10.0	15	6	25	7

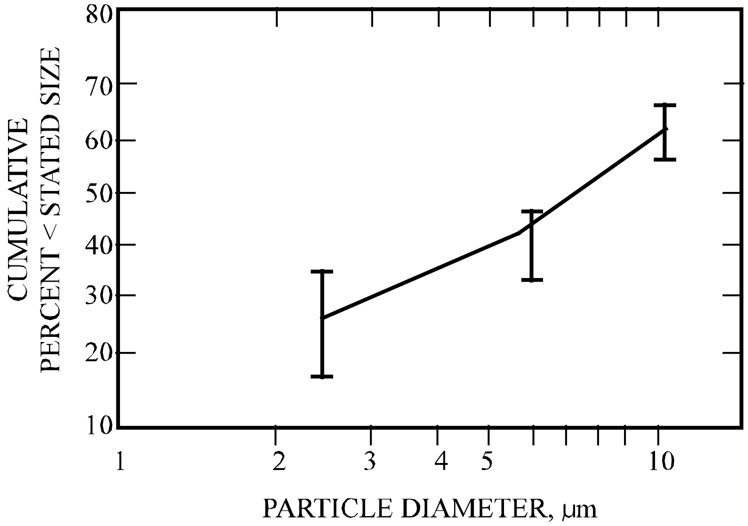
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 7
Process: Grain Processing
Material: Grain

Category 7 covers grain processing operations such as drying, screening, grinding, and milling. The particulate emissions are generated during forced air flow, separation, or size reduction.

REFERENCES: 1-2



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	8			
2.0[a]	18			
2.5	23	17	34	9
3.0[a]	27			
4.0[a]	34			
5.0[a]	40			
6.0	43	35	48	7
10.0	61	56	65	5

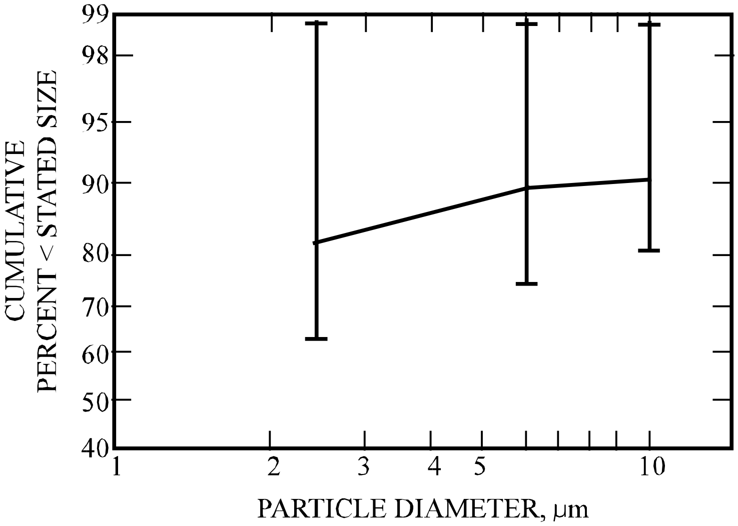
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category: 8
Process: Melting, Smelting, Refining
Material: Metals, except Aluminum

Category 8 covers the melting, smelting, and refining of metals (including glass) other than aluminum. All primary and secondary production processes for these materials which involve a physical or chemical change are included in this category. Materials handling and transfer are not included. Particulate emissions are a result of high temperature melting, smelting, and refining.

REFERENCES: 1-2



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	72			
2.0[a]	80			
2.5	82	63	99	12
3.0[a]	84			
4.0[a]	86			
5.0[a]	88			
6.0	89	75	99	9
10.0	92	80	99	7

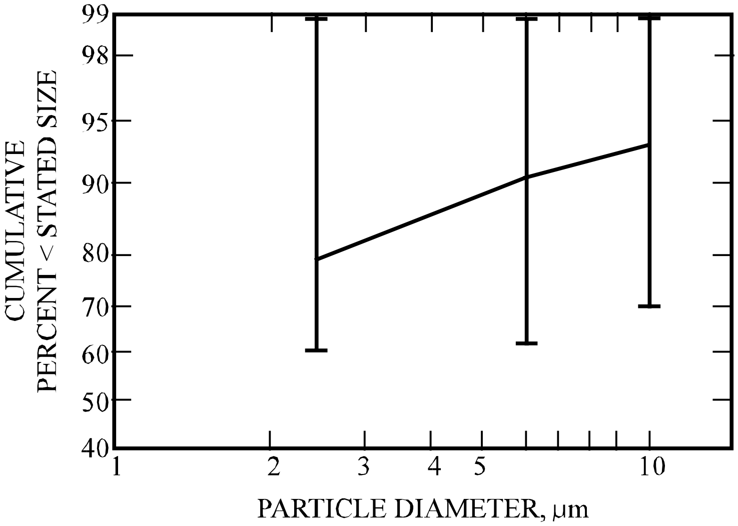
[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

Table B.2.2 (cont.).

Category:	9
Process:	Condensation, Hydration, Absorption, Prilling, and Distillation
Material:	All

Category 9 covers condensation, hydration, absorption, prilling, and distillation of all materials. These processes involve the physical separation or combination of a wide variety of materials such as sulfuric acid and ammonium nitrate fertilizer. (Coke ovens are included since they can be considered a distillation process which separates the volatile matter from coal to produce coke.)

REFERENCES: 1,3



Particle Size, µm	Cumulative % ≤ Stated Size (Uncontrolled)	Minimum Value	Maximum Value	Standard Deviation
1.0[a]	60			
2.0[a]	74			
2.5	78	59	99	17
3.0[a]	81			
4.0[a]	85			
5.0[a]	88			
6.0	91	61	99	12
10.0	94	71	99	9

[a] Value calculated from data reported at 2.5, 6.0, and 10.0 µm. No statistical parameters are given for the calculated value.

B.2.3 How To Use The Generalized Particle Size Distributions For Controlled Processes

To calculate the size distribution and the size-specific emissions for a source with a particulate control device, the user first calculates the uncontrolled size-specific emissions. Next, the fractional control efficiency for the control device is estimated using Table B.2-3. The Calculation Sheet provided (Figure B.2-2) allows the user to record the type of control device and the collection efficiencies from Table B.2-3, the mass in the size range before and after control, and the cumulative mass. The user will note that the uncontrolled size data are expressed in cumulative fraction less than the stated size. The control efficiency data apply only to the size range indicated and are not cumulative. These data do not include results for the greater than 10 µm particle size range. In order to account for the total controlled emissions, particles greater than 10 µm in size must be included.

