EMISSION FACTOR DOCUMENTATION FOR

AP-42 SECTION 1.3,

FUEL OIL COMBUSTION

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1. INTRODUCTION

An emission factor is an average value which relates the quantity (weight) of a pollutant released to the atmosphere with the activity associated with the release of that pollutant. Emission factors for many activities are listed in the document "Compilation of Air Pollutant Emission Factors" (AP-42) published by the U.S. Environmental Protection Agency (EPA) since 1972. The uses for the emission factors reported in AP-42 include:

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

The EPA routinely updates AP-42 in order to respond to the needs of State and local air pollution control programs, industry, as well as the Agency itself. Section 1.3 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to fuel oil combustion in stationary, external equipment.

The prior revisions of AP-42 Section 1.3 focused primarily on the criteria pollutants, together with particle sizing. The purpose of this revision is to update the data base for the earlier revisions and extend the section's scope to other pollutant species. Specifically, the scope of the current update includes the following:

- Updating of emission factors for criteria pollutants during baseline, uncontrolled operation using data that has become available since the prior revision (i.e., 1986).

- Inclusion of several non-criteria emission species for which data are available: organics speciation, air toxics, and greenhouse or ozone depletion gases [e.g., nitrous oxide (N_2O) and carbon dioxide (CO_2)].

- Expand and update the technical discussion and control efficiency data for boilers operating with nitrogen oxides (NO_x), carbon monoxide (CO), or particulate matter (PM) control systems.

The update of Section 1.3 of AP-42 began with a review of the existing version of Section 1.3. Spot checks were made on the quality of existing emission factors by selecting primary data references from the background files and recalculating emission factors.

An extensive literature review was undertaken to improve technology descriptions, update usage trends, and collect new test reports for criteria and non-criteria emissions. The new test reports were subjected to data quality review as outlined in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). The data points obtained from test reports receiving sufficiently high quality ratings were then combined with existing data, wherever possible, and used to produce new emission factors.

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

Chapter 2 of this report gives a description of the fuel oil combustion industry. It includes a characterization of fuel oil applications, an overview of the different process types, a description of emissions, and a description of the technology used to control emissions resulting from fuel oil combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emissions data reports, and the quality rating system for both emission data and emission factors. Chapter 4 details pollutant emission factor development. It includes reviews of specific data sets and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.3.

2. SOURCE DESCRIPTION

The amount and type of oil consumed, design of combustion equipment, and application of emission control technology have a direct bearing on emissions from oil-fired combustion equipment. This chapter characterizes oil applications, fuel oil combustion processes, and emission control technologies pertaining to the United States.

2.1 CHARACTERIZATION OF FUEL OIL APPLICATIONS

Annual consumption of fuel oil in boilers in the United States totalled about 4200 kJ (4400 x 10^{12} Btu) in 1990.[1] This consumption in boilers was divided into four sectors: (1) utility boilers producing steam for the generation of electricity; (2) industrial boilers generating steam or hot water for process heat, electricity generation, or space heat; (3) boilers used for space heating of commercial facilities; and (4) residential furnaces used for space heating purposes.

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 numbers 1 and 2 being distillate oils; numbers 5 and 6 being residual oils; and number 4 being either distillate oil or a mixture of distillate and residual oils. Grade 6 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 0.5 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications.

Being more viscous and less volatile than distillate oils, the heavier residual oils (grades 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue left over after the lighter fractions (e.g., 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.

Table 2-1 summarizes the Department of Energy data on oil use by combustion sector in 1990.[1]

2.2 PROCESS DESCRIPTIONS

The three major boiler configurations for fuel oil-fired combustors (i.e., watertube, firetube, and cast iron) are described below. 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.

2.2.1 Watertube Boilers

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.

Industrial watertube boilers are available as packaged or field erected units, in capacities ranging from less than 2.9 to over 200 MW [10 to over 700 million Btu per hour (MMBtu/hr)].[1] Utility oil-fired boilers are field erected and have thermal heat input ratings up to about 2,300 MW (8,000 MMBtu/hr). New industrial oil-fired boilers as large as 70 MW (250 MMBtu/hr) input capacity are typically shop assembled and shipped as packaged units. Larger oil-fired boilers are field-erected units assembled on-site. In general, field-erected watertube boilers are much more common than packaged units in the boiler size category above 58 MW (200 MMBtu/hr) input capacity whereas, below this capacity, watertube boilers are usually packaged. There are, however, packaged watertube units as large as 102 MW (350 MMBtu/hr) input capacity.

2.2.2 Firetube Boilers

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.[3] As a consequence, firetube boilers are typically small, with heat input capacities limited to less than 15 MW (50 MMBtu/hr) and steam pressures limited to 150 kPa (300 psig), although high-end steam pressures of 76 kPa (150 psig) are more common.[4] Firetubes are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size. Firetube boilers are generally available as packaged units in capacities ranging from 0.1 MW (0.4 MMBtu/hr) to 15 MW (50 MMBtu/hr).

2.2.3 Cast Iron Boilers

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 and have input capacities up to 4 MW (14 MMBtu/hr).[4]

2.2.4 Other Boilers

A fourth 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. This type of boiler is packaged and is available in heat input capacities ranging from 0.07 to 1.2 MW (0.25 to 4.2 MMBtu/hr).[5]

Boilers used in thermally enhanced oil recovery (TEOR) operations are referred to as oil field steam generators. These units are typically packaged watertube boilers with heat input capacities from about 5.8 to 18 MW (20 to 63 MMBtu/hr). Steam generators are typically cylindrical in shape and horizontally oriented, with watertubes arranged in a coil-like design. For a given size, there is little variability in the design or configuration of oil field steam generators.[6] Table 2-2 summarizes the use of the three major types of boilers in various sectors.[7]

2.3 EMISSIONS

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing practices used, and the level of equipment maintenance. The term "baseline emissions" of criteria and non-criteria pollutants refer to emissions from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment, low-NO_x burners, or other modifications for emission control. Baseline emissions for sulfur dioxide (SO_2) and PM can be obtained from controlled sources if measurements are taken upstream of APC equipment. This may not be possible with combustion modification controls for NO_x, where the controls are an intrinsic part of the boiler design.

For this update of AP-42, point source emissions of NO_x, SO_2, PM, and CO are being evaluated as criteria pollutants (those emissions which have established National Primary and Secondary Ambient Air Quality Standards).[34] Particulate matter emissions are sometimes reported as total suspended particulate (TSP). The portion of inhalable particulate matter which is less than 10 microns in aerodynamic diameter (PM-10) has been redesignated as a criteria pollutant. In addition to the criteria pollutants, this update includes point source emissions of some non-criteria pollutants (e.g., N_2O, VOCs, and hazardous air pollutants) as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of CO_2 are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels, including fuel oil, is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO, much of which ultimately oxidizes to CO_2, or as carbon in the ash. Finally, fugitive emissions associated with the use of fuel oil at the combustion source are being included in this update of AP-42.

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

2.3.1 Particulate Matter Emissions[10-14,19-20,28,30-31]

The PM emissions from fuel oil-firing under normal non-sooting conditions depend primarily on the grade of oil fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of Nos. 4 and 5 usually produces less PM than does the firing of heavier No. 6.

In general, PM emissions depend on the completeness of combustion as well as the oil ash content. The PM emitted by distillate oil-fired boilers is primarily carbonaceous particles resulting from incomplete combustion of oil and does not correlate with the ash or sulfur content of the oil. This is because lower sulfur (distillate) oil has substantially lower viscosity and reduced asphaltene and ash contents. Consequently, lower sulfur oils atomize better and burn easier. The level of PM emissions from residual oil combustion, however, is related to the oil sulfur content. This applies regardless of whether the fuel oil is refined from naturally occurring low sulfur crudes or is desulfurized by current refinery practice.

Boiler load can also affect particulate emissions in units firing No. 6 oil. At low load conditions, particulate emissions may be lowered by 30 to 40 percent from utility boilers and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emissions have been noted at low loads from boilers firing any of the lighter oil grades. At very low load conditions, proper combustion conditions typically cannot be maintained and particulate emissions may increase drastically.

2.3.2 Sulfur Oxide Emissions[8-12,29]

Sulfur oxide 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.[13] On average, more than 95 percent of the fuel sulfur is converted to SO_2; about 1 to 5 percent further oxidized to sulfur trioxide (SO_3); and about 1 to 3 percent is emitted as sulfate particulate. The SO_3 readily reacts with water vapor (both in air and in flue gases) to form a sulfuric acid mist.

2.3.3 Nitrogen Oxides Emissions [8-18,21-22,27,31]

Oxides of nitrogen formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x"), or to the conversion of chemically-bound nitrogen in the fuel ("fuel NO_x"). Although five oxides of nitrogen exist, the term NO_x is customarily used to describe the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Nitrous oxide is of increasing interest as an upper atmosphere gas, but is not included in NO_x. Test data have shown that for most stationary fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of NO.[13]

On a global basis, thermal NO_x formation rates in flames is exponentially dependent on temperature and proportional to the nitrogen (N_2) concentration in the flame, the square root of the oxygen (O_2) concentration in the flame, and the residence time.[27] These relationships are corroborated by experimental data which show that thermal NO_x formation is most strongly dependant on three factors: (1) peak temperature, (2) O_2 concentration (or stoichiometric ratio), and (3) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly consistent for all types of boilers: an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production regardless of the boiler type.

Fuel nitrogen conversion is an important NO_x-forming mechanism in residual oil-fired boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing.[32] The percent conversion of fuel nitrogen to NO_x, however, varies greatly. Anywhere 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 residual oil, fuel NO_x will generally account 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.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. The NO_x emissions from tangentially (or corner)-fired boilers are, on the average, less than those with horizontally opposed burners. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), or some combination thereof may result in NO_x reductions of 5 to 60 percent (see Section 2.4.1 for a discussion of these techniques). Load reduction can likewise decrease NO_x production. Emissions of NO_x may be reduced from 0.5 to 1 percent for each percentage reduction in load below full load operation. It should be noted that most of these variables, with the exception of excess air, influence the NO_x emissions only of large oil-fired boilers. Low excess air firing is possible in many small boilers, but the resulting NO_x reductions may not be significant.

Nitrous oxide emissions for most oil-fired boilers are only a small fraction of the NO_x levels. Earlier data (prior to 1988) had suggested much higher levels of N_2O. However, these data are thought to be erroneous due to a sampling artifiact introduced as a result of the time lapse between sampling and analysis. New methods have been proposed to circumvent this problem. Recent N_2O emissions data, indicate that direct N_2O emissions from oil combustion units are considerably below the measurements made prior to 1988.[35] Nevertheless, the N_2O formation and reaction mechanisms are still not well understood nor well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O mechanism. Emissions can vary widely from unit to unit, or even from the same unit under different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature.[36] For this AP-42 update, an average emission factor based on reported test data was developed for conventional oil combustion systems.

The nationwide inventory of PM, SO_2, and NO_x emissions resulting from fuel oil combustion in 1985 are summarized in Table 2-3. Table 2-4 summarizes the new source performance standards (NSPS) pertinent to PM, SO_2, and NO_x emissions from fossil fuel-fired boilers.[48]

2.3.4 Carbon Monoxide Emissions [23-26]

The rate of CO emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not 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 leading to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency than large combustors. Larger combustors also have more complex combustion control systems to trim O_2 to a level which gives low CO emissions but high efficiency.

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

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

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

2.3.5 Organic Compound Emissions [23-26]

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends 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 which remain in a gaseous state in ambient air, semi-volatile organic compounds, and condensible organic compounds. According to the Federal Register definition (57 FR 3945), VOC has been defined as any organic compound excluding CO, CO_2, carbonic acid, metallic carbides or carbonates, and ammonium carbonate which participates in atmospheric photochemical reactions. The following additional compounds have been deemed to be of "negligible photochemical reactivity" and also are exempt from the definition of VOC: methane, ethane, methyl chloroform, methylene chloride, and most chlorinated-fluorinated compounds (commonly referred to as CFCs). Although these compounds are considered "exempt" from most ozone control programs due to their low photochemical reactivity rates, they are of concern when developing complete emission inventories which are necessary for the design of effective ozone control strategies. The term TOC will refer to all organic compounds: VOCs plus the "exempt" compounds, including methane and ethane, toxic compounds, aldehydes, perchloroethylene, semi-volatiles, and condensibles (as measured by EPA Reference Methods).

Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, ethyl benzene, etc.).[37,38]

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). Information available in the literature on POM compounds generally pertains to these PAH groups. Because of the dominance of PAH information (as opposed to other POM categories) in the literature, many reference sources have inaccurately used the terms POM and PAH interchangeably.

A few comments are in order concerning an extremely toxic subclass of PNA -- the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources concluded that, although PCB formation is thermodynamically possible for combustion of fuels containing some chlorine (e.g., some coals and residual oil), it is unlikely due to low chlorine concentrations and to short residence times at conditions favoring PCBs.[39] Also, with efficient mixing, O_2 availability, and adequate residence time at temperatures in the 800-1000^o C (1500-1800^o F) range, PCBs (together with polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans) will be efficiently destroyed.[40] Other research has shown, however, that chlorinated PNAs can be formed via catalyzed reactions on fly ash particles at low temperatures in equipment downstream of the combustion device.[60]

Formaldehyde is formed and emitted during the combustion of hydrocarbon-based fuels, including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Since formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion, large units with efficient combustion resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long residence times should have lower formaldehyde emission rates relative to small, less efficient combustion units.[41,42]

2.3.6 Trace Element Emissions [23-26]

Trace elements are also emitted from oil combustion with the emission rate largely dependant on the metals concentration of the 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 (CAAA-90) are considered.[43] The quantity of trace metals emitted depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the partitioning of ash into heavier material which deposits on boiler surfaces and lighter, smaller ash which is emitted with the flue gas.

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

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

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (e.g., bottom ash, collector ash, flue gas particulate), while others do not.[44] Various classification schemes to describe this partitioning have been developed.[45-47] The schemes have been derived for solid fuel-firing, but are also relevant to oil-firing. The classification scheme used by Baig, et al. is as follows:[47]

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.
- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.
- Class 3: Elements which are intermediate between Classes 1 and 2.
- Class 4: 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.[44] For example, several boiler NO_x control techniques reduce peak flame temperatures (e.g., staged combustion, FGR, reduced air preheat, and load reduction). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment in the fine particle fractions. 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.

Local O_2 concentration is also expected to affect metal emissions from boilers with particulate 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 in the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metals emissions should remain unchanged.

Other combustion NO_x controls which decrease local O_2 concentrations (such as staged combustion and FGR) also reduce peak flame temperatures. Under these conditions, the effect of reduced combustion temperature is expected to be stronger than that of lower O_2 concentrations.

2.4 CONTROL TECHNOLOGIES

The various control techniques and/or devices employed with oil combustion sources depend on the source category and the pollutant being controlled. Only controls for criteria pollutants are discussed here because controls designed specifically for non-criteria emissions have not been demonstrated nor commercialized for oil combustion sources.

Control techniques may be classified into three broad categories: fuel substitution, combustion modification, and post combustion control. Fuel substitution involves using "cleaner" fuels to reduce emissions. Combustion modification and post combustion control are both applicable and widely commercialized for oil combustion sources. Combustion modification is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Post combustion control is applied to emissions of PM, SO_2, and, to some extent, NO_x from oil combustion.

2.4.1 Fuel Substitution[10,12,15,51]

Fuel substitution, or the firing of "cleaner" fuel oils, can substantially reduce emissions of a number of pollutants. Lower sulfur oils, for instance, will reduce SO_x emissions in all boilers, regardless of size or type of unit or grade of oil fired. Particulate loading generally will be reduced when a lighter grade of oil is fired. Nitrogen oxide emissions will be reduced by switching to either a distillate oil or a residual oil with less nitrogen. The practice of fuel substitution, however, may be limited by the ability of a given operation to fire a better grade of oil and by the cost and availability of that fuel.

2.4.2 Combustion Modification[8-11,15-16,20-21,27]

Combustion modification includes any physical change in the boiler/burner hardware or in boiler operation. Maintenance of the burner system, for example, is important to assure proper atomization and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units for maximum operating efficiency and emission control, particularly of smoke and CO. Combustion modifications, such as limited excess air firing, FGR, staged combustion and reduced load operation, result in lowered NO_x emissions in large facilities.

2.4.2.1 Particulate Matter Control.[51] Control of PM emissions from residential and commercial units is accomplished by improved burner servicing and by incorporating appropriate equipment design changes to improve oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered to be the best approach toward achieving the triple goals of low PM, low NO_x, and high thermal efficiency.

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

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

(2-1) $N_2 + O \leftrightarrow NO + N$
(2-2) $N + O_2 \leftrightarrow NO + O$
(2-3) $N + OH \leftrightarrow NO + H$

Reaction (2-1) is generally believed to be the rate-determining step due to its large activation energy.[44] Kinetically, thermal NO_x formation is related to nitrogen (N_2) concentration, combustion temperature, and O_2 concentration by the following equation:[44]

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

where:

[ ] = mole fraction

T = temperature (°K)

t = residence time

k_1, k_2 = reaction rate coefficient constants

From this relationship and the Zeldovich mechanism, it can be seen that thermal NO_x formation can be controlled by four approaches: (1) reduction of peak temperature of reaction, (2) reduction of N_2 concentration, (3) reduction of O_2 level, and (4) reduction of the residence time of exposure. Typically, the N_2 mole fraction in hydrocarbon-air flames is on the order of 0.7 and is difficult to modify.[44] Therefore, combustion modification techniques to control thermal NO_x in boilers have focused on reducing O_2 level, peak temperature, and time of exposure at peak temperature in the primary flame zones of the furnaces. Equation 2-4 also shows that thermal NO_x formation depends exponentially on temperature, parabolically on O_2 concentration, and linearly on residence time. Hence, temperature has a dominant effect on production of thermal NO_x.

In boilers fired on coal, crude oil, or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since typically fuel NO_x accounts for 50 to 80 percent of the total NO_x formed.[52-53] 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.[54] 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 O_2 creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

In the formation of both thermal and fuel NO_x, all of the above reactions and conversions do not take place at the same time, temperature, or rate. The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel bound nitrogen, if any, and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal NO_x and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels.[55] Additionally, thermal NO_x is greatly increased by increased residence time at high temperatures, as mentioned earlier. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control approaches:

- Decrease primary flame zone O_2 level:
  - Decrease overall O_2 level
  - Control (delay) mixing of fuel and air
  - Use of fuel-rich primary flame zone
- Decrease residence time at high temperatures:
  - Decrease adiabatic flame temperature through dilution
  - Decrease combustion intensity
  - Increase flame cooling
  - Decrease primary flame zone residence time

Table 2-5 shows the relationship between these control strategies and combustion modification NO_x control techniques currently in use on boilers firing fuel oil.[44]

2.4.3 Post Combustion Control[49-51]

Post combustion control refers to removal of pollutants from combustion flue gases. Its use is relatively rare with oil-fired boilers due to relatively high cost per mass of pollutant removed. Some larger installations have, however, been equipped with controls for PM, NO_x, or SO_x.

2.4.3.1 Particulate Control.[51] Industrial and utility boilers are, generally, well-designed and well-maintained. Hence, particulate collectors are usually needed only in special circumstances. The use of particulate collectors with oil-firing is described below.

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. During 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 will not be nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are used in a few oil-fired power plants. Older ESPs, usually small, remove generally 40 to 60 percent of the PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Today, new or rebuilt ESPs have collection efficiencies of 99 percent or greater.

Scrubbing systems have been installed on oil-fired boilers, especially of late, to control both SO_x and PM. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

2.4.3.2 NO_x Control. The variety of flue gas treatment NO_x control technologies is nearly as great as combustion-based technologies. Although these technologies differ greatly in cost, complexity, and effectiveness, they all involve the same basic chemical reaction:

$$\text{(2-5)} \quad NH_3 + NO_x \leftrightarrow N_2 + H_2O$$

In selective catalytic reduction (SCR), the reaction takes place in the presence of a catalyst, improving performance. Non-catalytic systems rely on a direct reaction, usually at higher temperatures, to remove NO_x. Although removal efficiencies are lower, non-catalytic systems are typically less complex and often significantly less costly. Table 2-6 presents various catalytic and non-catalytic technologies.[56]

2.4.3.3 SO_2 Control. Commercialized post combustion flue gas desulfurization (FGD) uses an alkaline reagent to absorb SO_2 in the flue gas to produce sodium or calcium sulfate or sodium or calcium sulfite compounds. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable, such that the reagent material can be treated and reused, or are nonregenerable, in which all waste streams are de-watered and discarded. Table 2-7 summarizes commercially available post-combustion SO_2 control technologies.

Wet regenerable FGD processes are attractive because they have the potential for greater than 95 percent sulfur removal efficiency, have minimal waste-water discharges, and produce saleable sulfur product.[57] 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 scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables.

The lime and limestone scrubbing process uses a slurry of calcium oxide (CaO) or limestone ($CaCO_3$) to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods have been demonstrated.[58] The process produces a calcium sulfite and calcium sulfate mixture.

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. Sodium scrubbers are generally applied to smaller sources because of high reagent costs, however these systems have been installed on industrial boilers up to 125 MW (430 million Btu/hr) thermal input.[1] Demonstrated SO_2 removal efficiencies of up to 96.2 percent have been demonstrated.[58] Because the SO_2 removal efficiency can vary during load swings and process upsets, a long term mean efficiency of at least 91 percent is necessary to comply with the 90 percent NSPS reduction requirement based on a 30-day rolling average. The operation of the scrubber is characterized by a low liquid-to-gas ratio [1.3 to 3.4 l/m^3 (10 to 25 gal/ft^3)] and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. The scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts.

The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. Most of the effluent from the sodium scrubber is recycled back to the scrubber, but a slipstream is withdrawn and reacts with lime or limestone in a regeneration reactor. Performance data indicate average SO_2 removal efficiencies of 90 to 96 percent.[1] However, initial reports of long-term operating histories with dual alkali scrubbing have indicated SO_2 control system reliability averages of only slightly higher than 90 percent.[59]

TABLE 2-1. U.S. OIL CONSUMPTION BY SECTOR IN 1990[a]

Sector	Oil consumption, 10^{12} kJ (10^{12} Btu)		
	Residual	Distillate[b]	Sum of Residual and Distillate
Utility	1201.6 (1139.4)	91.0 (86.3)	1292.6 (1225.7)
Industrial	437.1 (414.5)	1245.4 (1180.9)	1682.5 (1595.4)
Commercial	255.6 (242.4)	513.6 (487.0)	769.2 (729.4)
Residential	0.0 (0.0)	883.1 (837.4)	883.1 (837.4)
Total for all Sectors	1894.4 (1796.3)	2733.1 (2591.6)	4627.5 (4387.9)

[a]Reference 1
[b]For the utility sector this value includes distillate oil (No. 2), kerosene, and jet fuel. For the other three sectors it includes distillate oil only.

