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DCN 86-231-020-26-17

BACKGROUND INFORMATION DOCUMENT
FOR
SMALL STEAM GENERATING UNITS

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Under Contract No. 68-02-3816

Prepared for:

U. S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Emission Standards and Engineering Division
Research Triangle Park, North Carolina 27711

January 1987

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TABLE OF ABBREVIATIONS

1. Temperature

^oC = degree Celsius

^oF = degree Farenheit

K = degree Kelvin

R = Rankine

2. Pressure

kPa = kilopascal

in w.g. = inches of water gauge

atm = atmosphere

3. Length or diameter

um = microns, 10^{-6} meters

mm = millimeter, 10^{-3} meters

ft = foot

4. Area

m^2 = square meter

ft^2 = square foot

5. Velocity

m/sec = meter per second

ft/sec = foot per second

6. Concentrations

ppmv = parts per million by volume

wt. % = weight percent

TABLE OF ABBREVIATIONS (Continued)

7. Density

kg/m^3 = kilogram per cubic meter

lb/gal = pound per gallon

8. Flow Rate

kg/hr = kilogram per hour

lb/hr = pound per hour

m^3/min = cubic meter per minute

gal/min = gallon per minute

9. Heat Input

MW = megawatts, 10^6 watts

GW = gigawatts, 10^9 watts

10^6 Btu/hr = million Btu/hr = million British thermal unit per hour

10. Heating Value

kJ/kg = kilojoule per kilogram

Btu/lb = British unit per pound

kJ/m^3 = kilojoule per cubic meter

11. Fuel Consumption

J/yr = joule per year

Btu/yr = British thermal unit per year

12. Heat Release Rates

$kJ/sec\text{-}m^2$ = kilojoule per second per square meter

$kJ/sec\text{-}m^3$ = kilojoule per second per cubic meter

$Btu/hour\text{-}ft^2$ = British thermal unit per hour per square foot

$Btu/hour\text{-}ft^3$ = British thermal unit per hour per cubic foot

TABLE OF ABBREVIATIONS (Continued)

13. Energy Intensity

kJ/m^2-yr = kilojoule per square meter per year

Btu/ft^2-yr = British thermal unit per square foot per year

14. Emissions

ng/J = nanograms of pollutant per joule heat input

$lb/10^6$ Btu = pounds of pollutant per million British thermal unit heat input

lb/ton = pound of pollutant per ton of fuel fired

lb/1000 gal = pound of pollutant per thousand gallons of fuel fired

Mg/yr = Megagrams of pollutant per year

tons/yr = Tons of pollutant per year

lb/bbl = pound of pollutant per barrel of fuel fired

lb/hr = pound of pollutant per hour

15. ESP Abbreviations

resistivity: ohm-cm = ohm - centimeter

Specific collection area: $m^2/(1000\ m^3/s)$ = square meter of collection area per thousand cubic meters per second of flue gas.

ft^2/1000 acfm = square foot of collection area per thousand actual cubic feet per minute of flue gas.

16. Fabric Filter Abbreviations

air-to-cloth: $acfm/ft^2$ = actual cubic foot per minute of flue gas per square foot of cloth area

$m^3/min\text{-}m^2$ = cubic meter per minute of flue gas per square foot of cloth area.

TABLE OF ABBREVIATIONS (Continued)

17. Wet Scrubber Abbreviation

in w.c. = differential pressure in inches of water

18. Costs Abbreviations

Fuel Price: \$/KJ = dollar per kilojoule

\$/Btu = dollar per British thermal unit

Solid Waste Unit Cost: \$/Mg = dollar per megagram

\$/ton = dollar per ton

1.0 OVERVIEW

This document was prepared to provide background information on the small steam generating unit (i.e., boiler) source category [i.e., steam generators rated at 29.3 MW (100 million Btu/hour) heat input or less] in support of potential new source performance standards (NSPS). Fossil and nonfossil fuels discussed and analyzed include natural gas, oil, coal, solid waste, and wood.

This document contains information on the use of small boilers in different applications and an assessment of controlled and uncontrolled emissions from different configurations of boilers firing fossil and nonfossil fuels. Costs and emission levels for several model boiler configurations meeting alternative control levels are also presented. The information has been compiled from available sources, primarily documents used in the development of background information for proposed NSPS (40 CFR Part 60, Subpart Db) for industrial boilers of heat input capacity greater than 29.3 MW (100 million Btu/hour). The information has been compiled herein as a summary specific to the small boiler source category.

Section 2 presents descriptions of the small boilers which make up the source category, estimates of the current population of small boilers, a review of existing regulations limiting their emissions, and projections of baseline emissions expected in the absence of NSPS. Section 3 provides a comprehensive review and evaluation of the control techniques which are being used to limit emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) from small boilers. Based on the information in Section 2, model boilers are developed in Section 4 to represent the predominant types of boilers to be installed in the near future which would be subject to potential NSPS. In addition, based on the data presented in Section 3, emission limits and control techniques are selected for each model boiler which are representative of both baseline emission levels and one or two levels of more stringent emissions control. Capital, operating, and annualized costs which would be required of new small boiler operations to meet the baseline and more stringent emission control alternatives are estimated on a model boiler basis in Section 5. The costs associated with the more stringent control alternatives are compared to the baseline emissions costs. Finally, in Section 6, the emissions of PM, SO_2, and NO_x associated with all control alternatives are estimated on a model boiler basis and the emission reductions of the more stringent control alternatives relative to the baseline are calculated.

2.0 CHARACTERISTICS OF THE SMALL STEAM GENERATING UNIT SOURCE CATEGORY

2.1 GENERAL CHARACTERISTICS

In this section, small steam generating units (i.e., boilers) are described and classified by design type and fuel use. The existing population of small boilers is characterized by design type, capacity, and fuel usage. Existing regulations applicable to small boilers are reviewed and used as the basis for projecting baseline emissions. Baseline emissions correspond to emissions from new small boilers expected in the absence of new source performance standards.

Unlike larger industrial boilers, small boilers are predominantly of the shop-assembled, or packaged, method of construction with very few field-erected units. Therefore, shop-assembled boilers will be considered the predominant construction method for this source category.

2.1.1 Small Boiler Source Category

The small boiler source category is large and diverse, characterized by a number of different boiler types, fuels, and applications. Small boilers are defined as industrial, commercial, or institutional steam generating units with heat input capacities of 29.3 MW (100 million Btu/hour) or less. Small boilers burn fossil and nonfossil fuels including natural gas, distillate oil, residual oil, coal, wood, municipal solid waste (MSW), Industrial Solid Waste (ISW), Refuse Derived Fuel (RDF) and combinations of these fuels. Of these, the first four are commonly recognized fuels. Wood includes various types ranging from sawdust to wood bark. Municipal solid waste consists of wood, paper, metal, glass, and garbage. The exact constituents of MSW may vary both seasonally and geographically. Industrial solid waste includes processing wastes and plant trash such as paper, cardboard, plastic, rubber, textiles, wood, and refuse. A subcategory of MSW and ISW is RDF, which is waste which has been processed or classified to remove some of the noncombustibles and produce a fuel of more uniform particle size.

Particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) are the pollutants emitted to the atmosphere from these sources that will be considered in this document.

Small boilers are used in a variety of applications in the industrial, commercial, and institutional sectors. Boilers in the industrial sector may be used for space heating and for process steam; while boilers in the commercial and institutional sectors are used primarily for space heating and water heating.

2.1.2 Classification of Small Boilers

There are three principal design types of small boilers: cast iron, firetube, and watertube. The following sections describe the design, typical size range, and fuels burned for each principal small boiler type. A more detailed description and illustration of each boiler type is presented in the Background Information Document for Industrial Boilers.[1]

2.1.2.1 Cast Iron Boilers. Cast iron boilers are built such that the hot combustion gases are contained inside tubes--that is, in a furnace--which, in turn, are surrounded by water. Heat from the gases transfers through the walls of the tubes or furnace to heat the surrounding water. As the name implies, these boilers are constructed of cast iron rather than steel. Boiler sizes can range from 0.0009 to 2.9 MW (0.003 to 10 million Btu/hour) heat input. Most cast iron boilers, however, are smaller than 0.12 MW (0.4 million Btu/hour) heat input, with very few larger than 0.44 MW (1.5 million Btu/hour). Cast iron boilers primarily fire natural gas or distillate oil.

2.1.2.2 Firetube Boilers. In firetube boilers, the hot combustion gases flow through a cylindrical or rectangular furnace and tubes that are surrounded by water. The tubes are typically horizontal and the gases may make as many as four passes along the length of the boiler before exiting to a stack. Firetube boilers are almost exclusively packaged units. There are two major types of firetube boilers: firebox boilers and Scotch Marine boilers.

2.1.2.2.1 <u>Firebox boilers</u>. Firebox boilers are built with a single internal steel furnace which is surrounded by water. Combustion gases leave this furnace and make at most three passes through the firetubes, also surrounded by water, before exiting the boiler.

These boilers are rectangular, short, compact, and require proper matching of the burner flame length and furnace volume. Generally, firebox boiler sizes are below 5.9 MW (20 million Btu/hour) heat input.[2] A variety of fuels including natural gas, distillate and residual oil, and coal can be fired in the boilers. A boiler efficiency of 80 percent is typical for these boilers.[3]

2.1.2.2.2 <u>Scotch Marine boilers</u>. Like firebox boilers, Scotch-Marine boilers are also compact, self-contained units which require minimal space for installation.[4] Scotch Marine boilers are cylindrical in shape, however, with one or more water-cooled cylindrical chambers where combustion occurs. Combustion gases leave the rear of the chambers and make two to four firetube passes before exiting to the stack at the front of the boiler. The combustion chambers of a Scotch Marine boiler are either of wet-back or dry-back design. A wet-back boiler has a rear wall surrounded by water; a dry-back boiler has its rear wall insulated by refractory.

Scotch Marine boilers are manufactured in sizes up to 14.7 MW (50 million Btu/hour) heat input and generally fire natural gas, oil, or gas/oil combinations. Boiler efficiency is approximately 80 percent.[5]

There are a number of advantages in using firetube boilers over watertube boilers. These include:

- o Lower costs than watertube boilers without economizers,
- o More rapid response to load swings,
- o Easier tube replacement,

- Less space required,
- Greater corrosion resistance, and
- Higher thermal efficiencies (compared to watertube boilers without heat recovery auxiliaries).[6]

2.1.2.3 Packaged Watertube Boilers. The packaged watertube boiler is the most common type of watertube boiler below 29.3 MW (100 million Btu/hour) heat input. There are approximately 50 percent more packaged watertube boilers than field-erected units between 2.9 and 29.3 MW (10 and 100 million Btu/hour) heat input.[7] The popularity of packaged watertube boilers in this size range is primarily due to lower capital costs.

In a watertube boiler, the hot combustion gases surround the outside of the boiler tubes while water and/or steam are contained within the tubes. Heat is transferred from the gases, across the tube wall, to the water or steam. Each tube is connected to an upper and a lower steam drum.

Packaged watertube boilers are used in commercial, institutional, and industrial applications and are generally available in sizes greater than 2.9 MW (10 million Btu/hour) heat input. Natural gas, distillate oil, and residual oil can be fired in these boilers. For coal and other solid fuel burning, stoker boilers and fluidized bed combustion units, which are also types of watertube boilers, are normally used.

2.1.2.4 Stoker Boilers. A stoker is a watertube boiler in which coal, wood, MSW, or other solid fuels are conveyed and fed onto a grate where the fuel is burned. Stokers are classified into three types according to the way they introduce fuel into the furnace: spreader, underfeed, and overfeed (or massfeed) stokers.

Stoker boilers can be either packaged or field-erected. Packaged boilers are available in sizes up to 14.7 MW (50 million Btu/hour) heat input.[8] These boilers are usually preferred in this size range because they are less expensive than field-erected boilers.

2.1.2.4.1 Spreader stokers. In spreader stokers, fuel is thrown to the rear of the furnace grate by a rotary feeder. There are basically three types of spreader stokers distinguished by grate design. These are stationary and dumping, traveling, and vibrating grates. The traveling grate spreader stoker is typically used on larger sized stokers, while the stationary and dumping grate and vibrating grate stokers are used mostly on small and medium-sized boilers.

The following heat release rates (calculated as the heat input at full load per effective grate area in kilojoules per second per square meter [$kJ/sec{-}m^2$]) are the maximum allowable rates for coal operation recommended by a leading vendor for each type of spreader stoker:[9]

- Stationary and dumping grate - 1,420 $kJ/sec{-}m^2$ (450,000 $Btu/hour{-}ft^2$)
- Traveling grate - 2,365 $kJ/sec{-}m^2$ (750,000 $Btu/hour{-}ft^2$)
- Vibrating grate - 1,262 $kJ/sec{-}m^2$ (400,000 $Btu/hour{-}ft^2$)

These maximum allowable heat release rates assume the use of coals suitable for each stoker type and are designed to avoid grate overheating and premature failure. The traveling grate spreader stoker is usually preferred by industrial users due to its high allowable heat release rate. These stokers tend to emit higher NO_x emissions, however, because of their higher heat release rates compared to the other two types of spreader stokers.[10]

Overfire air ports provide additional air needed to burn the suspended fuel above the stoker grate. Usually two rows of overfire air ports are installed on the rear furnace wall and one row is placed on the front furnace wall.[11] Increasing the overfire air and reducing the undergrate air to achieve higher than normal levels of air staging in spreader stokers can lead to operational problems such as clinker formation and grate overheating.[12]

Among the various stoker types, the spreader stoker is the most generally used in capacities of 14.7 MW (50 million Btu/hour) heat input and above. This is due to their rapid response to load swings and their ability to burn a wide range of fuels.[13]

2.1.2.4.2 Underfeed stokers. Underfeed stokers feed the fuel, usually coal, through a retort below the burning fuel bed. Two common types of underfeed stokers used in this source category are the single retort/horizontal feed stoker and the multiple retort/gravity feed stoker. In the single retort/horizontal feed stoker, fuel is moved from a feed hopper to a single trough or retort by a fuel ram. Once in the retort, the fuel burns and is moved to the rear furnace wall by pusher blocks. Then it is conveyed upward and spread over the air tuyeres. As more fuel is pushed over the air tuyeres, the excess or spent fuel is dumped to a side dumping grate. Overfire air ports are used to reduce smoke and particulate emissions, especially at low loads.[14]

Single retort stokers have either stationary or moving grates. Most stationary grate underfeed stokers have heat input capacities between 2.9 and 5.9 MW (10 and 20 million Btu/hour). While the moving grate underfeed stokers are available in sizes up to 10.2 MW (35 million Btu/hour) heat input, the maximum allowable heat release rate for coal operation recommended for these stokers on an effective grate area basis is 1,351 kJ/sec-m^2 (425,000 Btu/hour-ft^2).[15] These small underfeed stokers are used principally for space heating and are usually installed in sizes of less than 10.2 MW (35 million Btu/hour) heat input.[16]

In multiple retort/gravity feed stokers, the fuel is fed from the fuel hopper to inclined retorts and grates. The retorts and grates are usually inclined by 20 to 25 degrees.[17] Excess fuel and ash are spread over the air tuyeres and dumped via gravity onto an ash discharge plate.

Multiple retort/gravity feed stokers are available in larger sizes than are the single retort/horizontal feed stokers. However, large underfeed stokers have been largely displaced by spreader stokers in the intermediate size range.[18] Hence, few underfeed stokers greater than 10.2 MW (35 million Btu/hour) heat input are currently being sold.

2.1.2.4.3 Overfeed or massfeed stokers. In this type stoker, fuel is fed by gravity from above the combustion zone and falls onto a moving grate. The fuel, usually coal, is burned as the grate moves along the furnace. Municipal solid waste and wood can also be fired in this type of stoker. Ash is then dumped into an ash pit near the end of the furnace.

Overfeed stokers are generally characterized as either chain grate (or traveling grate) units or water-cooled vibrating grate units. For chain grate units, the amount of grate cooling depends solely on the air flow through the grate. Since water is used to cool a vibrating grate, this type of overfeed stoker can operate at lower excess air levels than chain grate units, thereby further improving both boiler efficiency and NO_x emission reduction potential.[19]

Overfire air ports can also be incorporated into the design of overfeed stokers. The air flow from these ports is controlled separately from the primary air flowing under the grate.[20] Depending upon the type of coal fired, the recommended maximum allowable heat release rates based on effective grate area range between 1,112 and 1,589 kJ/sec-m^2 (350,000 and 500,000 Btu/hour-ft^2). Overfeed stokers are typically available in sizes ranging from 5.9 MW (20 million Btu/hour) to 73.3 MW (250 million Btu/hour) heat input.[21]

2.1.2.5 Atmospheric Fluidized Bed Combustion Boilers. Atmospheric fluidized bed combustion (AFBC) boilers have developed rapidly over the past few years and are now offered commercially in several different configurations primarily for coal and wood combustion. The increasing popularity of AFBC boilers is due to two reasons. First, NO_x and SO_2 emissions from coal combustion can be controlled within the combustion chamber thereby eliminating the need for scrubbers, compliance coal, or elaborate combustion modifications. Secondly, a wide range of solid fuels can be burned, in particular fuels containing high ash and moisture contents. Seventeen U.S. boiler manufacturers currently offer AFBC boilers in sizes below 29.3 MW (100 million Btu/hour), with some offering units down to 0.6 MW (2 million Btu/hour) heat input.[22]

Design alternatives which are currently available include the conventional bubbling fluidized bed (with or without solids recycle), staged fluidized beds, and circulating fluidized beds.[23]

2.1.2.5.1 Bubbling bed FBC boilers. In the conventional bubbling bed system, fuel and sorbent (usually coal and limestone) are continuously fed into a bed of fluidized particles. The limestone is added for SO_2 removal. The fluidized bed, consisting of unreacted, calcined, and sulfated limestone particles; coal; and ash, is suspended in a stream of combustion air blowing upwards from an air distribution plate.

Bed material is drained from the bottom of the bed. Some bed material is also elutriated by entrainment with the combustion gases. This entrained material is separated from the gases by a cyclone, baghouse, electrostatic precipitator, or a combination of these devices. The collected material, along with the bed drain material, is then discarded as a solid waste. A more detailed description of conventional bubbling bed AFBC boilers is presented in another report.[24]

In an AFBC boiler with solids recycle, flue gas with entrained bed material passes through a primary cyclone where 80 to 90 percent of the entrained material is removed.[25] All or part of this material is then fed back to the fluidized bed. The net effect of solids recycle is to increase fuel and sorbent residence times in the bed, which leads to improvements in combustion efficiency and SO_2 control.[26]

Staging of combustion air in conventional bubbling bed units is a recently developed option which reduces NO_x emissions.[27] A substoichiometric amount of air is added at the fluidizing air (primary air) injection point. The balance of the air needed to achieve adequate combustion efficiency is added above the bed. This allows the combustion to be completed in the freeboard area (i.e., space between the top of the fluidized bed and the flue gas outlet).

2.1.2.5.2 Staged bed FBC boilers. For coal operation, another approach to minimizing NO_x formation while maximizing SO_2 retention in fluidized beds is to actually operate the FBC unit with two separate beds.

In this arrangement, one bed is placed above the other. The lower bed contains only coal and is operated at substoichiometric air conditions to limit NO_x formation. Limestone only is maintained in the upper bed where desulfurization and final combustion occur. Since SO_2 capture and NO_x formation occur in separate beds, operating conditions in the two beds can be varied independently to achieve the desired performance.

2.1.2.5.3 Circulating bed FBC boilers. Another recently developed AFBC technology for coal combustion involves a circulating fluidized bed (CFB).[28] Similar technology was originally used in other applications such as fluidized catalytic cracking of petroleum feedstocks. Several CFB boiler systems have been developed.

Circulating fluidized bed systems are characterized by higher gas velocities, resulting in better mixing and reduced particle channeling in larger-sized units. Circulating fluidized beds are operated by circulating the solids, which generally leads to improved combustion efficiency and limestone utilization. Staging of combustion air to reduce NO_x emissions is also a design option. Various designs incorporating separate heat recovery systems and/or multiple beds can result in improved turndown capabilities relative to conventional AFBC systems.

However, CFB boilers are generally larger in size, resulting in greater capital costs and energy requirements (due to higher bed pressure drops) compared to bubbling bed units. As a result of these factors, CFB units are not prevalent in the small boiler size range; only three units in the small boiler size range were reported in a February 1985 survey.[29]

2.1.2.6 Small Modular Incinerators With Heat Recovery. In addition to overfeed stokers, MSW is also combusted in small modular incinerators and rotary combustors which fall within the small boiler source category.