B.2.4 Example Calculation

An example calculation of uncontrolled total particulate emissions, uncontrolled size-specific emissions, and controlled size specific emission is shown in Figure B.2-1. A blank Calculation Sheet is provided in Figure B.2-2.

Table B.2-3. TYPICAL COLLECTION EFFICIENCIES OF VARIOUS PARTICULATE CONTROL DEVICES[a]
(%)

AIRS Code[b]	Type Of Collector	Particle Size (µm) 0 - 2.5	2.5 - 6	6 - 10
001	Wet scrubber - hi-efficiency	90	95	99
002	Wet scrubber - med-efficiency	25	85	95
003	Wet scrubber - low-efficiency	20	80	90
004	Gravity collector - hi-efficiency	3.6	5	6
005	Gravity collector - med-efficiency	2.9	4	4.8
006	Gravity collector - low-efficiency	1.5	3.2	3.7
007	Centrifugal collector - hi-efficiency	80	95	95
008	Centrifugal collector - med-efficiency	50	75	85
009	Centrifugal collector - low-efficiency	10	35	50
010	Electrostatic precipitator - hi-efficiency	95	99	99.5
011	Electrostatic precipitator - med-efficiency			
	boilers	50	80	94
	other	80	90	97
012	Electrostatic precipitator - low-efficiency			
	boilers	40	70	90
	other	70	80	90
014	Mist eliminator - high velocity >250 FPM	10	75	90
015	Mist eliminator - low velocity <250 FPM	5	40	75

Table B.2-3 (cont.).

AIRS Code[b]	Type Of Collector	Particle Size (µm)		
		0 - 2.5	2.5 - 6	6 - 10
016	Fabric filter - high temperature	99	99.5	99.5
017	Fabric filter - med temperature	99	99.5	99.5
018	Fabric filter - low temperature	99	99.5	99.5
046	Process change	NA	NA	NA
049	Liquid filtration system	50	75	85
050	Packed-gas absorption column	90	95	99
051	Tray-type gas absorption column	25	85	95
052	Spray tower	20	80	90
053	Venturi scrubber	90	95	99
054	Process enclosed	1.5	3.2	3.7
055	Impingement plate scrubber	25	95	99
056	Dynamic separator (dry)	90	95	99
057	Dynamic separator (wet)	50	75	85
058	Mat or panel filter - mist collector	92	94	97
059	Metal fabric filter screen	10	15	20
061	Dust suppression by water sprays	40	65	90
062	Dust suppression by chemical stabilizer or wetting agents	40	65	90
063	Gravel bed filter	0	5	80
064	Annular ring filter	80	90	97
071	Fluid bed dry scrubber	10	20	90
075	Single cyclone	10	35	50
076	Multiple cyclone w/o fly ash reinjection	80	95	95
077	Multiple cyclone w/fly ash reinjection	50	75	85
085	Wet cyclonic separator	50	75	85
086	Water curtain	10	45	90

[a] Data represent an average of actual efficiencies. Efficiencies are representative of well designed and well operated control equipment. Site-specific factors (e. g., type of particulate being collected, varying pressure drops across scrubbers, maintenance of equipment, etc.) will affect collection efficiencies. Efficiencies shown are intended to provide guidance for estimating control equipment performance when source-specific data are not available. NA = not applicable.

[b] Control codes in Aerometric Information Retrieval System (AIRS), formerly National Emissions Data Systems.

References For Appendix B.2

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APPENDIX C.1

PROCEDURES FOR SAMPLING SURFACE/BULK DUST LOADING

Appendix C.1

Procedures For Sampling Surface/Bulk Dust Loading

This appendix presents procedures recommended for the collection of material samples from paved and unpaved roads and from bulk storage piles. (AP-42, Appendix C.2, "Procedures For Laboratory Analysis Of Surface/Bulk Dust Loading Samples", presents analogous information for the analysis of the samples.) These recommended procedures are based on a review of American Society For Testing And Materials (ASTM) methods, such as C-136 (sieve analysis) and D-2216 (moisture content). The recommendations follow ASTM standards where practical, and where not, an effort has been made to develop procedures consistent with the intent of the pertinent ASTM standards.

This appendix emphasizes that, before starting any field sampling program, one must first define the study area of interest and then determine the number of samples that can be collected and analyzed within the constraints of time, labor, and money available. For example, the study area could be defined as an individual industrial plant with its network of paved/unpaved roadways and material piles. In that instance, it is advantageous to collect a separate sample for each major dust source in the plant. This level of resolution is useful in developing cost-effective emission reduction plans. On the other hand, if the area of interest is geographically large (say a city or county, with a network of public roads), collecting at least 1 sample from each source would be highly impractical. However, in such an area, it is important to obtain samples representative of different source types within the area.

C.1.1 Samples From Unpaved Roads

Objective -

The overall objective in an unpaved road sampling program is to inventory the mass of particulate matter (PM) emissions from the roads. This is typically done by:

1. Collecting "representative" samples of the loose surface material from the road;
2. Analyzing the samples to determine silt fractions; and
3. Using the results in the predictive emission factor model given in AP-42, Section 13.2.2, Unpaved Roads, together with traffic data (e. g., number of vehicles traveling the road each day).

Before any field sampling program, it is necessary to define the study area of interest and to determine the number of unpaved road samples that can be collected and analyzed within the constraints of time, labor, and money available. For example, the study area could be defined as a very specific industrial plant having a network of roadways. Here it is advantageous to collect a separate sample for each major unpaved road in the plant. This level of resolution is useful in developing cost-effective emission reduction plans involving dust suppressants or traffic rerouting. On the other hand, the area of interest may be geographically large, and well-defined traffic information may not be easily obtained. In this case, resolution of the PM emission inventory to specific road segments would not be feasible, and it would be more important to obtain representative road-type samples within the area by aggregating several sample increments.