TABLE 2-2. BOILER USAGE BY SECTOR

Sector	Capacity, MW (MMBtu/hr)	Boiler type	Application
Utility	> 29 (>100)	Watertube	Electricity generation
Industrial	0.29 - 29 (10 - 100)	Watertube	Electricity generation
		Watertube	Process steam
		Watertube	Space heat
		Firetube	Process steam
		Firetube	Space heat
Commercial	0.1 - 2.9 (0.5 - 10)	Watertube	Space heat
		Firetube	Space heat
		Cast iron	Space heat
Residential	<0.1 (< 0.5)	Cast iron	Space heat

TABLE 2-3. TOTAL U.S. ANTHROPOGENIC EMISSIONS BY CATEGORY FOR SO_2, NO_x, AND TSP IN 1989[33]

Oil type	Sector	Emissions inventory, MT (tons)		
		SO_2	NO_x	TSP
Distillate	Residential	116 (128)	68 (75)	9 (10)
	Commercial/ Institutional	83 (91)	50 (55)	5 (5)
	Industrial	92 (101)	79 (87)	7 (8)
	Electric Generation	15 (17)	18 (20)	0.9 (1)
Residual	Residential	0.9 (1)	0 (0)	0 (0)
	Commercial/ Institutional	132 (146)	43 (47)	14 (15)
	Industrial	582 (641)	169 (186)	48 (53)
	Electric Generation	538 (593)	153 (169)	26 (29)

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Low Excess Air (LEA)	Reduction of combustion air	22 residual oil boilers, 7 distillate oil boilers	0 to 28	0 to 24	Generally excess O_2 can be reduced to 2.5 % representing a 3 % drop from baseline	Available	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	3 residual oil boilers, 1 distillate oil boiler	20 to 50	17 to 44	70-90 % burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on package 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 firing fuel rich.	8 boilers	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner or burners out of service. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculatio n (FGR)	Recirculation of portion of flue gas to burners	1 distillate oil boiler, 2 residual oil boilers	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	Only one packaged watertube boiler	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil	Combined techniques are still at experimental stage. Needs more R&D.	Retrofit may not be feasible. Best implemented on new units.
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	17 residual oil-fired boilers, 7 distillate oil-fired boilers	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 now as a retrofit application. Better implemented with improved firebox design.	Technique not effective when it necessitates an increase in excess O_2 levels. LR possibly implemented in new designs as reduced combustion intensity (enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	Large number tested in Japan	20 to 50	20 to 50	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking

TABLE 2-5. COMBUSTION MODIFICATION NO_x CONTROLS EVALUATED FOR OIL-FIRED BOILERS

Control technique	Description of technique	No. of boilers	Effectiveness of control (% NO_x reduction)		Range of application	Commercial availability/ R&D status	Comments
			Residual oil	Distillate oil			
Ammonia/ urea Injection	Injection of urea or NH_3 as a reducing agent in the flue gas	5 (4 Japanese installations , 1 domestic)	40 to 70	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring and control system required. Possible load restrictions on boiler and air preheater fouling when burning high sulfur oil.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2 residual oil-fired boilers	5 to 16	N/A	Combustion air temperature can be reduced to ambient conditions (340K)	Available. Not implemented because of significant loss in thermal efficiency.	Application of this technique on new boilers requires installation of alternate heat recovery system (e.g., an economizer)

TABLE 2-6. POST COMBUSTION NO_x REDUCTION TECHNOLOGIES[56]

Technique	Description	Advantages	Disadvantages
1. Urea Injection	Injection of urea into furnace to react with NO_x to form N_2 and water.	- Low capital cost - Relatively simple system - Moderate NO_x removal (30-60%) - Non-toxic chemical - Typically, low energy injection is sufficient	- Temperature dependent - Design must consider boiler operating conditions and configuration - Reduction may decline at lower loads
2. Ammonia Injection (Thermal-DeNO$_x$)	Injection of ammonia into furnace to react with NO_x to form N_2 and water.	- Low operating cost - Moderate NO_x removal (30-60%)	- Moderately high capital costs - Ammonia handling, storage, vaporization, and injection systems required - Ammonia is a toxic chemical
3. Air Heater SCR (AH-SCR)	Air heater baskets replaced with catalyst-coated baskets. Catalyst promotes reaction of ammonia with NO_x.	- Moderate NO_x removal (40-65%) - Moderate capital cost - No additional ductwork or reactor required - Low pressure drop - Can use urea or ammonia - Rotating air heater assists mixing and contact with catalyst	- Design must address pressure drop, maintain heat transfer - Due to rotation of air heater, only 50% of catalyst is active at any time
4. Duct SCR	A smaller version of conventional SCR is placed in existing ductwork.	- Moderate capital cost - Moderate NO_x removal (30%) - No additional ductwork required	- Duct location unit specific - Some pressure drop must be accommodated
5. Activated Carbon SCR	Activated carbon catalyst, installed downstream of air heater, promotes reaction of ammonia with NO_x at low temperature.	- Active at low temperature - High surface area reduces reactor size - Low cost of catalyst - Can use urea or ammonia - Activated carbon is a non-hazardous material - SO_x removal as well as NO_x removal	- High pressure drop - Not a fully commercial technology
6. Conventional SCR	Catalyst located in flue gas stream (usually upstream of air heater) promotes reaction of ammonia with NO_x.	- High NO_x removal (90%)	- Very high capital cost - High operating cost - Extensive ductwork to/from reactor - Large volume reactor - Increased pressure drop may require ID fan or larger FD fan - Reduced efficiency - Ammonia sulfate removal equipment for air heater - Water treatment of air heater wash

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

Control technology	Process	Available control efficiencies	Remarks
Wet Scrubber	Lime/Limestone	80 - 95+%	Applicable to high sulfur fuel, Wet sludge product
	Sodium Carbonate	80 - 98%	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.

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3. GENERAL EMISSION DATA REVIEW AND ANALYSIS PROCEDURES

3.1 CRITERIA POLLUTANTS

3.1.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of criteria and non-criteria pollutant emission data associated with fuel oil-fired boilers. This search included a broad range of relevant EPA reports as well as the archive files from prior AP-42 revisions, and numerous additional reports and contacts with testing groups, regulatory agencies, and trade groups. On-line computerized databases were also accessed to gather information on sources of emissions data. The details of the literature search are summarized in Table 3-1.

3.1.2 Literature Evaluation

A large number of references were identified and compiled through the literature search. Subsequently, each item in this large body of literature was screened for data on criteria pollutant emissions and/or information on control technology pertaining to NO_x, SO_2, and PM emissions. Checklists were developed to document this scanning procedure. These checklists can be found in the background files for this update to AP-42. Thereafter, references with data on criteria pollutants were subjected to a rigorous data evaluation to determine if they contained candidate data for use in developing uncontrolled emission factors. References relating only to control technology information were used in characterizing control efficiencies and, as such, were not subjected to any data evaluation procedure.

The following general criteria were used in evaluating literature with criteria pollutant data:

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

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

These criteria were used in a thorough review of the reports, documents, and information to produce a final set of reference materials. The data contained in this final set of references were then subjected to a thorough quality and quantity evaluation to determine their suitability for use for developing emission factors. Checklists were employed to facilitate and document this evaluation. The completed checklists were placed in the background files for this update to AP-42.

Data with the following characteristics were always excluded from further consideration:

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

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

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

4. Test series in which the source process was not clearly identified and described; and

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

Data sets that were not excluded were assigned a quality rating. The rating system used was that specified in "Technical Procedures for Developing AP-42 Emission Factors and Preparing AP-42 Sections".[8] The data were rated as follows:

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

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

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

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

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

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

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

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

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

3.1.3 Emission Factor Quality Rating

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

> A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough so that variability within the source category population may be minimized.
>
> B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.
>
> C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.
>
> D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Any limitations on the use of the emission factor are footnoted in the emissions factor table.
>
> E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry.. There also may be evidence of variability within the source category population. Any limitations on the use of these factors are always clearly noted.

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

3.2 SPECIATED VOCs

3.2.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of speciated VOC emissions data associated with fuel oil-fired boilers. Some specific areas of search include Tennessee Valley Authority, Electric Power Research Institute (EPRI)/PISCES, EPA/Air and Waste Management (A&WMA) Air Toxic Symposiums, and Toxic Air Pollutants: State and Local Regulatory Strategies 1989.

3.2.2 Literature Evaluation

Until recently, little concern existed for VOC speciation on stationary external combustion sources. Therefore, available data for VOC speciation were very sparse and inadequate, limiting this data evaluation to EPA's Office of Air Quality Planning and Standards (OAQPS) databases: the VOC/PM Speciation Data System (SPECIATE) and the Crosswalk Air Toxic Emission Factor Database (XATEF), and their references.

3.2.3 Data and Emission Factor Quality Rating

The ratings of emission factors in SPECIATE and XATEF should not be used without first reviewing primary sources of numerical data against the criteria presented in Chapter 3.1. The quality of the data is insufficient to satisfy the requirements for assignment of an emission factor; therefore, the data is unratable or, at best, E-rated.

3.3 AIR TOXICS

3.3.1 Literature Search

A separate literature search was conducted for hazardous air pollutants (HAPs) since this category was not included in prior AP-42 revisions. The HAPs data base is expanding rapidly as a result of recent regulations. The prior data base is very sparse and largely based on obsolete protocols. Many of the data identified and evaluated were not of suitable quality for developing emission factors and were, therefore, eliminated for use in this update following the criteria outlined in Section 3.1.

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

Searches of the EPA's air toxics data bases were also performed. These data bases include the XATEF and the SPECIATE databases, and the Air Clearing House for Inventory and Emission Factors (CHIEF) CD ROM which contains additional data in conjunction with XATEF and SPECIATE. The computer searches were performed by source classification code (SCC) for all boiler sizes and types that combust oil. The reference numbers were recorded for each of the "hits" and these references were obtained for review.

Various air pollution control districts (APCDs) located in California were contacted to obtain air toxics data collected under the California Assembly Bill 2588, the Air Toxics "Hot Spots" Information and Assessment Act of 1987. This bill requires reporting of emissions of a specified list of air toxic compounds. The following APCDs were contacted by phone and with a written information request: Bay Area, South Coast, Fresno County, North Coast Unified, Sacramento Metropolitan, San Joaquin County, Ventura County, Calaveras County, Lake County, Lassen County, Santa Barbara, San Diego, Kern County, and the California Air Resources Board.

Several industry and non-agency sources were also contacted in order to obtain source test data for development of emission factors. These include the Western States Petroleum Association (WSPA), the Canadian Electrical Association (CEA), and the Ontario Ministry of the Environment.

3.3.2 Literature Evaluation

The references obtained from the literature search were evaluated for their applicability for generating emission factors. Table 3-2 summarizes the data sources and indicates which sources were used in generating the emission factors. The table contains a reference number which corresponds to the list of references provided at the end of this section. The references are evaluated and discussed in greater detail in Section 4.3.1. The criteria used to perform this evaluation are discussed in detail in Section 3.3.3.

3.3.3 Data and Emission Factor Quality Rating Criteria

Emissions data used to calculate emission factors were obtained from many sources, such as published technical papers and reports, documented emissions test results, and regulatory agencies (such as local APCDs). The quality of these data must be evaluated in order to determine how well the calculated emission factors represent the emissions of an entire source category. Data sources may vary from single source test runs to ranges of minimum and maximum values for a particular source. Some data must be eliminated all together due to their format or lack of documentation. Factors such as the precision and accuracy of the sampling and analytical methods and the operating and design specifications of the unit being tested are key in the evaluation of data viability. The key factors for data evaluation and rating were essentially the same as detailed for criteria pollutants in Section 3.1.

The first step in evaluating a data report was to determine whether the source is a primary or secondary source. A primary source is that which reports the actual source test results while a secondary source is one that references a data report. Many of the sources referenced by XATEF, SPECIATE, and the CD ROM are secondary, tertiary, etc. sources. Preferably, only primary sources are used in the development of emission factors.

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

When primary data could not be obtained in the time frame of this initial update, secondary sources were evaluated to determine the representativeness of the emission factors to a source category. A judgement of the quality of the primary data analysis was made in this case, which automatically warrants a lower quality rating for the emission factor. The secondary sources can potentially provide at least an order of magnitude estimate of emissions.

3.4 N_2O

3.4.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of N_2O emissions data associated with fuel oil-fired boilers. Some specific resources searched included the European N_2O Workshop, EPA/Air and Energy Engineering Research Laboratory, AWMA, and the journals Combustion and Flame and Journal of Geophysical Research.

3.4.2 Literature Evaluation

The literature evaluation criteria were lowered for N_2O to allow the inclusion of sufficient data to calculate emission factors. Data were evaluated even if they failed one or more questions on the test report exclusion criteria checklist described in Section 3.1.2. This treatment was necessitated by the sparseness of the data base resulting from the development of a protocol only since 1988.

3.4.3 Data and Emission Factor Quality Rating

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

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

b. Removing SO_2: scrubbing the sample through NaOH solution;

c. A combination of a and b above (the second method preference).

The N_2O emission data for residual oil-fired utility boilers came from full-scale facilities and were rated B quality. The data obtained for distillate oil-fired boilers came from two small pilot-scale systems and were assigned a B quality rating. These data were obtained with on-line GC/ECD N_2O analysis. The emission factors for residual and distillate oil were assigned a D rating, because the data were taken from small pilot scale systems or because the test data were from a small number of facilities and do not represent a cross-section of the industry.

3.5 FUGITIVE EMISSIONS

Fugitive emissions have not historically been covered in Chapter 1 of AP-42. Chapter 4 of AP-42 contains emission factors for evaporative losses from petroleum storage facilities and will continue to be the source of such data. Fugitive particulate emissions are very low from oil-fired boilers and only result from ash liberated during maintenance activities. These ash deposits are usually removed during a boiler wash (in which most of the deposits are removed in a liquid stream). Therefore, fugitive particulate emissions from these facilities are minimal. Particulate matter fugitive emission factors from these operations can be developed using the procedures in AP-42 Chapter 11.

A literature search was conducted to quantify fugitive emissions from leaking seals and fittings that would be present in the fuel feed system for oil-fired boilers. These sources include valves, pumps, flanges, sampling connections, and open-end lines. The literature evaluation verified the conclusions of previous attempts at determining emission factors for VOCs in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). During the establishment of proposed standards for fugitive VOC emissions from SOCMI, EPA determined that (1) the only quality emission factor data were generated during a study of 13 petroleum refineries for EPA and (2) the best data for percent leaking of each equipment type resulted from an EPA study of leak frequency in the SOCMI.

Data from the primary reference above were subjectively rated B quality per the general guidelines previously described. Because of the complexity of calculating new emission factors for fugitive emissions, the remainder of the references were not used.

3.6 PARTICLE SIZE DISTRIBUTION

3.6.1 Literature Search[8]

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

The background files for the previous AP-42 update were reviewed. A Dialog Information Retreival System search was conducted, focussing on reports since 1980. Based on the results of the Dialog search, NTIS documents, EPA reports, and conference proceedings were ordered and journal articles were collected. Conference symposia that were searched included the Eighth and Ninth Particulate Control Symposia and the AWMA annual conferences for 1988 through 1991.

The following PM-10 "gap filling" documents were examined:

- "PM-10 Emission Factor Listing Developed by Technology Transfer" (EPA-450/4-89-022): The factors applicable to sections 1.1, 1.3, and 1.7 all came from AP-42. The factor for a bituminous coal commercial facility assumes that 52% of particulate is < 10 um.

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

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

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

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

The primary source of the particulate size distribution data for the 1986 AP-42 update was the Fine Particulate Emissions Information System (FPEIS). The FPEIS has not been updated since the printouts obtained during the 1986 AP-42 update. The printouts used for the previous update were available in the background files.

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

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

3.6.2 Literature Evaluation

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

The 1986 update was also evaluated with respect to the development of emission factors from the particle size distribution data.

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

(1) To ensure that only filterable particulate matter was included in the cumulative percent mass results; and

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

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

3.6.3 Data Quality Ranking

Data were reviewed and ranked according to the criteria described in Section 3.1 and the data evaluation criteria presented for the previous update. Data quality was assessed based on the particle sizing and/or PM-10 measurement method used and the availability of sampling and process data.

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

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

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

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

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

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

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

The effects of such errors are described in Reference 10.

The ranking of data for CPM was based primarily on the methodology employed in the testing. Most CPM source tests have been conducted using the back-half of an EPA Method 5, EPA Method 17 or South Coast Methods 5.2 or 5.3 trains. However, these test methods do not require an N_2 purge of the impingers. Without the N_2 purge, dissolved SO_2 remains in the impingers and is included in the inorganic CPM results. This type of CPM data is considered very low-quality.[9] In contrast, Method 202 includes a one-hour N_2 purge of the impingers immediately after sampling to remove dissolved SO_2. Therefore, Method 202 CPM data should be ranked higher than Method 5 or Method 17 CPM data, even though Method 202 is a relatively new method. The following rankings were selected for CPM data:

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

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

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

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

TABLE 3-1. LITERATURE SEARCH/CONSULTATION RECORD

Literature type	New baseline data	NO_x control information	Particulate control information	SO_X control information
(A) "Minimum" list given in the task order				
1. AP-42 files	✓	✓	✓	✓
2. ESD Files/NSPS Background Information Documents	✓	✓	✓	✓
3. CTC publications	none	✓	none	none
4. ORD reports	✓	✓	✓	✓
5. NTIS	✓	✓	✓	✓
(B) Other sources				
1. EPRI	none	✓	none	none
2. Contractor in-house documents	✓	✓	✓	✓
3. American Petroleum Institute	✓	none	none	none

TABLE 3-2. EVALUATION OF REFERENCES

Reference	Evaluation	Parameter of Interest
1	Not a primary reference; however, data quality is sufficient to determine emission estimates.	POM
2	Emission factors presented are of sufficient quality.	Metals
3	Not a primary reference, however, data of sufficient quality.	Cr
4	Not a primary reference, however, data of sufficient quality.	HCOH
5	Not a primary reference; however, data are of sufficient quality.	Metals, POM, HCOH
6	Not a primary reference; however, some data presented of sufficient quality.	Metals
7	Not a primary reference; however, data of sufficient quality.	Mn

CHAPTER 3 REFERENCES

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2. Leavitt, C., K. Arledge, C. Shih, R. Orsini, W. Hamersma, R. Maddalone, R. Beimer, G. Richard, M. Yamada, Environmental Assessment of Coal- and Oil-Firing in a Controlled Industrial Boiler; Volume I, II, III. Comprehensive Assessment and Appendices, EPA-600/7-78-164abc, U.S. Environmental Protection Agency, Research Triangle Park, NC, August 1978.

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

4. Locating and Estimating Air Emissions From Sources of Formaldehyde (Revised), EPA-450/4-91-012, Emission Inventory Branch Technical Support Division, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1991.

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

6. Surprenant, N.F., et. al., Emissions Assessment of conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources, EPA-600/7-81-003c, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1981.

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

8. Technical Procedures for Developing AP-42 Emission Factors and Preparing AP-42 Sections, Draft Report, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1992.

9. Private communication with Ron Meyers, U.S. Environmental Protection Agency, March 24, 1992.

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

4. EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for the fuel oil combustion category.

4.1 CRITERIA POLLUTANTS

4.1.1 Review of Previous AP-42 Data

A review of the 1986 version of Section 1.3 was conducted by spot checking the quality of existing emission factors. This was done by selecting primary data references from the section Background File and recalculating emission factors. The results of these spot checks are summarized in Table 4-1.

In almost all cases, the results of spot checks indicated that existing emission factors were accurate. Spot checks also revealed that, in general, ample A-rated data were available for the criteria pollutants. However, the SO_3 emission factor in the 1986 Section 1.3 was found to be incorrect and was changed as described in Section 4.1.3.

4.1.2 Review of New Baseline Data

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

References 1-3

These references document the multi-media emission tests conducted on Boiler No. 4 of the Firestone Tire and Rubber Co. plant located in Pottstown, Pennsylvania. Flue gas sampling was conducted before and after a pilot flue gas desulfurization unit to establish which pollutants were removed, modified, or produced by the control device. In these tests, continuous monitors were used to measure CO, NO_x, SO_2, and total hydrocarbons (THC) while a Source Assessment Sampling System (SASS) was used to collect gaseous and particulate samples. Adequate source descriptions were provided in the reports. A rating of A was assigned to criteria pollutant data in these reports.

References 4-5

These reports describe tests performed on two industrial watertube boilers to characterize the effects of combustion modifications and operating variable changes on thermal efficiency and pollutant emissions. In these tests, gaseous emissions were measured by standard gas analyzer methods while EPA Method 5 was used to measure PM emissions. Adequate source descriptions were provided in the reports. A rating of A was assigned to criteria pollutant data in these reports.

Reference 6

This report details results of a comprehensive emissions assessment performed on the Haynes No. 5 utility boiler in Long Beach, California. Adequate details on tests including source operation and sampling and analysis of pollutants are provided in the report. A rating of A was assigned to criteria pollutant data in this report. This report was cited as Reference 26 in the 1986 AP-42 Section 1.3 but data contained in it had not been used. Hence, these data have been included in current emission factor calculations.

Reference 7

This report describes results of tests conducted on a 26.4 MW residual oil-fired boiler using SC and LEA as the NO_x emission control technology. Tests were conducted to determine whether combustion modification techniques which demonstrated reductions in air pollutant emissions during short-term tests are feasible for longer periods. Adequate details on tests including source operation and sampling and analysis of pollutants are provided in the report. A rating of A was assigned to criteria pollutant data in this report. This report was cited as Reference 27 in the 1986 AP-42 Section 1.3 but data contained in it had not been used. Hence these data have been included in current emission factor calculations.

Reference 8

This report describes the results of tests conducted on Boiler No. 7 at the Boston Edison Company's Mystic River Station located at Everett, Massachusetts. The purpose of the sampling program was to determine the effect of raising the temperature of the filter and probe of an EPA Method 5 train from 120^{o}C to 160^{o}C and of baking the filter at 160^{o}C on the amounts of particulate, sulfate, and sulfuric acid emissions. However, baseline data were obtained using EPA Method 5 procedures, including a filter termperature of 120^{o}C. A data rating of A was assigned to PM emissions data.

Reference 9

This report describes the second phase of an investigation into ways to improve the air pollutant emission and thermal efficiency characteristics of residential oil furnaces. Detailed description of source operation and sampling methodology are provided in the report. The data were assigned a rating of A.

Reference 10

This report presents the results of a field testing effort to characterize particulate emissions from refinery combustion sources. The major objective of this program was to determine emission factors, size distribution, and chemical composition of particulates from refinery combustion sources. EPA Method 5 was used for PM emissions measurements. Adequate details on source operation are provided in this report. The data were assigned a rating of A.

Reference 11

This symposium paper describes a series of tests conducted on a 100 horsepower (HP) firetube boiler. In these tests, shale oil and two types of residual oil - No. 6 oil and a coal-oil mixture were fired. The paper does not provide enough details on emission measurement methodology and, hence, data in this paper are rated B.

Reference 12

This report provides an overview of the regulatory baseline, technical basis, and alternative control levels available for developing NSPS for SO_2 emissions from small steam generating units (i.e., boilers). The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

Reference 13

This report provides an overview of the emissions data and technical basis for NO_x NSPS for small boilers. The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

Reference 14

This report provides an overview of the regulatory baseline, technical basis, and alternative control levels available for developing NSPS limiting PM emissions from small steam generating units (i.e., boilers). The report includes data from various sources but does not provide details of source operation and emission sampling. Hence, the data in this report are rated B.

4.1.3 Compilation of Baseline Emission Factors

The references described above were used in updating the uncontrolled (baseline) emission factors for criteria pollutants. A computer spreadsheet was created to calculate emission factors from the data contained in the above references. The formulae and conversion factors used in this spreadsheet are shown in Appendix A. Relevant parts of this spreadsheet, pertaining to specific pollutants, are discussed in the corresponding sections below.

As previously mentioned, spot check results revealed that criteria pollutant emission factors are supported by ample A- rated data points. Hence, only new A-rated data points were used in the emission factor determinations described below.

PM Emission Factors

The PM emission factors for various sources are summarized in Table 4-2. As seen in this table, the following new data points have been added to the PM emission factors database:

- Utility boilers firing No. 6 oil: 5 points
- Industrial boilers firing No. 6 oil: 4 points
- Industrial boilers firing No. 2 oil: 1 point

No new data points were found for commercial boilers or residential furnaces. Also, no new data were found for No. 4 and No. 5 oil firing. Spot checks revealed that PM data from References 26 and 27 in the 1986 AP-42 Section 1.3 were not included in previous PM emission factor determinations. These data have been included in this effort.

For No. 6 oil-firing, PM emissions can be correlated with the percent sulfur content of the fuel (designated as S). This correlation, published in the 1986 AP-42 Section 1.3, has been updated in this effort. The steps involved in updating this correlation are detailed in Table 4-2. The proposed new correlation has a correlation coefficient, or r-value, of 0.96 as opposed to the previously published correlation with r-value of 0.65.

SO_2 Emission Factors

The SO_2 emission factors for various sources are summarized in Table 4-3. As seen in this table, the following new data points have been added to the SO_2 emission factors database:

- Utility boilers firing No. 6 oil: 1 point
- Industrial boilers firing No. 6 oil: 3 points
- Industrial boilers firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers or residential furnaces. Also, no new data could be found for No. 4 and No. 5 oil-firing. Spot checks revealed that SO_2 data from Reference 26 in the 1986 AP-42 Section 1.3 were not included in previous SO_2 emission factor determinations. These data have been included in this effort.

As discussed in Section 2.3.2, SO_2 emissions are almost entirely dependent on the sulfur content of the fuel. Hence, correlations between fuel sulfur content and SO_2 emission factors are derived in Table 4.1-3. These correlations are then compared with emission factors developed from measured emissions. Sulfur dioxide emission factor updates are based on such comparisons; results are shown in Table 4-3.

SO_3 Emission Factors

The SO_3 emission factors for various sources are summarized in Table 4-4. As seen in this table, the following new data points have been added to the SO_3 emission factors database:

- Industrial boilers firing No. 6 oil: 2 points
- Industrial boilers firing No. 2 oil: 1 point

No new A-rated data points were found for utility and commercial boilers or residential furnaces. Also, no new data could be found for No. 4 and No. 5 oil-firing.