Combustion of MSW in small modular incinerators (SMI) was introduced in the late 1960's. These units are shop fabricated on a packaged basis. They are batch-fed using a ram to push the MSW into the primary combustion chamber. To accommodate expansion in burning capacity for small towns and industries, the modular boiler system is designed to allow installation of additional units in modules as refuse generation increases.[30]

The boiler of a typical SMI consists of an incinerator with primary and secondary combustion chambers. Units of this type are commonly referred to as "controlled air" boilers because the air in the primary combustion chamber is limited to minimize ash and fuel entrainment. Controlled air boilers are grouped into two main categories according to the degree of combustion, complete or partial, achieved in the primary chamber. Since complete combustion requires excess air and partial combustion entails substoichiometric conditions, these units are categorized as excess air incinerators and "starved air" incinerators, respectively. Steam generation, or water heating, takes place in a waste heat boiler where heat from the incinerator flue gases is recovered before the gases exit the stack. Small modular incinerators typically combust refuse at around 820°C (1500°F) in the primary chamber and at 1000°C (1900°F) in the secondary chamber.

Controlled air incinerators are produced in sizes as small as 1.3 MW (4.5 million Btu/hour) heat input. The largest controlled air incinerator sizes are 11.1 MW (38 million Btu/hour) heat input for starved air incinerators and over 29.3 MW (100 million Btu/hour) for excess air incinerators.[31,32]

2.1.2.7 Rotary Combustors. Another boiler type used for MSW combustion is a rotary combustor. In this system, MSW is continuously fed into the elevated end of a water-cooled cylindrical combustor. Dry materials burn first, providing heat for drying and burning wet materials. About 95 percent of the combustibles burn as they tumble down the combustor. The remaining combustibles are burned on an inclined grate in a waterwall boiler. Heat transfer occurs through the walls of the combustor as well as between hot combustion gases and watertubes located in the boiler.

Specific advantages claimed for this type of boiler are that no refractory is required; there are no moving or reciprocating grates; and an overall efficiency of over 70 percent (versus an efficiency of about 55 percent for small modular incinerators) is typical.[33]

Rotary combustor boilers range in size from 6.4 to over 29.3 MW (22 to over 100 million Btu/hour) heat input.[34] At the present time, only one unit firing MSW is in operation. However, these boilers may become more prevalent in the future in view of the operating characteristics discussed above.

2.2 EXISTING SMALL BOILER POPULATION AND FUEL USAGE PATTERNS

The existing population of small boilers can be divided into two major fuel use categories: fossil fuel-fired boilers and nonfossil fuel-fired boilers. The first category contains boilers firing natural gas, oil, or coal, or combinations of these fuels. Boilers in the second category burn nonfossil materials which include wood and solid waste.

This section describes the existing population of small boilers with respect to number, capacity, size distribution, and fuel use.

2.2.1 Fossil Fuel-Fired Boilers

A study performed in 1979 for the EPA provides detailed information on the number of industrial, commercial, and institutional (ICI) boilers, installed capacity, boiler design, fuel type, and application for existing boilers in 1977.[35] This study showed that ICI boilers with heat input capacities of 29.3 MW (100 million Btu/hour) or less represent over 99 percent of the total ICI population and about 70 percent of the total ICI capacity.

Table 2-1 summarizes sales data obtained from the Hydronics Institute (HI) for cast iron boilers and the American Boiler Manufacturers Association (ABMA) for firetube and watertube boilers from 1975 through 1984. Using these sales data, it is possible to estimate the existing boiler population in 1984 using certain assumptions regarding boiler distribution and the ratio of "new growth" to replacement boilers. It was assumed that 50 percent of the cast iron boiler sales represent replacement boilers and that 27 percent of the firetube boiler sales represent replacement boilers.[36] For watertube boilers, no boilers were assumed to be replaced. Using these

TABLE 2-1. BOILER SALES DATA FOR 1975-1984[a]

Year	Number of boilers				Capacity, 10^3 MW (10^9 Btu/hour) heat input			
	Cast iron	Firetube	Watertube[b]	Total	Cast iron	Firetube	Watertube[b]	Total
1975	15,900	7,210	340	23,450	2.7 (9.4)	8.3 (28.4)	4.3 (14.7)	15.4 (52.5)
1976	19,500	8,260	270	28,030	3.3 (11.3)	8.9 (30.4)	3.2 (11.1)	15.5 (52.8)
1977	21,200	8,740	340	30,280	3.6 (12.2)	9.8 (33.3)	4.2 (14.2)	17.5 (59.7)
1978	20,200	8,440	320	28,960	3.4 (11.7)	8.9 (30.4)	5.4 (18.5)	17.8 (60.6)
1979	20,800	8,700	320	29,820	3.5 (12.0)	9.0 (30.9)	5.0 (17.1)	17.6 (60.0)
1980	29,100	7,630	250	36,980	4.4 (15.1)	7.6 (26.1)	4.1 (14.1)	16.2 (55.3)
1981	19,200	6,710	210	26,120	3.3 (11.4)	7.2 (24.5)	3.5 (12.0)	14.0 (47.9)
1982	17,900	5,880	160	23,940	3.1 (10.6)	6.1 (20.9)	2.7 (9.1)	11.9 (40.6)
1983	17,900	6,390	140	24,430	3.0 (10.2)	6.9 (23.6)	2.3 (7.9)	12.2 (41.7)
1984	19,200	6,680	140	26,020	3.2 (10.8)	7.3 (24.9)	2.3 (7.8)	12.7 (43.5)

[a]Based on data from References 37 and 38.

[b]Only includes watertubes with steam capacities of 4,500 to 45,000 kg/hr (10,000 to 100,000 lb/hr). Sales for smaller watertubes are included as firetubes.

assumptions, the projected 1984 boiler population represents nearly a 5 percent increase over the 1977 population of cast iron boilers predicted by Reference 35, about a 13 percent increase over the firetube population, and a 3 percent increase over the watertube population. Assuming the same distribution of boiler sizes and fuel types as predicted by Reference 35, the estimated 1984 population of small boilers is shown in Table 2-2.

Table 2-2 presents the distribution of existing ICI boilers smaller than or equal to 29.3 MW (100 million Btu/hour) heat input by size, fuel type, and boiler type. Table 2-2 shows that about 80 percent of the boilers are cast iron boilers, 16 percent are firetubes, and 4 percent are watertubes. However, watertube boilers have the largest installed capacity, followed by firetubes, with cast iron boilers having the smallest installed capacity. Table 2-2 also shows that natural gas- and distillate oil-fired boilers represent about 67 percent of the total number of boilers and about 58 percent of the total installed capacity. Residual oil-fired boilers represent about 22 percent of the total number of boilers and about 28 percent of the total capacity, while coal-fired boilers represent about 11 percent of the total number of boilers and 14 percent of the total capacity.

Since actual fuel consumption data for boilers with heat input capacities of 29.3 MW (100 million Btu/hour) or less are generally unavailable, a study was conducted to estimate 1980 fuel consumption in these boilers. This study made use of data presented in Reference 35, as well as data in an Energy Information Administration (EIA) report, and certain key assumptions which will be discussed in this section.[39,40]

The EIA report is a survey of the 1980 energy use in non-residential buildings and provides information on the amount of floorspace, the energy-use intensity, and typical boiler operating hours for various types of buildings (e.g., education, offices, assembly, health care). This information is summarized in Table 2-3. The weighted average annual operating rate based on fuel consumption is about 3,300 hours/year. In Reference 35, it was assumed that boilers in the commercial/institutional sector operate at an effective capacity which is 70 percent of the installed or nominal capacity. The basis for this assumption is that the installed

TABLE 2-2. DISTRIBUTION STATISTICS FOR EXISTING ICI BOILERS WITH HEAT INPUT CAPACITIES EQUAL TO OR LESS THAN 29.3 MW (100 MILLION BTU/HOUR) IN 1984[a]

Boiler size range, MW (10^6 Btu/hour) heat input	Fuel type	Number of boilers, 1,000				Capacity, 10^3 MW (10^6 Btu/hour) heat input			
		Cast iron	Firetube	Watertube	Total	Cast iron	Firetube	Watertube	Total
0-0.44 (0-1.5)	Natural Gas/Distillate Oil	964	129	5	1,098	114 (390)	37.8 (129)	1.8 (6)	154 (525)
	Residual Oil	289	52	1	342	32.5 (111)	15.2 (52)	0.3 (1)	48.0 (164)
	Coal	168	21	0	189	19.3 (66)	6.2 (21)	0 (0)	25.5 (87)
	Total	1,421	202	6	1,629	166 (567)	59.1 (202)	2.1 (7)	227 (776)
0.44-2.9 (1.5-10)	Natural Gas/Distillate Oil	83	53	7	143	72.1 (246)	87.0 (297)	8.8 (30)	168 (573)
	Residual Oil	26	25	3	54	23.7 (81)	39.3 (134)	5.3 (18)	68.3 (233)
	Coal	21	6	2	29	13.8 (47)	10.0 (34)	1.8 (6)	25.5 (87)
	Total	130	84	12	226	110 (374)	136 (465)	15.8 (54)	262 (893)
2.9-7.3 (10-25)	Natural Gas/Distillate Oil	-	12	3	15	-	67.7 (231)	16.1 (55)	83.8 (286)
	Residual Oil	-	6	3	9	-	29.6 (101)	13.5 (46)	43.1 (147)
	Coal	-	2	1	3	-	9.1 (31)	4.7 (16)	13.8 (47)
	Total	-	20	7	27	-	106 (363)	34.3 (117)	141 (480)
7.3-14.7 (25-50)	Natural Gas/Distillate Oil	-	2	6	8	-	25.8 (88)	64.5 (220)	90.2 (308)
	Residual Oil	-	1	5	6	-	10.2 (35)	55.7 (190)	65.9 (225)
	Coal	-	1	2	3	-	4.4 (15)	28.1 (96)	32.5 (111)
	Total	-	4	13	17	-	40.4 (138)	148 (506)	189 (644)
14.7-29.3 (50-100)	Natural Gas/Distillate Oil	-	-	3	3	-	-	68.8 (235)	68.8 (235)
	Residual Oil	-	-	2	2	-	-	49.2 (168)	49.2 (168)
	Coal	-	-	2	2	-	-	35.2 (120)	35.2 (120)
	Total	-	-	7	7	-	-	153 (523)	153 (523)
Total	Natural Gas/Distillate Oil	1,047	196	24	1,267	186 (636)	218 (745)	160 (546)	565 (1,927)
	Residual Oil	315	84	14	413	56.3 (192)	94.3 (322)	124 (423)	274 (937)
	Coal	189	30	7	226	33.1 (113)	29.6 (101)	69.7 (238)	132 (452)
		1,551	310	45	1,906	275 (941)	342 (1,168)	354 (1,207)	971 (3,316)

[a]Based on data from References 41, 42, and 43.

TABLE 2-3. ENERGY INTENSITIES AND USE IN BUILDINGS IN THE COMMERCIAL/INSTITUTIONAL SECTOR[a]

Category of building	1980 Operating rate, hours/year	Energy intensity, 10^3 kJ/m^2-yr (10^3 Btu/ft^2-yr)		Floorspace, 10^6 m^2 (10^6 ft^2)	
		Total	Boiler[b]	Total	Boiler[b]
Assembly	2,110	908 (80)	545 (48)	467 (5,028)	323 (3,480)
Auto Sales/Service	3,610	1,181 (104)	704 (62)	169 (1,821)	74 (801)
Education	3,700	1,022 (90)	613 (54)	543 (5,851)	477 (5,140)
Food Sales	4,790	1,907 (168)	1,147 (101)	173 (1,864)	80 (859)
Health Care	3,800	4,190 (369)	2,509 (221)	157 (1,687)	140 (1,509)
Lodging	5,370	1,703 (150)	1,022 (90)	187 (2,012)	159 (1,714)
Office	2,740	1,646 (145)	988 (87)	760 (8,184)	589 (6,336)
Residential	3,300	976 (86)	590 (52)	289 (3,115)	236 (2,542)
Retail/Personal Services	3,080	1,067 (94)	636 (56)	710 (7,652)	470 (5,056)
Warehouse/Storage	2,520	1,203 (106)	727 (64)	564 (6,070)	366 (3,938)
Other	3,600	2,214 (195)	1,328 (117)	291 (3,129)	206 (2,219)
Vacant	1,530	681 (60)	409 (36)	118 (1,273)	74 (800)

[a]Reference 44.

[b]Reference 45.

capacity exceeds normal requirements because of the need to maintain some back-up capacity in the event of failure or to provide for peak load steam demands. An effective capacity of 70 percent combined with an operating rate of 3,300 hours/year yields an average capacity utilization factor of 0.26.

The National Emissions Data Survey (NEDS) contains site-specific information on fuel consumption which can be used to estimate the average annual capacity factor for boilers of various sizes, fuel types, and applications.[46] A qualitative review of the NEDS data showed that the annual capacity factors can range from less than 5 percent to 100 percent of the installed capacity for a particular boiler. The NEDS data showed that the average capacity factor did not vary significantly by boiler size, fuel fired, or application, with all categories examined having an average capacity factor of 0.20 to 0.40. Thus the NEDS data support the reasonableness of the average capacity factor estimate of 0.26 derived in Reference 35 for boilers of 29.3 MW (100 million Btu/hour) heat input or less.

Table 2-4 presents estimates of fuel consumption by boiler size range and fuel type, assuming an average capacity factor of 0.26. Table 2-4 shows that natural gas/distillate oil represents 58 percent, residual oil represents 28 percent, and coal represents 14 percent of all fuel consumed in ICI boilers with heat input capacities of 29.3 MW (100 million Btu/hour) or less. Table 2-4 further shows that natural gas/distillate oil consumption decreases significantly as boiler size increases, whereas residual oil consumption and coal consumption remain relatively constant across all size ranges.

2.2.2 Nonfossil Fuel-Fired Boilers

Information on the existing population and distribution of nonfossil fuel-fired boilers with heat input capacities equal to or less than 29.3 MW (100 million Btu/hour) is not as detailed as that for fossil fuel-fired boilers. A study was conducted in 1982 to characterize the existing population and the projected growth of industrial nonfossil fuel-fired

TABLE 2-4. FUEL CONSUMPTION IN EXISTING ICI BOILERS[a]

Boiler size range, MW (10^6 Btu/hour) heat input	Fuel consumption, 10^{15} J/yr (10^{12} Btu/yr)			
	Natural gas/ distillate oil	Residual oil	Coal	Total
0-0.44 (0-1.5)	1,261.5 (1,196)	394.5 (374)	208.9 (198)	1,864.9 (1,768)
0.44-2.93 (1.5-10)	1,376.5 (1,305)	560.1 (531)	208.9 (198)	2,145.5 (2,034)
2.93-7.33 (10-25)	686.7 (651)	353.4 (335)	112.9 (107)	1,152.9 (1,093)
7.33-14.65 (25-50)	740.5 (702)	540.1 (512)	266.9 (253)	1,547.4 (1,467)
14.65-29.3 (50-100)	564.3 (535)	404.0 (383)	288.0 (273)	1,256.3 (1,191)
Total	4,629.5 (4,389)	2,252.0 (2,135)	1,085.0 (1,029)	7,967.4 (7,553)

[a]Based on the installed capacities presented in Table 3.2-2 and an annual capacity factor of 0.26.

boilers.[47] Of the various information sources available, this study is the most useful as it attempts to characterize the nonfossil fuel-fired boiler population by boiler size range. Table 2-5 presents the 1978 and 1980 populations of nonfossil fuel-fired boilers. The NEDS database was used to estimate the population of wood-fired boilers in 1978.[48,49]

Sales data for nonfossil fuel-fired boilers with heat input capacities of 29.3 MW (100 million Btu/hour) or less for 1980 and later are not readily available. Table 2-6 presents estimates of average annual sales for new nonfossil fuel-fired boilers of 29.3 MW (100 million Btu/hour) heat input or less from 1980 through 1990. These projections are based on historical sales data and predictions of future growth by ABMA and other sources.[50]

Historical sales data for bagasse-fired units indicate that sales of units with heat input capacities of 29.3 MW (100 million Btu/hour) or less declined markedly in the 1970's and represented less than 2 percent of total sales in 1980. Although agricultural wastes such as peanut hulls, cotton gin trash, peach pits, corn husks, walnut shells, and olive pits may be burned as a boiler fuel, these wastes are generally more valuable as a chemical or animal feedstock. Thus, no new boilers designed specifically to fire agricultural wastes are expected to be built in the foreseeable future. Some FBC units may be built in this size range which burn agricultural wastes as a secondary fuel.

Table 2-7 presents estimates of the 1984 population of nonfossil fuel-fired boilers. These estimates are based on data on the existing population and boiler sales projections. It was assumed that 95 percent of the wood-fired boiler sales represent new growth and 100 percent of the solid waste-fired boiler sales represent new growth.[51] These assumptions are reasonable since most existing nonfossil fuel-fired boilers are relatively new. Table 2-7 shows that approximately 1,400 wood-fired boilers with an installed heat input capacity of 12.1 GW (41.2 billion Btu/hour) and 800 solid waste-fired boilers with an installed heat input capacity of 4.1 GW (14.0 billion Btu/hour) are estimated in the 1984 small boiler population.

TABLE 2-5. 1978 AND 1980 POPULATIONS OF NONFOSSIL FUEL-FIRED BOILERS[52]

Fuel[a]	1978 Boiler population		1980 Boiler population	
	Heat input capacity MW (10^6 Btu/hr)	Number of boilers	Heat input capacity MW (10^6 Btu/hr)	Number of boilers
Wood	30,692 (104,750)	1,600	34,164 (116,600)	1,660
Solid Waste				
MSW[b]	681 (2,325)	20	805 (2,747)	22
RDF	166 (567)	5	1,241 (4,236)	15
MSW, ISW[c]	209 (714)	57	610 (2,082)	166

[a] MSW = municipal solid waste
RDF = refuse derived fuel
ISW = industrial solid waste

[b] Does not include MSW-fired small modular incinerators (SMI) with heat recovery.

[c] Includes only SMI.

TABLE 2-6. PROJECTED ANNUAL SALES OF WOOD FUEL-FIRED BOILERS (1980 - 1990)[53]

Boiler size range, MW (10^6 Btu/hour) heat input	Average size, MW (10^6 Btu/hour)	Number of boilers	Installed capacity, MW (10^6 Btu/hour)
0-14.7 (0-50)	10.7 (36.6)	7	76.2 (260)
14.7-29.3 (50-100)	22.8 (77.7)	15	342.8 (1,170)
Total		22	419.0 (1,430)

TABLE 2-7. ESTIMATED NONFOSSIL FUEL-FIRED BOILER POPULATION IN 1984[a]

Fuel	Boiler size range, MW (10^6 Btu/hour) heat input	Number of boilers	Installed capacity 10^3 MW (10^9 Btu/hour)
Wood	0-14.7 (0-50)	1,106	5.2 (17.8)
	14.7-29.3 (50-100)	297	6.9 (23.4)
	Total	1,403	12.1 (41.2)
Solid Waste	0-14.7 (0-50)	760	3.1 (10.6)
	14.7-29.3 (50-100)	41	1.0 (3.4)
	Total	801	4.1 (14.0)

[a]Based on data presented in Reference 54.

2.3 EMISSIONS UNDER CURRENT REGULATIONS

Current regulations applicable to small boilers (with capacities of 29.3 MW heat input or less) were examined through EPA reports and computer database files. Also, a survey of EPA Regions, States, and local agencies was conducted. The purpose of this survey was to determine the current practices for regulating small boilers. This section presents the results of this review of the current regulatory environment for small boilers.

2.3.1 State Implementation Plan Limits

New boilers with heat input capacities of 29.3 MW (100 million Btu/hour) or less are not subject to new source performance standards, but are subject to State emission limits for NO_x, SO_2, and PM. Particulate emissions are typically limited by both a mass emission limit and an opacity or visible emission limit. State regulations of NO_x emissions are scarce.

State Implementation Plans (SIP's) reflect local conditions and needs. As a result, emission limits for small boilers vary considerably from State to State. Also, certain areas which are not attaining the National Ambient Air Quality Standard(s) (NAAQS) may require regulations with more stringent control technologies and/or emission limits than those required by the overall SIP.