Procedure -

For a network consisting of many relatively short roads contained in a *well-defined study area* (as would be the case at an industrial plant), it is recommended that one collect a sample for each 0.8 kilometers (km) (0.5 miles [mi]) length, or portion thereof, for each major road segment. Here, the term "road segment" refers to the length of road between intersections (the nodes of the network) with other paved or unpaved roads. Thus, for a major segment 1 km (0.6 mi) long, 2 samples are recommended.

For longer roads in *study areas that are spatially diverse*, it is recommended that one collect a sample for each 4.8 km (3 mi) length of the road. Composite a sample from a minimum of 3 incremental samples. Collect the first sample increment at a random location within the first 0.8 km (0.5 mi), with additional increments taken from each remaining 0.8 km (0.5 mi) of the road, up to a maximum length of 4.8 km (3 mi). For a road less than 1.5 mi in length, an acceptable method for selecting sites for the increments is based on drawing 3 random numbers (x1, x2, x3) between zero and the length. Random numbers may be obtained from tabulations in statistical reference books, or scientific calculators may be used to generate pseudorandom numbers. See Figure C.1-1.

The following steps describe the collection method for samples (increments).

1. Ensure that the site offers an unobstructed view of traffic and that sampling personnel are visible to drivers. If the road is heavily traveled, use 1 person to "spot" and route traffic safely around another person collecting the surface sample (increment).

2. Using string or other suitable markers, mark a 0.3 meters (m) (1 foot [ft]) wide portion across the road. (WARNING: *Do not mark the collection area with a chalk line or in any other method likely to introduce fine material into the sample*.)

3. With a whisk broom and dustpan, remove the loose surface material from the hard road base. Do not abrade the base during sweeping. Sweeping should be performed slowly so that fine surface material is not injected into the air. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline).

4. Periodically deposit the swept material into a clean, labeled container of suitable size, such as a metal or plastic 19 liter (L) (5 gallon [gal]) bucket, having a sealable polyethylene liner. Increments may be mixed within this container.

5. Record the required information on the sample collection sheet (Figure C.1-2).

Sample Specifications -

For uncontrolled unpaved road surfaces, a gross sample of 5 kilograms (kg) (10 pounds [lb]) to 23 kg (50 lb) is desired. Samples of this size will require splitting to a size amenable for analysis (see Appendix C.2). For unpaved roads having been treated with chemical dust suppressants (such as petroleum resins, asphalt emulsions, etc.), the above goal may not be practical in well-defined study areas because a very large area would need to be swept. In general, a minimum of 400 grams (g) (1 lb) is required for silt and moisture analysis. Additional increments should be taken from heavily controlled unpaved surfaces, until the minimum sample mass has been achieved.

C.1.2 Samples From Paved Roads

Objective -

The overall objective in a paved road sampling program is to inventory the mass of particulate emissions from the roads. This is typically done by:

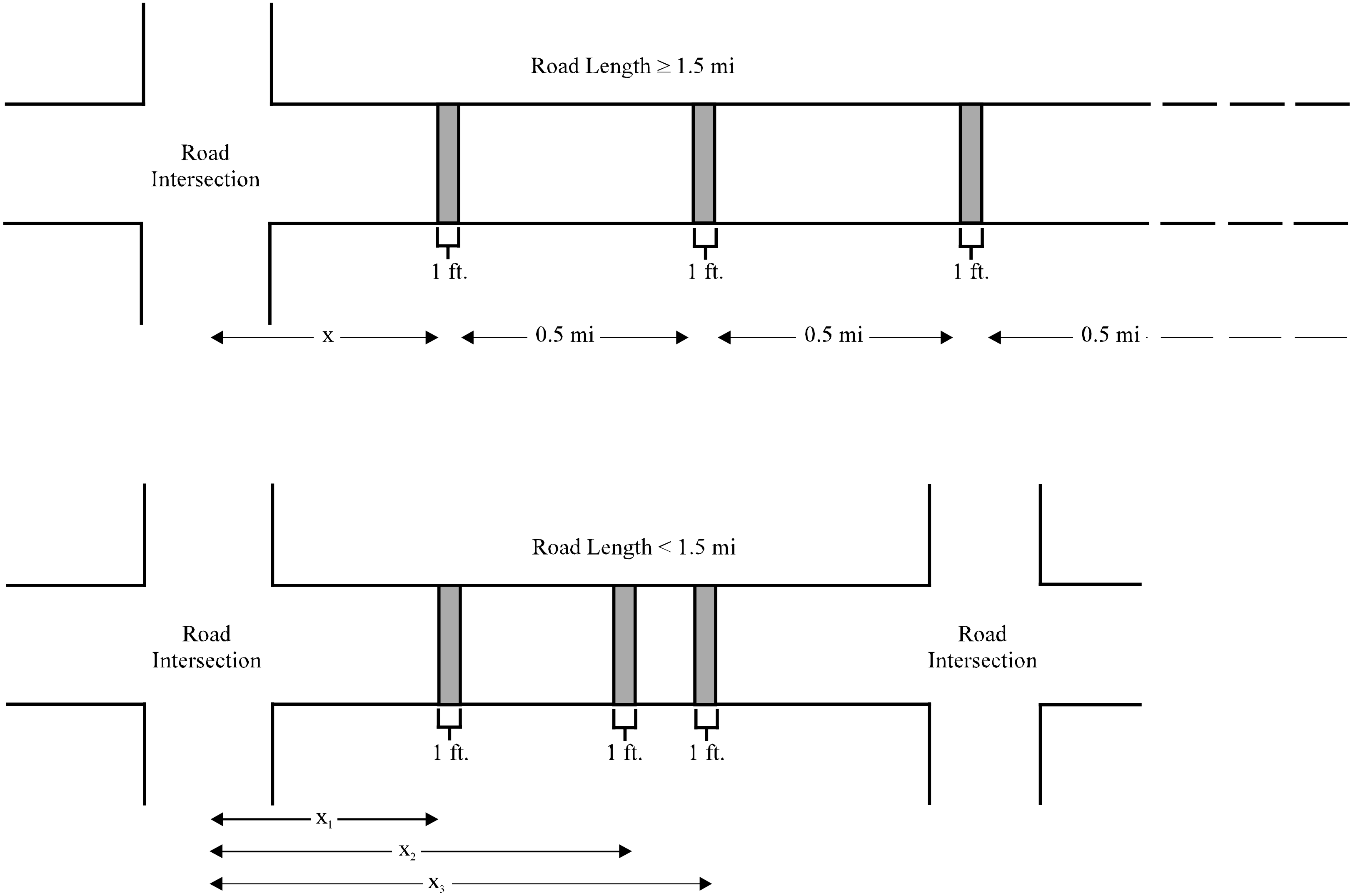

Figure C.1-1. Sampling locations for unpaved roads.