For utility boilers firing No. 6 oil, the previous emission factor was based on information provided in Reference 25 as cited in the 1986 section. Spot checks revealed this emission factor to be incorrect. The development of a new emission factor is shown in Table 4-4. This table also contains new data for industrial boilers; new calculations have been made for the SO_3 emission factors for residual and distillate oil.[4-5]

Because of the limited amount of test data available, engineering estimates were considered based on published conversion factors of fuel sulfur to SO_3. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel. About 1 to 5 percent of the sulfur is oxidized to SO_3. The 1986 Section 1.3 used a factor of 2.86 percent for conversion of fuel sulfur to SO_3. This factor agrees well with the median value of the published range of 1 to 5 percent.

CO Emission Factors

The CO emission factors for various sources are summarized in Table 4.1-5. As seen in this table, the following new data points have been added to the CO emission factors database:

- Utility boilers firing No. 6 oil: 1 point
- Industrial boilers firing No. 6 oil: 3 points
- Industrial boilers firing No. 2 oil: 1 point
- Residential furnace firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers. Also, no new data were found for No. 4 and No. 5 oil-firing. Spot checks revealed that CO data from Reference 26 in the 1986 AP-42 Section 1.3 were not included in previous CO emission factor determinations. These data have been included in this effort.

As per spot checks, CO emissions typically range between 0.1 to 120 kg/10^3 liters of oil (1 to 10 lb/10^3 gal oil). Based on this information, an emission factor of 0.6 kg/10^3 liters of oil (5 lb/10^3 gal) was adopted in 1986, along with a qualifying footnote about the sensitivity of CO emission to combustion conditions. This emission factor has been retained as explained in Table 4-5.

NO_x Emission Factors

The NO_x emission factors for various sources are summarized in Table 4.1-6. As seen in this table, the following new data points have been added to the NO_x emission factors database:

- Utility boilers firing No. 6 oil: 2 points
- Industrial boilers firing No. 6 oil: 4 points
- Industrial boilers firing No. 2 oil: 1 point
- Residential furnace firing No. 2 oil: 1 point

No new A-rated data points were found for commercial boilers. Also, no new data were found for No. 4 and No. 5 oil firing. Spot checks revealed that NO_x data from Reference 27 in the 1986 AP-42 Section 1.3 were not included in previous NO_x emission factor determinations. These data have been included in this effort.

Results regarding NO_x emission factors are shown in Table 4-6. The correlation between the NO_x (as NO_2) emission factor and the fuel nitrogen content, for industrial/commercial boilers firing residual oil, was based on 36 points as indicated in the 1986 Emission Factor Documentation (EFD).[19] However, these points were not documented adequately in the previous. Hence, well-documented data points, given in Reference 15, were used to develop a new correlation and to compare this correlation with the 1986 correlation. This new correlation is based on least squares fitting of data. A comparison of means and standard deviations of error sets pertaining to the new correlation and the 1986 correlation indicates that the new correlation is more accurate in the data range covered. Hence, this new correlation has been adopted in place of the previously published one.

It is generally known that NO_x emissions depend on boiler heat release rate (HRR), where HRR is a function of boiler size and design.[16] Using data from Reference 15, efforts were made to correlate NO_x emissions with capacity and then with load-to-capacity ratio. However, these efforts did not meet with success as correlation coefficients were near 0 for the correlations developed. This is probably because the effects of boiler design and excess air could not be excluded from the data under consideration.

<u>VOC Emission Factors</u>

Only one data point providing a TOC emission factor was found in this update. This data point is shown in Table 4-7. As seen in spot checks, 1986 emission factors were based on multiple data points and, therefore, have been retained. The results of the emission factor development efforts, described above, are summarized in Tables 1.3-1 through 1.3-4 in Chapter 5.

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

A compilation of controlled emissions and control efficiencies, attained on application of some of the control technologies discussed in Section 2.4, is given in Tables 4-8 through 4-10.

4.2 SPECIATED VOCs

As discussed in Section 3.2, there were insufficient data to develop emission factors for speciated VOC. Some isolated data were identified in the general air toxics literature search summarized in Section 4.3.

4.3 HAZARDOUS AIR POLLUTANTS

4.3.1 Review of New Data

The screening of identified HAP data sources discussed in Section 3.3 yielded a smaller data base which was evaluated in more detail. These data were subjected to the quality ranking criteria discussed in sections 3.1 and 3.3. The overall evaluation of the key references follows. In general, the data base is very sparse, with older data taken with questionable protocols, and generally insufficient sensitivity to the importance of equipment operation and control system operation on emission rates. The data that are available indicate a high degree of variability of HAP emission with fuel content, combustion conditions, and control system settings. To adequately characterize such variability will require a comprehensive testing data base, much more comprehensive than was developed for criteria species.

Reference 20

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

Reference 21

This document is a compilation of the available information on sources and emission of POM and is not a primary reference. The document cautions against the use of these data for development of an exact assessment of emissions from any particular facility; however, the data are useful for comparing with other sources to verify the validity of calculated emission factors. The data are based primarily on utility boiler test data.

Reference 22

The emission factors for oil combustion are of sufficient quality for one of the tests presented in the report.

Metals: Metals emission factors for an oil test were used.

Organics: It was stated in the report that the organics recovered were not combustion products but were components in the sample collection media and in the analytical laboratory.

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

<u>Reference 23</u>

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

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

No analytical data are presented for fuels used for the testing nor for measured control efficiencies on the abatement devices.

The emission factors presented are calculated using average concentrations obtained from reference sources.

The raw emissions data (in units of $\mu g/m^3$) are never presented. Only pg/J units are presented for the results and there is no documentation on how these were calculated.

POM: The sampling and analytical methods are also of lower quality, e.g. SASS and GC/MS.

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

<u>Reference 24</u>

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

<u>Reference 25</u>

The emission factors for oil combustion that were summarized in this document came from Reference 23. These data were eliminated from use in this update due to their poor quality.

Reference 26

This report summarizes a study that was performed to determine organic compounds emitted from stationary sources which contribute to the formation of smog in the atmosphere. The report provides a summary of organic concentrations from the exhaust from a utility boiler and provides data on families of organics but does not clearly indicate emissions of specific compounds.

Reference 27

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

Reference 28

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

Reference 29

This document presents a summary of emission factors for different types of processes which emit formaldehyde. The emission factors are presented in mass per heat unit input. A factor is provided for residual and for distillate oil; however, the factors are based on one test only. The emission factor is, therefore, rated with a low rating.

Reference 30

This document provides a summary of the emissions factors for metals, POM, and formaldehyde for oil-fired boilers. The emission factors for metals were based on the contents of typical residual and distillate oil compositions with the assumption that all metals in the oil are emitted. The existing source test data are used to demonstrate that the metal emission factors are within reason. The emission factors for oil-fired boilers do not differentiate between residual and distillate oils nor by boiler configuration or size because the number of data points is not high enough to do so.
The document cautions that relatively limited data are available on toxic air pollutants resulting from these types of processes and that emissions data in the document should not be used to develop an exact assessment of emissions from any particular facility. Emission factors for the processes outlined in the document are summarized and provided for use in determining order of magnitude emissions. The emission factors are rated with a lower quality because this document is not a primary source of information and, therefore, data acquisition and manipulation could not be verified.

Reference 31

Source testing was performed on three utility boilers in southern California. Testing was performed for the following parameters: PAH with California Air Resources Board (CARB) Method 429; benzene, toluene, xylenes with CARB Method 410; formaldehyde, acetaldehyde, and acrolein with CARB Method 430; metals with CARB draft multiple metals. The QA/QC data, sampling points, number of test runs, etc. were reviewed by the South Coast Air Quality Management District (SCAQMD) for conformance with the applicable CARB test methods. These data were used by the SCAQMD to generate emission factors and are considered to be of sufficient quality for this update. It is not clear from the data, however, whether the samples were taken prior to or after the control device. Therefore, these data will not be used in this update until the request for clarification is received.

Reference 32

This report summarizes the results of the source testing of three distillate oil-fired boilers, and five residual oil-fired boilers. The samples were taken using a SASS train. The metals were analyzed using SSMS which is a semiquantitative method for determining metals. The report does present an average fuel analysis of metals for residual oil. These data are used in the presentation of emission factors for residual oil emissions.

Reference 33

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

Reference 52

This article focused on mechanisms which control the emissions of trace metals from waste combustion systems. A model was developed based on phenomena including particle entrainment, chemical interactions, vaporization, condensation, particle coagulation, and particle collection by gas cleaning system. The model was tested against the results from metals spiking in a pilot scale rotary kiln incinerator. The emissions data collected were not considered to be applicable for development of trace metal emission factors for oil-fired boilers.

Reference 53

In this article thermodynamic methods were used to calculate the volatility of chromium in the offgas for a decontamination and waste treatment facility incinerator and molten salt processor. The results were not considered to be applicable for development of trace metal emission factors for oil-fired boilers.

4.3.2 Baseline Emission Factors

Emission factors for metals, or trace elements, are quite often presented in the units of mass emitted per unit thermal heat input and are not specific to a particular boiler configuration. Ideally, emission factors for metals should be developed as a function of the boiler firing configuration, boiler size, trace element content in the fuel, fuel heating value, enrichment factor, and the collection efficiency of the control device.

The concepts of partitioning and enrichment are often used to characterize the behavior of trace metals in the combustion process. These concepts are used to describe the distribution of trace elements among the boiler outlet streams and particle sizes. Outlet streams for oil-firing include soot deposits, and particulate or vapor in the flue gas. Enrichment refers to the preferential concentration of trace metals in a specific particle size fraction or outlet stream. The process of enrichment is usually facilitated by the action of a control device.

The physical and chemical properties of a trace metal govern how that metal will distribute in the outlet streams. For example, mercury is a highly volatile metal and, therefore, the majority of the mass of mercury in the fuel oil tends to be emitted from the boiler in the flue gas and not deposited as bottom ash or convective section deposits.

A method for describing partitioning behavior is to report the fraction of the total elemental mass input that has left the boiler in an outlet stream. Another method for quantifying the distribution of a metal is to calculate an enrichment factor by comparing the trace element concentration of an outlet stream to the trace element concentration in the inlet fuel stream. The enrichment ratio calculation that is outlined in Reference 1 is performed using the following equation:

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

where:

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

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

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

C_{ic} = concentration of element i in fuel

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

Enrichment ratios greater than 1 indicate that an element is enriched in a given stream, (e.g. stream j), or that it partitions to a given stream. A reference element is used because its partitioning and enrichment behavior is often comparable to that for the total mass. In other words, the reference element partitions with consistent concentrations in all streams and normalizes the calculation. Typical reference elements are aluminum (Al), iron (Fe), scandium (Sc), and titanium (Ti). The enrichment behavior of elements is somewhat consistent in different types of boilers and can be explained by a volatilization-condensation or adsorption mechanism. A summary of the enrichment behavior for the HAPs metals and the reference metals is presented in Table 4-11.

Insufficient data were available to develop enrichment ratios for different sizes and configurations of oil-fired boilers. As stated in Reference 33, it is reasonable to estimate metals emissions based on the assumption that the entire metal content in the fuel is emitted. This approach results in an emission factor that is theoretically the maximum for the fuel under analysis. The only means by which actual emissions could be greater than the calculated value is if a metal is added to the emission stream from metal erosion in the boiler or control device, or if the metal is present in combustion air at a significant level. The most significant factor influencing the uncontrolled emission is the content of the metal in the fuel. The metals content in the fuel were used in conjunction with source test data to develop uncontrolled emission factors.

As stated in Reference 28, residual oils appear to have higher chromium contents than crude oils as a result of the refining process. A heavy metal such as chromium has a very low vapor pressure and exists distillation operations as a low pressure organo-metallic complex along with the higher molecular weight hydrocarbons in the crude oil. The metal concentrates in the residual part of the crude oil as it is distilled. This concentration phenomenon explains why the chromium content of distillate oils is generally lower than that of residual and crude oils. This phenomenon holds true for similar metals.

Unlike metals emissions, POM emissions are a direct product of inefficiency in the combustion process as described in Reference 6. The primary constituents of the POM emissions are naphthalene, biphenyl, phenanthrene, anthracene, and fluoranthene. Based on very limited data, POM emissions from distillate oil combustion appear to be slightly higher than emissions from residual oil combustion. This trend may be due to the fact that smaller distillate oil boilers have less efficient combustion systems than larger residual oil boilers.

Tables 4-12 and 4-13 present emission factors for metals, POM, and formaldehyde in metric and English units, respectively. Limited data are available on other HAPs compounds and could not be obtained for this update. The metals data were more abundant while data for formaldehyde were very limited. The POM data were also relatively limited. The data are presented in the units of mass emitted per unit thermal heat input as reported in most of the references. Insufficient documentation was available to convert the factors to mass emitted per volume of fuel combusted.

4.3.4 Controlled Emission Factors

Insufficient data were available to generate emission factors for controlled HAPs emissions. It is clear that control devices for criteria pollutants will impact emissions of HAPs. For example, PM control devices will control nonvolatile metals and some semivolatile organic compounds that are associated with PM. Additional testing of these sources for HAPs and further data acquisition from agencies and industries which have performed these tests will need to occur for future updates of AP-42.

4.4 Nitrous Oxide

4.4.1 Review of Specific Data Sets

A total of 29 references were identified and reviewed during the literature search. Of these, 27 references proved to be unusable for developing N_2O emission factors. The primary reasons for rejection were:

- Data were taken with a pre-1988 protocol which has subsequently proven to give erroneously high measurements due to artifacts resulting from reactions in the sampling container;

- ! Insufficient documentation of source or sampling/analysis methods;
- ! Pilot scale data.

The screening results showed two of the 29 reports to be useable. The treatment in the current update is summarized below.

Reference 36

This reference contained N_2O emissions data from eight full-scale utility boilers. All test reports were rejected except for the test report from the Italian power plant. The Italian power plant had two sources: one source ran on fuel oil and the other source ran on bituminous coal. The data from the fuel oil source were used in this update. The report provided adequate detail for validation and the sampling and analysis methodology appeared sound. A B quality rating was assigned to the data.

Reference 37

This test report contained data for N_2O emissions from two sub-scale boilers. Both of the boiler units were run with natural gas, No. 2 fuel oil, and No. 5 fuel oil. The N_2O data were measured with an on-line GC/ECD N_2O analysis. Because the test report was from a small pilot scale system, a rating of D was assigned to the data for both boilers.

For the useable data contained in these reports, emission factor calculations were made in terms of mass of pollutant per mass of fuel. It should be noted that the terms "controlled" and "uncontrolled" in this discussion are indicative only of the location at which the measurements were made.

A summary of the N_2O emission data is contained in Table 4-14.

4.5 FUGITIVE EMISSIONS

There were no previous data on fugitive emissions in Chapter 1 of AP-42 and therefore, no existing data were available for validation. Most fugitive emissions from fuel oil handling or ash handling can be estimated from AP-42 Chapters 4 and 11. The data added to Section 1-3 for this update were for fugitive emissions from valves and flanges.

4.5.1 Review of Specific Data

A total of 10 references were documented and reviewed during the literature search. Nine of the ten were rejected using the criteria summarized in Chapter 3.1. The most common reason for rejection was lack of quantified process conditions.

4.5.2 Compilation of Emission Factors

Emission factors for fuel and fly ash handling and storage are found in Chapters 4 and 11 of AP-42, respectively. The VOC emission factors for the fuel feed system selected for inclusion in AP-42 were taken directly from the Petroleum Refineries study and the 24-unit SOCMI study.[38] The factors specified for fuel oil-fired boilers are the EPA-approved values for valves, pumps, flanges, and open-ended lines handling heavy liquids, which are defined as liquids with a vapor pressure less than kerosene. These values were derived through a well-described emission factor development approach derived as part of the SOCMI fugitive emissions standards proposed by EPA in January 1981. The procedure called for a determination of leaking and non-leaking source emission factors from the refinery data set and applying these factors to the leak frequencies found in the SOCMI 24-unit screening study to yield emission factors for average SOCMI units. The resultant "average" SOCMI factors evolved from a comprehensive and thorough study and were considered valid for this update. Table 4-15 presents the developed VOC emission factors for fuel oil feed systems.

4.6 PARTICULATE SIZE DISTRIBUTION

The revised AP-42 scope is intended to include particulate size distribution emission factors as well as filterable and condensible PM-10 emission factors. The 1986 AP-42 Section 1.3 includes detailed analysis of particulate size distribution data. Filterable PM-10 data are included in this analysis by default, because they are among the cumulative size fractions considered. Condensible PM-10 data are not in the 1986 Section 1.3; they should be added to future revisions of the section.

4.6.1 Review of 1986 Section 1.3 Data

The 1986 database was evaluated with respect to sources of data, data analysis, and calculations. Only filterable particulate data were retrieved and analyzed for that update.

Table 4-16 lists the sets of A-and B-rated data used to develop the current AP-42 emission factors for oil-fired particulate. The FPEIS printouts were the primary sources of emission data for the 1986 update. The original printouts were spot-checked to ensure that the data were used appropriately in the 1986 update. The spot-checking did not uncover any inaccuracies in the previous analysis. During the FPEIS evaluation, several FPEIS printouts were obtained that contained inorganic and organic impinger data. The data were evaluated for development of condensible PM-10 emission factors. The results of this analysis are discussed below.

4.6.2 Review of New Data

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

Although a variety of sources were contacted regarding particulate sizing and PM-10 data, very little additional data were obtained. State and district offices that were contacted either had no PM-10 data available or were unable to process such a request in a timely fashion due to other staff commitments. Several divisions within the CARB were contacted because CARB considers condensible particulate as a portion of total particulate. However, the personnel contacted did not have any reportable data. An official at the Stanislaus County Air Pollution Control District in California stated that they assume that all particulate from fuel-oil-fired boilers is PM-10, therefore, they do not require specific PM-10 testing.

Thirty source tests were performed on five boilers fueled with fuel oil.[41] Condensible particulate matter was one of the parameters measured during this test phase. None of the boilers was equipped with an abatement device for particulate emissions. Two different test trains were employed in the program: an EPA SASS and a modified EPA Method 5 train. Both trains consisted of a heated probe; three calibrated cyclones with nominal cut sizes of 10, 3, and 1 um contained in an oven capable of being heated to 400°F; a millipore filter also in the oven; two impingers containing distilled water; one dry impinger; one impinger containing desiccant; vacuum pump; and a dry gas meter. The primary difference in the two trains was size. The SASS was the larger of the two trains. It had a sampling rate of 4.0 standard dry cubic feet per minute (SDCFM) whereas the Method 5 sampling train had a sampling rate of 1.0 SDCFM. Condensible particulate matter data from this report are shown in Table 4-17 to 4-20.

One Method 202 test report was obtained that contained CPM emission data for an oil-fired boiler equipped with a mechanical collector.[42] The test objectives were to document the precision and sampling train collection efficiency of Draft Method 202, as well as to assess the general performance of the method at a source category expected to have significant CPM emissions. The boiler was fired on moderately high-sulfur oil and was expected to emit significant quantities of inorganic CPM.

The data are presented as mg emitted/m^3. The test matrix included the volumetric flow rates in the stacks but the process data, such as the size of the boiler or the oil-firing rate, were not recovered. Therefore, it is not possible to prepare emission factors from the results. However, conclusions may be drawn regarding the relative size of the organic and inorganic portions of the CPM. These results are presented in Table 4-21. The results indicate that CPM originating from high-sulfur oil-fired boilers are at least 90 percent inorganic matter.

4.6.3 Compilation of Uncontrolled Emission Factors

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

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

4.6.4 Control Technology Emission Factors

There were two calculation steps in the development of controlled emission factors in the previous AP-42 particulate sizing update. First, a controlled emission factor was developed for total particulate by multiplying the uncontrolled total particulate emission factor from the criteria pollutant table by one of the following control efficiency factors:

- Multiple cyclone - 80 percent,

- Baghouse - 99.8 percent,
- ESP - 99.2 percent, and
- Scrubber - 94 percent.

Nest, a controlled emission factor was developed for each of the cumulative size ranges by multiplying the controlled emission factor for total particulate by the cumulative percent mass for the size range. Thus, the quality of the right-hand side of each size distribution table in the 1986 Section 1.3 is directly related to the quality of three other numbers: (1) the control efficiency factors, (2) the total particulate emission factor (taken from the criteria pollutant table), and (3) the cumulative percent mass data. This, in part, explains the low ratings generally listed the section for the controlled emission factors for the particulate size fractions.

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

It is useful to note that the procedure does not assume a single control efficiency for each particle size. Rather, it assumes a single overall efficiency and applies this to the total particulate emission factor. The size-based emission factors depend on the total controlled emission factor and the percent of the total mass within a particular size range.

Although different methods could be used to develop controlled emission estimates, the procedure used in the 1986 document is logical. The process appears to generate conservatively high values for the controlled emission factors, as there are occasionally controlled emission factors in the tables that are larger than the uncontrolled factors.

With respect to the appropriateness of the four particulate control efficiencies used throughout the previous update, the values for the ESP and scrubbers appear to be high. The text of the 1986 AP-42 Section 1.3 indicates that the particulate removal efficiency of older ESPs is only 40 to 60 percent and that new or rebuilt ESPs remove up to 80 percent. This varies significantly from the efficiency of 99.2 percent assumed for the calculation of the controlled emission factors. The NSPS for small steam generating units confirms the discussion in AP-42. It lists source test data from two different oil-fired boilers that shows particulate control efficiencies ranging from 40 to 83 percent, with an average value of 64 percent. The boiler sizes were 28 MW (94 MMBtu/hr) and 1610 MW (5500 MMBtu/hr).

The 1986 AP-42 controlled emission factor calculations assume a scrubber efficiency of 94 percent. However, the AP-42 text notes that scrubbers remove only 50 to 60 percent of the particulate generated from oil-fired boilers. The NSPS document lists design particulate removal efficiencies for several wet scrubbers applied to oil-fired boilers. The efficiencies range from 40 to 92 percent with an average of 72 percent.

It is suggested that the control efficiencies used in the fuel oil tables be changed to 50 percent for old ESPs, 80 percent for new or rebuilt ESPs, and 80 percent for scrubbers.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
Particulate[a]	Utility	#6	7, pp. 68-74 24, printouts	53 10	2 2	A data point from a controlled facility;
	Industrial/ Commercial	#6	3, Table VI-4 4, Table F-3 5, Table 4-1	21	1 1 1	
	Industrial/ Commercial	#5	3, Table VI-4 4, Table F-3 5, Table 4-1	9	1	Average emission factor (10 lb/1000 gal) adopted in footnote g.
	Industrial/ Commercial	#4	3, Table VI-4 4, Table F-3	3	1	Average emission factor (7 lb/1000 gal) adopted in footnote g.
	Industrial/ Commercial	#2	3, Table VI-4 4, Table F-3 5, Table 4-1	15	1 1	Average emission factor (2 lb/1000 gal) adopted in footnote g.
	Residential	#2	4, Table I-3	33	-	Emission factor suggested in the table has been adopted.
SO_2[b]	Utility	Residual	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.
	Industrial	Residual	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.
	Commercial	Residual	3, pp. I-14, 16	5	-	Generally agrees with the EPA value (159S vs. 157S).
			4, p. I-20, 21	11	-	Suggest using a range (154S - 162S: #4 - #6).
	Industrial	Distillate	5, pp. 16-17	-	-	States that SOx emissions are proportional to fuel S% and are not affected by boiler size, burner design, or fuel.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
	Commercial	Distillate	3, pp. I-14, 16	1	-	Generally agrees with the EPA value (140S vs. 142S).
			4, p. I-20, 21	8	-	Suggest using the EPA value of 142S.
	Residential	Distillate	3, pp. I-13, 15	18	-	Lower than the EPA value (127S vs. 142S).
SO_3[c]	Utility	Residual	25, p. 20	-	-	Calculations based on Ref. 25 do not yield the EPA value.
	Industrial/ Commercial	Residual	-	-	-	Emission factor seems to be based on a simple mass balance indicated in ref. 1.
	Industrial/ Commercial/ Residential	Distillate	-	-	-	Appears that the result for Industrial/Commercial-Residualhas been used.
CO[d]	Utility	Residual	8, Table 2-13	9	-	CO ranged in 1-8 lb/1000 gal oil for all utility boilers.
			9, pp. 114-142	5	-	CO for all utility boilers, under normal baseline conditions, was in the range 5-10 lb/1000 gal oil.
	Industrial	Residual	5, p. 73	-	-	CO, typically, was less than 100 ppm (12.5 lb/1000 gal).
	Commercial	Residual	3, pp. I-14, 16	5	-	Average CO emission factor was 3.8 lb/1000 gal oil.
			4, p. I-20, 21	11	-	Suggest using a range (0.9 - 1.2 lb/1000 gal oil : #4 - #6).
	Industrial	Distillate	5, p. 73	-	-	CO, typically, was less than 100 ppm (12.5 lb/1000 gal).
	Commercial	Distillate	3, pp. I-14, 16	2	-	Average CO emission factor was 2.7 lb/1000 gal oil.
			4, p. I-20, 21	8	-	Suggest using 0.5 lb/1000 gal oil.
	Residential	Distillate	3, pp. I-13	18	-	Average CO emission factor was 5.1 lb/1000 gal oil.