States vary with respect to the smallest capacity boiler regulated. A common size cutoff is 0.73 MW (2.5 million Btu/hour) heat input. The actual size cutoffs contained in the State regulations are discussed in Reference 55. Compliance and enforcement practices utilized for smaller capacity size boilers were examined in a survey whose results are also presented in Reference 55.

Each state is composed of one or more Air Quality Control Regions (AQCR's). Each AQCR establishes emission limits for SO_2, PM, and NO_x in keeping with the overall requirements of the SIP. A detailed listing of emission limits arranged by AQCR and boiler size is contained in Reference 55.

2.3.2 National and Regional Average Emission Limits

To develop estimates of national SIP emission levels of SO_2, PM, and NO_x, it was necessary to average the AQCR emission limits in those States with more than one AQCR and then develop a weighted national average using industrial/commercial fuel consumption as the weighting function. It would be more accurate to weight-average AQCR emission limits by fuel consumption to develop a national average, but fuel consumption data on an AQCR basis were not available.

The details of this weighting analysis are contained in Reference 55. The results of the analysis are presented in Table 2-8 in the form of national and EPA regional average emission levels for a 29.3 MW (100 million Btu/hr) heat input boiler. The EPA regional averages are simply the fuel-weighted averages of the States' emission levels for those regions. As indicated in Table 2-8, the national average SO_2 and PM emission levels are based on the emission limits for over 90 percent of the national AQCR's (the remaining AQCR's do not have emission limits which apply to small boilers). For NO_x, however, only 13 percent of AQCR's have emission limits for coal-fired boilers; only 16 percent have limits for oil-fired boilers.

National and EPA regional averages for other boiler sizes are contained in Reference 55.

2.4 BASELINE EMISSIONS

Baseline emission levels for SO_2, PM, and NO_x are defined as those levels which are expected for new small boilers in the absence of new source performance standards but under the current mix of existing regulations.

Table 2-9 presents the baseline emission levels corresponding to each boiler size/pollutant category. The baseline SO_2 emission level for coal is based on the national average SIP emission limit for coal-fired small boilers. The national average SO_2 values range from 1,402 ng/J (3.26 lb/ $lb/10^6$ Btu) for the 29.3 MW (100 million Btu/hour) heat input capacity boiler to 1,509 ng/J (3.51 $lb/10^6$ Btu) for the 2.9 MW (10 million Btu/hour)

TABLE 2-8. NATIONAL AND EPA REGIONAL AVERAGE EMISSION LEVELS FOR A 29.3 MW (100 MILLION BTU/HOUR) BOILER[a]

EPA region number	Coal SIP ng/J (lb/10^6 Btu)			Residual oil SIP ng/J (lb/10^6 Btu)		
	PM	SO_2	NO_x	PM	SO_2	NO_x
1	99 (0.23)	1,028 (2.39)	301 (0.70)	99 (0.23)	761 (1.77)	129 (0.30)
2	138 (0.32)	1,221 (2.84)	301 (0.70)	90 (0.21)	847 (1.97)	129 (0.30)
3	90 (0.21)	1,096 (2.55)	301 (0.70)	86 (0.20)	1,049 (2.44)	129 (0.30)
4	129 (0.30)	1,505 (3.50)	NR[b]	142 (0.33)	1,217 (2.83)	129 (0.30)
5	155 (0.36)	1,161 (2.70)	NR	138 (0.32)	1,161 (2.70)	NR
6	146 (0.34)	920 (2.14)	301 (0.70)	138 (0.32)	529 (1.23)	129 (0.30)
7	181 (0.42)	2,365 (5.50)	NR	176 (0.41)	1,561 (3.63)	129 (0.30)
8	103 (0.24)	851 (1.98)	301 (0.70)	103 (0.24)	765 (1.78)	129 (0.30)
9	224 (0.52)	912 (2.12)	365 (0.85)	133 (0.31)	727 (1.69)	288 (0.67)
10	103 (0.24)	869 (2.02)	NR	73 (0.17)	709 (1.65)	NR
National Average	138 (0.32)	1,290 (3.00)	314 (0.73)	125 (0.29)	980 (2.28)	151 (0.35)
Percent of Total AQCR's Represented[c]	97	92	13	95	93	16

[a]National and EPA Regional average emission levels for other boiler sizes are contained in Reference 55.

[b]NR = Not regulated.

[c]These values represent the number of AQCR's that have emission limits applicable to small boilers.

TABLE 2-9. BASELINE EMISSION LEVELS FOR SMALL BOILERS NG/J (LB/MILLION BTU)

Fuel	Boiler size MW (10^6 Btu/hour) heat input	SO_2 Baseline	PM Baseline	NO_x Baseline
Coal	0.3 (1)	-[a]	-[a]	-[a]
	2.9 (10)	1,226 (2.85)	193 (0.45)	172 (0.400)
	7.3 (25)	1,226 (2.85)	193 (0.45)	172 (0.400)
	14.7 (50)	1,226 (2.85)	258 (0.60)	172 (0.400)
	22.0, 29.3 (75, 100)	1,226 (2.85)	258 (0.60)	286 (0.6650)
Residual Oil	0.3 (1)	-[a]	-[a]	-[a]
	2.9 (10)	1,011 (2.35)	77 (0.18)	198 (0.460)
	7.3 (25)	1,011 (2.35)	77 (0.18)	198 (0.460)
	14.7 (50)	1,011 (2.35)	77 (0.18)	198 (0.460)
	22.0, 29.3 (75, 100)	1,011 (2.35)	77 (0.18)	198 (0.460)
Natural Gas	0.3 (1)	-[a]	-[a]	60 (0.140)
	2.9 (10)	-[a]	-[a]	60 (0.140)
	7.3 (25)	-[a]	-[a]	60 (0.140)
	14.7 (50)	-[a]	-[a]	65 (0.150)
	29.3 (100)	-[a]	-[a]	71 (0.1650)
Distillate Oil	0.3 (1)	-a	-a	118 (0.2750)
	2.9 (10)	-a	-a	118 (0.2750)
	7.3 (25)	-a	-a	118 (0.2750)
	14.7 (50)	-a	-a	95 (0.2200)
	29.3 (100)	-a	-a	95 (0.2200)
Wood	7.3 (25)	-[a]	172 (0.40)	-[a]
	14.7, 29.3 (50, 100)	-[a]	159 (0.37)	-[a]
Solid Waste	7.3 (25)	-a	129 (0.30)	-a
	14.7, 29.3 (50, 100)	-a	73 (0.17)	-a

[a]Not Applicable due to very low inherent emissions.

heat input capacity boiler. The overall average coal-based SIP emission limit is 1,460 ng SO_2/J (3.4 lb $SO_2/10^6$ Btu).

To meet this limit on a continuous basis using a 30-day rolling average, prior statistical analysis indicates that a boiler operator would have to limit emissions to approximately 1,380 ng SO_2/J (3.2 lb $SO_2/10^6$ Btu) on a long-term average basis to make adequate allowances for the variability of SO_2 emissions.[56] Such a long-term average emission level could be achieved with a general class of coals whose sulfur content ranges from 1,075 ng SO_2/J (2.50 lb $SO_2/10^6$ Btu) to 1,432 ng SO_2/J (3.33 lb $SO_2/10^6$ Btu) and averages 1,226 ng SO_2/J (2.85 lb $SO_2/10^6$ Btu).[57] Thus the baseline SO_2 emissions level for small coal-fired boilers is estimated as 1,226 ng/J (2.85 lb/10^6 Btu). ?, 2.02 ?

The baseline SO_2 emission level for residual oil is also based on the national average emission limit. The average emission limits were essentially independent of boiler size. The calculated values range from 1,002 to 1,019 ng SO_2/J (2.33 to 2.37 lb $SO_2/10^6$ Btu) for the 29.3 and 2.9 MW (100 and 10 million Btu/hour) heat input boiler size, respectively. Therefore, the average of the two calculated averages was used for the baseline SO_2 emission level for residual oil. Due to the low variability of SO_2 emissions from oil combustion, no further allowances to reduce the baseline level were required. Therefore, the baseline emissions level for small residual oil-fired boilers is estimated as 1,011 ng SO_2/J (2.35 lb $SO_2/10^6$ Btu).

Baseline PM emission levels for coal and residual oil are based on both national average emission limits and emission data for PM control devices. The national average emission limits for coal range from 142 to 198 ng PM/J (0.33 to 0.46 lb PM/10^6 Btu) for the 29.3 and 2.9 MW (100 and 10 million Btu/hour) heat input boiler sizes, respectively. The PM control system typically used to meet these emission limits is a mechanical collector. Based on emissions test data presented in Section 3.1.2, baseline levels of 258 ng PM/J (0.60 lb PM/10^6 Btu) for spreader stokers and 193 ng PM/J (0.45 lb PM/10^6 Btu) for underfeed stokers were selected as representative of mechanical collector performance on these boiler types. Spreader stokers are predominant in the 7.3 to 29.3 (25 to 100 million Btu/hour) heat input size range while underfeed stokers are most prevalent in the 2.9 to 7.3 MW (10 to 25 million Btu/hour) size range. Therefore, the corresponding PM emission levels are applied to these boiler size ranges as estimates of baseline emissions.

The national average PM levels for residual oil ranged from 129 to 190 ng PM/J (0.30 to 0.45 lb PM/10^6 Btu). However, as stated above, the baseline SO_2 emission levels for residual oil correspond to the combustion of a 1,011 ng SO_2/J (2.35 lb $SO_2/10^6$ Btu) oil. The uncontrolled PM emission level associated with this oil, according to AP-42 emission factors, is 77 ng PM/J (0.18 lb PM/10^6 Btu). This baseline PM emission level for residual oil-fired boilers would be expected in consideration of the baseline SO_2 emission level.

For wood-fired boilers, the baseline PM emission levels in Table 2-9 reflect the national average SIP levels calculated in the Nonfossil Fuel-Fired Background Information Document.[58] Baseline PM emissions for solid waste-fired boilers are based on uncontrolled emissions of 129 ng PM/J (0.30 lb PM/10^6 Btu) for small modular incinerators operating in the 2.9 to 7.3 MW (10 to 25 million Btu/hour) heat input size range as discussed in Section 3.1.11. New solid waste-fired boilers larger than 45 Mg/day (50 tons/day) charging capacity, which are typically stokers or rotary combustors, are already subject to a new source performance standard (40 CFR Part 60, Subpart E) limiting emissions to 73 ng PM/J (0.17 lb PM/10^6 Btu). This limit is based on the use of an electrostatic precipitator for PM control.

The baseline NO_x emission levels for coal-, residual oil-, and distillate oil/natural gas-fired boilers represent typical operational conditions for these small boilers since so few States currently regulate NO_x emissions from this source category. The baseline emissions levels correspond to average oxygen (O_2) levels for uncontrolled boilers as specified in Section 3.3. The baseline emission level for coal corresponds to 60 percent excess air (8 percent stack gas O_2) operation. The baseline levels for residual oil, distillate oil, and natural gas correspond to 38 percent excess air (6 percent stack gas O_2) operation.

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3.0 EMISSION CONTROL TECHNIQUES

Emission control techniques applicable to small boiler sources firing both fossil and nonfossil fuels are described in this section. These descriptions include discussions of the design of each control technique, its status of development, and its applicability to small boilers. Also discussed are factors which affect the performance of the control techniques, including design parameters, operating conditions, and fuel quality. Emission data taken by approved EPA test methods to verify control technique performance are presented and discussed.

Control techniques discussed in this section are those meeting one of the following criteria:

- currently used on small boilers;
- currently applied in the industrial boiler, greater than 29.3 MW (100 million Btu/hour) heat input, source category; technology transferability is indicated;
- rapidly developing and likely to be commercially available in the next several years.

This section has three subsections, organized by pollutant. Section 3.1 discusses controls for particulate matter (PM), Section 3.2 discusses controls for sulfur dioxide (SO_2), and Section 3.3 discusses nitrogen oxides (NO_x) emissions controls.

3.1 PARTICULATE MATTER CONTROL TECHNIQUES

3.1.1 Introduction

This section will describe PM emission control techniques applicable to small boilers. These descriptions include discussions of the design of each control technique, factors which affect the performance of the control technique, and PM emission test data for control device/fuel combinations.

3.1.1.1 Particulate Matter Formation and Control Theory. Particulate matter emissions from boilers result primarily from the ash present in the fuel and from carbonaceous compounds that are the product of incomplete combustion. Sources of PM emissions and factors influencing these emissions are discussed below for oil, coal, solid waste, and wood. Table 3-1 presents AP-42 emissions factors for uncontrolled PM emissions from small boilers firing these fuels.

3.1.1.1.1 Natural gas. Particulate matter emissions from boilers firing natural gas are very low because natural gas has a negligible ash content. Also, combustion with natural gas is generally very complete. Thus, PM emissions from natural gas combustion will not be considered further.

3.1.1.1.2 Oil. Particulate matter emissions from distillate oil-fired boilers are primarily carbonaceous particles resulting from incomplete combustion of the fuel, and do not correlate with the ash or sulfur content of the fuel. However, PM emissions from residual oil-fired boilers result from incomplete combustion, ash present in the fuel, and formation of sulfates and sulfites. In general, PM emissions from distillate oil-fired boilers are lower than from residual oil-fired boilers as distillate oils tend to be lower in ash, sulfur, and carbon residue than residual oils.

Carbon residue is a fuel property obtained analytically by measuring the carbonaceous residue formed after evaporation and pyrolysis of a petroleum product. Carbon residue is the best fuel property by which PM emissions from residual oil can be predicted. The residue is not entirely composed of carbon, but is a coke which can be further changed by pyrolysis.

3.1.1.1.3 Coal. As shown in Table 3-1, PM emissions from coal-fired boilers are generally directly related to the ash content of the coal and

TABLE 3-1. AP-42 UNCONTROLLED PM EMISSIONS FACTORS FOR SMALL BOILERS[1]

Boiler type	Coal[a,b]		Oil[c,d]		Wood	Solid waste
	(lb/ton)[e]	(lb/10^6 Btu)[f]	(lb/1,000 gal)[g]	(lb/10^6 Btu)	(lb/ton)	(lb/ton)
Pulverized Coal-Fired						
Dry Bottom	10 (A)	5,000 (A)/HV	-	-	-	-
Wet Bottom	7 (A)	3,500 (A)/HV	-	-	-	-
Spreader Stoker	60	30,000/HV	-	-	-	-
Overfeed Stoker	16	8,000/HV	-	-	-	-
Underfeed Stoker	15	7,500/HV	-	-	-	-
Residual Oil-Fired	-	-	10 (S) + 3	0.0675(S) + 0.0203	-	-
Stoker	-	-	-	-	8.8	30[h]
Small Modular Incinerator	-	-	-	-	-	1.4[i]

[a]A = Percent ash content.

[b]HV = Heat content (Btu/lb).

[c]Based on Grade 6 oil; S = Sulfur content (weight percent).

[d]Based on an average heat content of 4.12×10^7 kJ/1000 m^3 (148 million Btu/1,000 gallons).

[e]To convert emissions in lb/ton to kg/Mg, multiply lb/ton by 0.5.

[f]To convert emissions in lb/10^6 Btu to ng/J, multiply lb/10^6 Btu by 430.

[g]To convert emissions in lb/1000 gal to ng/J, multiply lb/1000 gal by 2.91.

[h]Multiple chamber incinerator with uncontrolled air.

[i]Controlled air incinerator.

the boiler firing method. Poor combustion control is also a factor in PM emissions from coal-fired boilers. Although some excess air is necessary for proper combustion, minimizing PM emissions due to unburned carbon, too much combustion air can increase gas velocities in the furnace, causing fuel particles to exit the furnace prior to complete combustion. This effect is greatest if the air is injected under the coal grate. Increasing undergrate air directly affects the upward furnace gas velocities and increases fuel and particle entrainment.

3.1.1.1.4 <u>Nonfossil fuels</u>. Nonfossil fuels commonly combusted in steam generating units are wood and solid waste. Of these fuels, wood is by far the most common. However, many small manufacturing facilities fire solid waste from the manufacturing process and municipal solid waste (MSW) is fired by many municipalities.

Two major factors that influence uncontrolled PM emissions from wood-fired boilers are boiler design and operation. Most wood-fired boilers are of the spreader stoker type because of their ease of operation and relatively high efficiency (typically around 65 to 70 percent based on the energy available in the fuel).[2] In addition, spreader stokers can burn fuels with high moisture contents (up to about 65 percent), an important consideration since nonfossil fuels entering the boiler can have moisture contents of 50 percent or more.

Another design for firing wood is a fuel cell. A fuel cell boiler is a two-step process in which the wood is fired on a stationary grate using forced draft air to drive off volatiles and burn the carbon; the volatiles are then completely combusted in a second chamber. If a fuel cell boiler is used, PM emissions are generally less than those from spreader stokers.

Solid waste consists of refuse and garbage from cities, communities, and industries. Because of their similarities MSW, industrial solid waste (ISW), and refuse derived fuel (RDF) are included in the solid waste fuel category. The factors that influence PM emissions from boilers burning solid waste are boiler type, fuel quality, and boiler operation.

Boiler type defines the fuel and combustion air feed systems which in turn affect emissions of particulate matter resulting from unburned fuel, products of incomplete combustion, and entrained ash. Two types of boilers are currently used to combust MSW. The most common type is the mass burning stoker boiler. Boilers that mass burn are capable of burning solid waste fuels with large size variations. The other common boiler is the small modular boiler with multichamber controlled-air combustion. This boiler is also designed to burn the waste without extensive fuel preparation. In order to achieve good combustion with poor quality fuels, this boiler employs a two combustion chamber design. The small modular boiler has lower uncontrolled PM emissions in part due to greater combustion efficiency and in part due to lower air velocities resulting in less ash entrainment. At present, ISW is burned in this same type of small controlled air boiler. Refuse derived fuel can be co-fired with coal or burned alone in coal-fired spreader stoker boilers.[3]

The quality of solid waste fuels varies widely with resulting effects on particulate matter emissions. In general, moisture content is high (on the order of 25 percent) and heat content is low (on the order of 6700 Btu/lb) relative to fossil fuels. Moisture evaporates during combustion, increasing gas velocity in the combustion zone, impeding combustion, and increasing ash entrainments. Both moisture and heating value affect combustion and therefore particulate matter from products of incomplete combustion. Lack of uniformity within the solid waste fuels also makes it difficult to maintain complete combustion conditions. The composition of solid waste fuels can even vary with the season. For example, the yard waste component of municipal solid waste in northern states is higher in summer months than it is in winter. The non-uniform and varying fuel composition hinders complete combustion tending to increase emissions of particulate matter. The preceding discussion holds for all three categories of solid waste (MSW, ISW, and RDF); however, ISW and RDF typically are more uniform, vary less and generate fewer particulate matter emissions.

Boiler operation influences particulate matter emissions during startup. Relatively more particulate per unit heat is generated during startup prior to achieving steady operating conditions. Use of supplementary fuels, such as natural gas or oil, to ignite the solid waste fuel and to help achieve normal operating temperatures in less time will minimize startup particulate matter emissions.

The combustion air adjustment can affect particulate matter emissions during startup and during normal operation. Increasing the combustion air rate above design levels can increase particulate matter emissions by increasing the amount of fuel that is entrained and carried out of the furnace area before combustion is complete.

The commercially available systems of emission reduction for PM emissions vary by fuel type. For residual oil-fired boilers, low sulfur/low ash oil, wet scrubbers, and electrostatic precipitators (ESP's) are discussed. For coal-fired boilers, PM control techniques based on side-stream separators and fabric filters are discussed. For wood-fired boilers, PM control techniques based on wet scrubbers, ESP's, and electrostatic gravel beds are discussed. For solid waste-fired boilers, ESP's are discussed.

3.1.2 Combustion of Low Sulfur/Low Ash Oils

Combustion of low sulfur/low ash residual oils is an effective means of reducing the PM emissions from residual oil-fired boilers. Distillate fuel oils will not be discussed in this section because of their inherent low PM emission rate.