SAMPLING DATA FOR UNPAVED ROADS

Date Collected __________ Recorded by __________

Road Material (e.g., gravel, slag, dirt, etc.):* ____

Site of Sampling: ____

METHOD:
1. Sampling device: whisk broom and dustpan
2. Sampling depth: loose surface material (do not abrade road base)
3. Sample container: bucket with sealable liner
4. Gross sample specifications:
    a. Uncontrolled surfaces -- 5 kg (10 lb) to 23 kg (50 lb)
    b. Controlled surfaces -- minimum of 400 g (1 lb) is required for analysis

Refer to AP-42 Appendix B.1 for more detailed instructions.

Indicate any deviations from the above: ____

SAMPLING DATA COLLECTED:

Sample No.	Time	Location +	Surf. Area	Depth	Mass of Sample

* Indicate and give details if roads are controlled.
\+ Use code given on plant or road map for segment identification. Indicate sampling location on map.

Figure C.1-2. Example data form for unpaved road samples.

1. Collecting "representative" samples of the loose surface material from the road;
2. Analyzing the sample to determine the silt fraction; and
3. Combining the results with traffic data in a predictive emission factor model.

The remarks above about definition of the study area and the appropriate level of resolution for sampling unpaved roads are equally applicable to paved roads. Before a field sampling program, it is necessary first to define the study area of interest and then to determine the number of paved road samples that can be collected and analyzed. For example, in a well-defined study area (e. g., an industrial plant), it is advantageous to collect a separate sample for each major paved road, because the resolution can be useful in developing cost-effective emission reduction plans. Similarly, in geographically large study areas, it may be more important to obtain samples representative of road types within the area by aggregating several sample increments.

Compared to unpaved road sampling, planning for a paved road sample collection exercise necessarily involves greater consideration as to types of equipment to be used. Specifically, provisions must be made to accommodate the characteristics of the vacuum cleaner chosen. For example, paved road samples are collected by cleaning the surface with a vacuum cleaner with "tared" (i. e., weighed before use) filter bags. Upright "stick broom" vacuums use relatively small, lightweight filter bags, while bags for industrial-type vacuums are bulky and heavy. Because the mass collected is usually several times greater than the bag tare weight, uprights are thus well suited for collecting samples from lightly loaded road surfaces. On the other hand, on heavily loaded roads, the larger industrial-type vacuum bags are easier to use and can be more readily used to aggregate incremental samples from all road surfaces. These features are discussed further below.

Procedure -

For a network of many relatively short roads *contained in a well-defined study area* (as would be the case at an industrial plant), it is recommended that one collect a sample for each 0.8 km (0.5 mi) length, or portion thereof, for each major road segment. For a 1 km long (0.6 mi) segment, then, 2 samples are recommended. As mentioned, the term "road segment" refers to the length of road between intersections with other paved or unpaved roads (the nodes of the network).

For longer roads *in spatially heterogeneous study areas*, it is recommended that one collect a sample for each 4.8 km (3 mi) of sampled road length. Create a composite sample from a minimum of 3 incremental samples. Collect the first increment at a random location within the first 0.8 km (0.5 mi), with additional increments taken from each remaining 0.8 km (0.5 mi) of the road, up to a maximum length of 4.8 km (3 mi.) For a road less than 2.4 km (1.5 mi) long, an acceptable method for selecting sites for the increments is based on drawing 3 random numbers (x1, x2, x3) between zero and the length (See Figure C.1-3). Random numbers may be obtained from tabulations in statistical reference books, or scientific calculators may be used to generate pseudorandom numbers.

The following steps describe the collection method for samples (increments).

1. Ensure that the site offers an unobstructed view of traffic and that sampling personnel are visible to drivers. If the road is heavily traveled, use 1 crew member to "spot" and route traffic safely around another person collecting the surface sample (increment).

2. Using string or other suitable markers, mark the sampling portion across the road. (WARNING: *Do not mark the collection area with a chalk line or in any other method likely to introduce fine material into the sample*.) The widths may be varied between 0.3 m (1 ft) for visibly dirty roads and 3 m (10 ft) for clean roads. When an industrial-