TABLE 4-1. RESULTS OF 1986 SECTION 1.3 DATA SPOT CHECKS

Pollutant	Boiler	Fuel	1986 Section 1.3 reference	Total data points	Spot checked data points	Observations
			10, p. 25	38	-	Average CO emission factor was 0.12 lb/1000 lb oil (.86 lb/1000 gal oil).
NO_x[e]	Utility	Residual/ tangential	17, Table 2-1	2	-	New (16% lower) emission factor adopted.
		Residual/ vertical		-	-	Old emission factor retained.
		Residual/other		49	-	New (lower) emission factor adopted.
	Industrial/	Residual	17, Tables 3-1 & 4-1	28	-	Average emission factor adopted by EPA.
	Industrial/ Commercial	Distillate	17, Tables 3-1 & 4-1	19	-	Average emission factor adopted by EPA.
	Residential	Distillate	3, p. I-8;	19	-	Verified the notes in EFD.
			4, p. I-9, 11;	33	-	
			& 10, p. 25	38	-	
	1986 Footnote j		3, 4, 5	36	-	
VOC[f]	Utility	Residual	19, pp. 201 & 207	10	1	Verified the details in EFD.
	Industrial	Residual	21, pp. 102 & 106	4	-	
		Distillate	21, pp. 102 & 106	4	-	
	Commercial	Residual	20, pp. 75 & 79	4	-	
		Distillate	20, pp. 75 & 79	3	-	
	Residential	Distillate	18, pp. 58 & 62	5	-	

[a]Insufficient number of data points for #5 firing. Hence, emission factors for these cases should be rated B.
Adequate number of data points for #6 and #2 firing. Hence, a rating of A for corresponding emission factors.

[b]General comments for SO_2:

1. EFD does not provide sufficient information.
2. Emission factor for residual oil seems to be based on a simple mass balance indicated in Ref. 1 (see Table 4.1-3).
3. Emission factor for distillate oil (#2), calculated as per the simple mass balance indicated in Ref. 1, seems to be somehwat lower than the EPA value (137S vs. 142 S, where S = % sulfur - see Table 4.1.-3).
4. Ref. 2 is quite non-specific and probably should be purged.

5. Ref. 27 does not apply.
6. Emission factor rating:

Since emission factor estimates based on a mass balance assuming ~98% conversion of fuel S to SO_2, are very close to AP-42 values, emission factor ratings of A are assigned.

[c]General comments for SO_3:

1. EFD does not provide enough information.
2. Ref. 2 is quite non-specific and probably should be purged.
3. Ref. 27 does not apply.
4. Utility emission factor, based on Ref. 25, seems to be incorrect (see Section 4.1.3).
5. Emission factor rating:

For rating boiler firing residual oil, Ref. 25 does not provide adequate information. Hence, emission factors for this case should be rated C.

For cases other than utility boiers firing residual oil, emission factor estimates based on 1% fuel S to SO_3, are very close to AP-42 value of 2S. Hence, a rating of A was assigned.

[d]General comments for CO:

1. EFD does no provide adequate information.
2. An emission factor of 5 lb/1000 gal seems to have been adopted for all cases and published with a qualifying footnote.
3. Emission factor rating:

In general, as shown above, CO emission factors are between 1-10lb/1000 gal. Hence, a median valuee of 5 lb/1000 gal, with a qualifying footnote about CO emissions on combustion conditions, should be rated A.

[e]General comments for NO_x:

1. EFD is reasonably explicit but does not address footnote j adequately. No information available on specific pages in references used in connection with footnote j.
2. Emission factor rating:

Since NO_x emission factors are based on ample A-rated data points, corresponding emission factor rating of A is assigned.

[f]General comments for VOC:

1. EFD is quite explicit and, therefore, only utility/residual case was spot checked.
2. Emission factor rating: Since emission factors are based on ample A-rated data points, ratings of A are assigned.

TABLE 4-2. PM EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Fuel			Density, lb/gal	Load/ capacity	Sample O_2,	PM, lb/MBtu	PM, lb/Kgal
					HHV, Btu/lb	S, %	Ash, %			%		
6	Utility	Low S Oil	A	Haynes #5	18958	0.18	0.01	7.59	0.92	3-4	0.0153	2.202
8	Utility	6	A	Boiler No. 7	18477	1.99	0.08	8.14	1	5		16.690
					18451	1.9	0.09	8.17	1	6.1		22.606
					18466	1.91	0.1	8.16	1	5.5		23.600
											Average	20.965
					18477	1.99	0.08	8.14	1			29.5
					18451	1.9	0.09	8.17	1			15.2
					18466	1.91	0.1	8.16	1			15.823
											Average	20.178
10	Utility	6	A	Refinery B,	18750	0.73	0.03	7.951	0.97	4.9	0.035	5.218
				Source 2	18750	0.73	0.03	7.951	0.98	6.6	0.035	5.218
											Average	5.218
	Utility	6	A	Refinery C,	18610	1.19	0.02	8.027	1.02	7.3	0.054	8.067
				Source 1	18610	1.19	0.02	8.027	0.775	9.6	0.088	13.146
											Average	10.606
1-3	Industrial	6	A		17515	1.96	0.02	7.88	0.7-1		0.14	19.323
4,5	Industrial	2	A	Location 19	19680	0.16	0.00	6.97	0.8	3.2	0.0564	7.736
					19680	0.16	0.00	6.97		2.95		0.000
											Average	7.736
	Industrial	6	A	Location 19	19000	0.54	0.01	7.75	0.8	3	0.084	12.369
					19000	0.54	0.01	7.75		3.1		0.000
											Average	12.369

TABLE 4-2. PM EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Fuel: HHV, Btu/lb	Fuel: S, %	Fuel: Ash, %	Density, lb/gal	Load/ capacity	Sample O_2, %	PM, lb/MBtu	PM, lb/Kgal
	Industrial	6	A	Location 38	18467	1.88	0.05	8.04	0.89	2.9	0.1543	22.910
7	Industrial	6	A	Site 2	18950	0.97	0.02	7.71	1	8.9	0.0475	6.940
					19020	0.88	0.02	7.69	1.02	7.6	0.0757	11.077
											Average	9.008

Results:

<u>1. Industrial boilers firing distillate oil:</u>

The average emission factor from one data point, shown above, is 7.74 lb/1000 gal.
AP-42 emission factor, based on 15 points, is 2 lb/1000 gal.
AP-42 factor is retained.

<u>2. Utility/Industrial/Commercial boilers firing No. 6 oil:</u>

A. Original 71 points reduced to 3 average points in the sulfur brackets shown below

S range (%)	# of points	S%	PM, lb/1000 gal
1.5 - 2.5	19	2.063	23
0.625 - 1.25	33	0.937	13
0.10 - 0.625	19	0.5	8.6

B. 10 Additional points (added in last EFD from reference 24):

Point	S%	PM, lb/MMB	HHV, Btu/gal	PM, lb/1000 gal
1	0.41	0.05	145551	7.27755
2	0.46	0.06	143156	8.58936
3	0.33	0.03	147184	4.41552
4	0.34	0.019	153192	2.94112864
5	0.39	0.106	149152	15.914518
6	0.37	0.09	142540	12.28286
7	0.44	0.006	142700	0.8562
8	0.34	0.05	142790	7.3645
9	0.37	0.03	147700	4.431
10	0.45	0.03	149289	4.47867

Points from B reduced to 1 average point:

---Average---

S range, %	# of points	S%	PM, lb/1000 gal
0.25 - 0.625	8	0.38	6.7

Note that points 1 and 2 have not been averaged in as these were taken after an ESP

C. 9 additional points added in this effort:

Point	S %	PM, lb/1000 gal
1	0.18	2.2
2	1.93	21
3	1.93	20
4	0.73	5.2
5	1.19	11
6	1.96	19
7	0.54	12.37
8	1.88	23
9	0.925	9

Above 9 points are reduced to 3 average points shown below

-----Average---------

S range, %	# of points	S, %	PM, lb/1000 gal
1.5 - 2.5	4	1.9	21
0.625 - 1.25	3	0.9	8.3
0.10 - 0.625	2	0.4	7.29

D. Linear regression using average points from A, B, and C.

---------Average----------

S ,	PM lb/1000 gal
2.1	23
0.94	13
0.5	8.6
0.38	6.7
1.9	21
0.95	8.3
0.36	7.3

Regression Output:

Constant	3.22
Std Err of Y Est	2.109
R Squared	0.94
No. Of Observations	7
Degrees of Freedom	5
X Coefficient(s)	9.19

In view of above, the algorithm given in previous AP-42 is changed to:

PM, lb/1000 gal = 9.19*S% + 3.22

This has a correlation coefficient of r = 0.97

TABLE 4-3. SO_2 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Density, lb/gal	Load/ capacity	O_2, %	SO_2, lb/MMBtu	SO_2, lb/Kgal.	SO_2/S% Residual	SO2/S% Distillate
6	Utility	Low S oil	B	Haynes #5	143	18958	0.18	7.59	0.92	3-4	0.209	30.07	167.07	
1-3	Industrial	6	B		202-3 & 4	17515	1.96	7.88	0.7-1		2.28	314.68	160.55	
4,5	Industrial	2	B	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.146	20.03		
					19-7	19680	0.16	6.97		2.95	0.223	30.59		
												25.31		158.17
	Industrial	6	B	Location 19	19-97	19000	0.54	7.75	0.8	3	0.596	87.76		
					19-99	19000	0.54	7.75		3.1	0.644	94.83		
												91.30	169.06	
	Industrial	6	B	Location 38	200-24	18467	1.88	8.04	0.89	2.9	1.713	254.34	135.29	
												Average	157.99	158.17

TABLE 4-3. SO_2 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Density, lb/gal	Load/ capacity	O_2, %	SO_2, lb/MMBtu	SO_2, lb/Kgal.	SO_2/S% Residual	SO2/S% Distillate

Results:

1. Residual Oil Firing:

SO_2 emission factor based on fuel oil S weight percent can be estimated as follows:

$$0.98 \times 64/32 \times \%S/100 \times 8 \times 1000 = 156.8S$$

assuming 98% conversion of S to SO_2 and oil density of 8 lb/gal.

1986 AP-42 emission factor is identical to the above estimated value.
The average emission factor, shown above, is also very close to the AP-42 value.

Hence, 1986 emission factor is retained.

2. Distillate Oil Firing:

SO_2 emission factor based on fuel oil S weight percent can be estimated as follows:

$$0.98 \times 64/32 \times \%S/100 \times 7 \times 1000 = 137.2S$$

assuming 98% conversion of S to SO_2 and oil density of 7 lb/gal.

1986 AP-42 emission factor is very close to the above estimated value.
The average emission factor, based on one data point, is higher than the above estimated value.

In light of paucity of new data and above estimate, 1986 emission factor is retained.

3. No. 4 Oil firing:

No. 4 oil properties can be approximated by averaging residual & distillate oils properties. Hence, emission factor is also an average.

TABLE 4-4. SO_3 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2, %	SO_3, lb/MMBtu	SO_3, lb/Kgal	SO_3/S%
4,5	Industrial	2	A	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.0023	0.315	2.0
	Industrial	6	A	Location 19	19-97	19000	0.54	7.75	0.8	3	0.0093	1.369	2.5
	Industrial	6	A	Location 38	200-24	18467	1.88	8.04	0.89	2.9	0.0509	7.557	4.0

TABLE 4-4. SO_3 EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2, %	SO_3, lb/MMBtu	SO_3, lb/Kgal	SO_3/S%

Results:

<u>1. Utility boilers firing No. 6 oil:</u>

An emission factor for utility boilers firing No. 6 oil, based on information in 1986 Section 1.3 Reference 25, can be estimated as follows:

$$0.0286 \times 80/32 \times S\%/100 \times 8 \times 1000 = 5.72S$$

assuming a mean conversion of 2.86% for S to SO_3 and oil density of 8 lb/gal.

Above estimate suggests that for utility boilers firing No. 6 oil the 1986 AP-42 value of 2.9S lb/Kgal is incorrect.

The above estimated value is accepted as the emission factor for this case, with a C rating as data in 1986 Reference 25 are rated B due to lack of adequate information.

<u>2. Other hardware/fuel combinations:</u>

An emission factor, for residual oil firing, can be estimated as follow:

$$0.01 \times 80/32 \times S\%/100 \times 8 \times 1000 = 2S$$

assuming a mean conversion of 1% for S to SO_3 (as per Ref.1) and oil density of 8 lb/gal.

Since there is a wide variability in conversion of S to SO_3, the emission factor of 2S (lb $SO_3/10^3$ gal oil) is also valid for distillate oil firing.

The averaged emission factor for industrial boilers is close to the 1986 AP-42 value of 2S.

In view of paucity of new data, and above result, 1986 AP-42 value is retained.

TABLE 4-5. CO EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel S, %	Fuel density, lb/gal	Load/ capacity	O_2	CO, lb/MBtu	CO, lb/Kgal.
6	Utility	Low S oil	A	Haynes #5	143	18958	0.18	7.59	0.92	3-4	0.013	1.87
1-3	Industrial	6	A		202-3 & 4	17515	1.96	7.88	0.7-1		0.01	1.38
						17515	1.96	7.88	0.7-1		0.01	1.38
												1.38
4,5	Industrial	2	A	Location 19	19-5	19680	0.16	6.97	0.8	3.2	0.003	0.45
					19-7	19680	0.16	6.97		2.95	0.01	1.30
												0.88
	Industrial	6	A	Location 19	19-97	19000	0.54	7.75	0.8	3	0.003	0.49
					19-99	19000	0.54	7.75		3.1	0.003	0.49
												0.49
	Industrial	6	A	Location 38	200-24	18467	1.88	8.04	0.89	2.9	0.017	2.58
9	Residential	2	A		43					8.5	0.37 g/kg	2.59
					44					8.5	0.33 g/kg	2.31
												2.45
											Average	1.61

Results:

As shown above, the average emission factor for CO is less than the 1986 AP-42 value of 5 lb/1000 gal. However, the 1986 AP-42 value is based on many more observations; therefor it is retained.

TABLE 4-6. NO_x EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel N, %	Fuel density, lb/gal	Load/ capacity	Sample O_2, %	NO_2, lb/MMBtu	NO_2, lb/Kgal
10	Utility (Horizontal fired)	6	A	Refinery B, Source 2	10,11,12	18750	0.22	7.951	0.97	4.9	0.22	32.80
					7,8,9	18750	0.22	7.951	0.98	6.6	0.23	34.29
												33.54
	Utility (Horizonal fired)	6	A	Refinery C, Source 1	1,2,3	18610	0.18	8.027	1.02	7.3	0.27	40.33
					4,5,6	18610	0.18	8.027	0.775	9.6	0.34	50.79
												45.56
1-3	Industrial	6	A		202-3 & 4	17515	0.36	7.88	0.7-1		0.38	52.45
						17515	0.36	7.88	0.7-1		0.365	50.38
												51.41
4,5	Industrial	2	A	Location 19	19-5	19680	0.00 1	6.97	0.8	3.2	0.241	33.06
					19-7	19680	0.00 1	6.97		2.95	0.2301	31.56
												32.31
	Industrial	6	A	Location 19	19-97	19000	0.2	7.75	0.8	3	0.428	63.02
					19-99	19000	0.2	7.75		3.1	0.438	64.50
												63.76
	Industrial	6	A	Location 38	200-24	18467	0.31	8.04	0.89	2.9	0.52	77.21
7	Industrial	6	A	Site 2	1-1 & 1-2	18950	0.27	7.71	1	8.9	0.506	73.93
					1-3	19020	0.24	7.69	1.02	7.6	0.4487	65.65
												69.79
9	Residential	2	A		43					8.5	2.602 g/kg	27.92
					44					8.5	2.577 g/kg	27.66
												27.79

TABLE 4-6. NO_x EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Site	Run	Fuel HHV, Btu/lb	Fuel N, %	Fuel density, lb/gal	Load/ capacity	Sample O_2, %	NO_2, lb/MMBtu	NO_2, lb/Kgal

Results:

1. Utility boilers firing No. 6 oil:

Since no new data was uncovered for tangentially fired and vertical fired boilers, old emission factors are retained for these cases. However two data points, uncovered above, are used in determining emission factor for other firing configurations.

Average (lb/Kgal)	n	n x average	
67	49	3283	1986 data described in EFD and 1986 Ref. 17
33.54	1	34	New data point
45.56	1	46	New data point
	51	3362	

New emission factor (EF) = 65.92 (lb/1000 gal)
% change in EF = -1.49

Since % change in EF is small, 1986 EF (67 lb/Kgal) is retained.

2. Industrial/Commercial boilers firing residual oil:

Average (lb/Kgal)	n	n x average	
53	20	1060	1986 data described in EFD and 1986 Ref. 17
60	8	480	1986 data described in EFD and 1986 Ref. 17
51.41	1	51	New data point
63.76	1	64	New data point
77.21	1	77	New data point
69.79	1	70	New data point
	32	1802	

New emission factor (EF) = 56.32 lb/1000 gal
% change in EF = -2.4

Since % change in EF is small, 1986 EF (55 lb/Kgal) is retained.

3. Industrial/Commercial boilers firing distillate oil

Average (lb/Kgal)	n	n x average	
20	12	240	1986 data was described in EFD and Ref. 17
19	7	133	1986 data was described in EFD and Ref. 17
32.31	1	32.31	New data point
	20	405.3	

New emission factor (EF) = 20.27 lb/1000 gal
% change in EF = 1.35

Since % change in EF is small, 1986 EF (20 lb/Kgal) is retained.

4. Residential units firing distillate oil:

Since only one data point was obtained for this case, 1986 emission factor of 18lb/1000 gal, based on multiple data points, has been retained.

TABLE 4-7. VOC EMISSION FACTOR UPDATE

Ref.	Boiler	Fuel	Data quality	Run	Sample O_2, %	TOC, g/kg	TOC, lb/Kgal
9	Residential	2	A	43	8.5	0.04	0.28
				44	8.5	0.04	0.28
							0.28

Results:

The average emission factor for TOC is less than the 1986 AP-42 value of 2.49 lb/1000 gal.

The 1986 value is retained as it is derived from multiple data points.

TABLE 4-8. CONTROLLED PM EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Fuel HHV, Btu/lb	Control technology	Emissions uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
NR/15 MW (NR/52 MMBtu/h)	Residual oil	1.10		Venturi scrubber	0.94[a]/0.03	96.8[a]	14
14.5 MW/17 MW (49 MMBtu/h/57 MMBtu/h)	Residual oil	1.10		Steam Venturi/ spray tower	0.94[a]/0.052	94.5[a]	14
13 MW/17 MW (59.3 MMBtu/h/57 MMBtu/h)	Residual oil	2.80		Steam Venturi/ spray tower	2.08[a]/0.095	95.4[a]	14
13.7 MW/15 MW (52.4 MMBtu/h/50 MMBtu/h)	Residual oil	1.65		Heat. Tech. caustic scrubber	1.31[a]/0.08	93.9[a]	14
6.4 MW/7 MW (22.8 MMBtu/h/25 MMBtu/h)	Residual oil	1.46		Koch caustic scrubber	1.18[a]/0.07	94.1[a]	14
12.9 MW/15 MW (42.5 MMBtu/h/50MMBtu/h)	Residual oil	1.46		And. 2000 caustic scrubber	1.18[a]/0.08	93.2[a]	14
13.7 MW/15 MW (45.5 MMBtu/h/50 MMBtu/h)	Residual oil	1.34		Heat. Tech. caustic scrubber	1.10[a]/0.09	91.8[a]	14
13.5 MW/15 MW (45.0 MMBtu/h/50 MMBtu/h)	Residual oil	1.14		Koch caustic scrubber	0.96[a]/0.06	93.8[a]	14
NR/28 MW (NR/94 MMBtu/h)	Oil fired	0.7		ESP	0.063/0.035	45	14
1630 MW/1610 MW (5580 MMBtu/h 5500 MMBtu/h)	Oil fired	2	0.08	ESP	0.041/0.007	83	14
1640 MW/1610 MW (5590 MMBtu/h/5500 MMBtu/h)	Oil fired	2	0.09	ESP	0.045/0.012	69	14
1610 MW/1610 MW (5490 MMBtu/h/5500 MMBtu/h)	Oil fired	2	0.10	ESP	0.049/0.011	78	14
NR/10 MW	Oil fired	0.7	NR	ESP	0.092/0.056[a]	40	18
NR/10 MW	Oil fired	0.7	NR	ESP	0.14/0.07[a]	51	18
NR/48 MW	Oil fired	2.4	NR	ESP	0.18/0.113[a]	38.0	18
NR/48 MW	Oil fired	2.4	NR	ESP	0.35/0.15[a]	57.0	18

TABLE 4-8. CONTROLLED PM EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Fuel HHV, Btu/lb	Control technology	Emissions uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
NR/48 MW	Oil fired	2.4	NR	ESP	0.11/0.033[a]	71.0	18
NR/593 MW	Oil fired	2.2	NR	ESP	0.38/0.065[a]	83.0	18
NR/595 MW	Oil fired	2.2	NR	ESP	0.33/0.102[a]	69.0	18
NR/589 MW	Oil fired	2.2	NR	ESP	0.32/0.07[a]	78.0	18
NR/119 MW	Oil fired	1.95	0.09	ESP	NR/0.07	NR	18
NR/600 MW	Oil fired	0.3	0.02	ESP	0.02/0.017[a]	16	18
NR/350 MW	Oil fired	0.37	NR	ESP	0.026/0.012[a]	54	18
5.3 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		LEA	0.06/0.04	33.3	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		LEA	0.06/0.01	83.3	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Distillate oil/ WT packaged	NR		OFA	0.06/0.03	50.0	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil/ WT packaged	NR		LEA	0.08/0.07	12.5	13
13.6 MW/16 MW (47.6 MMBtu/h 56 MMBtu/h)	Residual oil/ WT packaged			LEA	0.15/0.11	26.7	13
NR/6.5 MW	Residual oil/ WT packaged			OFA	0.08/0.07	12.5	13

[a]Calculated value.
ESP = Electrostatic precipitator.
LEA = Low excess air.
OFA = Overfired air.
NR = Not reported.
WT = Watertube.