3.1.2.1 Factors Influencing PM Emissions From Oil Combustion. There are four primary sources of PM emissions from fuel oil combustion. These sources are inert ash entering with the oil, sulfates and sulfites formed from the combustion of sulfur in the oil, oil additives used to protect the boiler, and carbonaceous compounds formed from the incomplete combustion of hydrocarbons composing the oil itself.[4] A low sulfur/low ash oil fired in a boiler with good combustion techniques will reduce each of the sources of PM emissions. The fact that the oil has a low ash content will directly reduce the ash component of the PM emissions. Likewise, reduction of the sulfur content of the oil will reduce the sulfate/sulfite component of the PM emissions. A low sulfur/low ash oil is generally of a higher quality which requires fewer oil additives. Therefore, the reduction of the need for additives will reduce the additive carryover in the flue gas. Additionally, the low sulfur/low ash oil tends to have lower carbon residue and lower viscosity, which improves combustion. This improved combustibility will lower the carbonaceous products of incomplete combustion and the resulting PM emissions in the flue gas.

Previous studies on small residential and commercial boilers indicate that boiler/burner characteristics including atomization conditions, fuel-air mixing, firing rate, and furnace volume have low correlations with PM emissions.[5] Some of the variables having the greatest influence on PM emissions are carbon residue, fuel nitrogen, API gravity, and carbon content. Particulate emissions are directly related to carbon residue, fuel nitrogen, and carbon content, while API gravity is inversely related to PM emissions. The single most important fuel property influencing PM emissions is carbon residue. API gravity, the American Petroleum Institute's oil density indicator, generally reflects some of the other fuel properties (ash, sulfur, etc.) and is itself a commonly measured fuel property. The carbon residue, fuel nitrogen, and carbon content tend to be lower and the API gravity property tends to be higher for low sulfur/low ash residual oil. These fuel properties result in lower PM emissions from a low sulfur/low ash residual oil fired in small boilers.

3.1.3 Electrostatic Precipitators

3.1.3.1 Process Description. Electrostatic precipitators are high efficiency particulate collection devices applicable to a variety of boiler types and flue gas conditions. Particulate collection in ESP's occurs in three steps: application of an electrical charge to the particles, migration of the charged particles to a collecting electrode of opposite polarity, and dislodging of the particles from the electrodes into a collection hopper. Electrostatic precipitators can be either wet or dry; dry ESP's are commonly used for boiler applications. A dry ESP consists of a shell to enclose the collection and discharge systems, collecting electrodes, discharge electrodes, a high-voltage transformer-rectifier for application of electrical power, a system of rappers to dislodge the particles from the electrodes, and a hopper to collect the dislodged particles and remove them from the ESP. A typical dry ESP is shown in Figure 3-1.

As a high-voltage current passes through the discharge electrode, it produces an electrical corona of charged gas molecules which radiates from the electrode, decreasing in strength with greater distance from the electrode. The corona is generally negatively charged due to the inherently superior electrical characteristics of a negative corona over a positive corona. Flue gas particle charging and subsequent collection take place between the outer boundary of the corona and the collecting electrode, where the particle comes in contact with the negatively charged corona ions. As ions continue to impinge on the particle, the charge on it increases until it reaches a "saturation" charge (i.e., the charge on the particle so distorts the surrounding electrical field that no further ions can come into contact with it). For very fine particles, charging is generally accomplished by diffusion, or random thermal motion bringing the particle and the ion into contact. When the dust particle is sufficiently charged, it is drawn to the oppositely-charged collecting electrode, to which it adheres until activation of the rappers dislodges it, moving it down the electrode into the collection hopper.

3.1.3.2 Factors Affecting Performance. Electrostatic precipitators are commercially available and applicable to most types of boilers. Although applicable to coal, ESP's are more frequently applied on residual oil-, wood-, and solid waste-fired boilers.

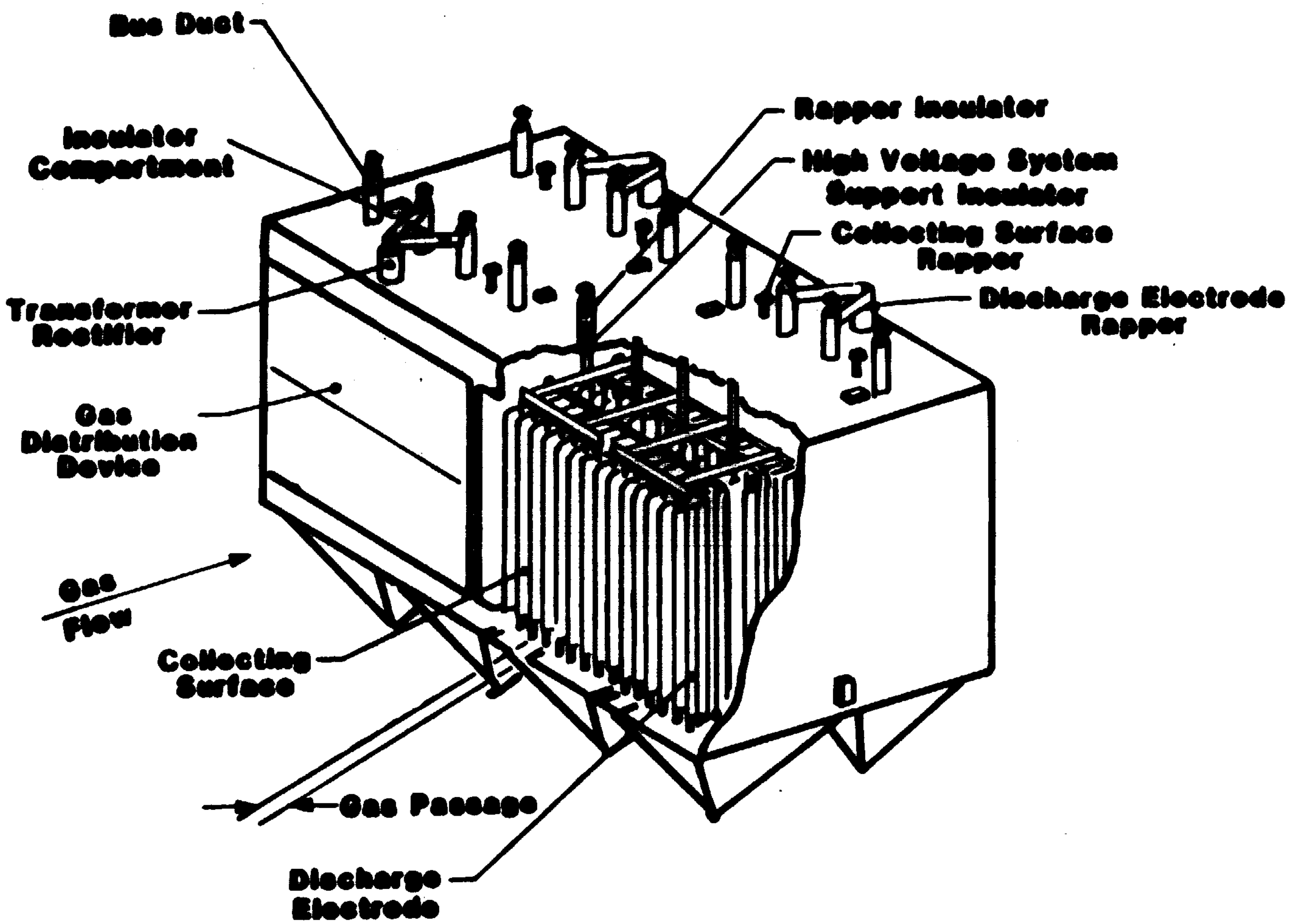


Figure 3-1. Typical dry electrostatic precipitator.[6]

Electrostatic precipitators are sensitive to variations in the resistivity of the particulate. Mechanical or cyclonic pre-collectors are generally useful on stoker-fired boilers since they tend to reduce the amount of large, low resistivity particulates that are delivered to the ESP.

Electrostatic precipitators have demonstrated very high particle collection efficiencies. In fact, collection efficiencies greater than 99 percent have been reached. Collection efficiency for an ESP is affected by a variety of factors, including particle characteristics and ESP design. Particle resistivity plays a major role in determining the suitability of an ESP. In general, particles with resistivities in the range of 10^4 to 10^{10} ohm-centimeters (ohm-cm) are the most suitable for electrostatic precipitation. The resistivity of a given particle will vary with temperature and moisture as well as the specific fuel properties of the particle. The basic factors affecting resistivity are: (1) increasing sulfur content reduces resistivity (2) increasing sodium content reduces resistivity and (3) increasing temperature increases resistivity. Flue gas temperature can be controlled by installing the ESP downstream (for lower temperatures) or upstream (for higher temperatures) of the boiler air preheater.[7]

A major ESP design factor affecting collection efficiency is the specific collection area (SCA), or the ratio of the total collection plate area to the gas flow rate. For a given application, collection efficiency improves as the SCA increases.

3.1.4 Side Stream Separators

3.1.4.1 Process Description. A side stream separator system consists of a mechanical collector followed in series by a baghouse system. Of the mechanical collectors available, multitube cyclones are the most versatile and efficient and are the devices applied in most side stream separator systems.

Cyclonic collectors use inertia to separate the particles from the gas stream. As the flue gas enters the cyclone, a spin is imparted, creating a centrifugal force which causes the particulate matter to move away from the axis of rotation and toward the walls of the cyclone. Particles contacting the walls of the cyclone drop into a dust hopper for collection and removal. The cleaned gas then makes a 180-degree turn to exit at the top of the cyclone.

In a multitube cyclone, the gas enters axially and has a spin imparted to it by a stationary "spin" vane that is in its path. This allows the use of many small, higher efficiency cyclone tubes, with a common inlet and outlet in parallel to the gas flow stream.

A typical side stream separator system is depicted in Figure 3-2. The side stream separator system typically consists of a single multitube cyclone connected to a small pulse jet baghouse. The particle-laden gas enters the cyclone and passes to the bottom of the tube in a vortex. Approximately 15 to 40 percent of the flue gas is drawn off through the bottom of the tube and enters the dust collection hopper. Dust-laden gas from the dust collection hopper containing fine particulate is ducted to the side stream baghouse. The cleaned flue gas is drawn off the top of the multitube cyclones, combined with the cleaned flue gas from the baghouse, and exhausted to a common stack.[9]

The gas stream at the bottom of the cyclonic vortex has a higher concentration of fine particles, since many of the larger particles have already been collected by the cyclone. The addition of the fabric filter to the cyclone results in increased overall efficiency. Fabric filters are discussed in more detail in the Section 3.1.5.

3.1.4.2 <u>Factors Affecting Performance</u>.[10] Most of the factors that affect performance of mechanical collectors and fabric filters also affect the performance of the side stream separator. The performance of the mechanical collector is influenced by the diameter of the tubes, the number and angle of entry vanes, construction materials, and pressure drop. Fabric filter performance is affected by air-to-cloth ratio, filter fabric, cleaning mechanism, baghouse temperature, and fuel properties.

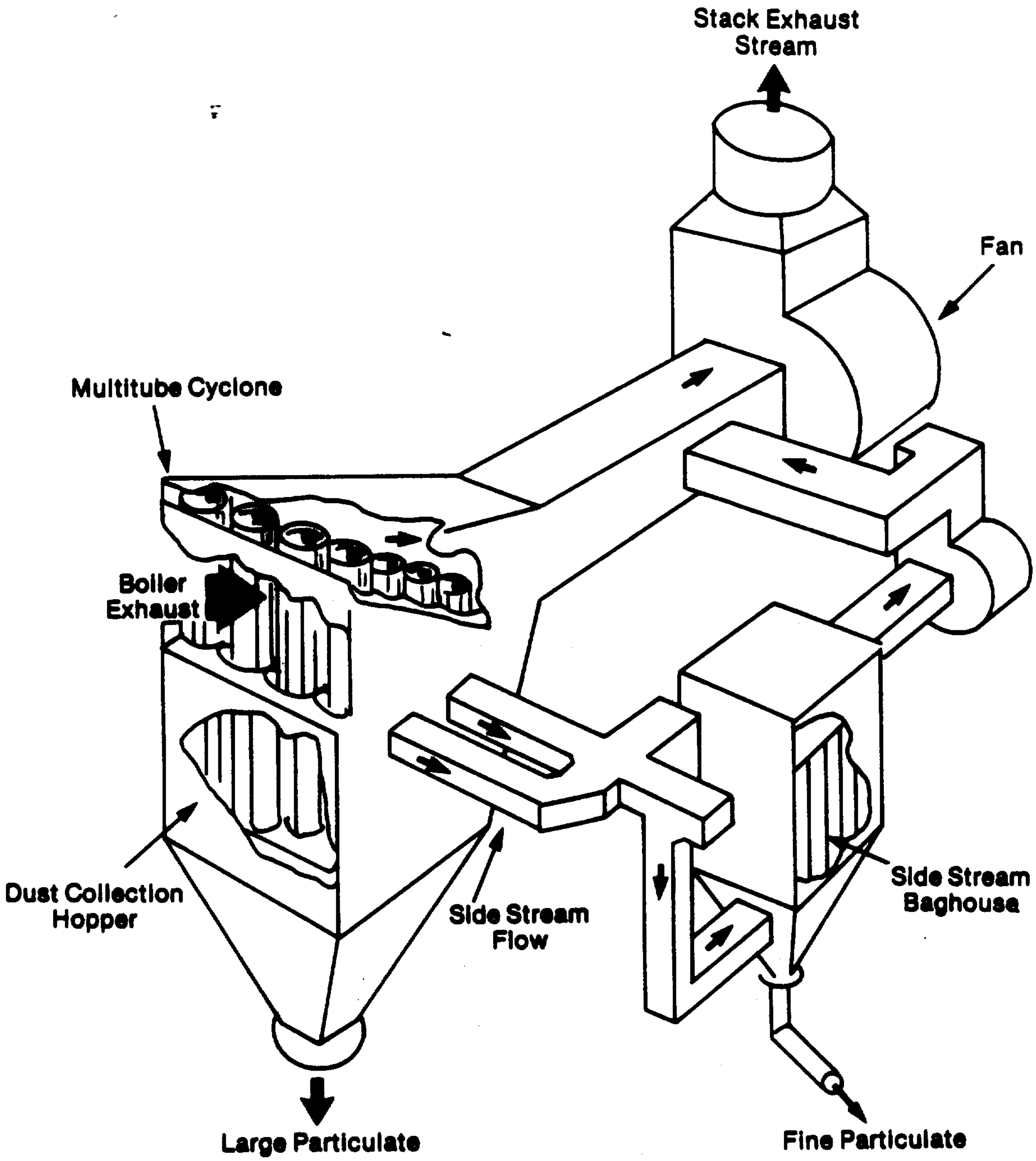


Figure 3-2. Schematic of a Typical Side Stream Separator[8]

The performance of mechanical collectors is also affected by the proportion of small fly ash particles (less than 10 microns in diameter) at the inlet to the collector. However, this factor should have less impact on side stream separators since the fabric filter used with the mechanical collector is relatively efficient with respect to fine particles.

Mechanical collector efficiency drops off rapidly at low boiler loads. Mechanical collectors rely on high flue gas velocities to achieve particle collection. This factor will result in decreased side stream separator efficiency at low loads, unless uncontrolled emissions at low loads are reduced enough to compensate for the reduced efficiency.[11] Currently, side stream separators are equipped with constant flow rate fans. Therefore, as boiler load decreases, a higher percentage of the total flow is routed to the side stream baghouse. This design option may act to compensate for reduced mechanical collector efficiency at low loads.

3.1.5 Fabric Filters

3.1.5.1 Process Description. A fabric filtration system consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure equipped with dust hoppers. Particulate-laden gas enters the collection device and passes through the bags, which retain the particles, and the cleaned gas exits through the outlet duct. Depending on the type of filtration employed, particles may be collected on either the outside or the inside of the bags.

There are three primary mechanisms of particle capture that form the basis of fabric filtration: inertial impaction, direct interception, and diffusion. Inertial impaction is generally associated with relatively larger particles. When a particulate-laden gas travels on a collision course with an interceptor (in this case the filter bag), the gas will move in a streamline around the object. However, due to their relative mass, inertia keeps the particles on a relatively straight path, forcing them into contact with the interceptor. In direct interception, smaller particles that are not subject to inertia may contact the filter element at the point of closest approach as they streamline around the bag. This occurs because the gas streamlines converge as they move around the bag, and the particle radius is greater than the distance between the gas stream and the bag. The smallest particles may be captured by diffusion. In this mechanism, particles contact the filter bag as a result of random molecular movement.[12]

As filtration proceeds, a dust layer (cake) accumulates on the bag surfaces. As this dust cake builds up, additional surface area is available to collect particles. This increases both the collection efficiency and the pressure drop across the bag surface. Since the system cannot continue to operate indefinitely with an increasing pressure drop, the bags are cleaned periodically. There are three major methods of fabric cleaning: mechanical shaking, reverse air cleaning, and pulse-jet cleaning. Each of these devices is depicted in Figure 3-3.

3.1.5.2 Factors Affecting Performance.[13] The most important design and operating factor for fabric filters is the air-to-cloth ratio (A/C). This parameter relates the volume of gas filtered (m^3/min or acfm) to the available filtering area (m^2 or ft^2). The A/C ratio is, in effect, the superficial velocity of the gas through the filtering media. Air-to-cloth ratios typically range from 0.6 to 1.2 m/min (2 to 4 ft/min) for reverse-air cleaning systems and from 1.2 to 2.4 m/min (4 to 8 ft/min) for pulse-jet cleaning systems.[14] Emission tests have shown that fabric filter collection efficiency generally improves as the air-to-cloth ratio is decreased.[15] Since the air-to-cloth ratio is greatest at maximum flue gas flow (i.e., maximum boiler load), the fabric filter must be designed to operate at the desired air-to-cloth ratio at maximum boiler load. Operation at lower boiler loads will result in a lower air-to-cloth ratio and a collection efficiency equal to or greater than that at maximum boiler load (provided all fabric filter compartments are kept on line during reduced load operation to maintain the same available cloth area).

Variations in fuel properties also affect fabric filter performance. Fuel sulfur content dictates the flue gas SO_2 content and subsequent acid condensation temperature. The baghouse temperature must be maintained above

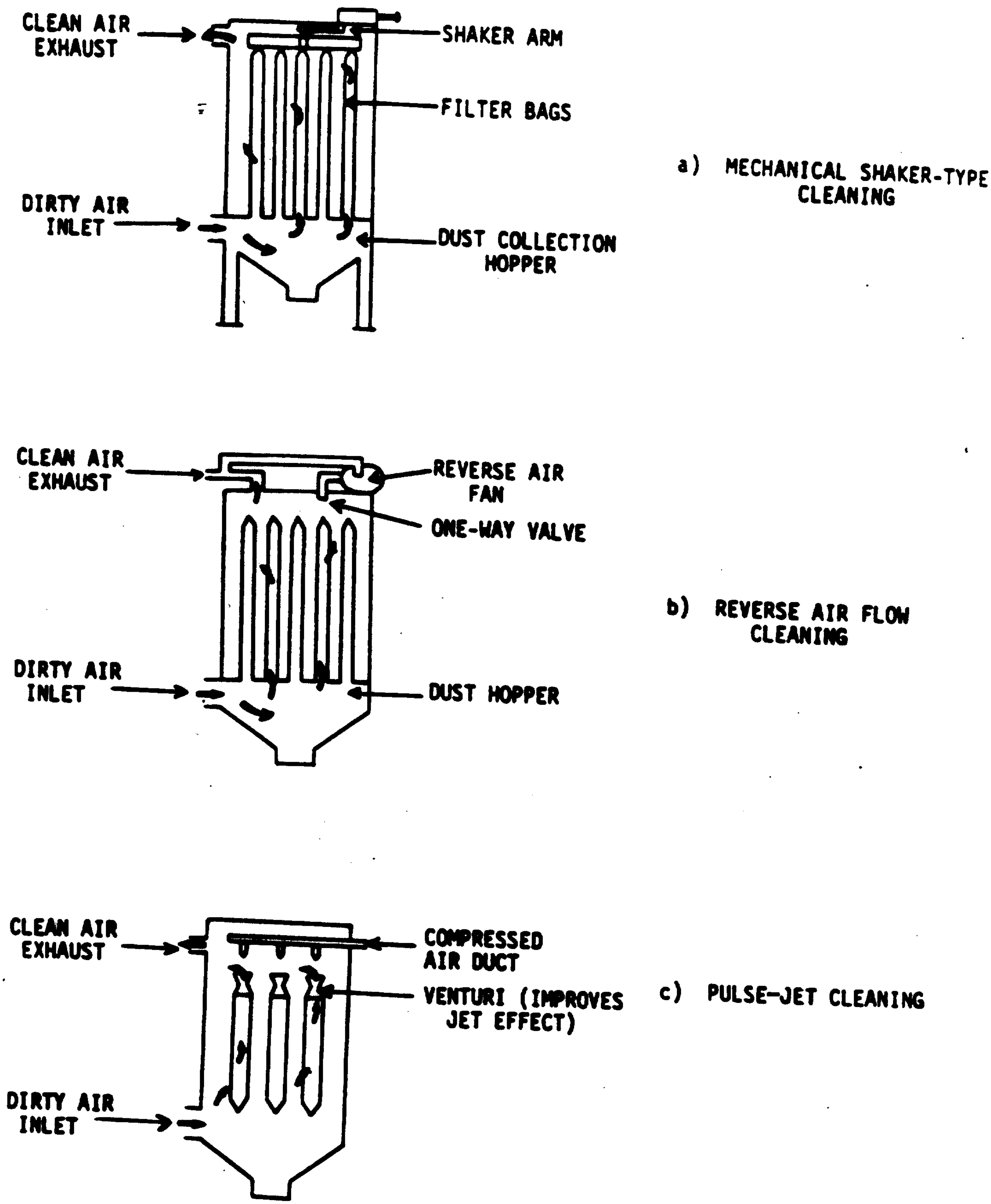


Figure 3-3. Types of fabric filtration systems.

the acid condensation point in order to reduce corrosion in the baghouse and ductwork and to reduce bag wear and destruction. This is especially important during startup and shutdown operations when the temperature is most likely to fall below the acid condensation temperature. If acid condensation occurs after shutdown, the acid mist moisture eventually evaporates and crystallization on the bag filter may occur. In this situation, the bag filter may become brittle and subject to cracking when stress is once again applied.[16]

The composition and weave of filter material helps determine the life and collection efficiency of the filter system. In general, material is chosen to withstand the specific flue gas environment expected to be encountered. Mechanical strength is also an important factor with respect to the structural demands exerted on the fabric by the gas flow and cleaning system. The bag material used in coal-fired boiler applications is usually fiberglass with a coating of silicone, graphite, and/or teflon.[17] Teflon coated felt bags are used in some pulse jet systems.