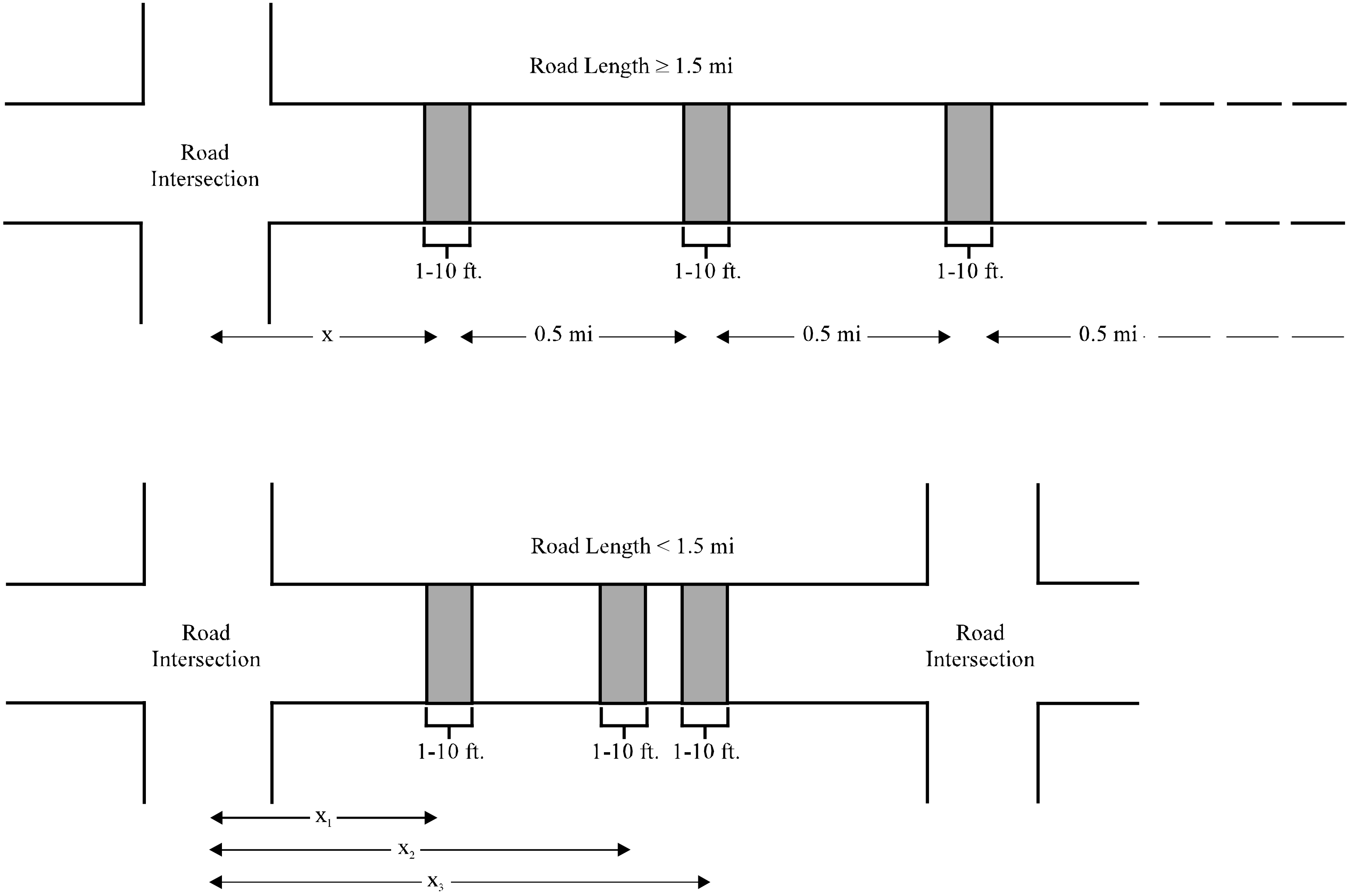

Figure C.1-3. Sampling locations for paved roads.

type vacuum is used to sample lightly loaded roads, a width greater than 3 m (10 ft) may be necessary to meet sample specifications, unless increments are being combined.

3. If large, loose material is present on the surface, it should be collected with a whisk broom and dustpan. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline). On roads with painted side markings, collect material "from white line to white line" (but avoid centerline mounds). Store the swept material in a clean, labeled container of suitable size, such as a metal or plastic 19 L (5 gal) bucket, with a sealable polyethylene liner. Increments for the same sample may be mixed within the container.

4. Vacuum the collection area using a portable vacuum cleaner fitted with an empty tared (preweighed) filter bag. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline). On roads with painted side markings, collect material "from white line to white line" (but avoid centerline mounds). The same filter bag may be used for different increments for 1 sample. For heavily loaded roads, more than 1 filter bag may be needed for a sample (increment).

5. Carefully remove the bag from the vacuum sweeper and check for tears or leaks. If necessary, reduce samples (using the procedure in Appendix C.2) from broom sweeping to a size amenable to analysis. Seal broom-swept material in a clean, labeled plastic jar for transport (alternatively, the swept material may be placed in the vacuum filter bag). Fold the unused portion of the filter bag, wrap a rubber band around the folded bag, and store the bag for transport.

6. Record the required information on the sample collection sheet (Figure C.1-4).

Sample Specifications -

When broom swept samples are collected, they should be at least 400 g (1 lb) for silt and moisture analysis. Vacuum swept samples should be at least 200 g (0.5 lb). Also, the weight of an "exposed" filter bag should be at least 3 to 5 times greater than when empty. Additional increments should be taken until these sample mass goals have been attained.

C.1.3 Samples From Storage Piles

Objective -

The overall objective of a storage pile sampling and analysis program is to inventory particulate matter emissions from the storage and handling of materials. This is done typically by:

1. Collecting "representative" samples of the material;
2. Analyzing the samples to determine moisture and silt contents; and
3. Combining analytical results with material throughput and meteorological information in an emission factor model.

As initial steps in storage pile sampling, it is necessary to decide (a) what emission mechanisms - material load-in to and load-out from the pile, wind erosion of the piles - are of interest, and (b) how many samples can be collected and analyzed, given time and monetary constraints. (In general, annual average PM emissions from material handling can be expected to be

SAMPLING DATA FOR PAVED ROADS

Date Collected __________ Recorded by __________

Sampling location* ______________________________ No. of Lanes __________

Surface type (e.g., asphalt, concrete, etc.)_______________________________________

Surface condition (e.g., good, rutted, etc.) _______________________________________

* Use code given on plant or road map for segment identification. Indication sampling location on map.

METHOD:

1. Sampling device: portable vacuum cleaner (whisk broom and dustpan if heavy loading present)
2. Sampling depth: loose surface material (do not sample curb areas or other untravelled portions of the road)
3. Sample container: tared and numbered vacuum cleaner bags (bucket with sealable liner if heavy loading present)
4. Gross sample specifications: Vacuum swept samples should be at least 200 g (0.5 lb), with the exposed filter bag weight should be at least 3 to 5 times greater than the empty bag tare weight.

Refer to AP-42 Appendix C.1 for more detailed instructions.

Indicate any deviations from the above: ____
____
____

SAMPLING DATA COLLECTED:

Sample No.	Vacuum Bag ID	Vacuum Bag Tare Wgt (g)	Sampling Surface Dimensions (l x w)	Time	Mass of Broom-Swept Sample +

+ Enter "0" if no broom sweeping is performed.

Figure C.1-4. Example data form for paved roads.

much greater than those from wind erosion.) For an industrial plant, it is recommended that at least 1 sample be collected for each major type of material handled within the facility.