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
6.1 MW/8.1 MW (20.6 MMBtu/h/27.5 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	390 ng/J/43.0 ng/J	89	12
13.5 MW/14.7 MW (46 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.65	Sodium scrubbing	700 ng/J/21.5 ng/J	96.9	12
14.1 MW/14.7 MW (48 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.34	Sodium scrubbing	700 ng/J/25.8 ng/J	96.3	12
11.8 MW/16.2 MW (40.3 MMBtu/h/55.2 MMBtu/h)	Oil-fired units	.60	Sodium scrubbing	345 ng/J/17.2 ng/J	95.0	12
6.9 MW/7.3 MW (23.8 MMBtu/h/25 MMBtu/h)	Oil-fired units	1.00	Sodium scrubbing	350 ng/J/1.7 ng/J	99.5	12
12.9 MW/14.7 MW (44 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.46	Sodium scrubbing	700 ng/J/12.9 ng/J	98.1	12
4.5 MW/6.4 MW (15.6 MMBtu/h/22 MMBtu/h)	Oil-fired units	1.56	Sodium scrubbing	825 ng/J/103 ng/J	87.5	12
4.3 MW/6.4 MW (14.7 MMBtu/h/22 MMBtu/h)	Oil-fired units	1.61	Sodium scrubbing	690 ng/J/38.7 ng/J	94.4	12
15.4 MW/14.7 MW (52.5 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.58	Sodium scrubbing	750 ng/J/77.4 ng/J	89.7	12
14.8 MW/14.7 MW (50.5 MMBtu/h/50 MMBtu/h)	Oil-fired units	1.66	Sodium scrubbing	825 ng/J/34.4 ng/J	95.8	12
15.7 MW/18.3 MW (53.8 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	.85	Sodium scrubbing	575 ng/J/17.2 ng/J	97.0	12
16.6 MW/18.3 MW (56.9 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.15	Sodium scrubbing	500 ng/J/12.9 ng/J	97.4	12
15.4 MW/18.3 MW (52.5 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.00	Sodium scrubbing	545 ng/J/21.5 ng/J	96.0	12
15.0 MW/18.3 MW (51.3 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.10	Sodium scrubbing	425 ng/J/17.2 ng/J	96.0	12

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
15.0 MW/18.3 MW (51.3 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.10	Sodium scrubbing	530 ng/J/215 ng/J	96.0	12
19.8 MW/18.3 MW (67.5 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	1.01	Sodium scrubbing	975 ng/J/19.2 ng/J	98.0	12
17.2 MW/18.3 MW (58.8 MMBtu/h/62.5 MMBtu/h)	Oil-fired units	.80	Sodium scrubbing	550 ng/J/4.3 ng/J	99.2	12
6.7 MW/8.8 MW (22.8 MMBtu/h/30 MMBtu/h)	Oil-fired units	1.20	Sodium scrubbing	465 ng/J/30.1 ng/J	93.5	12
6.7 MW/7.3 MW (23 MMBtu/h/25 MMBtu/h)	Oil-fired units	1.46	Sodium scrubbing	695 ng/J/12.9 ng/J	98.1	12
15 MW/15 MW (52 MMBtu/h/52 MMBtu/h)	Residual oil fired	1.10	Venturi scrubber	NR	92	14
14.5 MW/17 MW (473 MMBtu/h/57 MMBtu/h)	Residual oil fired	1.10	Steam venturi/spray tower	NR	99	14
13 MW/17 MW (40 MMBtu/h/57 MMBtu/h)	Residual oil fired	2.80	Steam venturi/spray tower	NR	99.9	14
13.7 MW/15 MW (40 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.65	Heater tech, Caustic scrubber	NR	95.0	14
6.4 MW/7 MW (22.8 MMBtu/h/25 MMBtu/h)	Residual oil fired	1.46	Koch Caustic scrubber	NR	98	14
12.9 MW/15 MW (42.5 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.46	And. 2000 Caustic scrubber	NR	96.0	14
13.7 MW/15 MW (45.5 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.34	Heater tech scrubber	NR	92.0	14
13.5 MW/15 MW (45 MMBtu/h/50 MMBtu/h)	Residual oil fired	1.14	Koch Caustic scrubber	NR	99.0	14
89 MW (310 MMBtu/h)	Oil	1.5	Dual alkali scrubber	1.1 lb/MMBtu/0.091 lb/MMBtu	91.7	12

TABLE 4-9. CONTROLLED SO_2 EMISSIONS

Boiler load, actual/design	Boiler type	Fuel S, %	Control technology	Emissions, uncontrolled/ controlled	Removal efficiency, %	Ref.
6.2 MW/6.7 MW (21.2 MMBtu/h/23 MMBtu/h)	Oil-fired units	1.0	Sodium scrubbing	425 ng/J/38 ng/J	91	12
70,000 SCFM	Industrial oil	1.5	Double Alkali System	17,750/710 ppm	96	8

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
2.5 MW/2.6 MW (8.6 MMBtu/h/9 MMBtu/h)	Firetube/residual oil	0.27	LEA	(0.389/0.328)	16	13
4.0 MW/3.8 MW (13.5 MMBtu/h/13 MMBtu/h)	Firetube/residual oil	1.30	LEA	(0.239/0.227)	5	13
6.3 MW/6.7 MW (21.6 MMBtu/h/23 MMBtu/h)	Firetube/residual oil	0.03	LEA	(0.213/0.201)	6	13
19.2 MW/24 MW (65 MMBtu/h/81 MMBtu/h)	Field erected water tube/ residual oil	0.38	LEA	(0.641/0.572)	11	13
20 MW/24 MW (67 MMBtu/h/81 MMBtu/h)	Packaged water tube/residual oil	0.29	LEA	(0.256/0.236)	8	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.25	LEA	(0.278/0.193)	31	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.44	LEA	(0.459/0.438)	5	13
5.4 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.44	LEA	(0.436/0.368)	16	13
18.6 MW/29 MW (64 MMBtu/h/100 MMBtu/h)	Packaged water tube/residual oil	0.37	LEA	(0.398/0.356)	11	13
5.3 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/residual oil	0.14	LEA	(0.217/0.159)	27	13
7.1 MW/9.1 MW (24.2 MMBtu/h/31 MMBtu/h)	Packaged water tube/residual oil	0.19	LEA	(0.200/0.145)	28	13
10.7 MW/26 MW (36.1 MMBtu/h/88 MMBtu/h)	Packaged water tube/residual oil	NR	LEA	(0.263/0.231)	12	13
12.2 MW/15 MW 40.5 MMBtu/h/50 MMBtu/h)	Packaged water tube/residual oil	0.30	LEA	(0.251/0.230)	8	13
13.6 MW/16 MW (47 MMBtu/h/56 MMBtu/h)	Packaged water tube/residual oil	0.14	LEA	(0.386/0.305)	21	13

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
13.0 MW/16 MW (45.4 MMBtu/h/56 MMBtu/h)	Packaged water tube/residual oil	0.49	LEA	(0.419/0.312)	26	13
1.9 MW/3.8 MW (65 MMBtu/h/13 MMBtu/h)	Firetube/distillate oil	NR	LEA	(0.221/0.197)	11	13
3.4 MW/7.3 MW (11.8 MMBtu/h/25 MMBtu/h)	Firetube/distillate oil	NR	LEA	(0.224/0.186)	17	13
5.5 MW/11 MW (18 MMBtu/h/36 MMBtu/h)	Packaged water tube/distillate oil	0.045	LEA	(0.136/0.118)	13	13
5.1 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.096/0.088)	10	13
5.1 MW/6.4 MW (17.6 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.134/0.125)	7	13
4.2 MW/6.4 MW (14.5 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.006	LEA	(0.107/0.105	2	13
5.3 MW/6.4 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	LEA	(0.154/0.125)	19	13
8.7 MW/11 MW (28.4 MMBtu/h/36 MMBtu/h)	Packaged water tube/distillate oil	0.045	LEA	(0.158/0.134)	15	13
16 MW/16 MW (56 MMBtu/h/56 MMBtu/h)	Packaged water tube/distillate oil	NR	FGR-10 %	(0.185/0.152)	18	13
5.4 MW/6.5 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	FGR-28 %	(0.154/0.041)	73	13
5.4 MW/6.5 MW (18.3 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.004	OFA	(0.154/0.125)	19	13
18.5 MW/22 MW (63 MMBtu/h/75 MMBtu/h)	Packaged water tube/distillate oil	NR	SCB	(NR/0.110)	NR	13
6.1 MW/9.1 MW (20.8 MMBtu/h/31 MMBtu/h)	Packaged water tube/distillate oil	0.19	FGR-7 %	(0.161/0.157)	3	13

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
6.1 MW/9.1 MW (20.8 MMBtu/h/31 MMBtu/h)	Packaged water tube/distillate oil	0.19	FGR-19 %	(0.161/0.112)	30	13
5.3 MW/6.5 MW (17.8 MMBtu/h/22 MMBtu/h)	Packaged water tube/distillate oil	0.25	FGR-25 %	(0.278/0.193)	31	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.14	OFA	(0.217/0.166)	24	13
5.2 MW/6.5 MW (17.6 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.44	OFA	(0.217/0.141)	35	13
5.1 MW/6.5 MW (17.4 MMBtu/h/22 MMBtu/h)	Residual oil packaged watertube	0.44	OFA	(0.278/0.194)	30	13
12.8 MW/16 MW (44.8 MMBtu/h/56 MMBtu/h)	Residual oil packaged watertube	0.49	OFA	(0.419/0.222)	47	13
13.6 MW/16 MW (47.6 MMBtu/h/56 MMBtu/h)	Residual oil packaged watertube	0.31	OFA	(0.386/0.245)	37	13
40-80%-170 MW	O/G wall fired		BOOS	(0.42/0.25)	40	17
40-80%-170 MW	O/G wall fired		FGR	(0.42/0.20)	52	17
40-80%-170 MW	O/G wall fired		LNB + OFA	(0.42/0.20)	52	17
40-80%-170 MW	O/G wall fired		LNB + OFA + FGR	(0.42/0.12)	71	17
40-80%-170 MW	O/G wall fired		SNCR	(0.15/0.08)	47	17
40-80%-170 MW	O/G wall fired		NCR	(0.15/0.04)	73	17
40-80%-170 MW	O/G tangentially fired		SNCR	(0.37/0.18)	51	17
40-80%-170 MW	O/G tangentially fired		NCR	(0.37/0.07)	81	17
60-123 MW/150 MW	Oil/wall fired		BOOS	(O.42/0.25)	40	17
60-123 MW/150 MW	Oil/wall fired		FGR	(O.42/0.20)	52	17
60-123 MW/150 MW	Oil/wall fired		LNB + OFA	(O.42/0.20)	52	17

TABLE 4-10. CONTROLLED NO_x EMISSIONS

Boiler load, actual/design	Boiler type	Fuel N, %	Control technology	Emissions, uncontrolled/ controlled, lb/MMBtu	Removal efficiency, %	Ref.
60-123 MW/150 MWO	Oil/wall fired		LNB + OFA + FGR	(O.42/0.12)	71	17
60-123 MW/150 MW	Oil/tangential		FGR	(O.32/0.15)	71	17
60-123 MW/150 MW	Oil/tangential		LNB + OFA	(O.32/0.12)	78	17
60-123 MW/150 MW	Oil/wall tangential		SCR	(O.15/0.04)	73	17
60-123 MW/150 MW	Oil/wall tangential		SCR	(O.37/0.07)	81	17
60-123 MW/150 MW	Oil/wall tangential		SNCR	(O.15/0.08)	47	17
60-123 MW/150 MW	Oil/wall tangential		SNCR	(O.37/0.18)	51	17

LEA = Low excess air.
NR = Not reported.
FGR = Flue gas recirculation.
OFA = Overfired air ports.
O/G = Oil/gas.
BOOS = Burners out of service.
LNB = Low NO_x burner.
SCR = Selective catalytic reduction.
SNCR = Selective non-catalytic reduction.

TABLE 4-11. METALS ENRICHMENT BEHAVIOR

Class	Description	Reference 30	Reference 22	Reference 34
I	Equal distribution between fly ash and soot		Al, Co, Fe, Mn, Sc, Ti	Al, Co, Cr, Fe Mn, Sc, Ti
II	Enriched in fly ash relative to soot	As, Cd	As, Cd, Pb, Sb	As, Cd, Pb, Sb
III	Somewhere in between Class I and II, multiple behavior	Be, Cr, Ni, Mn	Cr, Ni	Ni
IV	Emitted in gas phase	Hg	Hg	Hg

TABLE 4-12. HAP EMISSION FACTORS (METRIC UNITS) FOR RESIDUAL AND DISTILLATE OIL COMBUSTION[a]

Firing configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH[b]
Residual, Grade 6, Normal Firing (10100401)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10100404)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10200401)	10-20	8.2-49	1.8	6.8-91	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Residual, Grade 6, Normal Firing (10300401)	10-20	8.2-49	1.8	6.8	9.0-55	33-50	12-80	10-30	0.6-14	360-964	16	3.2-3.6[c]	69-174
Distillate, Grade 2, (10100501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174
Distillate, Grade 2, (10200501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174
Distillate, Grade 2, (10300501)	-	1.8	1.1	4.5	21-29	-	3.8	6.0	1.3	7.3	-	9.7[d]	100-174

[a]All emission factors in pg/J. All emission factors rated as E quality.
[b]Based on 1964 data, only four data points.
[c]Particulate and gaseous POM.
[d]Particulate POM only.

TABLE 4-13. HAP EMISSION FACTORS (ENGLISH UNITS) FOR RESIDUAL AND DISTILLATE OIL COMBUSTION[a]

Firing configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH[b]
Residual, Grade 6, Normal Firing (10100401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10100404)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10200401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Residual, Grade 6, Normal Firing (10300401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4[c]	161-405
Distillate, Grade 2, (10100501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405
Distillate, Grade 2, (10200501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405
Distillate, Grade 2, (10300501)	-	4.2	2.5	11	48-67	-	8.9	14	3.0	170	-	22[d]	233-405

[a]All emission factors in lb/10^{12} Btu. All emission factors rated as E quality.
[b]Based on 1986 and limited new data.
[c]Particulate and gaseous POM.
[d]Particulate POM only.

TABLE 4-14. SUMMARY OF N_2O EMISSION FACTORS FOR FUEL OIL COMBUSTION

Boiler type	Emission factor rating	Nitrous oxide emissions,	
		$lb/10^3gal$	$kg/10^3l$
Utility boilers			
Residual oil-fired	D	0.11	0.013
Industrial boilers			
Residual oil-fired	E	0.11[a]	0.013[a]
Distillate oil-fired	E	0.11[a]	0.013[a]
Commercial boilers			
Residual oil-fired	E	0.11[a]	0.013[a]
Distillate oil-fired	E	0.11[a]	0.013[a]
Residential furnaces			
Distillate oil-fired	D	0.05	0.006

[a]No data were available, therefore the value for utility boilers was extrapolated.

TABLE 4-15. COMPARISON OF FUGITIVE EMISSIONS OF VOCs FROM EQUIPMENT TYPES

Equipment type	Emission factor, kg/h/source[a]	Sources leaking, %
Valve - light liquid	0.0071	11.5[b]
Valve - heavy liquid	0.00023	0.2[b]
Pump - light liquid	0.0494	24.0[b]
Pump - heavy liquid	0.0214	3.8[b]
Compressor	0.2280	58.4[b,d]
Sampling connections	0.0150	2.8[c]
Open-ended line	0.0017	11.9[d]
Flange	0.00083	7.2[b,d]

[a]Reference 38.
[b]Reference 38: Table 2-2 through Table 2-6.
[c]Reference 39.
[d]Reference 38: Table 2-25.

TABLE 4-16. OIL-FIRED PARTICULATE SIZING DATA FOR THE CURRENT AP-42 SECTIONS: NUMBER OF A- AND B-RATED DATA SETS[a]

Source category	Emission control device				
	None	Multiple cyclones	Scrubber	ESP	Baghouse
Fuel oil					
- utility boilers, residual	16	0	4	0	0
- industrial boiler, residual	14	0	0	0	0
- industrial boiler, distillate	0	0	0	0	0
- commercial, residual	15	0	0	0	0
- commercial, distillate	3	0	0	0	0
- residential furn., distillate	0	NA	NA	NA	NA

NA = Not applicable.
[a]Data from Reference 40.

TABLE 4-17. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A 5 MILLION BTU/HR SCOTCH DRY-BACK BOILER[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
1S	9.6	.02	16.1	50.1	.10	83.9
1J	23.0	.04	32.1	48.8	.08	67.9
2S	5.4	.01	26.2	15.0	.03	73.8
2J	6.0	.01	26.2	17.1	.03	73.8
3S	1.9	.003	3.0	62.8	.11	97.0
3J	3.1	.006	15.1	17.4	.03	84.9

[a]Reference 41.
[b]Tests 1 and 3 were run using Wilmington crude oil with a sulfur content of 1.35% sulfur and an ash content of 0.017%. Test 2 was run with No. 6 fuel oil with a sulfur content of 0.28% and an ash content of 0.016%.
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-18. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A TYPE-H STIRLING BOILER FIRING NO. 2 FUEL OIL[a]

Run number[b]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
16J	.2	.005	1.0	13.4	.41	99.0

[a]Reference 41.
[b]Fuel analysis results showed the sulfur content at 0.38% and the ash content at 0.001%.

TABLE 4-19. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A FACE-FIRED SUPERCRITICAL 480 MW STEAM GENERATOR[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
11S	1.9	5.9	13.4	12.2	38.1	86.6
11J	4.7	14.6	53.1	4.1	12.9	46.9
12S	.7	2.5	8.3	8.3	28.0	91.7
12J	1.6	5.6	28.8	4.1	13.8	71.2
13J	1.2	4.1	7.7	14.4	49.2	92.2
24S	.6	1.2	3.4	18.5	33.3	96.6
24J	6.8	12.3	27.7	17.7	32.0	72.3
32S	2.8	8.5	13.3	18.6	55.6	86.7
32J	1.6	4.7	14.9	8.9	26.5	85.1
33S	2.4	7.7	12.3	17.1	54.7	87.7
33J	8.5	27.3	47.7	9.3	29.9	52.3

[a]Reference 41
[b]All tests were run with No. 6 fuel oil with an average sulfur content of 0.21% and an ash content of 0.011%.
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-20. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A FACE-FIRED, BALANCED DRAFT UTILITY BOILER[a]

Run number[b,c]	Organic CPM			Inorganic CPM		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
21S	3.0	4.3	19.7	12.4	17.6	80.3
21J	.1	.1	.9	10.3	14.6	99.1
22S	1.1	.9	5.2	19.2	15.5	94.8

[a]Reference 41.
[b]Fuel analysis results showed the sulfur content at 0.20% and the ash content at 0.012%
[c]The letter S shown immediately after the run number denotes the use of the SASS train; the letter J denotes the use of the EPA Method 5 train.

TABLE 4-21. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM AN OIL-FIRED BOILER EQUIPPED WITH A MECHANICAL COLLECTOR[a]

Run number[b]	Organic CPM			Inorganic CPM[c]		
	mg/m^3	lb/hr	% of CPM	mg/m^3	lb/hr	% of CPM
1	2.3	5.6	7.7	27.6	67.5	92.3
2	0.69	1.6	3.4	19.7	44.3	96.6
3	0.72	1.4	2.1	33.0	62.1	97.9

[a]Reference 42.
[b]Results for runs 1 and 2 are an average of 4 simultaneous trains purged with N_2; run 3 is an average of 3 simultaneous trains.
[c]Corrected for chlorides.

CHAPTER 4 REFERENCES

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5. AP-42 SECTION 1.3: FUEL OIL COMBUSTION

The revision to Section 1.3 of AP-42 is presented in the following pages as it would appear in the document. A marked-up copy of the 1986 version of this section is included in Appendix B.

TABLE A-1. CONVERSION FACTORS

To obtain:	From:	Multiply by:	Use:
lb pollutant/10^3 gal	lb pollutant/MMBtu	10^{-3} x Oil HHV in Btu/gal[a]	
kg pollutant/10^3 ℓ	lb pollutant/10^3 gal	0.1195	
Oil HHV in Btu/gal	Oil HHV in Btu/lb	Oil density in lb/gal[b]	
Oil density in lb/gal	°API		141.5/(131.5 + °API) x 8.34

[a]If oil higher heating value (HHV) is not available, use:

Residual oil HHV = 150,000 Btu/gal.

Distillate oil HHV = 140,000 Btu/gal.

[b]If oil density is not available, use:

Residual oil density = 8 lb/gal.

Distillate oil density = 7 lb/gal.

APPENDIX B

MARKED-UP 1986 AP-42 SECTION 1.3

REPORT ON REVISIONS TO
5TH EDITION AP-42
Section 1.3
Fuel Oil Combustion

Prepared for:

Contract No. EPA 68-D2-0160, WA-50
EPA Work Assignment Officer: Roy Huntley
Office of Air Quality Planning and Standards
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December 1996

Table of Contents

1.0 INTRODUCTION

This report supplements the Emission Factor (EMF) Documentation for AP-42 Section 1.3, Fuel Oil Combustion, dated April, 1993. The EMF describes the source and rationale for the material in the most recent updates to the 4th Edition, while this report provides documentation for the updates written in both Supplements A and B to the 5th Edition.

Section 1.3 of AP-42 was reviewed by internal peer reviewers to identify technical inadequacies and areas where state-of-the-art technological advances need to be incorporated. Based on this review, text has been updated or modified to address any technical inadequacies or provide clarification. Additionally, emission factors were checked for accuracy with information in the EMF Document and new emission factors generated if recent test data were available.

If discrepancies were found when checking the factors with the information in the EMF Document, the appropriate reference materials were then checked. In some cases, the factors could not be verified with the information in the EMF Document or from the reference materials, in which case the factors were not changed.

Four sections follow this introduction. Section 2 of this report documents the revisions and the basis for the changes. Section 3 presents the references for the changes documented in this report. Section 4 presents the revised AP-42 Section 1.3, and Section 5 contains the EMF documentation dated April, 1993.

2.0 REVISIONS

2.1 General Text Changes

Information in the EMF Document was used to enhance text concerning fuel oil firing practices. Also, at the request of EPA, the metric units were removed.

2.2 Sulfur Oxides, SO_x

The uncontrolled SO_x factors were checked against information in Table 4-3 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.3 Sulfur Trioxide, SO_3

The SO_3 factors were checked against information in Table 4-4 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.4 Nitrogen Oxides, NO_x

The uncontrolled NO_x factors were checked against information in Table 4-6 of the EMF Document and the 10/86 version of Section 1.3 and no changes were required.

2.5 Carbon Monoxide, CO

The CO factors were checked against information in Table 4-5 of the EMF Document and the 10/86 version of AP-42 and no changes were required.

2.6 Filterable Particulate Matter, PM

Filterable PM emission factors were checked against information in Table 4-2 of the EMF Documentation and the 10/86 version of AP-42. The only change required was for the PM emission factors for residential furnaces.[1,2] Several new reports were reviewed and two contained PM emission data for new oil-fired residential furnaces. Based on these reports, it was determined that newer furnaces (i.e., pre-1970) emit significantly less PM than older furnaces (i.e., pre-1970). The existing PM emission factor for residential furnaces in the 5th Edition of AP-42 is based solely on pre-1970 data.

Table 1 presents the PM data for newer furnaces. The existing PM factor is 3.0 lb/1000 gal, is rated “A”, and is based on 33 pre-1970 data points. The PM emission factor for newer furnaces is 0.4 lb/1000 gal, is based on 9 post-1970 data points, and is rated “C”. The PM emission factor for new furnaces (0.4 lb/1000 gal) was added and a footnote included to qualify it as being based on new furnaces designs and pre-1970's burner designs may emit as high as 3.0 lb/1000 gal.

Table 1. Summary of Particulate Emission Data for New Residential Oil-Fired Furnaces

Reference/Page	Data Rating	Furnace/Burner type	Filterable PM Emission Factor (lb/1000 gal)
McCrillis, Page 4	B	Thermo-Pride Model: M-SR	0.42
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AF	0.38
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AFG	0.3
Krajewski, Page 40-42	B	R.W. Beckett Co. Model: AFG	0.4
Krajewski, Page 40-42	B	Riello Corp. Model: Mectron 3M	0.65 0.26 0.35
Krajewski, Page 40-42	B	Energy Kinetics Inc. Model: System 2000	0.4 0.24
Krajewski, Page 40-42	B	Bentone Electrol Oil Model: Airtronic	0.38
Krajewski, Page 40-42	B	Combustion Technology No model number	0.35
Krajewski, Page 40-42	B	Foster Miller Carlin Co. No model number	No data
Average	C		0.4

2.7 Total Organic Compounds (TOC) and Non-Methane TOC (NMTOC)

The TOC and NMTOC factors were checked against information on page 4-7 of the EMF Document and the 10/86 version of AP-42 and no changes were necessary.

2.8 Particle Size Distribution

The particle size factors were checked against information in the EMF Document and the 10/86 version of AP-42 and no changes were required.

2.9 Polycyclic Organic Matter (POM) and Formaldehyde (HCOH)

The POM and HCOH factors in Table 1.3-7 were checked with information in Tables 4-12 and 4-14 of the EMF Document and no changes were required.

2.10 Trace Elements

Trace element factors were checked against Table 4-12 in the EMF Document. Based on recent test data, the factors for residual oil firing shown in Table 1.3-8 were revised (with the exception of antimony). New factors for barium, chloride, chromium VI, copper, fluoride, molybdenum, phosphorus, vanadium, and zinc were added. The data used to calculate the new and revised factors are presented in Appendix A.

The spreadsheets found in Appendix A present calculated average emissions factors based on new test data. Trace elements and speciated organic compounds are presented in Section A.1. Section A.2 contains the individual source test report summaries.

Data from sources tested at several EPRI, Southern California Edison, and Pacific Gas and Electric sites were entered into the spreadsheets. The emission factor were evaluated for patterns based on boiler type and controls. No patterns were found; therefore, the data were averaged (arithmetic mean) together by pollutant.

Special consideration was given to non-detected values in calculating the average factors. If a pollutant was not detected in any sampling run, half of the detection limit (DL/2) was used in the calculated average factor. For a given pollutant, any DL/2 factors that were greater than any factors based on detected values were not included in the calculated averages.