In general, nonwoven fabrics (i.e., felt) are the most efficient particle collectors; however, they also are the most difficult to clean. Texturized filament fabrics (i.e., teflon coated fiberglass) represent a middle ground in cleanability, durability and efficiency.

Most fabrics are efficient in collecting a wide range of sub-micron particles. Emission tests conducted on a 63,100 kg steam/hr (139,000 lb steam/hr) spreader stoker equipped with a reverse-air fabric filter demonstrated that for particles in the 0.02 to 2 micron range, fabric filter fractional efficiency did not fall below 99.9 percent.[18]

3.1.6 <u>Wet Scrubbers</u>

3.1.6.1 <u>Process Description</u>.[19] A wet scrubber is a collection device which uses an aqueous stream or slurry to remove particles and/or gaseous pollutants. Wet scrubbers for particulate collection commonly operate under three basic collection mechanisms: direct interception, inertial impaction, and diffusion. There are many types of wet scrubbers, but the ones primarily used for PM control on small boilers are gas-atomized spray scrubbers (e.g., venturi and flooded disc scrubbers) and fixed-bed absorbers (e.g., sieve tray units).

In a typical venturi scrubber, illustrated in Figure 3-4, gas entering the venturi is accelerated until it reaches its maximum velocity in the venturi throat. Scrubbing liquid (usually water) is atomized by the high velocity gas stream to produce droplets which act as targets for the interception and inertial impaction of particulate. These droplets, with their attached particulate matter, are then removed from the gas stream by centrifugal action in a cyclone separator or by impaction on a mist eliminator. Venturi scrubbers are the most common wet scrubbing systems applied for particulate control on small boilers.

3.1.6.2 Factors Affecting Performance. Wet scrubbers are applicable to coal-, oil-, and wood-fired boilers. Wet scrubbers have particulate collection efficiencies ranging from less than 50 percent to greater than 99 percent for particles smaller than 10 microns, depending primarily on the type of scrubber, the particle size distribution, the gas phase pressure drop, and the liquid-to-gas (L/G) ratio. The scrubber types most suited to particulate control on small boilers are venturis and plate towers. Venturi scrubbers are the most effective for removal of particulates less than 1 micron in diameter. However, venturi scrubbers generally consume more energy than plate towers.

The major factor influencing particulate removal efficiency for venturi scrubbers is the gas phase pressure drop. Removal efficiency increases with increasing gas phase pressure drop (and subsequent increasing energy requirements). Most venturis are equipped with a variable throat system to control pressure drop, allowing a constant pressure drop and PM control efficiency to be maintained at varying boiler loads.

A method of increasing particulate removal efficiency in a plate tower is to increase the pressure drop across a single tray, by raising the weir height and the liquid head that the gas must overcome when passing through the tray. Alternatively, efficiency may be increased by using a smaller diameter tower, thereby increasing the velocity of the gas through the tray.

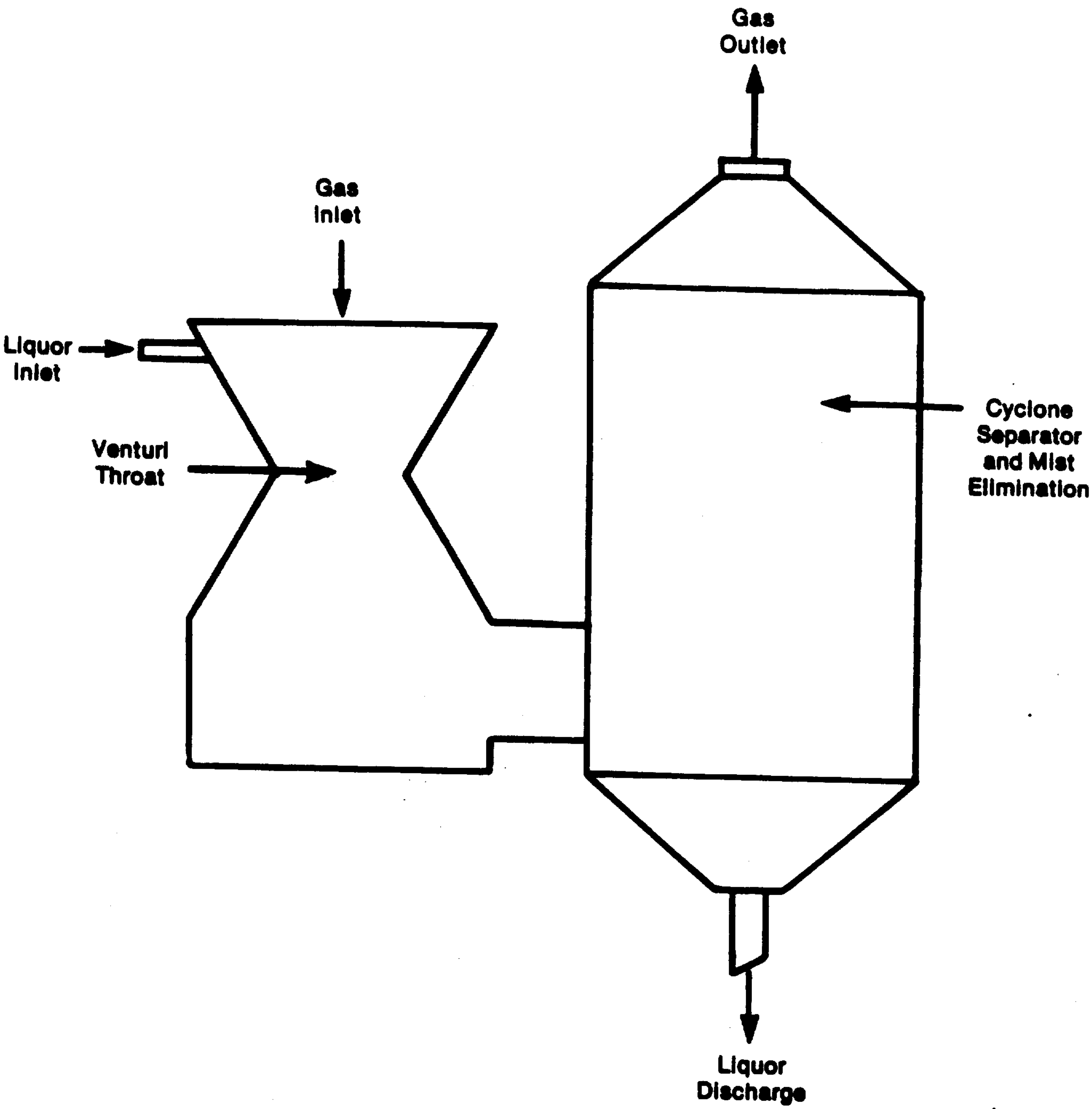


Figure 3-4. Typical Venturi Scrubber.

3.1.7 Gravel-Bed and Electrostatic Gravel-Bed Filtration

3.1.7.1 Process Description.[20] Gravel-bed and electrostatic gravel-bed (EGB) filters remove particulate matter from gas streams in a dry form using a moving bed or filter media. Electrostatic filters additionally feature an electrically-charged grid within the gravel bed to augment collection by impaction. A typical EGB filter is shown in Figure 3-5.

The gravel-bed filter or electrostatic gravel-bed filter consists of two concentric louvered cylindrical tubes contained in a cylindrical vessel. The annular space between the tubes is filled with pea-sized gravel media. Particulate-laden gas enters the filter through breeching and is distributed to the filter face by a plenum section formed by the outer louvered cylinder and the vessel wall. Particulate matter is removed from the gas stream by impaction with the media. The PM-laden media exits the bottom of the gravel-bed vessel and is pneumatically conveyed to a de-entrainment vessel through a vertical lift pipe. The particulate matter is removed from the gravel media by the abrasion of media as it is conveyed up the lift pipe, by the scrubbing action of the air as it lifts the media, and by a rattler section in the de-entrainment vessel. The gravel media falls from the conveyor air stream by gravity and is returned to the filter bed. The separated PM is air conveyed to a storage silo where it is removed from the air stream by fabric filtration.[21]

3.1.7.2 Factors Affecting Performance.[22] The principal factors affecting performance are:

- the grid voltage;
- the particle size of the particulate matter;
- the air/media ratio;
- the pressure drop across the media; and
- the extent of particulate separation from the spent media.

The effects of the first two factors are shown in Figure 3-6. Particle

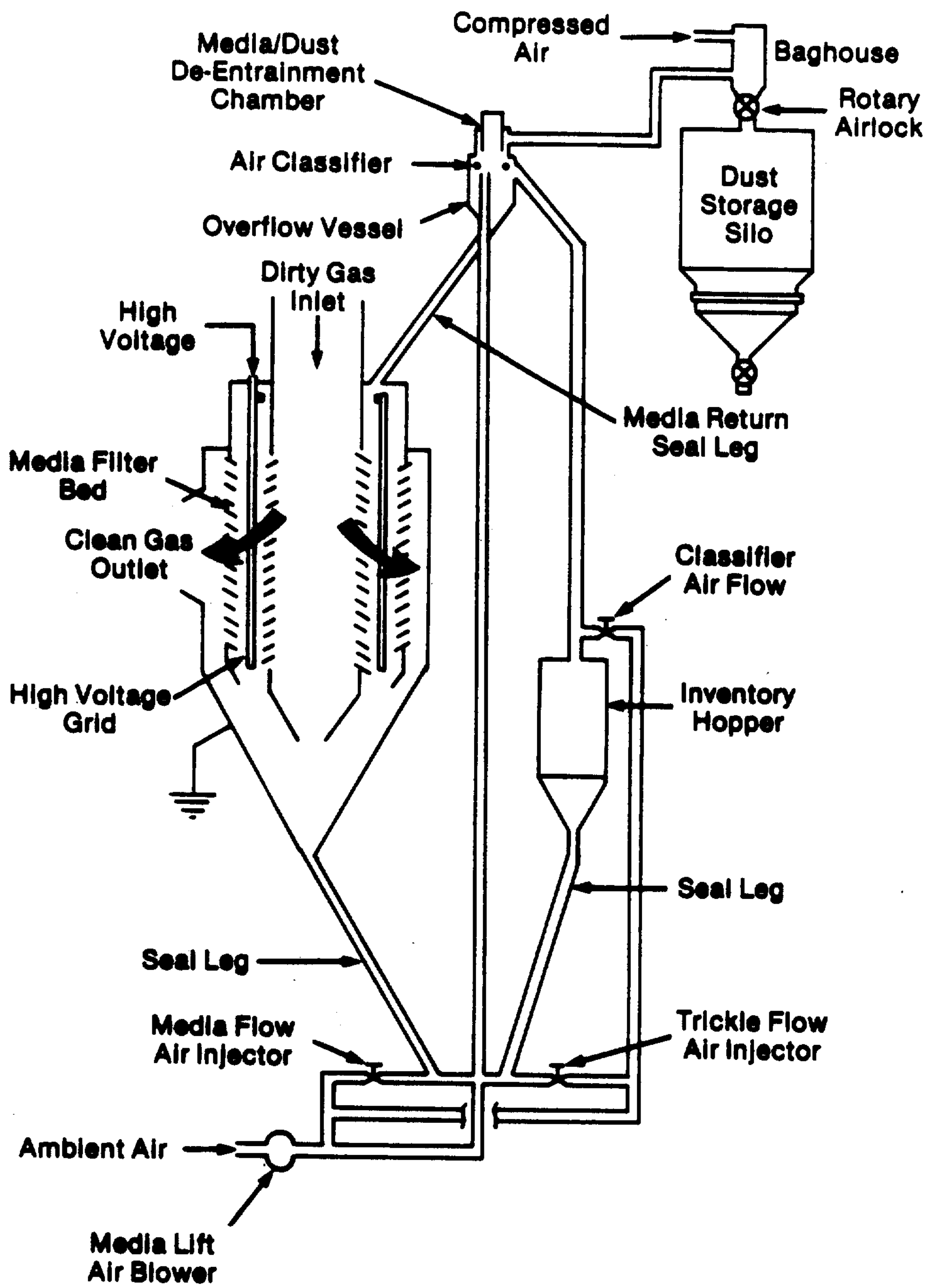


Figure 3-5. Schematic of an electrostatic gravel bed filter.

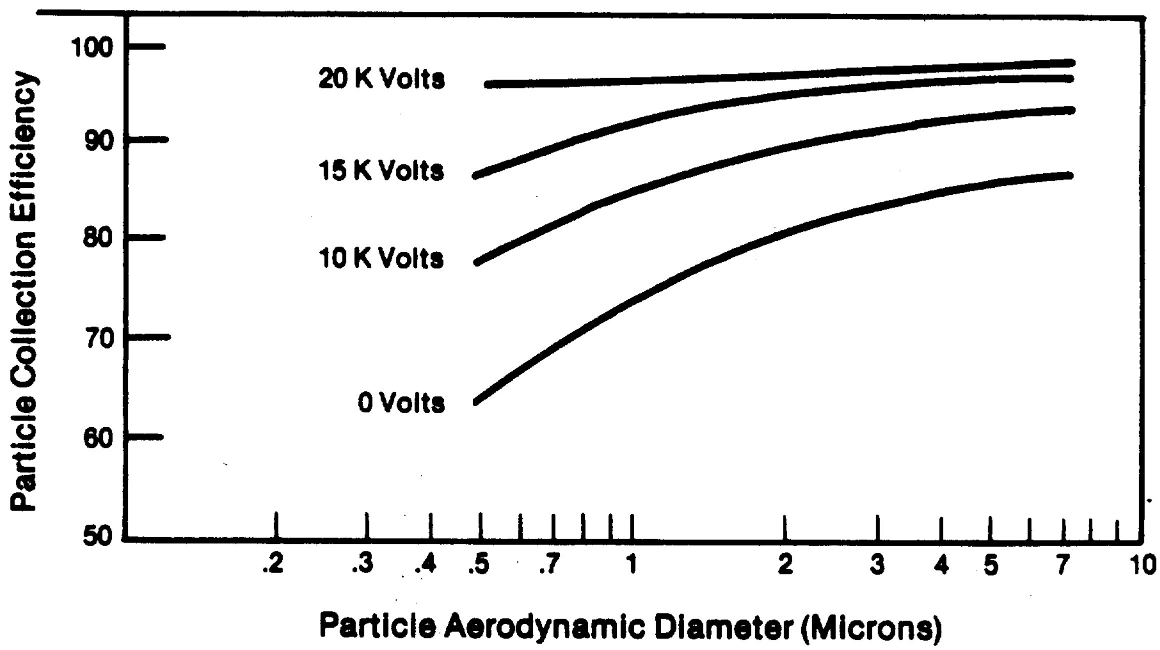


Figure 3-6. Fractional collection efficiency curves for the Electroscrubber™, electrostatic granular filter (courtesy of Combustion Power Company, Inc.).[23]

collection efficiency increases with increasing particle size and increasing grid voltage. Based on theoretical considerations and on data for ESP's and other PM control devices, particle collection efficiency should increase with decreasing air/collection media ratios and increasing gas-phase pressure drop.

3.1.8 PM Emission Test Data for Oil-Fired Boilers

This section summarizes the available data for both uncontrolled and controlled PM emissions from small oil-fired boilers. Data on controlled PM emissions from oil-fired boilers are limited since the average uncontrolled PM emission levels do not exceed the PM emission limits contained in most State Implementation Plans (SIP's).

The emission factors for oil-fired boilers were summarized in Table 3-1. Emissions from residual oil-fired boilers are expressed as a function of the sulfur contents of the fuel.

3.1.8.1 Low Sulfur/Low Ash Oil Test Data. Table 3-2 presents a summary of the PM emissions from residual oil-fired boilers with heat inputs of 29.3 MW (100 million Btu/hr) or less with no add-on control device. The data are presented by increasing PM emission results. The sulfur contents of the fuel oils range from about 0.2 to 2.2 percent. Fuel ash contents range from 0.007 to 0.3 percent by weight. Particulate emission rates based on EPA Method 5 (front half catch) results range from 8.6 to 61.5 ng/J (0.020 to 0.143 $lb/10^6$ Btu).

3.1.8.2 Electrostatic Precipitator Test Data. This section presents data from emission tests performed on oil-fired boilers equipped with ESP's. Most of the data available for ESP's on oil-fired units were gathered in a study of utility boilers, but the technology is directly transferable to small oil-fired boilers.[27] ESP performance is dependent primarily on SCA, irrespective of boiler size. The performance data for utility boiler ESP's therefore define small boiler ESP performance as well.

TABLE 3-2. PM EMISSIONS FROM SMALL RESIDUAL OIL-FIRED BOILERS (WITH NO ADD-ON CONTROL DEVICE)

Company	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel sulfur (wt. %)	Gravity (°API)	Fuel ash (wt. %)	Carbon residue (Conradson, %)	Fuel heat content (Btu/lb)	Test load (percent of design capacity)	Filterable particulate emissions (lb/10^6 Btu)[a]	Reference
19-2	6 (22)	0.37	29.2	0.009	1.61	19,365	80	0.020[b]	24
19-2	6 (22)	0.37	29.2	0.009	1.61	19,365	80	0.031	24
26-1	6 (22)	1.46	13.2	0.007	3.79	18,200	160	0.045	24
26-2	4 (13)	1.46	13.2	0.007	3.79	18,200	108	0.051	24
Borden Chemical	27 (94)	1.54[c]	NA	NA	NA	NA	NA	0.052	25
DuPont	27 (94)	2.19	NA	NA	NA	NA	NA	0.055	25
Monsanto	14 (47)	0.45	NA	NA	NA	NA	NA	0.057	25
19-1	6 (22)	0.78	NA	0.025	NA	18,819	80	0.064	24
26-1	6 (22)	1.46	13.2	0.007	3.79	18,200	79	0.064	24
Eastman Gelatin	27 (94)	0.93	NA	0.034	NA	NA	NA	0.069	25
20-4	29 (100)	1.49	15.0	0.019	9.92	18,500	63	0.070	24
Borden Chemical	27 (94)	1.02	NA	NA	NA	NA	NA	0.072	25
Univ. of Mass.	27 (94)	1.06	NA	0.30	NA	NA	NA	0.072	25
Eastman Gelatin	27 (94)	0.89	NA	0.043	NA	NA	NA	0.073	25
20-4	29 (100)	1.60	15.1	0.25	9.00	18,660	NA	0.074	24
24-TV	3 (12)	1.30	22.4	0.26	5.36	18,760	103	0.085	24
38-1	16 (56)	1.88	NA	0.05	NA	18,467	89	0.085	26
General Dynamics	27 (94)	1.0	NA	NA	NA	NA	NA	0.086	25
38-2	16 (56)	0.19	25.7	0.08	8.53	19,227[d]	80	0.090	24
Polaroid	14 (47)	0.70	NA	NA	NA	NA	NA	0.092	25
Eastman Gelatin	27 (94)	1.11	NA	0.044	NA	NA	NA	0.103	25
37-2	15 (50)	1.91	NA	0.07	NA	18,500	80	0.118	26
Polaroid	14 (47)	0.70	NA	NA	NA	NA	NA	0.143	25

[a]Based on EPA Method 5 (front half catch).