In a program to characterize load-in emissions, representative samples should be collected from material recently loaded into the pile. Similarly, representative samples for load-out emissions should be collected from areas that are worked by load-out equipment such as front end loaders or clamshells. For most "active" piles (i. e., those with frequent load-in and load-out operations), 1 sample may be considered representative of both loaded-in and loaded-out materials. Wind erosion material samples should be representative of the surfaces exposed to the wind.

In general, samples should consist of increments taken from all exposed areas of the pile (i. e., top, middle, and bottom). If the same material is stored in several piles, it is recommended that piles with at least 25 percent of the amount in storage be sampled. For large piles that are common in industrial settings (e. g., quarries, iron and steel plants), access to some portions may be impossible for the person collecting the sample. In that case, increments should be taken no higher than it is practical for a person to climb carrying a shovel and a pail.

Procedure -

The following steps describe the method for collecting samples from storage piles:

1. Sketch plan and elevation views of the pile. Indicate if any portion is not accessible. Use the sketch to plan where the N increments will be taken by dividing the perimeter into N-1 roughly equivalent segments.

    a. For a large pile, collect a minimum of 10 increments, as near to mid-height of the pile as practical.

    b. For a small pile, a sample should be a minimum of 6 increments, evenly distributed among the top, middle, and bottom.

    "Small" or "large" piles, for practical purposes, may be defined as those piles which can or cannot, respectively, be scaled by a person carrying a shovel and pail.

2. Collect material with a straight-point shovel or a small garden spade, and store the increments in a clean, labeled container of suitable size (such as a metal or plastic 19 L [5 gal] bucket) with a sealable polyethylene liner. Depending upon the ultimate goals of the sampling program, choose 1 of the following procedures:

    a. To characterize emissions from *material handling operations at an active pile*, take increments from the portions of the pile which most recently had material added and removed. Collect the material with a shovel to a depth of 10 to 15 centimeters (cm) (4 to 6 inches [in]). Do not deliberately avoid larger pieces of aggregate present on the surface.

    b. To characterize *handling emissions from an inactive pile*, obtain increments of the core material from a 1 m (3 ft) depth in the pile. A sampling tube 2 m (6 ft) long, with a diameter at least 10 times the diameter of the largest particle being sampled, is recommended for these samples. Note that, for piles containing large particles, the diameter recommendation may be impractical.

c. If characterization of *wind erosion*, rather than material handling is the goal of the sampling program, collect the increments by skimming the surface in an upwards direction. The depth of the sample should be 2.5 cm (1 in), or the diameter of the largest particle, whichever is less. Do not deliberately avoid collecting larger pieces of aggregate present on the surface.

In most instances, collection method "a" should be selected.

3. Record the required information on the sample collection sheet (Figure C.1-5). Note the space for deviations from the summarized method.

Sample Specifications -

For any of the procedures, the sample mass collected should be at least 5 kg (10 lb). When most materials are sampled with procedures 2a or 2b, 10 increments will normally result in a sample of at least 23 kg (50 lb). Note that storage pile samples usually require splitting to a size more amenable to laboratory analysis.

SAMPLING DATA FOR STORAGE PILES

Date Collected __________ Recorded by __________

Type of material sampled ____

Sampling location* ____

METHOD:

1. Sampling device: pointed shovel (hollow sampling tube if inactive pile is to be sampled)
2. Sampling depth:
   For material handling of active piles: 10-15 cm (4-6 in.)
   For material handling of inactive piles: 1 m (3 ft)
   For wind erosion samples: 2.5 cm (1 in.) or depth of the largest particle (whichever is less)
3. Sample container: bucket with sealable liner
4. Gross sample specifications:
   For material handling of active or inactive piles: minimum of 6 increments with total sample weight of 5 kg (10 lb) [10 increments totalling 23 kg (50 lb) are recommended]
   For wind erosion samples: minimum of 6 increments with total sample weight of 5 kg (10 lb)

Refer to AP-42 Appendix C.1 for more detailed instructions.

Indicate any deviations from the above: ____
____
____

SAMPLING DATA COLLECTED:

Sample No.	Time	Location* of Sample Collection	Device Used S/T **	Depth	Mass of Sample

* Use code given of plant or area map for pile/sample identification. Indicate each sampling location on map.

** Indicate whether shovel or tube.

Figure C.1-5. Example data form for storage piles.

APPENDIX C.2

PROCEDURES FOR LABORATORY ANALYSIS OF SURFACE/BULK DUST LOADING SAMPLES

Appendix C.2

Procedures For Laboratory Analysis Of Surface/Bulk Dust Loading Samples

This appendix discusses procedures recommended for the analysis of samples collected from paved and unpaved surfaces and from bulk storage piles. (AP-42 Appendix C.1, "Procedures For Sampling Surface/Bulk Dust Loading", presents procedures for the collection of these samples.) These recommended procedures are based on a review of American Society For Testing And Materials (ASTM) methods, such as C-136 (sieve analysis) or D-2216 (moisture content). The recommendations follow ASTM standards where practical, and where not, an effort has been made to develop procedures consistent with the intent of the pertinent ASTM standards.

C.2.1 Sample Splitting

Objective -

The collection procedures presented in Appendix C.1 can result in samples that need to be reduced in size before laboratory analysis. Samples are often unwieldy, and field splitting is advisable before transporting the samples.

The size of the laboratory sample is important. Too small a sample will not be representative, and too much sample will be unnecessary as well as unwieldy. Ideally, one would like to analyze the entire gross sample in batches, but that is not practical. While all ASTM standards acknowledge this impracticality, they disagree on the exact optimum size, as indicated by the range of recommended samples, extending from 0.05 to 27 kilograms (kg) (0.1 to 60 pounds [lb]).

Splitting a sample may be necessary before a proper analysis. The principle in sizing a laboratory sample for silt analysis is to have sufficient coarse and fine portions both to be representative of the material and to allow sufficient mass on each sieve to assure accurate weighing. A laboratory sample of 400 to 1,600 grams (g) is recommended because of the capacity of normally available scales (1.6 to 2.6 kg). A larger sample than this may produce "screen blinding" for the 20 centimeter (cm) (8 inch [in.]) diameter screens normally available for silt analysis. Screen blinding can also occur with small samples of finer texture. Finally, the sample mass should be such that it can be spread out in a reasonably sized drying pan to a depth of < 2.5 cm (1 in.).