Data from each source test were given a quality rating based on EPA procedures. The ratings ranged from B-D in the tests evaluated for this report. A "B" rating was given for tests performed by a generally sound methodology but lacking enough detail for validation. A "C" rating was given for tests based on untested or new methodology or lacking a significant amount of background data. When a test was based on a generally unacceptable method but provided an order-of-magnitude value for the source, a "D" rating was assigned.

2.11 Greenhouse Gases

2.11.1 Carbon Dioxide, CO_2

Table 1.3-1 computes CO_2 emissions through a footnote that assumes 100 percent conversion of fuel carbon content to CO_2 during combustion. This does not account for unoxidized fuel in the exhaust stream, which is typically 1 percent for liquid fuels in external combustion systems.[3-5] The factor in note f of Table 1.3-1 was modified to reflect 99 percent conversion instead of the current 100 percent. These new factors appear in Table 2, below.

Table 2. Emission Factor Equations for Solid and Liquid Fuel Combustion
Emission Factor Rating: B

Fuel	Multiply	Density (lb/gal)	Conversion Factor[a]	To Obtain
No. 1 (kerosene)	% carbon	6.88	250	lb CO_2/1000 gal
No. 2	% carbon	7.05	256	lb CO_2/1000 gal
No. 6	% carbon	7.88	286	lb CO_2/1000 gal

[a] The following equation was used to develop the emission factor equation for fuel oils in Table 3-1:

$$\frac{44 \text{ lb } CO_2}{12 \text{ lb C}} \times 0.99 \times 7.05 \frac{\text{lb}}{\text{gal}} \times \frac{1}{100\%} \times 1000 = 256 \frac{\text{lb } CO_2}{1000 \text{ gal } \%C}$$

Where: 0.99 = fraction of fuel oxidized during combustion (References 3-5), and
7.05 lb/gal = density of No. 2 fuel oil (AP-42 Appendix A).

The factors for kerosene and No. 6 oil were computed as shown in note a to Table 2 using the density values from AP-42 Appendix A.

Table 3 lists default emission factors for fuel oils when the carbon content is not known. These figures are based on average carbon contents for each type of fuel and the equation shown in note A of Table 2.

Table 3. Default CO_2 Emission Factors for Liquid Fuels
Quality Rating: B

Fuel Type	%C[a]	Density[b] (lb/gal)	Emission Factor (lb/1000 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]An average of the values of fuel samples in References 6-7.
[b]References 6 and 8.

2.11.2 Methane

No new data found.

2.11.3 Nitrous Oxide, N_2O

The current "E" rated N_2O emission factors in Table 1.3-9 were updated with more recent data that take into account an N_2O sampling artifact discovered by Muzio and Kramlich in 1998.[4] These new emission factors in Table 4 are based on a more complete database of source sampling than either of the references listed for the previous N_2O emission factors in AP-42.

Table 4. N_2O Emission Factors for Fuel Oil Combustion[a]
(lb N_2O/1000 gal)

Fuel	Combustion Category	New	New EF	Previous	Previous
No. 6	Industrial/utility boilers	B	0.53	0.11	E
No. 2	Industrial/utility boilers	B	0.26	0.11	E

[a]References 10-11.

The industrial/utility boilers data for No. 6 fuel oil is based on 6 tests at 4 different facilities collected by Nelson.[10] The data for No. 2 fuel oil for industrial/utility boilers is based on 14 source tests conducted at 6 facilities collected by Nelson.[10]

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

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

Where: C_d = N_2O;
F_d = F-factor for oxygen; and
$\%O_2$ = oxygen concentration in the exhaust gas.

The following F-factors and heating values were used for the calculations:

Fuel	**F-Factor (scf/MMBtu)**	**Heating Value (Btu/gal)**
No. 6 (residual)	9,190	150,000
No. 2 (distillate)	9,190	140,000

2.12 Speciated Organic Compounds

Based on new test data, a total of twenty-one new factors were developed for residual oil fired boilers. The average factors and the data used to calculate the factors are presented in Appendix A. The formaldehyde factor calculated with this data is based on recent tests of utility boilers only.

3.0 REFERENCES

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4.0 REVISED SECTION 1.3

This section contains the revised Section 1.3 of AP-42, 5th Edition. The electronic version can be located on the EPA TTN at http://134.67.104.12/html/chief/fsnpub.htm.

5.0 EMISSION FACTOR DOCUMENTATION, APRIL 1993

This section contains the Emission Factor Documentation for Section 1.3 dated April 1993. The electronic version can be located on the EPA TTN at http://134.67.104.12/html/chief/fbgdocs.htm. The zipped file on the TTN contains this (1996) background report as well as the 1993 Emission Factor Documentation.

APPENDIX A

SUPPORTING DOCUMENTATION

A.1 Data Used for Average Emission Factors Development

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. Of Test Runs
1	1	EPRI SITE 13	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
2	2	EPRI SITE 112	Residual (No. 6)	Tangentially-Fired	10100404	ESP	None	C	3
3	2	EPRI SITE 112	Residual (No. 6)	Tangentially-Fired	10100404	ESP	None	C	4
4	3	EPRI SITE 103	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
5	3	EPRI SITE 104	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
7	3	EPRI SITE 105	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
9	3	EPRI SITE 106	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
11	3	EPRI SITE 107	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
12	3	EPRI SITE 108	Residual (No. 6)	Opposed (Normal)	10100401	Uncontrolled	None	B	3
14	3	EPRI SITE 109	Residual (No. 6)	Opposed (Normal)	10100401	FGR	None	B	3
20	6	Southern California Edison Company, Alamitos Unit 5	Residual	Assumed Normal	10100401	FGR	None	C	3
21	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3
23	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. Of Test Runs
24	8	Southern California Edison Company, El Segundo Station 1	Residual	Assumed Normal	10100401	None	None	C	3
26	8	Southern California Edison Company, El Segundo Station 1	Residual	Assumed Normal	10100401	None	None	C	3
16	4	EPRI SITE 118	Residual (No. 6)	Front-fired (normal)	10100401	OFA/FGR	ESP	D[d]	3
17	5	Southern California Edison Company Long Beach Auxiliary Boiler	Distillate Oil	Assumed Normal	10100501	None	None	C	3

[a] UNC = Uncontrolled; FGR = Flue Gas Recirculation; OFA = Over-fire Air; ESP = Electrostatic Precipitator.

[b,c] At least one test run was "non detect" and the emission factor is based on detection limit values. (b = one "non detect", c = more than one "non detect").

[d] Data quality ratings of "D" were not used for averaging with "B" and "C" quality data.

[f] Pollutant was Not Detected in any of the sampling runs. Half of the detection limit value (DL/2) used to develop factor.

[g] For a given pollutant, any factors based solely on "non detect" values that were greater than any factors based on detected values were not included in the calculated average factor.

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Benzene	1,3-Butadiene	Carbon Tetrachloride	Chloro-benzene	Chloroform	Ethyl-benzene	Ethylene Dichloride
1	2.10e-04						
2							
3	3.51e-04						
4	4.90e-04[f]						
5	1.85e-04[f]						
7	1.87e-04[f]						
9	2.25e-04[f]						
11	3.02e-04[f]						
12	2.02e-04[f]						
14	7.20e-04[f]						
20	1.80e-04[f]						
21	1.85e-04[f]						
23							
24	2.27e-04[f]						
26							
Average[g]	2.14e-04						
16	7.83e-05	1.18e-05[f]	6.95e-05[f]	5.10e-05[f]	8.05e-05[f]	6.36e-05	1.56e-04[f]
17	9.00e-08[f]						

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Formaldehyde	Methyl Bromide	Naphthalene	Perchloro-ethylene	Propylene Dichloride	1,1,1-TCA	Toluene
1	1.26e-03[c]						7.94e-04
2	1.96e-03						
3							1.16e-02
4	1.50e-03[f]		4.53e-07[f]				
5	2.50e-02[b]		6.36e-04				
7	9.26e-02		1.94e-03[b]				
9	1.50e-03[f]		5.55e-04				
11	9.05e-02		9.05e-04[c]				
12	1.44e-03[f]		7.50e-05[b]				
14	5.96e-02		4.91e-03				
20	8.25e-04[f]		4.00e-04				
21	2.44e-02[c]						
23			6.18e-04				
24	1.12e-03[f]						
26			1.27e-03				
Average[g]	3.30e-02		1.13e-03				6.20e-03
16	7.98e-04	1.29e-04[f]	4.58e-05	3.73e-05[f]	1.78e-04[f]	2.36e-04	1.12e-03
17	3.20e-06[f]		7.00e-11[f]				

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Trichloroethane	Vinyl Chloride	o-Xylene	Acenaphthene	Acenaphthylene	Anthracene	Benz(a)anthracene
1							
2							
3							
4				4.53e-07[f]	4.53e-07[f]	4.53e-07[f]	4.53e-07[f]
5				1.48e-05[b]	7.40e-07[f]	7.40e-07[f]	7.40e-07[f]
7				5.25e-07[f]	5.25e-07[f]	5.25e-07[f]	4.48e-06[c]
9				9.90e-05	7.50e-07[f]	7.50e-07[f]	7.50e-07[f]
11				7.55e-07[f]	7.55e-07[f]	1.51e-06[c]	1.51e-05[b]
12				5.75e-07[f]	5.75e-07[f]	5.75e-07[f]	5.75e-07[f]
14				8.04e-06	2.53e-07	2.83e-06	1.31e-06
20				6.82e-05	6.11e-07[f]	1.31e-06[c]	6.11e-07[f]
21							
23				1.51e-05	6.82e-07[f]	1.36e-06[c]	6.82e-07[f]
24							
26				3.20e-06	5.23e-07[f]	2.16e-06[c]	1.54e-05[c]
Average[g]				2.11e-05	2.53e-07	1.22e-06	4.01e-06
16	8.85e-05[f]	1.06e-04[f]	1.09e-04				
17				7.00e-11[f]	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Benzo(a)pyrene	Benzo(b,k) fluoranthene	Benzo(g,h,i) perylene	Chrysene	Dibenzo(a,h)-anthracene	Fluoranthene	Fluorene
1							
2							2.93e-06
3							
4	4.53e-07[f]	4.53e-07[f]	4.53e-07[f]	4.53e-07[f]		4.53e-07[f]	4.53e-07[f]
5	7.40e-07[f]	7.40e-07[f]	7.40e-07[f]	7.40e-07[f]		7.40e-07[f]	2.07e-06
7	5.25e-07[f]	2.39e-06[c]	1.49e-06[c]	8.96e-07[c]		5.98e-06	2.99e-06[c]
9	7.50e-07[f]	7.50e-07[f]	7.50e-07[f]	7.50e-07[f]		1.35e-06[c]	5.55e-06
11	7.55e-07[f]	6.04e-06[c]	4.53e-06[c]	9.05e-06[b]		1.36e-05[b]	6.04e-07[c]
12	5.75e-07[f]	5.75e-07[f]	5.75e-07[f]	5.75e-07[f]		5.75e-07[f]	5.75e-07[f]
14				3.13e-06		1.12e-05	2.38e-05
20	6.11e-07[f]	6.11e-07[f]	6.11e-07[f]	6.11e-07[f]	6.11e-07[f]	1.41e-06[c]	3.82e-06
21							
23	6.82e-07[f]	6.82e-07[f]	6.82e-07[f]	6.82e-07[f]	6.82e-07[f]	1.36e-06[c]	4.66e-06[c]
24							
26	2.76e-06[f]	1.05e-06[c]	1.05e-05[c]	6.87e-06[c]	3.73e-06[c]	1.17e-05[c]	1.69e-06[c]
Average[g]		1.48e-06	2.26e-06	2.38e-06	1.67e-06	4.84e-06	4.47e-06
16							
17	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Indeno(1,2,3-cd)pyrene	Phenanthrene	Pyrene	2.3.7.8-TCDD	TCDD	PeCDD	HxCDD
1							
2		2.93e-06					
3							
4	4.53e-07[f]	4.53e-07[f]	4.53e-07[f]				
5	7.40e-07[f]	1.63e-06[b]	1.48e-06[c]				
7	1.49e-06[c]	1.34e-05	3.44e-06[c]				
9	7.50e-07[f]	5.40e-06	7.50e-07[f]				
11	4.53e-06[c]	1.81e-05[b]	1.21e-05[b]				
12	5.75e-07[f]	2.88e-06[c]	1.15e-06[b]				
14		4.91e-05	9.83e-06				
20	6.11e-07[f]	3.67e-06	1.26e-06[c]				
21							
23	6.82e-07[f]	1.63e-06[c]	1.40e-06[c]				
24							
26	9.44e-06[c]	1.63e-05[c]	1.07e-05[c]				
Average[g]	2.14e-06	1.05e-05	4.25e-06				
16		1.77e-06		3.18e-10[f]	3.18e-10[f]	3.40e-10[f]	5.05e-10[f]
17	7.00e-11[f]	7.00e-11[f]	7.00e-11[f]				

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - ORGANICS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	HpCDD	OCDD	2.3.7.8-TCDF	PeCDF	HxCDF	HpCDF	OCDF
1							
2							
3							
4							
5							
7							
9							
11							
12							
14							
20							
21							
23							
24							
26							
Average[g]							
16	1.85e-09[f]	3.10e-09[b]	1.33e-10[f]	1.92e-10[f]	3.70e-10[f]	2.52e-09[f]	1.18e-09[f]
17							

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - METALS - DL/2
FUEL OIL COMBUSTION

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. of Test Runs
1	1	EPRI SITE 13	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
2	2	EPRI SITE 112	Residual (No. 6)	Tangentially-Fired	10100404	ESP	None	C	3
4	3	EPRI SITE 103	Residual (No. 6)	Wall-Fired (Normal)	10100401	Uncontrolled	None	B	3
5	3	EPRI SITE 104	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
6	3	EPRI SITE 104	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	2
7	3	EPRI SITE 105	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
8	3	EPRI SITE 106	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	6
9	3	EPRI SITE 106	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
10	3	EPRI SITE 106	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	4
11	3	EPRI SITE 107	Residual (No. 6)	Assumed Normal	10100401	Uncontrolled	None	B	3
12	3	EPRI SITE 108	Residual (No. 6)	Opposed (Normal)	10100401	Uncontrolled	None	B	3
13	3	EPRI SITE 108	Residual (No. 6)	Opposed (Normal)	10100401	Uncontrolled	None	B	2
14	3	EPRI SITE 109	Residual (No. 6)	Opposed (Normal)	10100401	FGR	None	B	3
15	3	EPRI SITE 109	Residual (No. 6)	Opposed (Normal)	10100401	FGR	None	B	2
18	6	Southern California Edison Company, Alamitos Unit 5	Residual	Assumed Normal	10100401	FGR	None	B	6

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - METALS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Ref No.	Facility	Fuel Type	Boiler Type	SCC	Control Device 1[a]	Control Device 2[a]	Data Quality	No. of Test Runs
19	6	Southern California Edison Company, Alamitos Unit 5	Residual	Assumed Normal	10100401	FGR	None	C	3
22	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3
23	7	Pacific Gas and Electric Company, Morro Bay Unit 3	Residual	Radiant Heat	10100401	None	None	C	3
25	8	Southern California Edison Company, El Segundo Station 1	Residual	Assumed Normal	10100401	None	None	C	3
16	4	EPRI SITE 118	Residual (No. 6)	Front-fired (normal)	10100401	OFA/FGR	ESP	D[d]	3

[a] UNC = Uncontrolled; FGR = Flue Gas Recirculation; OFA = Over-fire Air; ESP = Electrostatic Precipitator.
[b,c] At least one test run was "non detect" and the emission factor is based on detection limit values. (b = one "non detect", c = more than one "non detect")
[d] Data quality ratings of "D" were not used for averaging with "B" and "C" quality data.
[f] Pollutant was Not Detected in any of the sampling runs. Half of the detection limit value (DL/2) used to develop factor.
[g] For a given pollutant, any factors based solely on "non detect" values that were greater than any factors based on detected values were not included in the calculated average factor.

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - METALS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Arsenic	Barium	Beryllium	Cadmium	Chloride	Chromium	Chromium VI	Cobalt	Copper
1	1.08e-03	3.59e-03	1.95e-05[f]	2.10e-03	1.68e-01	1.36e-03		1.51e-02	2.40e-03
2	1.76e-04[f]	1.54e-03	8.49e-05	4.83e-05	5.26e-01	5.42e-04		1.43e-03	9.37e-04
4	5.43e-04	9.60e-03[f]	3.62e-05[b]	4.83e-04		5.28e-04	1.36e-04[b]	1.52e-03	2.71e-04
5	9.61e-04		2.51e-05[b]	9.17e-05		4.44e-04	4.44e-06[f]		1.01e-03
6									
7	6.13e-04		2.69e-05[f]	1.03e-04		3.14e-04	6.28e-05[c]		1.49e-03
8	3.90e-03		2.25e-05[b]	1.80e-04[b]					2.10e-03
9						1.50e-03	5.70e-04		
10									
11	1.96e-03		7.55e-06[f]	2.41e-04		1.21e-03	2.57e-04		3.02e-03
12	9.81e-04		2.17e-06[f]	5.77e-04		8.65e-05[f]	4.33e-04		2.16e-03
13									
14	8.20e-05[f]		3.73e-05[f]	4.62e-04		1.64e-03	1.42e-04[f]		2.38e-03
15									
18	3.00e-03[b]		2.25e-05[c]	2.10e-04[c]					1.80e-03
19						9.60e-04	4.50e-04		
22	9.95e-04		3.16e-05[c]	1.06e-04					1.03e-03
23						5.97e-04	1.24e-04[c]		
25	1.56e-03		2.58e-05[c]	1.75e-04		9.53e-04	1.98e-04		2.49e-03
Average[g]	1.32e-03	2.57e-03	2.78e-05	3.98e-04	3.47e-01	8.45e-04	2.48e-04	6.02e-03	1.76e-03
16	8.13e-05	1.06e-03	2.22e-06[f]	6.65e-06[f]	5.31e-01	4.88e-04		2.87e-04	4.12e-04

(continued)

DATA USED FOR EMISSION FACTOR DEVELOPMENT (LB/1000 GALLONS) - METALS - DL/2
FUEL OIL COMBUSTION (CONTINUED)

Entry No.	Fluoride	Lead	Manganese	Mercury	Molybdenum	Nickel	Phosphorous	Selenium	Vanadium	Zinc
1	6.59e-03	1.23e-03	1.20e-03	3.44e-05	4.87e-04[f]	2.78e-01	2.92e-03[f]	4.87e-05[f]	5.29e-02	
2	6.81e-02	3.81e-04	2.14e-03	3.51e-05[b]	8.64e-04	4.44e-02	1.60e-02	3.52e-04[f]	3.51e-02	
4		5.58e-04	2.31e-03	2.72e-04[f]	1.01e-03[c]	5.25e-02		4.07e-05	7.43e-03	
5		2.37e-04[c]		8.85e-04[f]		5.38e-02		2.59e-04[f]		
6			3.25e-03							
7		1.34e-03	5.98e-04	3.51e-04[f]		7.62e-02		4.18e-04		
8		4.20e-03		3.75e-04[f]		5.70e-02		6.15e-04		
9										
10			6.45e-03							
11		1.51e-04[f]	1.51e-03	2.79e-03[f]		6.34e-02		1.51e-04[f]		
12		1.44e-03		2.31e-03[f]		2.02e-01		2.16e-03		
13			2.16e-03							
14		2.53e-03		2.68e-04[c]		3.57e-02		5.51e-04[c]		
15			8.64e-03							
18		3.30e-03	3.90e-03	3.00e-04[f]		4.50e-02		5.10e-04[c]		6.75e-02
19										
22		2.37e-03	2.57e-03	2.57e-03[f]		5.47e-02		5.59e-04[c]		1.57e-02[c]
23										
25		3.79e-04[c]	1.22e-03	2.33e-03[f]		5.13e-02		6.09e-04[c]		4.24e-03
Average[g]	3.73e-02	1.51e-03	3.00e-03	1.13e-04	7.87e-04	8.45e-02	9.46e-03	6.83e-04	3.18e-02	2.91e-02
16		2.63e-04[b]	2.73e-03	7.39e-05	5.91e-05	6.80e-03	3.99e-04[b]	1.85e-04	6.24e-03	

A.2 Source Test Report Summary Data

OIL EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 13 EMISSIONS MONITORING. RADIAN CORPORATION, AUSTIN, TEXAS. FEBRUARY, 1993.

FILENAME SITE13.tbl
FACILITY: EPRI SITE 13

PROCESS DATA	
Oil Type[a]	No. 6
Boiler configuration[a]	Wall-fired (normal)
SCC	10100401
Control device 1[a]	none
Control device 2	
Data Quality	B
Process Parameters[a]	350 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	3
Fuel Heating Value (Btu/lb)[d]	19,000
Oil density (lb/gal)[e]	7.88
Fuel Heating Value (Btu/gal)	149,720
Fuel Heating Value (Btu/1000 gal)	149,720,000
Fuel Heating Value (MMBtu/1000 gal)	149.72

[a]Page 2-1
[b]Appendix A, Table A-1
[c]Page 3-9
[d]Page 3-6
[e]Appendix A of Ap-42, residual oil density.

EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	7.2	7.20e-06	1.08e-03
Barium	24	2.40e-05	3.59e-03
Benzene	1.4	1.40e-06	2.10e-04
Beryllium[b]	0.26	2.60e-07	3.89e-05
Cadmium	14	1.40e-05	2.10e-03

OIL EF DATABASE REFERENCE NO. 1

EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Chloride	1,120	1.12e-03	1.68e-01
Chromium	9.1	9.10e-06	1.36e-03
Cobalt	101	1.01e-04	1.51e-02
Copper	16	1.60e-05	2.40e-03
Fluoride	44	4.40e-05	6.59e-03
Formaldehyde[c]	8.4	8.40e-06	1.26e-03
Lead	8.2	8.20e-06	1.23e-03
Manganese	8.0	8.00e-06	1.20e-03
Mercury	0.23	2.30e-07	3.44e-05
Molybdenum[b]	6.5	6.50e-06	9.73e-04
Nickel	1,860	1.86e-03	2.78e-01
Phosphorous[b]	39	3.90e-05	5.84e-03
Selenium[b]	0.65	6.50e-07	9.73e-05
Toluene	5.3	5.30e-06	7.94e-04
Vanadium	353	3.53e-04	5.29e-02

[a]Page 3-17, Boiler Outlet - Baseline data.
[b]Factor based on detection limit value only. See page 3-9.
[c]Detection limit values for two runs used in developing EF. See page 3-9.

PM, FILTERABLE EMISSION FACTORS

Emission Factor (lb/MMBtu)[a]	Emission Factor (lb/1000 gal)
0.049	7.34e+00

[a]Page 3-17, Boiler Outlet - Baseline data.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE103.tbl
FACILITY: EPRI SITE 103

PROCESS DATA		
Oil Type[a]	Residual (assume No. 6)	
Boiler configuration[a]	Wall-fired (Normal)	
SCCs	OIL: 10100401	NG: 10100601
Control device 1[a]	None	
Control device 2		
Data Quality	B	
Process Parameters[a]	150 MW	
Test methods[b]	EPA, or EPA-approved, test methods	
Number of test runs[c]	3	
Fuel Oil Heating Value (Btu/lb)[d]	19,137	
Fuel Oil density (lb/gal)[e]	7.88	
Fuel Oil Heating Value (Btu/gal)	150,800	
Fuel Oil Heating Value (Btu/1000 gal)	150,799,560	
Fuel Oil Heating Value (MMBtu/1000 gal)	150.80	
Fuel Oil Flow rate (lb/hr)[d]	73,333	
Fuel Oil Flow rate (gal/hr)	9,306	
Fuel Oil Flow rate (1000 gal/hr)	9.31	
Natural Gas (NG) Heating Value (Btu/Scf)[a]	1,030	
NG Heating Value (Btu/MM Cu Ft)	1,030,000,000	
NG Heating Value (E^12 Btu/MM Cu Ft)	0.00103	

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

[a]Part I: Site 103, page 2-1.
[b]Part I: Site 103, page 3-1.
[c]Part I: Site 103, page 3-6, 3-7.
[d]Part I: Site 103, page 3-4, Mean value.
[e]Appendix A of Ap-42, residual oil density.