[b]Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[c]NA = Not available.

[d]Assuming density = 971.5 kg/m^3 (8.1 lb/gal).

Table 3-3 presents a summary of PM emissions from oil-fired boilers based on the use of ESP's. The controlled PM emission rates based on the use of ESP's range from 17.6 to 30 ng/J (0.041 to 0.07 lb/10^6 Btu). Design data relative to precipitator SCA are available for only one test site. The Boston Mystic No. 7 unit is a cold side ESP with design SCA of 435 m^2/1000 m^3/s (133 ft^2/1000 acfm). The controlled PM emission rates from this unit ranged from 17.6 to 21 ng/J (0.041 to 0.049 lb/10^6 Btu) based on EPA Method 5 results.

3.1.8.3 Wet Scrubber Test Data. Table 3-4 presents a summary of PM emissions from small residual oil-fired boilers using wet scrubbers designed primarily for SO_2 removal. The data apply to boilers ranging in size from 6.5 to 16.7 MW (22 to 57 million Btu/hr) heat input. All of the boilers fire medium to high sulfur fuel oil. The sulfur contents range from 1.10 to 2.80 weight percent. All of the scrubbers have SO_2 removal efficiencies ranging from 85 to 99 percent. The controlled PM emissions range from 13 to 185 ng/J (0.03 to 0.43 lb/10^6 Btu) input.

Tray tower scrubbers have PM emission rates of 26 to 43 ng/J (0.06 to 0.10 lb/10^6 Btu). Data from venturi scrubbers ranged from 13 to 56 ng/J (0.03 to 0.13 lb/10^6 Btu) for controlled PM emissions. Data from two spray baffle scrubbers showed controlled PM emissions of 30 and 39 ng/J (0.07 and 0.09 lb/10^6 Btu).

3.1.9 PM Emission Test Data for Coal-Fired Boilers

3.1.9.1 Side-Stream Separator Test Data. Table 3-5 presents PM emissions data, fuel specifications, and boiler sizes for coal-fired boilers equipped with side stream separators. The emissions data range from 52 to 71 ng/J (0.120 to 0.165 lb/10^6 Btu), with an average 58 ng/J (0.136 lb/10^6 Btu). All eight units were tested using EPA Method 5. The results were provided by industry from seven stoker boilers using retrofitted side stream separators.[35]

TABLE 3-3. SUMMARY OF PARTICULATE EMISSION TEST DATA FOR ELECTROSTATIC PRECIPITATORS APPLIED TO OIL-FIRED BOILERS

Company	Number of units	Boiler capacity, MW (10^6 Btu/hr) heat input	Filterable particulate emissions (lb/10^6 Btu)[a]	Control efficiency (%)	Fuel (% Sulfur)	Fuel (% Ash)	Test load MW (10^6 Btu/hr) heat input	Reference[b]
Polaroid Corp.	2	28 (94)	0.055	40	0.7	NA[d]	NA	28
New Bedord			0.070	51	0.7	NA	NA	
Boston Edison[c]	1	1610 (5500)	0.041[e]	83[f]	2.0	0.08	1630 (5580)	29
Mystic Station			(0.012)[e]	NA	2.0	0.08		
Unit No. 7	1	1610 (5500)	0.045[e]	69[f]	2.0	0.09	1640 (5590)	
			(0.009)[e]	NA	2.0	0.09		
	1	1610 (5500)	0.049[e]	78[f]	2.0	0.10	1610 (5490)	
			(0.014)[e]	NA	2.0	0.10		
Hartford Electric Light Co.	1	328 (1120)	0.070	NA	1.95[g]	0.09	NA	28
Middletown Station	1	322 (1100)	0.057	NA	1.86[g]	0.07	NA	
	1	328 (1120)	0.067	NA	1.79[g]	0.07	NA	

[a]Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[b]Reference 28 cited in Technology Assessment Report for Industrial Boiler Applications: Particulate Collection.

[c]Design SCA is 435 $m^2/(1000\ m^3/s)$ (133 $ft^2/10^3$ ACFM). The ESP is a cold side unit controlling a high sulfur, high vanadium residual oil.

[d]NA = Not available.

[e]Data collected with EPA Method 5 train with filter temperature of about 320°F; following collection, filters were baked per EPA Method 5b; results in parenthesis are EPA Method 5b results.

[f]Efficiency calculation based on low temperature EPA Method 5 inlet and outlet data.

[g]Oil additives used to prevent boiler fouling and corrosion.

TABLE 3-4. PARTICULATE EMISSIONS FROM SO_2 WET SCRUBBERS APPLIED TO RESIDUAL OIL-FIRED BOILERS

Company	Number of units	Boiler capacity, MW (10^6 Btu/hr) heat input	Scrubber type	Design particulate control efficiency (%)	Fuel sulfur (wt. %)	SO_2 removal (%)	Test load percent of design capacity	Controlled particulate emissions ($lb/10^6$ Btu)[a]	Reference[b]
Chevron	7	15 (52)[c]	Venturi Scrubber	40	1.10	92.0	NA	0.03	30
Gen A-1, Run 1	1	17 (57)	Steam Venturi Eductor with Spray Tower	91	1.10	99.0	86	0.04	31
Run 3	1	17 (57)	Steam Venturi Eductor with Spray Tower	92	1.10	99.0	83	0.04	31
Run 5	1	17 (57)	Steam Venturi Eductor with Spray Tower	76	1.10	99.0	70	0.06	31
Run 6	1	17 (57)	Steam Venturi Eductor with Spray Tower	70	1.10	99.9	80	0.07	31
C-50, Run 1	1	17 (57)	Steam Venturi Eductor with Spray Tower	89	2.80	99.9	104	0.06	31
Run 3	1	17 (57)	Steam Venturi Eductor with Spray Tower	77	2.80	99.9	106	0.13	31
Union #12,									
Run 1	1	15 (50)	Heater Tech. Caustic Scrubber, Venturi	40	1.65	95	92	0.08	32
Run 2	1	15 (50)	Heater Tech. Caustic Scrubber, Venturi	40	1.65	95	90	0.08	32
#23, Run 1	1	7 (25)	Koch Caustic Scrubber, Tray Tower (3 Trays)	40	1.46	98	91	0.10	33
Run 2	1	7 (25)	Koch Caustic Scrubber, Tray Tower (3 Trays)	40	1.46	98	92	0.06	33
#24, Run 1	1	15 (50)	Anderson 2000 Caustic Scrubber, Spray Baffle	40	1.46	96	87	0.07	33
	1	15 (50)	Anderson 2000 Caustic Scrubber, Spray Baffle	40	1.46	96	84	0.09	33
#30, Run 1	1	15 (50)	Heater Tech. Caustic Scrubber, Venturi	40	1.34	92	90	0.09	32
	1	15 (50)	Heater Tech. Caustic Scrubber, Venturi	40	1.34	92	92	0.09	32
#33, 37, Run 2	5	15 (50)	Koch Caustic Scrubber, Tray Tower (3 Trays)	40	1.14	99	90	0.06	34
Run 4	5	15 (50)	Koch Caustic Scrubber, Tray Tower (3 Trays)	40	1.14	99	90	0.07	34
Run 6	5	15 (50)	Koch Caustic Scrubber, Tray Tower (3 Trays)	40	1.14	99	89	0.06	34

NA = Not available.

[a]Based on EPA Method 5 (front half catch). Multiply $lb/10^6$ Btu by 430 for conversion ng/J.

[b]References 30 to 34 were cited in the SO_2 Technology Update Report (July 30, 1984).

[c]Test load heat input.

TABLE 3-5. PM EMISSIONS DATA FOR SIDE STREAM SEPARATORS APPLIED TO SMALL COAL-FIRED BOILERS

Plant	Boiler size, MW (10^6 Btu/hr) heat input	Fuel			Test load range (percent of design capacity)	Boiler type[b]	Controlled particulate emissions (lb/10^6 Btu)[c]	Percent of flow to baghouse	Reference[d]
		Percent ash	Percent sulfur	Heating value (Btu/lb)[a]					
Gen Motors (DDD)	15 (50)	9.7	0.8	12,900	68	SS	0.120	16	36
Gen Motors (EEE-1)	15 (50)	9.0	1.8	12,400	84-93	SS	0.120	37	36
Gen Motors (GGG)	20 (70)	4.3	0.9	13,700	74-80	SS	0.120	30	36
Gen Motors (CCC)	23 (80)	10.1	0.8	11,400	71-80	SS	0.130	31	36
Gen Motors (EEE-3)	18 (60)	8.8	2.1	12,400	99-105	SS	0.142	51	36
Gen Motors (BBB-3)	18 (60)	7.8	0.8	13,100	97-108	SS	0.165	17	36
Gen Motors (FFF)	29 (100)	6.1	1.7	13,100	85-97	SS	0.156	15	36
Milliken & Co.	9 (31)	7.8	1.3	13,200	100	SS	0.120	NA[e]	37

[a]Multiply Btu/lb by 2.323 for conversion to kJ/kg.

[b]SS = Spreader Stoker

[c]Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[d]Reference 36 cited in the Fossil Fuel-Fired Industrial Boilers - Background Information, Volume 1.

[e]NA = Not available.

The results show that under relatively steady state conditions, average emissions from newly installed and adjusted collectors applied to boilers firing a low ash/low sulfur coal were less than 73 ng/J (0.17 lb/10^6 Btu) at all seven locations. Average emissions during the tests ranged from 52 to 73 ng/J (0.12 to 0.17 lb/10^6 Btu). The boilers tested operated under relatively steady state conditions and at boiler loads at or above 68 percent. No data were collected for low load or variable load operations. Percent ash in the fuel varied from site to site and ranged from 4.3 to 10.1 percent. The percent of the total flow sent to the baghouse also varied from site to site and ranged from 15 to 51 percent. It should be noted that extensive adjustment of the existing mechanical collectors was required to achieve the emission levels shown in Table 3-5.[38]

These data show that side stream separators on small coal-fired stoker boilers can achieve emission levels ranging from 51.6 to 73.1 ng/J (0.12 to 0.17 lb/10^6 Btu). These data were obtained under a relatively wide range of boiler operating conditions, with flue gas flow rates of up to 50 percent to the baghouse.

3.1.9.2 Fabric Filter Test Data. Table 3-6 presents PM emissions test data, boiler size, and fuel specifications for five coal-fired boilers and two fluidized bed combustors equipped with fabric filters. These data show PM emissions from fabric filters that range from 4.1 to 15 ng/J (0.010 to 0.035 lb/10^6 Btu). For the four coal-fired spreader stoker boilers, the fabric filters were operated with air-to-cloth (A/C) ratios of 0.7 to 1.1 meters per minute (m/min) (2.3 to 3.6 feet per minute [ft/min]).

3.1.9.3 Electrostatic Precipitator Test Data.[39] Table 3-7 presents PM emissions test data from coal-fired boilers equipped with ESP's. Particulate emissions ranged from 3 to 19 ng/J (0.006 to 0.044 lb/10^6 Btu). All test results were obtained with EPA Method 5 test methods.

Four of the tests were conducted on boilers with the ESP located downstream of the air preheater (cold side ESP). The two tests at Plant N were conducted on the ESP located upstream of the air preheater (hot side

TABLE 3-6. PM EMISSIONS DATA FOR FABRIC FILTERS APPLIED TO COAL-FIRED BOILERS

Plant	Boiler size, MW (10^6 Btu/hr) heat input	Fuel			Test load range (percent of) design capacity)	Boiler type[b]	Controlled particulate emissions (lb/10^6 Btu)[c]	Air/Cloth ratio (ACFM/ft^2)		Reference[d]
		Percent ash	Percent sulfur	Heating value (Btu/lb)[a]				Design	Actual	
DuPont (EE-2)	19 (64)	6.9	2.8	13,600	98-100	SS	0.015	3.4	3.4	40
Formica (J2-4)	19 (65)	6.9	0.8	NA[e]	84-96	SS	0.033	2.5	2.3	41, 42
DuPont (EE-4)	37 (125)	7.0	2.6	13,500	77-78	SS	0.010	3.7	2.9	40
DuPont (EE-5)	45 (181)	6.5	2.9	13,800	96	SS	0.028	3.7	3.6	40
SOHIO	33 (115)	12.3	3.6	11,900	71	FBC	0.019	NA	NA	43
World Carpets	13 (48)	8.3	0.6	13,700	74	SS	0.016	NA	NA	44
California Portland	59 (208)	8.8	0.4	12,200	99	CFB	0.035	NA	NA	45

[a] Multiply Btu/lb by 2.323 for conversion to kJ/kg.

[b] SS = Spreader Stoker; FBC = Fluidized Bed Combustor; CFB = Circulating Fluidized Bed Combustor.

[c] Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[d] Reference 36 cited in the Fossil Fuel-Fired Industrial Boiler - Background Information, Volume I.

[e] NA = Not available.

TABLE 3-7. PM EMISSIONS DATA FOR ELECTROSTATIC PRECIPITATORS APPLIED TO COAL-FIRED BOILERS

Plant	Boiler size, MW (10^6 Btu/hr) heat input	Fuel			Test load range (percent of design capacity)	Boiler type[b]	Controlled particulate emissions ($lb/10^6$ Btu)[c]	Specific collection area ($ft^2/10^3$ ACFM)[d]		Reference[e]
		Percent ash	Percent sulfur	Heating value (Btu/lb)[a]				Design	Operating	
Monsanto (K-7)	27 (92)	12.0	NA[f]	12,500	103-106	SS	0.007	132	128	46
Monsanto (K-8)	35 (120)	11.2	~1.0	12,500	93-98	SS	0.006	156	160	46
Monsanto (K-9)	46 (156)	11.4	0.57	11,400	99-102	SS	0.012	128	128	46
KVB Plant P	73 (250)	6.6	0.73	13,100	87-89	SS	0.021	349	397	47
KVB Plant N[g]	110 (375)	8.3	0.54	10,200	76	SS	0.044	344	542	48
KVB Plant N[g]	110 (375)	5.4	0.63	10,600	52-59	SS	0.018	344	634	48

[a] Multiply Btu/lb by 2.323 for conversion to kJ/kg.

[b] SS = spreader stoker.

[c] Multiply $lb/10^6$ Btu by 430 for conversion to ng/J.

[d] Multiply $ft^2/10^3$ ACFM by 3.2729 for conversion to $m^2/(1,000\ m^3/s)$.

[e] References 46 to 48 are cited in the Fossil Fuel-Fired Industrial Boiler - Background Information, Volume I.

[f] NA = Not available.

[g] All tests done on a hot side ESP.

ESP). Operating specific collection areas of the cold side ESP's ranged from 419 to 1300 $m^2/(1000\ m^3/s)$ (128 to 397 $ft^2/1000$ acfm). The hot side ESP at Plant N operated with SCA's of 1770 and 2080 $m^2/(1000\ m^3/s)$ (542 and 634 $ft^2/1000$ acfm).

All of the emission tests shown in Table 3-7 were conducted on boilers firing low sulfur coals (1 percent sulfur or less). A larger collection area is generally required to achieve a given particulate collection efficiency on low sulfur coal units than on high sulfur coal units.[49] Thus, the achievable emission control levels shown in Table 3-7 would be achievable on boilers firing high sulfur coal with SCAs equal or less than those shown.

The emission tests demonstrate that a cold side ESP with an SCA of at least 1310 $m^2/(1000\ m^3/s)$ (400 $ft^2/1000$ acfm) is capable of achieving PM emission levels ranging from 3 to 9 ng/J (0.006 to 0.021 $lb/10^6$ Btu) on small coal-fired boilers. A hot side ESP with an SCA of at least 2090 $m^2/(1000\ m^3/s)$ (640 $ft^2/1000$ acfm) could achieve emission levels ranging from 7 to 19 ng/J (0.018 to 0.044 $lb/10^6$ Btu).

3.1.10 PM Emission Test Data for Wood-Fired Boilers

3.1.10.1 Wet Scrubber Test Data. Table 3-8 presents PM emissions data from wood-fired boilers equipped with wet scrubbers. Particulate emissions range from 21 to 91 ng/J (0.048 to 0.212 $lb/10^6$ Btu).

All boilers reported are spreader stokers and the PM control systems consist of a mechanical collector followed by the wet scrubber. Fly ash reinjection is employed at all sources except at plants AC1 and AC2 in Table 3-8. All data were obtained using EPA Method 5, with most of the test results supplied through industry tests.

As shown in the table, wet scrubbers with operating pressure drops from 1.5 to 16 kPa (6 to 26 inches of water) consistently show emission levels of below 90 ng/J (0.21 $lb/10^6$ Btu). The scrubbers generally exhibit increasing PM emissions levels with decreasing pressure drop. These emission test data demonstrate that wet scrubbers with pressure drops between 1.5 and

TABLE 3-8. PM EMISSIONS DATA FOR WET SCRUBBERS APPLIED TO WOOD-FIRED BOILERS

Plant	Number of units	Boiler capacity, MW (10^6 Btu/hr) heat input	Scrubber type	Efficiency (%)	Sulfur (wt. %)	Ash (wt. %)	Test load percent of design capacity)[a]	Average operating pressure drop (in w.c.)[b]	Controlled particulate emissions (lb/10^6 Btu)[c]	Reference[d]
Champion International (AB2)	1	32 (108)	Impingement	NA[f]	NA	NA	79	6-8	0.068	50
Georgia Pacific (AC1)	2	17/17 (57/57)[e]	Impingement	NA	NA	NA	63	6-8	0.182	51
Georgia Pacific (AC2)	1	16 (55)	Impingement	NA	NA	NA	47	6-8	0.170	51
Georgia Pacific (AD1)	1	18 (61)	Venturi	NA	NA	NA	73[g]	6-8	0.182	52
Georgia Pacific (AG1)	1	50 (170)	Venturi	NA	NA	NA	103	6-8	0.169	53
Georgia Pacific (AI1)	1	50 (170)	Venturi	NA	NA	NA	86	6-8	0.212	54
Georgia Pacific (AF1)	1	54 (185)	Impingement	NA	NA	NA	72	6-8	0.100	55
Georgia Pacific (AE1)	1	54 (185)	Venturi	NA	NA	NA	85	6-8	0.131	56
Georgia Pacific (AH1)	1	63 (215)	Venturi	NA	NA	NA	65	6-8	0.148	57
St. Joe Paper (AJ2)[h]	1	50 (170)	Variable Throat Venturi	94	0.03	2.2	91	8	0.104	58
St. Joe Paper (AJ4)[h]	1	50 (170)	Variable Throat Venturi	96	0.01	1.9	95	13.5	0.137	58
St. Joe Paper (AJ5)[h]	1	50 (170)	Variable Throat Venturi	NA	NA	NA	91	15.2	0.057	58
Boise Cascade (AA1)	1	67 (230)	Variable Throat Venturi	NA	NA	2-8[i]	95	18	0.048	59
St. Regis Paper (AK2)[h]	1	61 (210)	Venturi	98	0.04	1.7	94	20	0.074	60
St. Regis Paper (AK3)[h]	1	61 (210)	Venturi	NA	0.17	4.2	100	26	0.063	61

[a]Average value during testing.

[b]Multiply inches of water by 0.2486 for conversion to kPa.

[c]Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[d]References 50 to 61 were cited in the Background Information Document for Nonfossil Fuel-Fired Boilers.

[e]Two boilers which exhaust into a single wet scrubber.

[f]NA = Not available.

[g]Estimated, based on mass emission rate and F-factor.

[h]EPA Method 5 data acquired on EPA tests.

[i]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

16 kPa (6 to 26 inches of water) preceded by a mechanical collector can achieve emission levels less than 90 ng/J (0.21 lb/10^6 Btu) while those with pressure drops greater than 3.8 kPa (15 inches of water) can achieve emission levels less than 26 ng/J (0.06 lb/10^6 Btu) on small wood-fired boilers.