Two methods are recommended for sample splitting: riffles, and coning and quartering. Both procedures are described below.

Procedures -

Figure C.2-1 shows 2 riffles for sample division. Riffle slot widths should be at least 3 times the size of the largest aggregate in the material being divided. The following quote from ASTM Standard Method D2013-72 describes the use of the riffle.

Divide the gross sample by using a riffle. Riffles properly used will reduce sample variability but cannot eliminate it. Riffles are shown in Figure C.2-1. Pass the material through the riffle from a feed scoop, feed bucket, or riffle pan having a lip or opening the full length of the riffle. When using any of the above containers to feed the riffle, spread the material evenly in the container, raise the container, and hold it with its front edge resting on top of the feed chute, then slowly tilt it so that the material flows in a uniform stream through the hopper straight down over the center of the riffle into all the slots, thence into the riffle pans, one-half of the sample being collected in a pan.

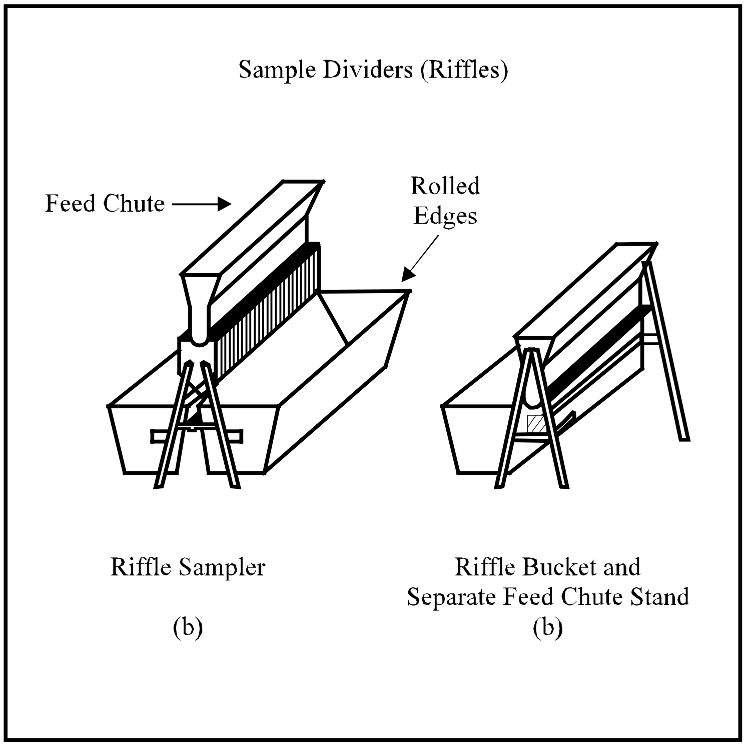

Figure C.2-1. Sample riffle dividers.

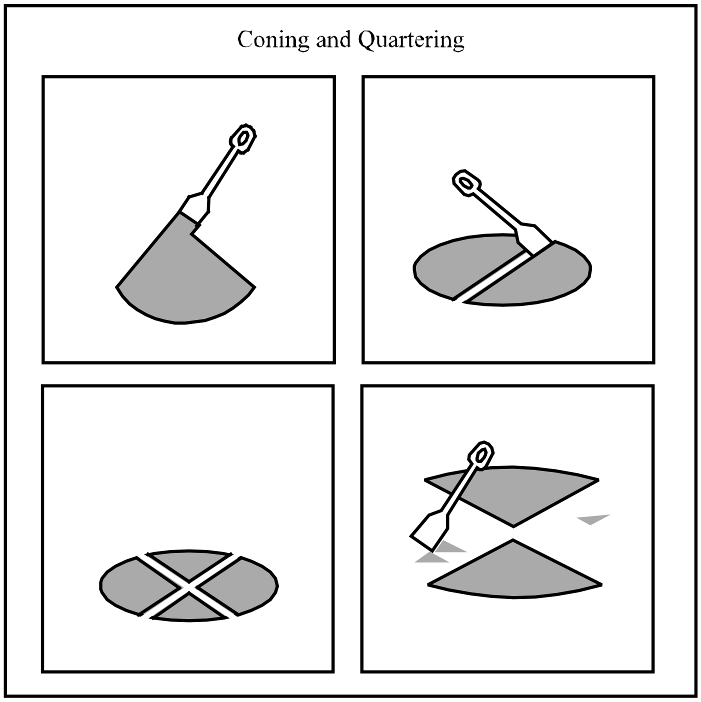

Figure C.2-2. Procedure for coning and quartering.

Under no circumstances shovel the sample into the riffle, or dribble into the riffle from a small-mouthed container. Do not allow the material to build up in or above the riffle slots. If it does not flow freely through the slots, shake or vibrate the riffle to facilitate even flow.[1]

Coning and quartering is a simple procedure useful with all powdered materials and with sample sizes ranging from a few grams to several hundred pounds.[2] Oversized material, defined as > 0.6 millimeters (mm) (3/8 in.) in diameter, should be removed before quartering and be weighed in a "tared" container (one for which its empty weight is known).

Preferably, perform the coning and quartering operation on a floor covered with clean 10 mil plastic. Take care that the material is not contaminated by anything on the floor or that any portion is not lost through cracks or holes. Samples likely affected by moisture or drying must be handled rapidly, preferably in a controlled atmosphere, and sealed in a container to prevent further changes during transportation and storage.

The procedure for coning and quartering is illustrated in Figure C.2-2. The following procedure should be used:

1. Mix the material and shovel it into a neat cone.

2. Flatten the cone by pressing the top without further mixing.

3. Divide the flat circular pile into equal quarters by cutting or scraping out 2 diameters at right angles.

4. Discard 2 opposite quarters.

5. Thoroughly mix the 2 remaining quarters, shovel them into a cone, and repeat the quartering and discarding procedures until the sample is reduced to 0.4 to 1.8 kg (1 to 4 lb).

C.2.2 Moisture Analysis

Paved road samples generally are not to be oven dried because vacuum filter bags are used to collect the samples. After a sample has been recovered by dissection of the bag, it is combined with any broom swept material for silt analysis. All other sample types are oven dried to determine moisture content before sieving.