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor ($lb/10^{12}$ Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	3.6	3.60e-06	5.43e-04
Barium[d]	127	1.27e-04	1.92e-02
Beryllium[b]	0.24	2.40e-07	3.62e-05
Cadmium	3.2	3.20e-06	4.83e-04
Chromium	3.5	3.50e-06	5.28e-04
Chrome VI[b]	0.9	9.00e-07	1.36e-04
Cobalt	10.1	1.01e-05	1.52e-03
Copper	1.8	1.80e-06	2.71e-04
Lead	3.7	3.70e-06	5.58e-04
Manganese	15.3	1.53e-05	2.31e-03
Mercury[d]	3.6	3.60e-06	5.43e-04
Molybdenum[c]	6.7	6.70e-06	1.01e-03
Nickel	348	3.48e-04	5.25e-02
Selenium	0.27	2.70e-07	4.07e-05
Vanadium	49.3	4.93e-05	7.43e-03
Acenaphthene[d]	0.006	6.00e-09	9.05e-07
Acenaphthylene[d]	0.006	6.00e-09	9.05e-07
Anthracene[d]	0.006	6.00e-09	9.05e-07
Benz(a)anthracene[d]	0.006	6.00e-09	9.05e-07
Benzo(a)pyrene[d]	0.006	6.00e-09	9.05e-07
Benzo(b,k)fluoranthene[d]	0.006	6.00e-09	9.05e-07
Benzo(g,h,i)perylene[d]	0.006	6.00e-09	9.05e-07
Chrysene[d]	0.006	6.00e-09	9.05e-07

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor ($lb/10^{12}$ Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Dibenz(a,h)anthracene[d]	0.006	6.00e-09	9.05e-07
Fluoranthene[d]	0.006	6.00e-09	9.05e-07
Fluorene[d]	0.006	6.00e-09	9.05e-07
Indeno(1,2,3-c,d)pyrene[d]	0.006	6.00e-09	9.05e-07
Naphthalene[d]	0.006	6.00e-09	9.05e-07
Phenanthrene[d]	0.006	6.00e-09	9.05e-07
Pyrene[d]	0.006	6.00e-09	9.05e-07
Formaldehyde[d]	19.9	1.99e-05	3.00e-03
Benzene[d]	6.5	6.50e-06	9.80e-04

[a]Part I; Site 103, pages 3-9, 3-10. See 3-6, 3-7, 3-8 for individual run data.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

PM, FILTERABLE EMISSION FACTORS (SCC 10100401)

Stack gas flow rate (Nm3/hr)[a]	PM concentration (ug/Nm3)[a]	PM Emission Rate (ug/hr)	PM Emission Rate (lb/hr)	PM Emission Factor (lb/1000 gal)
472,400	17,199	8.12e+09	17.92	1.93

[a]Part I: Site 103, page 3-6, Mean value.

EMISSION FACTORS FIRING NATURAL GAS

Pollutant	Emission Factor ($lb/10^{12}$ Btu)[a]	Emission Factor (lb/MM Cu Ft)
Formaldehyde[d]	17.7	1.82e-02
Benzene[d]	4.4	4.53e-03

[a]Page 3-10. Individual run data on page 3-8.
[d]Pollutant not detected in any sampling runs, emission factor developed from detection limits.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REF NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE104.tbl
FACILITY: EPRI SITE 104

PROCESS DATA		
Fuel Oil Type[a]	Residual (assume No. 6)	
Boiler configuration	Assumed Normal	
SCCs	OIL: 10100401	NG: 10100601
Control device 1[a]	None	
Control device 2		
Data Quality	B	
Process Parameters[a]	350 MW	
Test methods[b]	EPA, or EPA-approved, test methods	
Number of test runs[c]	SCC 10100401: 2 for manganese, 3 for all others	
	SCC 10100601: 3	
Fuel Oil Heating Value (Btu/lb)[d]	18,770	
Oil Density (lb/gal)[e]	7.88	
Oil Heating Value (Btu/gal)	147,908	
Oil Heating Value (Btu/1000 gal)	147,907,600	
Oil Heating Value (MMBtu/1000 gal)	147.91	
NG Heating Value (Btu/cu ft) f	1,036.0	
NG Heating Value (Btu/MM cu ft)	1,036,000,000	
NG Heating Value (E^12 Btu/MM cu ft)	0.00104	

[a]Part II: Site 104, page 2-1.
[b]Part II: Site 104, page 3-1.
[c]Part II: Site 104, pages 3-7, 3-8, 3-9, 3-10, 3-12.
[d]Part II: Site 104, page 3-6, mean value.
[e]Appendix A of Ap-42, residual oil density.
[f]Part II: Site 104, Appendix D, page D-3.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REF NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	6.5	6.50e-06	9.61e-04
Beryllium[b]	0.17	1.70e-07	2.51e-05
Cadmium	0.62	6.20e-07	9.17e-05
Chromium	3	3.00e-06	4.44e-04
Chrome VI[d]	0.06	6.00e-08	8.87e-06
Copper	6.8	6.80e-06	1.01e-03
Lead[c]	1.6	1.60e-06	2.37e-04
Manganese[e]	22	2.20e-05	3.25e-03
Mercury[d]	12	1.20e-05	1.77e-03
Nickel	364	3.64e-04	5.38e-02
Selenium[d]	3.5	3.50e-06	5.18e-04
Acenaphthene[b]	0.1	1.00e-07	1.48e-05
Acenaphthylene[d]	0.01	1.00e-08	1.48e-06
Anthracene[d]	0.01	1.00e-08	1.48e-06
Benz(a)anthracene[d]	0.01	1.00e-08	1.48e-06
Benzo(a)pyrene[d]	0.01	1.00e-08	1.48e-06
Benzo(b,k)fluoranthene[d]	0.01	1.00e-08	1.48e-06
Benzo(g,h,i)perylene[d]	0.01	1.00e-08	1.48e-06
Chrysene[d]	0.01	1.00e-08	1.48e-06
Dibenz(a,h)anthracene[d]	0.01	1.00e-08	1.48e-06
Fluoranthene[d]	0.01	1.00e-08	1.48e-06
Fluorene	0.014	1.40e-08	2.07e-06
Indeno(1,2,3-c,d)pyrene[d]	0.01	1.00e-08	1.48e-06
Naphthalene	4.3	4.30e-06	6.36e-04
Phenanthrene[b]	0.011	1.10e-08	1.63e-06
Pyrene[c]	0.01	1.00e-08	1.48e-06
Benzene[d]	2.5	2.50e-06	3.70e-04
Formaldehyde[b]	169	1.69e-04	2.50e-02

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REF NO. 1

[a]Part II: Site 104, pages 3-13. See pages 3-7 through 3-12 for individual run data.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.
[e]Emission factor based on 2 test runs.

EMISSION FACTORS NATURAL GAS (SCC 10100601)

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MM Cu Ft)
Benzene[d]	2.3	2.38e-03
Formaldehyde[c]	25	2.59e-02

[a]Page 3-13. Individual run data on page 3-12.
[b]Detection limit value (1/2) for one run used in developing EF.
[c]Detection limit value (1/2) for two runs used in developing EF.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE105.tbl
FACILITY: EPRI SITE 105

PROCESS DATA		
Oil Type[a]	Residual (assume No. 6)	
Boiler configuration	Assumed Normal	
SCCs	OIL: 10100401	NG: 10100601
Control device 1[b]	None	
Control device 2		
Data Quality	B	
Process Parameters[b]	750 MW	
Test methods[c]	EPA, or EPA-approved, test methods	
Number of test runs[d]	3	
Fuel Oil Heating Value (Btu/lb)[e]	18,960	
Fuel Oil density (lb/gal)[f]	7.88	
Fuel Oil Heating Value (Btu/gal)	149,405	
Fuel Oil Heating Value (Btu/1000 gal)	149,404,800	
Fuel Oil Heating Value (MMBtu/1000 gal)	149.40	
Natural Gas (NG) Heating Value (Btu/Scf)[g]	1,042.5	
NG Heating Value (Btu/MM Cu Ft)	1,042,500,000	
NG Heating Value (E^12 Btu/MM Cu Ft)	0.0010425	

[a]Part III: Site 105. Page 3-7, title of Table 3-2a.
[b]Part III: Site 105. Page 2-1.
[c]Part III: Site 105. Appendix A, various pages.
[d]Part III: Site 105. Pages 3-7, 3-8 and 3-12.
[e]Part III: Site 105. Page 3-6.
[f]Appendix A of Ap-42, residual oil density.
[g]Part III: Site 105. Appendix D, Page D-4.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)			
Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	4.1	4.10e-06	6.13e-04
Beryllium[d]	0.36	3.60e-07	5.38e-05
Cadmium	0.69	6.90e-07	1.03e-04
Chromium	2.1	2.10e-06	3.14e-04
Chrome VI[c]	0.42	4.20e-07	6.28e-05
Copper	10	1.00e-05	1.49e-03
Lead	9	9.00e-06	1.34e-03
Manganese	4.0	4.00e-06	5.98e-04
Mercury[d]	4.7	4.70e-06	7.02e-04
Nickel	510	5.10e-04	7.62e-02
Selenium	2.8	2.80e-06	4.18e-04
Acenaphthene[d]	0.007	7.00e-09	1.05e-06
Acenaphthylene[d]	0.007	7.00e-09	1.05e-06
Anthracene[d]	0.007	7.00e-09	1.05e-06
Benz(a)anthracene[c]	0.03	3.00e-08	4.48e-06
Benzo(a)pyrene[d]	0.007	7.00e-09	1.05e-06
Benzo(b,k)fluoranthene[c]	0.016	1.60e-08	2.39e-06
Benzo(g,h,i)perylene[c]	0.010	1.00e-08	1.49e-06
Chrysene[c]	0.006	6.00e-09	8.96e-07
Dibenz(a,h)anthracene[c]	0.006	6.00e-09	8.96e-07
Fluoranthene	0.04	4.00e-08	5.98e-06
Fluorene[c]	0.020	2.00e-08	2.99e-06
Indeno(1,2,3-c,d)pyrene[c]	0.010	1.00e-08	1.49e-06
Naphthalene[b]	13	1.30e-05	1.94e-03
Phenanthrene	0.09	9.00e-08	1.34e-05
Pyrene[c]	0.023	2.30e-08	3.44e-06
Benzene[d]	2.5	2.50e-06	3.74e-04
Formaldehyde	620	6.20e-04	9.26e-02

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

[a]Part III: Site 105. Page 3-13. Individual run data on pages 3-7, 3-8, 3-9, 3-10, 3-11 and 3-12.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

EMISSION FACTORS FIRING NATURAL GAS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MM Cu Ft)
Benzene[d]	1.0	1.04e-03
Formaldehyde	600	6.26e-01

[a]Part III: Site 105. Page 3-13. Individual run data on page 3-13.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE106.tbl
FACILITY: EPRI SITE 106

PROCESS DATA	
Oil Type[a]	Residual (assume No. 6)
Boiler configuration	Assumed Normal
SCCs	OIL: 10100401 NG: 10100601
Control device 1[a]	None
Control device 2	
Data Quality	B
Process Parameters[a]	480 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	6 for all metals except chrome, chrome VI and manganese. 4 for manganese, 3 for chrome, chrome VI, PAHs, benzene, formaldehyde. 2 for anthracene
Fuel Oil Heating Value (Btu/lb)[d]	19,035
Fuel Oil density (lb/gal)[e]	7.88
Fuel Oil Heating Value (Btu/gal)	149,996
Fuel Oil Heating Value (Btu/1000 gal)	149,995,800
Fuel Oil Heating Value (MMBtu/1000 gal)	150.00
Natural Gas (NG) Heating Value (Btu/Scf)[f]	947
NG Heating Value (Btu/MM Cu Ft)	947,000,000
NG Heating Value (E^12 Btu/MM Cu Ft)	0.000947

[a]Part IV: Site 106. Page 2-1.
[b]Part IV: Site 106. Page 3-1.
[c]Part IV: Site 106. Page 3-7, 3-8, 3-9, 3-10, 3-11.
[d]Part IV: Site 106. Page 3-6.
[e]Appendix A of AP-42, residual oil density.
[f]Part IV: Site 106. Appendix D, Page D-3.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	26	2.60e-05	3.90e-03
Beryllium[b]	0.15	1.50e-07	2.25e-05
Cadmium[b]	1.2	1.20e-06	1.80e-04
Chromium	10	1.00e-05	1.50e-03
Chrome VI	3.8	3.80e-06	5.70e-04
Copper	14	1.40e-05	2.10e-03
Lead	28	2.80e-05	4.20e-03
Manganese	43	4.30e-05	6.45e-03
Mercury[d]	5	5.00e-06	7.50e-04
Nickel	380	3.80e-04	5.70e-02
Selenium	4.1	4.10e-06	6.15e-04
Acenaphthene	0.66	6.60e-07	9.90e-05
Acenaphthylene[d]	0.01	1.00e-08	1.50e-06
Anthracene[d]	0.01	1.00e-08	1.50e-06
Benz(a)anthracene[d]	0.01	1.00e-08	1.50e-06
Benzo(a)pyrene[d]	0.01	1.00e-08	1.50e-06
Benzo(b,k)fluoranthene[d]	0.01	1.00e-08	1.50e-06
Benzo(g,h,i)perylene[d]	0.01	1.00e-08	1.50e-06
Chrysene[d]	0.01	1.00e-08	1.50e-06
Dibenz(a,h)anthracene[d]	0.01	1.00e-08	1.50e-06
Fluoranthene[c]	0.009	9.00e-09	1.35e-06
Fluorene	0.037	3.70e-08	5.55e-06
Indeno(1,2,3-c,d)pyrene[d]	0.01	1.00e-08	1.50e-06
Napththalene	3.7	3.70e-06	5.55e-04
Phenanthrene	0.036	3.60e-08	5.40e-06
Pyrene[d]	0.01	1.00e-08	1.50e-06
Benzene[d]	3	3.00e-06	4.50e-04
Formaldehyde[d]	20	2.00e-05	3.00e-03

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

[a]Part VI: Site 106. Page 3-13. Individual run data on pages 3-7, 3-8, 3-9, 3-10, 3-11.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

EMISSION FACTORS FIRING NATURAL GAS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MM Cu Ft)
Benzene[d]	4	3.79e-03
Formaldehyde	82	7.77e-02

[a]Part VI: Site 106. Page 3-13. Individual run data on page 3-11.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE107.tbl
FACILITY: EPRI SITE 107

PROCESS DATA	
Oil Type[a]	Residual (assume No. 6)
Boiler configuration	Assumed Normal
SCCs	OIL: 10100401 NG: 10100601
Control device 1[a]	None
Control device 2	
Data Quality	B
Process Parameters[a]	175 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	3 for all
Fuel Oil Heating Value (Btu/lb)[d]	19,150
Fuel Oil density (lb/gal)[e]	7.88
Fuel Oil Heating Value (Btu/gal)	150,902
Fuel Oil Heating Value (Btu/1000 gal)	150,902,000
Fuel Oil Heating Value (MMBtu/1000 gal)	150.90
Natural Gas (NG) Heating Value (Btu/Scf)[f]	957
NG Heating Value (Btu/MM Cu Ft)	957,000,000
NG Heating Value (E^12 Btu/MM Cu Ft)	0.000957

[a]Part V: Site 107. Page 2-1.
[b]Part V: Site 107. Page 3-1.
[c]Part V: Site 107. Page 3-7, 3-8, 3-9, 3-10, 3-11.
[d]Part V: Site 107. Page 3-6.
[e]Appendix A of Ap-42, residual oil density.
[f]Part V: Site 107. Appendix D, Page D-3.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	13	1.30e-05	1.96e-03
Beryllium[d]	0.1	1.00e-07	1.51e-05
Cadmium	1.6	1.60e-06	2.41e-04
Chromium	8	8.00e-06	1.21e-03
Chrome VI	1.7	1.70e-06	2.57e-04
Copper	20	2.00e-05	3.02e-03
Lead[d]	2	2.00e-06	3.02e-04
Manganese	10	1.00e-05	1.51e-03
Mercury[d]	37	3.70e-05	5.58e-03
Nickel	420	4.20e-04	6.34e-02
Selenium[d]	2	2.00e-06	3.02e-04
Acenaphthene[d]	0.01	1.00e-08	1.51e-06
Acenaphthylene[d]	0.01	1.00e-08	1.51e-06
Anthracene[c]	0.010	1.00e-08	1.51e-06
Benz(a)anthracene[b]	0.1	1.00e-07	1.51e-05
Benzo(a)pyrene[d]	0.01	1.00e-08	1.51e-06
Benzo(b,k)fluoranthene[c]	0.04	4.00e-08	6.04e-06
Benzo(g,h,i)perylene[c]	0.03	3.00e-08	4.53e-06
Chrysene[b]	0.06	6.00e-08	9.05e-06
Dibenz(a,h)anthracene[c]	0.010	1.00e-08	1.51e-06
Fluoranthene[b]	0.09	9.00e-08	1.36e-05
Fluorene[c]	0.004	4.00e-09	6.04e-07
Indeno(1,2,3-c,d)pyrene[c]	0.03	3.00e-08	4.53e-06
Naphthalene[c]	6	6.00e-06	9.05e-04
Phenanthrene[b]	0.12	1.20e-07	1.81e-05
Pyrene[b]	0.08	8.00e-08	1.21e-05
Benzene[d]	4	4.00e-06	6.04e-04
Formaldehyde	600	6.00e-04	9.05e-02

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

[a]Part V: Site 107. Pages 3-13, 3-14. Individual run data on pages 3-7 through 3-11.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

EMISSION FACTORS FIRING NATURAL GAS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MM Cu Ft)
Benzene[d]	4	3.83e-03
Formaldehyde	800	7.66e-01

[a]Part V: Site 107. Page 3-14. Individual run data on page 3-11.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE108.tbl
FACILITY: EPRI SITE 108

PROCESS DATA	
Oil Type[a]	Residual (assume No. 6)
Boiler configuration	Opposed fired (Assumed Normal)
SCCs	OIL: 10100401 NG: 10100601
Control device 1[a]	None
Control device 2	
Data Quality	B
Process Parameters[a]	50 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	2 for manganese, 3 for all others
Fuel Oil Heating Value (Btu/lb)[d]	18,300
Fuel Oil density (lb/gal)[e]	7.88
Fuel Oil Heating Value (Btu/gal)	144,204
Fuel Oil Heating Value (Btu/1000 gal)	144,204,000
Fuel Oil Heating Value (MMBtu/1000 gal)	144.20
Natural Gas (NG) Heating Value (Btu/lb)[a]	23500
NG Density (lb/scf)[f]	0.042
NG Heating Value (Btu/Scf)	987
NG Heating Value (Btu/MM Cu Ft)	987,000,000
NG Heating Value (E^12 Btu/MM Cu Ft)	9.87e-04

[a]Part VI: Site 108. Page 2-1.
[b]Part VI: Site 108. Page 3-1.
[c]Part VI: Site 108. Page 3-7, 3-8, 3-10, 3-12.
[d]Part VI: Site 108. Page 3-6.
[e]Appendix A of AP-42, residual oil density.
[f]Appendix A of AP-42, density of natural gas - 1 lb/23.8 ft3.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)			
Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic	6.8	6.80e-06	9.81e-04
Beryllium[d]	0.03	3.00e-08	4.33e-06
Cadmium	4.0	4.00e-06	5.77e-04
Chromium[d]	1.2	1.20e-06	1.73e-04
Chrome VI	3.0	3.00e-06	4.33e-04
Copper	15	1.50e-05	2.16e-03
Lead	10	1.00e-05	1.44e-03
Manganese	15	1.50e-05	2.16e-03
Mercury[d]	32	3.20e-05	4.61e-03
Nickel	1,400	1.40e-03	2.02e-01
Selenium	15	1.50e-05	2.16e-03
Acenaphthene[d]	0.008	8.00e-09	1.15e-06
Acenaphthylene[d]	0.008	8.00e-09	1.15e-06
Anthracene[d]	0.008	8.00e-09	1.15e-06
Benz(a)anthracene[d]	0.008	8.00e-09	1.15e-06
Benzo(a)pyrene[d]	0.008	8.00e-09	1.15e-06
Benzo(b,k)fluoranthene[d]	0.008	8.00e-09	1.15e-06
Benzo(g,h,i)perylene[d]	0.008	8.00e-09	1.15e-06
Chrysene[d]	0.008	8.00e-09	1.15e-06
Fluoranthene[d]	0.008	8.00e-09	1.15e-06
Fluorene[d]	0.008	8.00e-09	1.15e-06
Indeno(1,2,3-c,d)pyrene[d]	0.008	8.00e-09	1.15e-06
Naphthalene[b]	0.52	5.20e-07	7.50e-05
Phenanthrene[c]	0.02	2.00e-08	2.88e-06
Pyrene[b]	0.008	8.00e-09	1.15e-06
Benzene[d]	2.8	2.80e-06	4.04e-04
Formaldehyde[d]	20	2.00e-05	2.88e-03

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

[a]Part VI: Site 108. Page 3-13. Individual run data on pages 3-7, 3-8, 3-10, 3-12.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

EMISSION FACTORS FIRING NATURAL GAS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MM Cu Ft)
Benzene[d]	2.2	2.17e-03
Formaldehyde[c]	12	1.18e-02

[a]Part VI: Site 108. Page 3-13. Individual run data on page 3-12.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: EMISSIONS REPORT FOR SITES 103 - 109. PRELIMINARY DRAFT REPORT. RADIAN CORPORATION, AUSTIN, TEXAS. MARCH, 1993.

FILENAME SITE109.tbl
FACILITY: EPRI SITE 109

PROCESS DATA		
Oil Type[a]	Residual (assume No. 6)	
Boiler configuration[a]	Opposed fired (Assumed Normal)	
SCCs	OIL: 10100401	NG: 10100601
Control device 1[a]	Flue Gas Recirculation (FGR)	
Control device 2		
Data Quality	B	
Process Parameters[a]	230 MW	
Test methods[b]	EPA, or EPA-approved, test methods	
Number of test runs[c]	Oil firing: 2 for manganese, 3 for all others.	
	NG firing: 6 for all (formaldehyde)	
Fuel Oil Heating Value (Btu/lb)[d]	18,900	
Fuel Oil density (lb/gal)[e]	7.88	
Fuel Oil Heating Value (Btu/gal)	148,932	
Fuel Oil Heating Value (Btu/1000 gal)	148,932,000	
Fuel Oil Heating Value (MMBtu/1000 gal)	148.93	
Natural Gas (NG) Heating Value (Btu/Scf)[a]	1,000	
NG Heating Value (Btu/MM Cu Ft)	1,000,000,000	
NG Heating Value (E^12 Btu/MM Cu Ft)	1.00e-03	

[a]Part VII: Site 109. Page 2-1.
[b]Part VII: Site 109. Page 3-1.
[c]Part VII: Site 109. Page 3-6, 3-7, 3-10.
[d]Part VII: Site 109. Page 3-4.
[e]Appendix A of Ap-42, residual oil density.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING OIL (SCC 10100401)

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic[d]	1.1	1.10e-06	1.64e-04
Beryllium[d]	0.5	5.00e-07	7.45e-05
Cadmium	3.1	3.10e-06	4.62e-04
Chromium	11	1.10e-05	1.64e-03
Copper	16	1.60e-05	2.38e-03
Lead	17	1.70e-05	2.53e-03
Manganese	58	5.80e-05	8.64e-03
Mercury[c]	1.8	1.80e-06	2.68e-04
Nickel	240	2.40e-04	3.57e-02
Selenium[c]	3.7	3.70e-06	5.51e-04
Chrome VI[d]	1.9	1.90e-06	2.83e-04
Acenaphthene	0.054	5.40e-08	8.04e-06
Acenaphthylene	0.0017	1.70e-09	2.53e-07
Anthracene	0.019	1.90e-08	2.83e-06
Benz(a)anthracene	0.0088	8.80e-09	1.31e-06
Chrysene	0.021	2.10e-08	3.13e-06
Fluoranthene	0.075	7.50e-08	1.12e-05
Fluorene	0.16	1.60e-07	2.38e-05
Naphthalene	33	3.30e-05	4.91e-03
Phenanthrene	0.33	3.30e-07	4.91e-05
Pyrene	0.066	6.60e-08	9.83e-06
Benzene[d]	9.7	9.70e-06	1.44e-03
Formaldehyde	400	4.00e-04	5.96e-02

[a]Part VII: Site 109. Page 3-13, 3-14, 100% load. Individual run data 3-6, 3-7, 3-10.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit value for two runs used in developing EF.
[d]Factor based on detection limit value only.

OIL EF DATABASE REFERENCE NO. 3
NATURAL GAS EF DATABASE REFERENCE NO. 1

EMISSION FACTORS FIRING NATURAL GAS		
	Emission Factor	Emission Factor
Pollutant	(lb/10^12 Btu)[a]	(lb/MM Cu Ft)
Formaldehyde	46	4.60e-02

[a]Part VII: Site 109. Page 3-15, 100% load. Individual run data on page 3-10.