3.1.10.2 Electrostatic Precipitators and Electrostatic Gravel Bed Test Filter Test Data.[62] Table 3-9 presents the emission test data for wood-fired boilers controlled by ESP's or EGB's. All boilers are spreader stokers firing wood or coal/wood mixtures. A 65 percent boiler efficiency was assumed for the purpose of determining the boiler heat input. All control systems are designed with a mechanical collector prior to the ESP or EGB. Fly ash reinjection is used on all the sources tested, but fly ash was not reinjected during test BE4 and BE6. Test data for PM was obtained by EPA Method 5.

Three of the emission tests were performed on boilers firing wood or mixtures of wood and coal controlled with an ESP. These controlled particulate test results ranged from 18 to 31 ng/J (0.042 to 0.072 lb/10^6 Btu). The operating specific collection area ranged from 752 to 1480 $m^2/(1000\ m^3/s)$ (230 to 453 ft^2/1000 acfm). The lower specific collection area had the highest PM emission level.

The emission test data indicate that and ESP with an SCA of 980 $m^2/(1000\ m^3/s)$ (300 ft^2/1000 acfm) and preceded by a mechanical collector is capable of achieving a PM emission level of less than 30 ng/J (0.07 lb/10^6 Btu) on a small wood-fired boiler.

Two tests were performed on an EGB having three modules. Each module cleans one-third of the total flue gas and has its own stack. The first test (BE2) was performed by EPA. The data shown in Table 3-9 are the weighted average of the three stacks. This test was run under typical operating conditions at this facility. The second test was performed by the boiler operator and consisted of 15 test runs under a range of operating conditions. The data shown are the emissions from the outlet of Module 3 of the EGB only. The 15 test runs are grouped into 4 different sets. These sets are as follows:

TABLE 3-9. SUMMARY OF PARTICULATE EMISSION TEST DATA ON WOOD-FIRED BOILERS CONTROLLED WITH ESP's AND EGB's

Plant	Control device	Boiler capacity, MW (10^6 Btu/hr) heat input	Percent ash	Percent sulfur	Heating value (Btu/lb)[b]	Test load (percent of design capacity)	Boiler type	Specific collection area (ft^2/1,000 ACFM)[c] Operating	Specific collection area (ft^2/1,000 ACFM)[c] Design	Controlled particulate emissions (lb/10^6 Btu)[d]	Reference[e]
Champion International Coop (BA1)	ESP[a]	50 (170)	NA[a]	NA	NA	66	SS[a]	230	177	0.072	63
Westvaco Bleached Board (BI1)[f]	ESP	108/147 (370/500)	3.4[g]	0.3	10,750	25/25	SS	320	296	0.042	64
Westvaco Bleached Board (BB1)	ESP	202 (690)	4.8[h]	NA	8,250	69	SS	453	298	0.057	65
Weyerhaeuser Co. (BE2)[i]	EGB[a]	180 (615)	9.4[j]	0.06	8,270	96	SS	6.0[l]	NA	0.027	66
Weyerhaeuser Co. (BE3)[k]	EGB	180 (615)	3.8	NA	8,970	101	SS	3.4[l]	NA	0.025	67
Weyerhaeuser Co. (BE4)[k]	EGB	180 (615)	3.8	NA	8,910	116	SS	4.0[l]	NA	0.024	67
Weyerhaeuser Co. (BE5)[k]	EGB	180 (615)	4.8	NA	8,780	95	SS	5.6[l]	NA	0.039	67
Weyerhaeuser Co. (BE6)[k]	EGB	180 (615)	4.8	NA	8,830	107	SS	7.1[l]	NA	0.051	67

[a]NA = Not available; SS = Spreader stoker; ESP = Electrostatic precipitator; EGB = Electrostatic gravel bed filter.

[b]Multiply Btu/lb by 2.323 for conversion to kJ/kg.

[c]Multiply ft^2/1,000 ACFM by 3.2729 for conversion to $m^2/(1{,}000\ m^3/s)$.

[d]Multiply lb/10^6 Btu by 430 for conversion to ng/J.

[e]References 63 to 67 cited in the Background Information Document for Nonfossil Fuel-Fired Boilers.

[f]The flue gas from two boilers pass through individual mechanical collectors. It is then combined into a single duct and split to enter a two chamber ESP with two stacks. The test data and emission levels shown are the weighted average of both stacks.

[g]Boiler burns LSC with the wood. The analysis of the coal showed the following composition: Moisture - 5.5%; ash (dry) - 12.4%; sulfur (dry) - 0.86%.

[h]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

[i]The EGB has three modules, each of which cleans one-third of the flue gas. Each module has a separate stack. The emission levels shown are the weighted average of all three stacks.

[j]At this facility char from the first stage of the mechanical collector is slurried and separated by screens into large and small fractions. The large char is mixed with the hog fuel. These values represent an analysis of the mixture of char and hog fuel.

[k]Emissions are from the outlet of module 3 of the EGB.

[l]For EGB this value is pressure drop in inches of water. Multiply inches of water by 0.2468 for conversion to kPa.

- o Set BE3 consists of test runs 1, 2, 5, 7, and 9. In this set "good" hog fuel was fired and flyash was reinjected.
- o Set BE4 consists of test runs 3, 4, 8, and 15. "Good" hog fuel was fired and flyash was not reinjected.
- o Set BE5 consists of test runs 10, 11, and 13. "Poor" hog fuel was fired and flyash was reinjected.
- o Set BE6 consists of test runs 12 and 14. "Poor" hog fuel was fired and flyash was not reinjected.

For these tests, the definition of "good" hog fuel is hog fuel with moisture content of less than 55 percent. Hog fuel with a moisture content of 55 percent or more is defined as "poor." Test run 6 was made with the electrostatic grid turned off. This is not part of normal operation and this test run was not shown in the test run averages. However, the PM emission rate for the test run with the electrostatic grid off was 26 ng/J (0.06 lb/10^6 Btu). This result demonstrates the ability of the electrostatic filter to remove PM in a dry form using only the moving bed of filter media. The emission rates shown by the EGB's under normal operation and with the electrostatic grid off were comparable to those shown by ESP's.

These emission test data indicate that EGB's operated with a 0.8 kPa (3 inches of water) pressure drop are capable of achieving emission levels less than 30 ng/J (0.07 lb/10^6 Btu) on small boilers firing a variety of wood fuels and wood/coal fuel mixtures.

3.1.11 PM Emission Test Data for Solid Waste-Fired Boilers

Table 3-10 presents PM emissions test data from municipal waste incinerators with heat recovery. Particulate emissions ranged from 0.9 to 43 ng/J (0.002 to 0.099 lb/10^6 Btu). All test results were obtained with EPA Method 5.

Small mass feed boilers use similar fuel, grate design, and firing mechanism as the large MSW-fired boilers. Thus, the PM emitted from a small MSW and a large MSW unit should have similar PM characteristics, such as resistivity and particle distribution.

TABLE 3-10. PM EMISSIONS DATA FOR ELECTROSTATIC PERCIPITATORS APPLIED TO MSW-FIRED BOILERS

Location	Boiler design[a]	Design heat input,[b] MW (10^6 Btu/hr)	Average test load (percent of steam capacity)	Average specific collection area[c] (ft^2/1000 ACFM)[d] Design	Actual	Average particulate emissions[e] (lb/10^6 Btu)	Reference[f]
Chicago NW, Boiler #1	A,B	46 (158)	68	154	278	0.077	68
Chicago NW, Boiler #1	A,B	46 (158)	86	154	291	0.098	69
Chicago NW, Boiler #2	A,B	46 (158)	90	154	275	0.082	69
Chicago NW, Boiler #3	A,B	46 (158)	90	154	300	0.099	69
Chicago NW, Boiler #4	A,B	46 (158)	85	154	244	0.073	69
RESCO, Saugus, MA	D	73 (250)	NA	209	245	0.087	70
Nashville Thermal Transfer, Nashville, TN Boiler #1	A	56 (193)	77	316	573	0.046	71
Braintree Municipal Incinerator, Braintree, MA Boiler #2	B,C	12 (42)	160	126	139	0.020	72
RESCO, Baltimore, MD Boiler #1	B	70 (240)	100	577	592	0.004	73
RESCO, Baltimore, MD Boiler #2	B	70 (240)	99	577	664	0.009	73
RESCO, Baltimore, MD Boiler #3	B	70 (240)	100	577	693	0.002	73

(Continued)

TABLE 3-10. PM EMISSION DATA FOR ELECTROSTATIC PERCIPITATORS APPLIED TO MSW-FIRED BOILERS (CONTINUED)

NA = Not Available

[a]All processes are mass burn
- A = Reverse reciprocating grate
- B = Water wall furnace
- C = Horizontal traveling grate
- D = Mass burn only description available

[b]Calculated from steam capacity with a 70 percent overall thermal efficiency.

[c]Individual test runs available in reference 74.

[d]Specific collection area units, $ft^2/1,000$ ACFM, can be converted to $m^2/(1,000\ m^3/s)$ by multiplying by 3.2729.

[e]Multiply $lb/10^6$ Btu by 430 for conversion to ng/J.

[f]References 68, 70, 71, and 72 cited in Background Information Document for Nonfossil Fuel-Fired Boilers.

An analysis was performed on the test data to determine the ESP specific collection area required to achieve the various emission levels. The analysis was performed on 34 test data points relating the SCA and PM emission test results. The 34 test data points were from the individual test runs at the test sites in Table 3-10.[74]

The best fit model using the new database employs the Deutsch-Anderson form:

$$PM\ (lb/10^6\ Btu) = 0.414\ e^{(-0.00567\ *\ SCA)}$$

This model predicts that ESP's with SCA's of approximately 524, 818, 1210 $m^2/(1000\ m^3/s)$ (160, 250, and 370 $ft^2/1000$ acfm) are required to achieve PM emission levels of 73, 43, and 22 ng/J (0.17, 0.10, and 0.05 lb/million Btu), respectively.

Similar control technology information is not available for small modular MSW-fired boilers. However, uncontrolled emission data for MSW modular incinerators in Table 3-11 are comparable or lower than MSW-fired massfeed boilers.[75,76] Since the fuel has similar ash characteristics, the resistivity characteristics will be similar. Therefore, the PM emitted from a small modular MSW-fired boiler to an ESP will have similar resistivity and lower particle loading.

This information indicates that ESP's with SCA's of 524, 818, and 1210 $m^2/(1000\ m^3/s)$ (160, 250, and 370 $ft^2/1000$ acfm) are capable of achieving PM emission levels of 73, 43, and 22 ng/J (0.17, 0.10, and 0.05 $lb/10^6$ Btu) respectively on small MSW-fired modular and massfeed boilers.

3.2 SULFUR DIOXIDE CONTROL TECHNIQUES

3.2.1 Introduction

3.2.1.1 SO_2 Formation and Control Theory. In boilers, SO_2 is formed by the oxidation of sulfur contained in the fuel. Although sulfur trioxide (SO_3) emissions are also formed during the combustion process, they account

TABLE 3-11. UNCONTROLLED PM EMISSION DATA FROM SMALL MODULAR MSW INCINERATORS[a]

Facility	Boiler capacity, MW[b] (10^6 Btu/hour) heat input	Test load (percent of design capacity)	Average PM emissions ($lb/10^6$ Btu)[c]	Reference[d]
North Little Rock Recovery Facility North Little Rock, AR	5 (19)	90	0.283	77
Salem City Incinerator Salem, VA	11 (37)	76[e]	0.251	78,79

[a]All units are starved air small modular incinerators.

[b]Based on data provided by the facility. If no other data were available, the boiler heat input was calculated based on the design boiler throughout in tons per day assuming 24 hour per day operation, and higher heating values of 10,450, 16,260, and 13,450 kJ/kg (4500, 7000, and 5790 Btu/lb) for MSW, ISW, and RDF, respectively.

[c]Multiply $lb/10^6$ Btu by 430 for conversion to ng/J.

[d]References 77 to 79 cited in Background Information Document for Nonfossil Fuel-Fired Boilers.

[e]Based on steam production in pounds per hour.

for only one or two percent of the total sulfur oxide emissions.[80,81] Uncontrolled SO_2 emissions depend primarily on the fuel sulfur content. Other fuel properties, such as fuel ash alkalinity, can also affect uncontrolled SO_2 emissions. Alkaline species in the fuel ash react with SO_2 and retain a portion of the sulfur in the fly ash and bottom ash, reducing the level of SO_2 exiting the boiler in the flue gas. The type of firing mechanism does not affect SO_2 emissions, with the exception of fluidized bed combustion (FBC) with alkali addition.

Sulfur dioxide can be reduced in small boilers by three methods. The first method is to combust low sulfur fuels. This method results in a reduction in the amount of SO_2 in the flue gas by reducing the amount of sulfur to be combusted in the boiler. Sulfur dioxide emissions are directly proportional to sulfur content of the fuel. The second method is to contact the flue gas leaving the boiler with alkali sorbent. The third method is to inject alkali sorbent into the boiler. The latter two methods result in a reduction in the amount of SO_2 in the flue gas by a chemical reaction between the alkali and the SO_2. The captured SO_2 is contained in the liquid or solid waste stream.

3.2.1.2 <u>SO_2 Control Techniques Evaluated</u>. Various SO_2 control techniques are applicable to reduce SO_2 emissions from oil- and coal-fired small boilers. For oil-fired units, low sulfur oil and sodium scrubbing flue gas desulfurization (FGD) systems are considered. For coal-fired units, SO_2 control techniques based on low sulfur coal, sodium scrubbing FGD systems, and FBC with limestone addition are considered. While other FGD systems such as dual alkali, dry lime scrubbing, and lime/limestone systems are technically applicable to small boilers, sodium scrubbing systems are the only systems that have been directly applied to small boilers. The reason for the popularity of sodium scrubbing systems for small boilers is the system's simplicity in operation and high reliability (greater than 95 percent).[82,83]

Sulfur dioxide control techniques are not considered for natural gas-, distillate oil-, and nonfossil fuel-fired boilers. Sulfur dioxide emissions from these boilers are low because those fuels contain negligible amounts of sulfur.

3.2.2 Combustion of Low Sulfur Fuels

Low sulfur fuels limit SO_2 emissions by reducing the amount of sulfur available for SO_2 formation. In this section, low sulfur fuels will be defined as those fuels able to meet existing new source performance standards (NSPS) for boilers greater than 73.3 MW (250 million Btu/hour) heat input without additional SO_2 controls. The existing NSPS for this size range requires that SO_2 emissions cannot exceed 344 ng/J (0.8 lb/10^6 Btu) for oil-fired boilers and 516 ng/J (1.2 lb/10^6 Btu) for coal-fired boilers.

Low sulfur fuels may be produced from high sulfur fuels or may be obtained from naturally occurring low sulfur coal or oil deposits. Commercially available methods for producing low sulfur fuels from high sulfur fuels include physical coal cleaning (PCC) and oil hydrodesulfurization (HDS). Low sulfur fuels may be purchased from PCC and HDS plants which supply these fuels on the open market to owners and operators of small boilers. The design and operating factors and the mechanism by which PCC and HDS can reduce SO_2 emissions are discussed in another report.[84]

Coal gasification and liquefaction are additional means of obtaining a low sulfur fuel from coal but at present have seen very limited application in utilities. The primary reason for the limited application of coal gasification in utilities is the current low cost (relative to coal-derived gases) and high availability of natural gas and oil from conventional sources. Therefore, coal gasification and liquefaction will not be considered as processes for obtaining low sulfur fuels for small boiler applications.

As mentioned above, low sulfur fuels may also be obtained from naturally occurring deposits of low sulfur coal and low sulfur oil. In fact, the vast majority of low sulfur fuels currently in use come from naturally occurring sources.[85]

3.2.3 Sodium Scrubbing FGD System

3.2.3.1 Process Description. Sodium scrubbing processes currently in use employ an aqueous solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) in the scrubber to absorb SO_2 from the boiler flue gas. Figure 3-7 presents the flow diagram for such a process. Flue gas from the boiler exit is sent to the absorber. In the absorber, flue gas is contacted with the recycle stream containing sodium reagent. The scrubber liquid effluent flows to a recirculation tank where it is mixed with make-up reagent and feed water. Make-up water is added to account for the loss of water due to evaporation in the scrubber and to control the specific gravity of the liquor. If NaOH is used as the absorbent, it is typically added as a 50 weight percent solution. When Na_2CO_3 is the reagent, it is usually added as a saturated solution.[86] The absorption reactions which take place in the scrubber and recirculation tank are:

$$2NaOH + SO_2 \rightleftharpoons Na_2SO_3 + H_2O \qquad (3\text{-}1)$$

$$Na_2CO_3 + SO_2 \rightleftharpoons Na_2SO_3 + CO_2 \qquad (3\text{-}2)$$

$$Na_2SO_3 + SO_2 + H_2O \rightleftharpoons 2NaHSO_3 \qquad (3\text{-}3)$$

$$SO_2 + H_2O \rightleftharpoons H_2SO_3 \qquad (3\text{-}4)$$

$$Na_2SO_3 + 1/2\ O_2 \rightleftharpoons Na_2SO_4 \qquad (3\text{-}5)$$

The aqueous solution or wastewater leaving the recirculation tank contains NaOH (or Na_2CO_3), sodium sulfite (Na_2SO_3), sodium bisulfite ($NaHSO_3$), sulfurous acid (H_2SO_3), and sodium sulfate (Na_2SO_4). Most of this stream is recycled to the scrubber with a slipstream going to wastewater treatment and disposal.[87] The wastewater stream may be sent to a clarifier (or settler) in order to settle out fly ash and other insoluble compounds. Wastewater disposal is accomplished in one of several ways: recycle for non-FGD process use, evaporation ponding, deep-well injection, or discharge to a receiving water body or publicly-owned wastewater treatment plant.

Control parameters for the system's operation are the specific gravity and the pH of the solution in the recirculation tank. In some systems, the specific gravity is controlled by the addition of make-up water. The

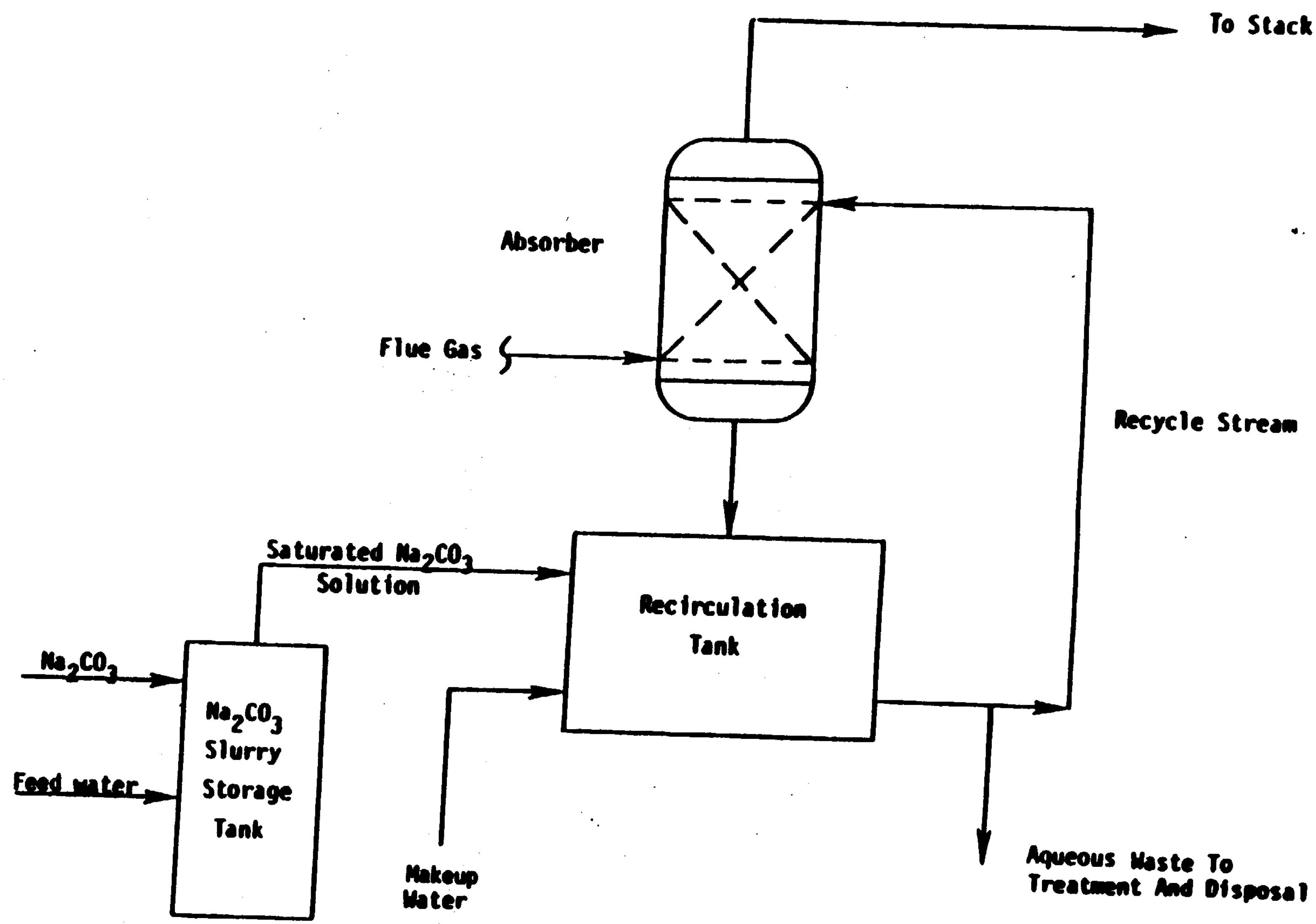


Figure 3-7. Process flow diagram for a sodium scrubbing system using soda ash slurry storage.

specific gravity determines both the buffering capacity of the scrubbing solution and the flow rate of the blowdown stream. The higher the specific gravity, the greater will be the buffering capacity of the solution and the lower will be the blowdown flow rate.[88] The pH is controlled by the addition of sodium reagent. If, for example, the process experiences a transient increase in SO_2 loading, then the pH in the recirculation tank will drop. This, in turn, signals the addition of make-up reagent to re-establish the pH to normal. Make-up water and blowdown flowrates will then both be increased to maintain the set-point value of the specific gravity.