Procedure -

1. Heat the oven to approximately 110°C (230°F). Record oven temperature. (See Figure C.2-3.)

2. Record the make, capacity, and smallest division of the scale.

3. Weigh the empty laboratory sample containers which will be placed in the oven to determine their tare weight. Weigh any lidded containers with the lids. Record the tare weight(s). Check zero before each weighing.

4. Weigh the laboratory sample(s) in the container(s). For materials with high moisture content, assure that any standing moisture is included in the laboratory sample container. Record the combined weight(s). Check zero before each weighing.

MOISTURE ANALYSIS

Date: ______________________________

Sample No: __________________________
Material: ____________________________

Split Sample Balance: __________________
Make ____________________________
Capacity __________________________
Smallest division ____________________

Total Sample Weight: __________________
(Excl. Container)
Number of Splits: _____________________

Split Sample Weight (before drying)
Pan + Sample: _______________________
Pan: ______________________________
Wet Sample: _________________________

By: ____________________________

Oven Temperature: __________________
Date In: ________ Date Out: ________
Time In: ________ Time Out: ________
Drying Time: ______________________

Sample Weight (after drying)
Pan + Sample: _____________________
Pan: _____________________________
Dry Sample: ______________________

MOISTURE CONTENT:
(A) Wet Sample Wt. _________________
(B) Dry Sample Wt. _________________
(C) Difference Wt. _________________

$\frac{C \times 100}{A}$ = _________ % Moisture

Figure C.2-3. Example moisture analysis form.

5. Place sample in oven and dry overnight. Materials composed of hydrated minerals or organic material such as coal and certain soils should be dried for only 1.5 hours.

6. Remove sample container from oven and (a) weigh immediately if uncovered, being careful of the hot container; or (b) place a tight-fitting lid on the container and let it cool before weighing. Record the combined sample and container weight(s). Check zero before weighing.

7. Calculate the moisture, as the initial weight of the sample and container, minus the oven-dried weight of the sample and container, divided by the initial weight of the sample alone. Record the value.

8. Calculate the sample weight to be used in the silt analysis, as the oven-dried weight of the sample and container, minus the weight of the container. Record the value.

C.2.3 Silt Analysis

Objective -

Several open dust emission factors have been found to be correlated with the silt content (< 200 mesh) of the material being disturbed. The basic procedure for silt content determination is mechanical, dry sieving. For sources other than paved roads, the same sample which was oven-dried to determine moisture content is then mechanically sieved.

For paved road samples, the broom-swept particles and the vacuum-swept dust are individually weighed on a beam balance. The broom-swept particles are weighed in a container, and the vacuum-swept dust is weighed in the bag of the vacuum, which was tared before sample collection. After weighing the sample to calculate total surface dust loading on the traveled lanes, combine the broom-swept particles and the vacuumed dust. Such a composite sample is usually small and may not require splitting in preparation for sieving.

Procedure -

1. Select the appropriate 20-cm (8-in.) diameter, 5-cm (2-in.) deep sieve sizes. Recommended U. S. Standard Series sizes are 3/8 in., No. 4, No. 40, No. 100, No. 140, No. 200, and a pan. Comparable Tyler Series sizes can also be used. The No. 20 and the No. 200 are mandatory. The others can be varied if the recommended sieves are not available, or if buildup on 1 particulate sieve during sieving indicates that an intermediate sieve should be inserted.

2. Obtain a mechanical sieving device, such as a vibratory shaker or a Roto-Tap® without the tapping function.

3. Clean the sieves with compressed air and/or a soft brush. Any material lodged in the sieve openings or adhering to the sides of the sieve should be removed, without handling the screen roughly, if possible.

4. Obtain a scale (capacity of at least 1600 grams [g] or 3.5 lb) and record make, capacity, smallest division, date of last calibration, and accuracy. (See Figure C.2-4.)

5. Weigh the sieves and pan to determine tare weights. Check the zero before every weighing. Record the weights.

6. After nesting the sieves in decreasing order of size, and with pan at the bottom, dump dried laboratory sample (preferably immediately after moisture analysis) into the top sieve. The sample should weigh between ~ 400 and 1600 g (~ 0.9 and 3.5 lb). This amount will vary for finely textured materials, and 100 to 300 g may be sufficient when 90% of the sample passes a No. 8 (2.36 mm) sieve. Brush any fine material adhering to the sides of the container into the top sieve and cover the top sieve with a special lid normally purchased with the pan.

7. Place nested sieves into the mechanical sieving device and sieve for 10 minutes (min). Remove pan containing minus No. 200 and weigh. Repeat the sieving at 10-min intervals until the difference between 2 successive pan sample weighings (with the pan tare weight subtracted) is less than 3.0%. Do not sieve longer than 40 min.

8. Weigh each sieve and its contents and record the weight. Check the zero before every weighing.

9. Collect the laboratory sample. Place the sample in a separate container if further analysis is expected.

10. Calculate the percent of mass less than the 200 mesh screen (75 micrometers [µm]). This is the silt content.

SILT ANALYSIS

Date: ____________________

Sample No: ____________________
Material: ____________________

Make ____________________
Smallest Division ____________________

By: ____________________

Sample Weight (after drying)
Pan + Sample: ____________________
Pan: ____________________
Split Sample Balance: ____________________
Dry Sample: ____________________
Capacity: ____________________
Final Weight: ____________________

$$\% \text{ Silt} = \frac{\text{Net Weight} < 200 \text{ Mesh}}{\text{Total Net Weight}} \times 100 = \_\_\%$$

SIEVING

Time: Start:	Weight (Pan Only)
Initial (Tare):	
10 min:	
20 min:	
30 min:	
40 min:	

Screen	Tare Weight (Screen)	Final Weight (Screen + Sample)	Net Weight (Sample)	%
3/8 in.				
4 mesh				
10 mesh				
20 mesh				
40 mesh				
100 mesh				
140 mesh				
200 mesh				
Pan				

Figure C.2-4. Example silt analysis form.

References For Appendix C.2

1. "Standard Method Of Preparing Coal Samples For Analysis", *Annual Book Of ASTM Standards, 1977,* D2013-72, American Society For Testing And Materials, Philadelphia, PA, 1977.

2. L. Silverman, *et al.*, *Particle Size Analysis In Industrial Hygiene*, Academic Press, New York, 1971.