OIL EF DATABASE REFERENCE NO. 2

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 112 EMISSIONS REPORT. CARNOT, Tustin, California. February 24, 1994.

FILENAME SITE112.tbl
FACILITY: EPRI SITE 112

PROCESS DATA	
Oil Type[a]	Residual (assume No. 6)
Boiler configuration[a]	Tangentially-Fired
SCC	10100404
Control device 1[a]	ESP
Control device 2	
Data Quality	C (They did not measure stack gas flow rate, but used an F-factor instead. See page 38.)
Process Parameters[a]	387 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	4 for benzene and toluene; 3 for all others
Fuel Heating Value (Btu/lb)[d]	18,582
Oil density (lb/gal)[e]	7.88
Fuel Heating Value (Btu/gal)	146,426
Fuel Heating Value (Btu/1000 gal)	146,426,160
Fuel Heating Value (MMBtu/1000 gal)	146.43

[a]Page 6
[b]Page 12
[c]Page 23
[d]Page 19
[e]Appendix A of AP-42, residual oil density.

EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Arsenic[b]	2.4	2.40e-06	3.51e-04
Barium	10.5	1.05e-05	1.54e-03
Beryllium	0.58	5.80e-07	8.49e-05
Cadmium	0.33	3.30e-07	4.83e-05

OIL EF DATABASE REFERENCE NO. 2

EMISSION FACTORS

Pollutant	Emission Factor (lb/10^12 Btu)[a]	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
Chromium	3.7	3.70e-06	5.42e-04
Cobalt	9.8	9.80e-06	1.43e-03
Copper	6.4	6.40e-06	9.37e-04
Lead	2.6	2.60e-06	3.81e-04
Manganese	14.6	1.46e-05	2.14e-03
Mercury[c]	0.24	2.40e-07	3.51e-05
Molybdenum	5.9	5.90e-06	8.64e-04
Nickel	303	3.03e-04	4.44e-02
Phosphorous	109	1.09e-04	1.60e-02
Selenium[b]	4.8	4.80e-06	7.03e-04
Vanadium	240	2.40e-04	3.51e-02
Chloride	3,590	3.59e-03	5.26e-01
Fluoride	465	4.65e-04	6.81e-02
Fluorene	0.020	2.00e-08	2.93e-06
Phenanthrene	0.020	2.00e-08	2.93e-06
2-Methylnaphthalene	0.015	1.50e-08	2.20e-06
Benzene	2.4	2.40e-06	3.51e-04
Toluene	79.5	7.95e-05	1.16e-02
Formaldehyde	13.4	1.34e-05	1.96e-03

[a]Pages 26 & 27.
[b]Pollutant not detected in all sampling runs. See page 23.
[c]Detection limit value for one run used in developing EF.

PM, FILTERABLE EMISSION FACTORS

Emission Factor (lb/MMBtu)[a]	Emission Factor (lb/1000 gal)
0.0177	2.59e+00

[a]Page 26

OIL EF DATABASE REFERENCE NO. 4

TEST REPORT TITLE: FIELD CHEMICAL EMISSIONS MONITORING PROJECT: SITE 118 EMISSIONS REPORT. CARNOT, Tustin, California. January 20, 1994.

FILENAME SITE118.tbl
FACILITY: EPRI SITE 118

PROCESS DATA	
Oil Type[a]	Residual (assume No. 6)
Boiler configuration[a]	Front-fired (normal)
SCC	10100401
Control device 1[a]	Over-fire Air, Flue Gas Recirculation
Control device 2[a]	ESP
Data Quality	D (high blank values)
Process Parameters[a]	850 MW
Test methods[b]	EPA, or EPA-approved, test methods
Number of test runs[c]	3
Fuel Heating Value (Btu/lb)[d]	18,756
Oil density (lb/gal)[e]	7.88
Fuel Heating Value (Btu/gal)	147,797
Fuel Heating Value (Btu/1000 gal)	147,797,280
Fuel Heating Value (MMBtu/1000 gal)	147.80

[a]Page 7
[b]Page 15
[c]Page 25, 26, 27, 28
[d]Page 18, mean value
[e]Appendix A of AP-42, residual oil density.

EMISSION FACTORS	Emission Factor	Emission Factor	Emission Factor
Pollutant	(lb/10^12 Btu)	(lb/MMBtu)	(lb/1000 gal)
Filterable PM[a]	---	0.0041	6.06e-01

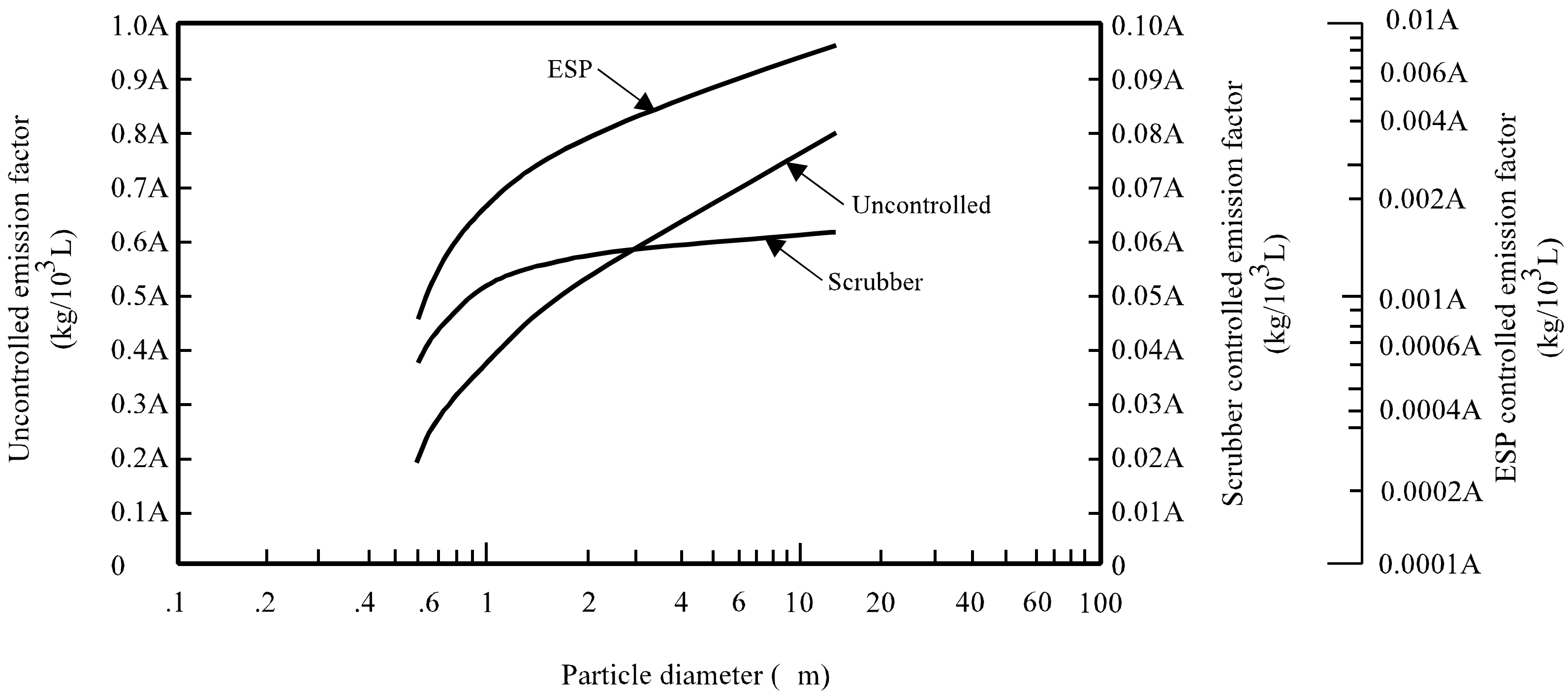
OIL EF DATABASE REFERENCE NO. 4

EMISSION FACTORS Pollutant	Emission Factor (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
METALS, ANIONS[a]			
Arsenic	0.55	5.50e-07	8.13e-05
Barium	7.16	7.16e-06	1.06e-03
Beryllium[d]	0.06	6.00e-08	8.87e-06
Cadmium[d]	0.18	1.80e-07	2.66e-05
Chromium	3.30	3.30e-06	4.88e-04
Cobalt	1.94	1.94e-06	2.87e-04
Copper	2.79	2.79e-06	4.12e-04
Lead[b]	1.78	1.78e-06	2.63e-04
Manganese	18.5	1.85e-05	2.73e-03
Mercury	0.50	5.00e-07	7.39e-05
Molybdenum	0.40	4.00e-07	5.91e-05
Nickel	46.0	4.60e-05	6.80e-03
Phosphorous[b]	2.70	2.70e-06	3.99e-04
Selenium	1.25	1.25e-06	1.85e-04
Vanadium	42.2	4.22e-05	6.24e-03
Chloride	3,590	3.59e-03	5.31e-01
PAHs[e]			
Naphthalene	0.31	3.10e-07	4.58e-05
Phenanthrene	0.012	1.20e-08	1.77e-06
2-Methylnaphthalene	0.027	2.70e-08	3.99e-06
PCDD/PCDF[f]			
2,3,7,8-TCDD[d]	4.3e-06	4.30e-12	6.36e-10
Total TCDD[d]	4.3e-06	4.30e-12	6.36e-10
Total PeCDD[d]	4.6e-06	4.60e-12	6.80e-10
Total HxCDD[d]	6.8e-06	6.80e-12	1.01e-09
Total HpCDD[d]	2.5e-05	2.50e-11	3.69e-09
OCDD[b]	2.1e-05	2.10e-11	3.10e-09

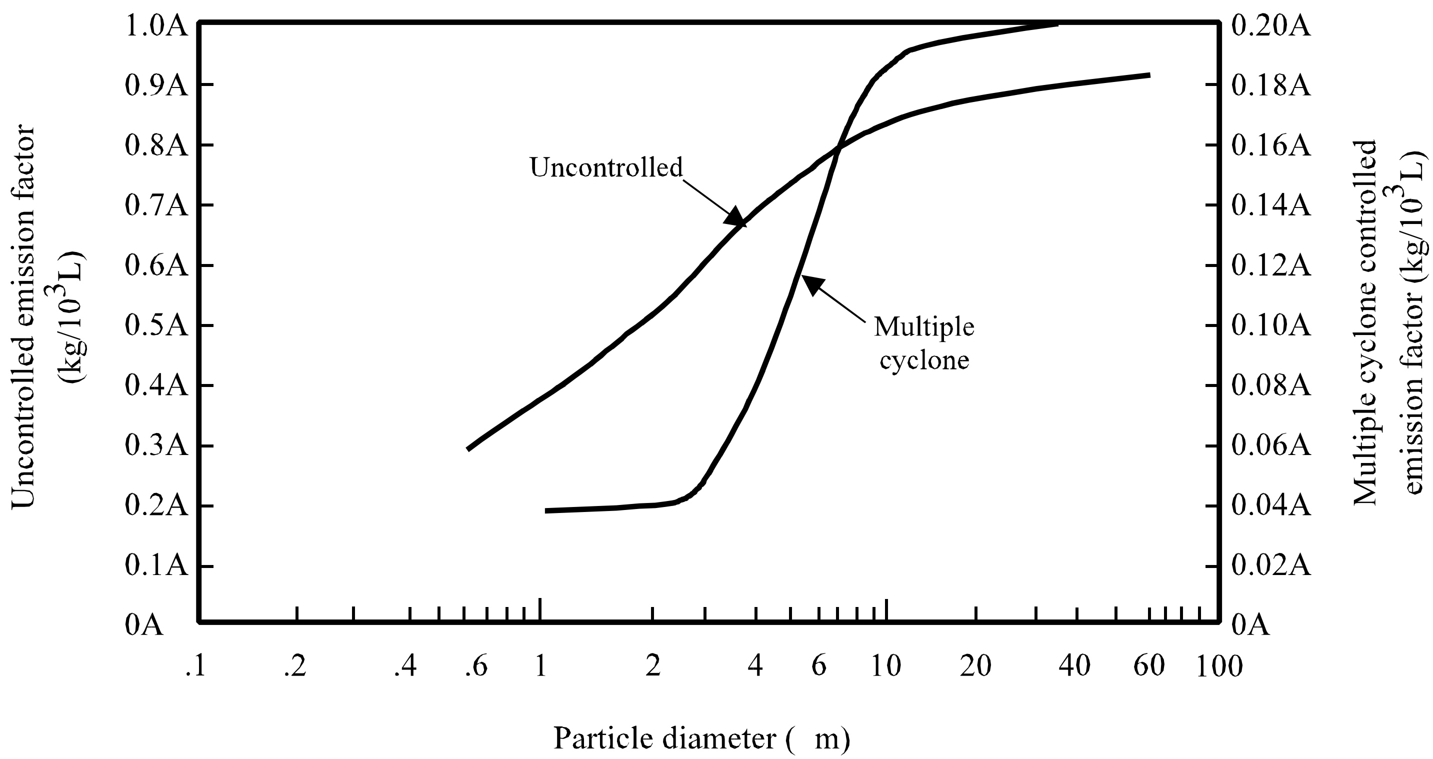
OIL EF DATABASE REFERENCE NO. 4

EMISSION FACTORS Pollutant	Emission Factor (lb/10^12 Btu)	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000 gal)
2,3,7,8-TCDF[d]	1.8e-06	1.80e-12	2.66e-10
Total TCDF[d]	1.8e-06	1.80e-12	2.66e-10
Total PeCDF[d]	2.6e-06	2.60e-12	3.84e-10
Total HxCDF[d]	5.0e-06	5.00e-12	7.39e-10
Total HpCDF[d]	3.4e-05	3.40e-11	5.03e-09
OCDF[d]	1.6e-05	1.60e-11	2.36e-09
PCBs[d]	---	---	---
VOCs[g]			
Benzene	0.53	5.30e-07	7.83e-05
Toluene	7.6	7.60e-06	1.12e-03
Vinyl Chloride[d]	1.43	1.43e-06	2.11e-04
1,3-Butadiene[d]	0.16	1.60e-07	2.36e-05
Methyl Bromide[d]	1.74	1.74e-06	2.57e-04
Chloroform[d]	1.09	1.09e-06	1.61e-04
1,2-Dichloroethane (Ethylene Dichloride)[d]	2.11	2.11e-06	3.12e-04
1,1,1-Trichloroethane	1.6	1.60e-06	2.36e-04
Carbon Tetrachloride[d]	0.94	9.40e-07	1.39e-04
1,2-Dichloropropane (Propylene Dichloride)[d]	2.41	2.41e-06	3.56e-04
Trichloroethane[d]	1.20	1.20e-06	1.77e-04
Perchloroethylene[d]	1.01	1.01e-06	1.49e-04
Chlorobenzene[d]	0.69	6.90e-07	1.02e-04
Ethylbenzene	0.43	4.30e-07	6.36e-05
o-Xylene	0.74	7.40e-07	1.09e-04
Formaldehyde	5.4	5.40e-06	7.98e-04

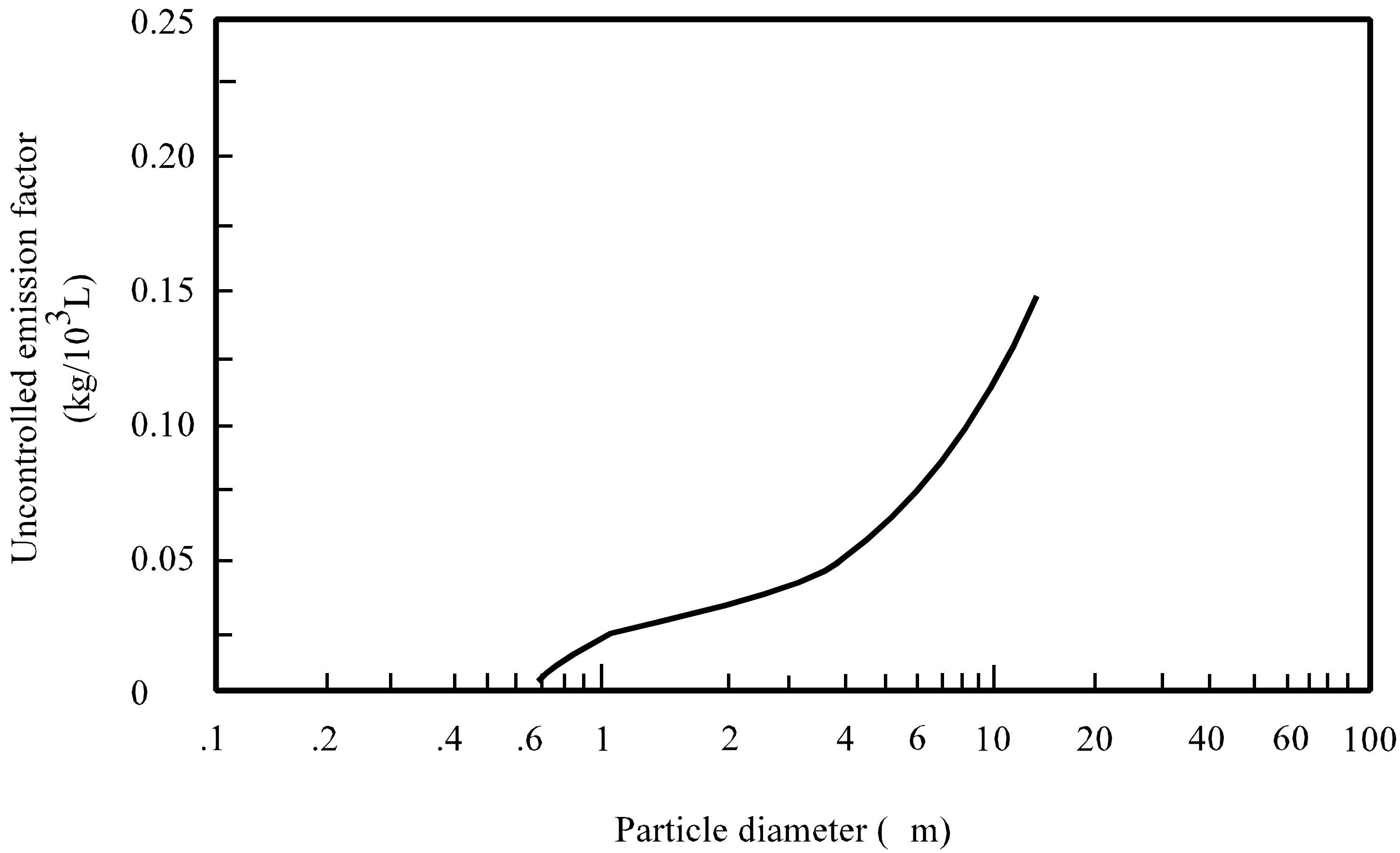
[a]Page 29. Individual run data on page 25.
[b]Detection limit value for one run used in developing EF.
[c]Detection limit values for two runs used in developing EF.
[d]Factor based on detection limit value only.
[e]Page 30. Individual run data on page 26.
[f]Page 30. Individual run data on page 27.
[g]Page 31. Individual run data on page 26 (formaldehyde) and page 28.



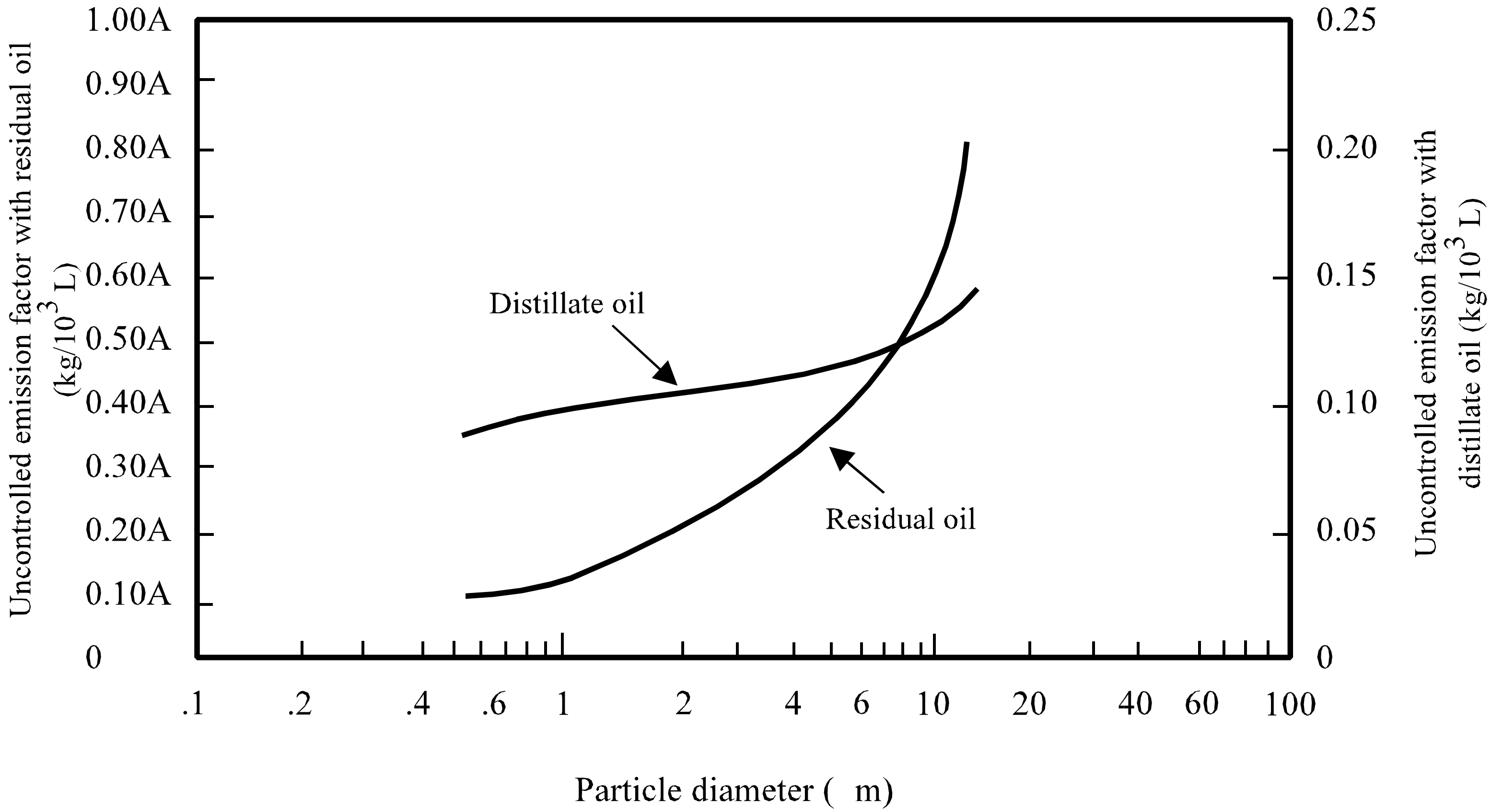
ESP
Uncontrolled
Scrubber
Uncontrolled emission factor (kg/10^3 L)
Scrubber controlled emission factor (kg/10^3 L)
ESP controlled emission factor (kg/10^3 L)
1.0A
0.9A
0.8A
0.7A
0.6A
0.5A
0.4A
0.3A
0.2A
0.1A
0
0.10A
0.09A
0.08A
0.07A
0.06A
0.05A
0.04A
0.03A
0.02A
0.01A
0
0.01A
0.006A
0.004A
0.002A
0.001A
0.0006A
0.0004A
0.0002A
0.0001A
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)



1.0A
0.9A
0.8A
0.7A
0.6A
0.5A
0.4A
0.3A
0.2A
0.1A
0A
0.20A
0.18A
0.16A
0.14A
0.12A
0.10A
0.08A
0.06A
0.04A
0.02A
0A
Uncontrolled emission factor ($kg/10^3L$)
Multiple cyclone controlled emission factor ($kg/10^3L$)
Uncontrolled
Multiple cyclone
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)



0.25
0.20
0.15
0.10
0.05
0
Uncontrolled emission factor
(kg/10^3L)
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)



Uncontrolled emission factor with residual oil (kg/10^3 L)
1.00A
0.90A
0.80A
0.70A
0.60A
0.50A
0.40A
0.30A
0.20A
0.10A
0
Uncontrolled emission factor with distillate oil (kg/10^3 L)
0.25
0.20
0.15
0.10
0.05
0
Distillate oil
Residual oil
.1
.2
.4
.6
1
2
4
6
10
20
40
60
100
Particle diameter (m)