Sodium scrubbing systems have demonstrated high reliability. Information from 15 industrial boiler operators reported reliabilities of between 89 and 100 percent with an average of 97.8.[89] Of the 15 responses gathered in that survey, 9 reported a 100 percent reliability and only two reported reliabilities less than 95 percent.[90]

These high reliabilities are due primarily to the simplicity of both the chemistry and design of the process. The sodium species in the recirculation stream remain in solution at the concentrations and temperature ranges typically found in sodium scrubbing systems.[91] Solution scrubbing minimizes the erosion of pumps and pipes, as well as the scaling of mist eliminators within the scrubbing unit, all of which contribute to a substantial fraction of the downtime in calcium-based system. Calcium, leached from the coal ash and sometimes present in the make-up water itself, is the predominant species subject to precipitation. However, its concentration generally is too low to cause scaling problems, even at relatively high pH values. Operating the system in the concentrated mode reduces the risk of calcium precipitation by reducing system pH.[92] In the concentrated mode of operation, the total dissolved solids (TDS) content of the scrubbing liquor typically exceeds 5 weight percent.

3.2.3.2 Factors Affecting Performance. The major operating variables affecting scrubber performance are the pH and total sulfite concentration (TSC) of the scrubbing solution. The pH primarily affects SO_2 removal efficiency while TSC affects SO_2 removal efficiency as well as reagent consumption. These two factors will be discussed in this section. Secondary factors affecting scrubber performance are the absorber type and the liquid to gas flow (L/G) ratio. These secondary factors will not be discussed in this section but have been thoroughly discussed in another report.[93]

3.2.3.2.1. pH. The pH of the scrubbing liquor is determined primarily by the ratio of Na_2SO_3 to $NaHSO_3$. Since the bisulfite ion (HSO_3^-) is a weaker acid (with a pKa of 7.45 at 50°C) than the sulfite ion (SO_3^{-2}), the greater the $Na_2SO_3/NaHSO_3$ ratio is, the higher will be the pH of the scrubbing liquor. The term pKa is defined as follows:

$$pKa = pH - \log \frac{[SO_3^{-2}]}{[HSO_3^-]} \qquad (3\text{-}6)$$

As shown on Figure 3-8, raising the pH will lower the equilibrium SO_2 partial pressure of the scrubbing liquor which will in turn increase the driving force for SO_2 absorption.[94,95] This means that if all other design and operating parameters are held constant, increasing the pH of the scrubbing solution will increase the SO_2 removal efficiency of the scrubbing system.

Typically, the pH of the scrubbing solution is maintained around 7.0, which corresponds to an $Na_2SO_3/NaHSO_3$ ratio of approximately 1:2.[96] At this pH, Figure 3-8 shows that the equilibrium SO_2 partial pressure is less than 20 parts per million by volume (ppmv) for most sodium scrubbing solutions.[97] Since inlet concentrations of SO_2 range from 1,000 to 3,000 ppmv, the theoretical SO_2 removal efficiency is greater than 95 percent. Because of the reactivity of dissolved SO_2 in aqueous sulfite solutions and the mass transfer capabilities of most absorber designs, these equilibrium values are approximated in practice. Commercially operating systems have consistently reported SO_2 removal efficiencies greater than 95 percent (refer to Sections 3.2.5.2 and 3.2.6.2).

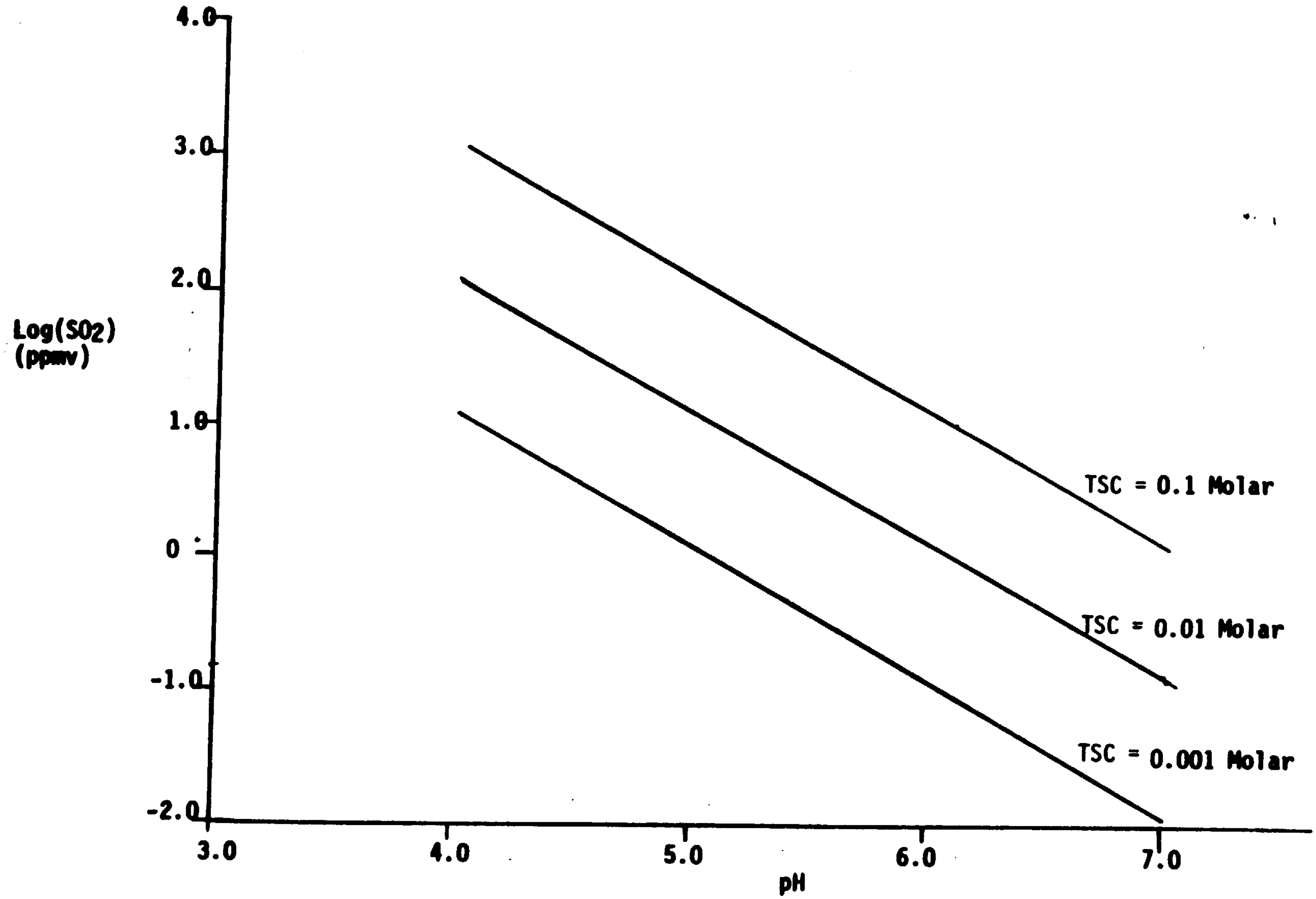


Figure 3-8. Equilibrium partial pressure of SO_2 over aqueous sodium sulfite sollutions.[98,99]

3.2.3.2.2 Total sulfite concentrations. The TSC is defined as the sum of all sulfite ions (SO_3^{-2}) and their corresponding cations. For the sodium scrubbing liquor, this includes primarily Na_2SO_3 and $NaHSO_3$. It should be noted that sulfate ion (SO_4^{-2}) will also be dissolved in the scrubbing solution, typically in a ratio of 1:3 relative to the sulfite species.[100] Sodium sulfite and sulfate are the primary dissolved species and together comprise the TDS of the scrubbing solution. Sulfate is a very stable species and has little effect on scrubber performance except when it becomes so concentrated that it promotes precipitation of the sulfite species and significantly reduces SO_2 removal efficiency.

Figure 3-8 shows that as the TSC increases, the equilibrium SO_2 back pressure will also increase. For example, for the TSC range between 0.001 molar (M) and 0.1 M, the SO_2 partial pressure will vary from 0.01 ppmv to 1.4 ppmv at a pH of 7.0 and at $50^{\circ}C$ ($120^{\circ}F$). Assuming that all other operating and design parameters remain constant, the SO_2 removal efficiency will theoretically decrease as TSC increases. However, when compared to inlet SO_2 partial pressures of 1,000 to 3,000 ppmv, this 140-fold change in equilibrium outlet partial pressure does not significantly affect the overall SO_2 removal efficiency. This fact has been substantiated by commercially operating systems which have shown no trend in SO_2 removal efficiency as a function of TSC.[101]

Although increasing TSC may reduce SO_2 removal efficiency by a small degree, it can significantly improve transient performance by stabilizing the solution pH.[102] Since HSO_3^- is a weak acid, $NaHSO_3$ and Na_2SO_3 serve as buffers in the scrubbing solution. The higher their concentrations, the greater the buffering capacity of the scrubbing liquor. Scrubbers operated in the concentrated mode will typically have an inlet pH of 7.0 to 7.5 and an outlet pH of 6.5 to 7.0.[103,104] On the other hand, scrubbers operated in the dilute mode (conventionally defined as TDS levels less than or equal to 5 weight percent) typically have an inlet pH of 9 to 10 and an outlet pH of 4 to 5.[105]

Buffering is important because it increases process reliability and improves transient performance. At pH levels above 8.0, the likelihood of calcium scaling is high. Within most sodium scrubbing loops, there are some background calcium cations (Ca^{+2}) present (e.g., from make-up water or ash leachate) which will combine with available sulfite and sulfate ions. At pH levels above 8.0, calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) will precipitate out of solution and cause scaling. This scaling can lead to plugging, especially in the recirculation lines and spray nozzles.[106] As a result, the SO_2 removal efficiency can be impaired; in extreme cases, the unit will have to be shut down and de-scaled. At low pH levels, substantial corrosion of the scrubber, tank, and pipe internals can occur, especially if the scrubbing solution has a high chloride ion concentration. This corrosion will increase the maintenance costs of the scrubbing unit and decrease the scrubber's reliability.

Buffering serves another useful function in that it helps to prevent large pH fluctuations from occurring, even when inlet SO_2 concentrations vary because of boiler load fluctuations. This ensures relatively constant outlet SO_2 concentrations.

3.2.4 Fluidized Bed Combustion With Limestone Addition

Fluidized bed combustion is a boiler design option which, because of its ability to incorporate limestone addition, can achieve significant SO_2 emission reductions. The technology offers a variety of advantages over conventional boiler designs, including SO_2 emission reduction without the use of FGD systems and greater flexibility in fuel use. The fluidized bed also operates at lower combustion temperatures than conventional combustion methods, typically 815 to 930°C (1500 to 1700°F) as opposed to 1500°C (2700°F).[107] This results in lower nitrogen oxide (NO_x) emissions because thermal fixation of atmospheric nitrogen which occurs at temperatures above 1,370°C (2500°F) is reduced (refer to Section 3.3.4.1).

Atmospheric fluidized bed combustion (AFBC) boilers have developed rapidly over the past 5 years and are now being applied to small boiler sizes. Two AFBC design alternatives which are currently available are the conventional bubbling fluidized bed (with or without solids recycle) and the circulating fluidized bed. Pressurized FBC technology has been under development for several years but has not yet been used in commercial applications and is unlikely to be used for small boiler applications.

Coal, wood, and process wastes are the primary fuels used in FBC systems. Oil has not been combusted to any great extent in FBC systems and will not be considered here. Of these solid fuels, only coal has significant sulfur content, making coal the primary fuel for which FBC with limestone addition is a candidate SO_2 control technology.

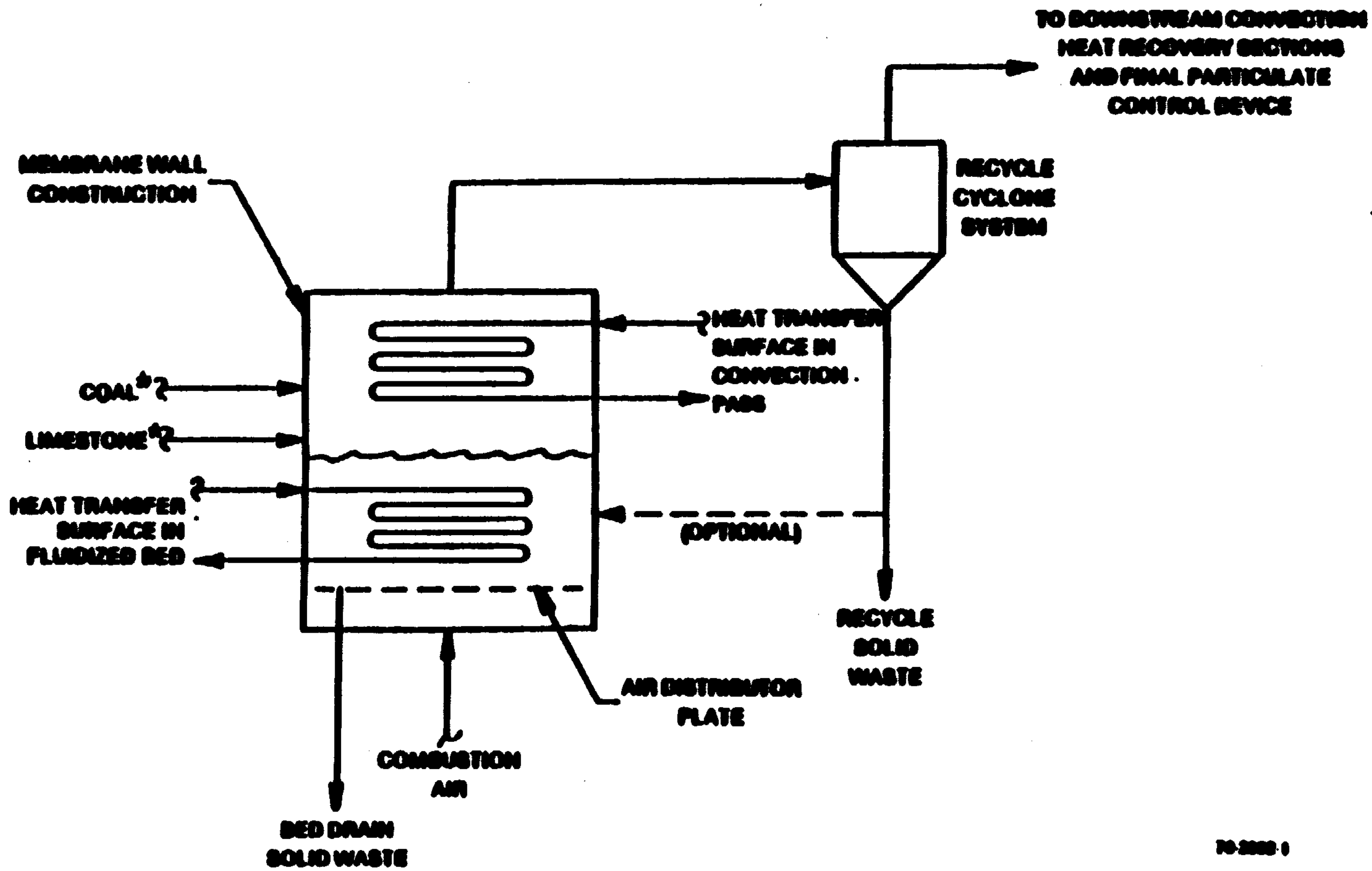
3.2.4.1. Process Description. In the conventional bubbling bed system illustrated in Figure 3-9, fuel and sorbent, usually coal and limestone, are continuously fed into a bed of fluidized particles. The limestone is added for SO_2 removal. The fluidized bed (consisting of unreacted, calcined, and sulfated limestone particles, coal, and ash) is suspended in a stream of combustion air blowing upward from an air distribution plate. When the coal is combusted, the following reactions take place:

Calcination: $$CaCO_3 \longrightarrow CaO + CO_2 \quad (3\text{-}7)$$

Sulfation: $$CaO + SO_2 + 1/2\ O_2 \longrightarrow CaSO_4 \quad (3\text{-}8)$$

$$CaO + SO_2 \longrightarrow CaSO_3 \quad (3.9)$$

Bed material is drained to maintain the desired bed depth. Material is also elutriated (carried over) from the bed with the combustion gas. This entrained material is separated from the flue gas by cyclones and a baghouse or ESP. Both the drained bed material and the carryover material are disposed of as solid waste.



*Coal and limestone may be fed above, in, or under the fluidized bed.

Figure 3-9. Conventional AFBC boiler flowsheet.[108]

In an FBC boiler with solids recycle, flue gas with entrained bed material is passed through a primary cyclone where 80 to 90 percent of the entrained material is removed.[109] All or part of this material is then recycled back to the fluidized bed. The net effect of solids recycle is an increased fuel and sorbent residence time in the bed, which in turn improves combustion efficiency and SO_2 and NO_x control.[110-113]

Two important FBC operating parameters are the bed temperature and the calcium-to-sulfur (Ca/S) molar feed ratio. The bed temperature must be maintained between 760° and 870°C (1400 and 1600°F) to fully calcine the limestone and to optimize boiler efficiency.[114] Although effective Ca/S ratios depend on many factors, tests on several boilers indicate that a Ca/S ratio of at least 3.0 is needed to sustain SO_2 removal efficiencies on the order of 90 percent.[115]

One bubbling bed system available at present makes use of a two-bed staged design. In this design the lower bed is operated at an optimum combustion temperature of 980 to 1,040°C (1800 to 1900°F) and the upper bed (where limestone is added) is operated at an optimum calcining temperature of 705 to 760°C (1300 to 1400°F). In this way, both boiler efficiency and SO_2 removal efficiency are optimized within the same unit.[116] Figure 3-10 shows a schematic of the two-staged design.

Circulating fluidized bed (CFB) combustion uses both a stationary dense bed of large particles and a circulating entrained bed of fine particles. The dense bed ensures adequate fuel/sorbent mixing and residence time in the combustion chamber, as well as uniform distribution of combustion air. The entrained bed of fine particles is continuously recycled through the combustion chamber to serve as the primary medium for heat transfer. Figure 3-11 shows one CFB design.

3.2.4.2 Factors Affecting Performance. The three primary factors affecting SO_2 removal performance in bubbling bed, staged bed, and circulating bed boilers are: Ca/S molar feed ratio, sorbent particle size, and gas phase residence time. The impacts of these primary factors on SO_2 emissions are discussed briefly in this section. Secondary factors

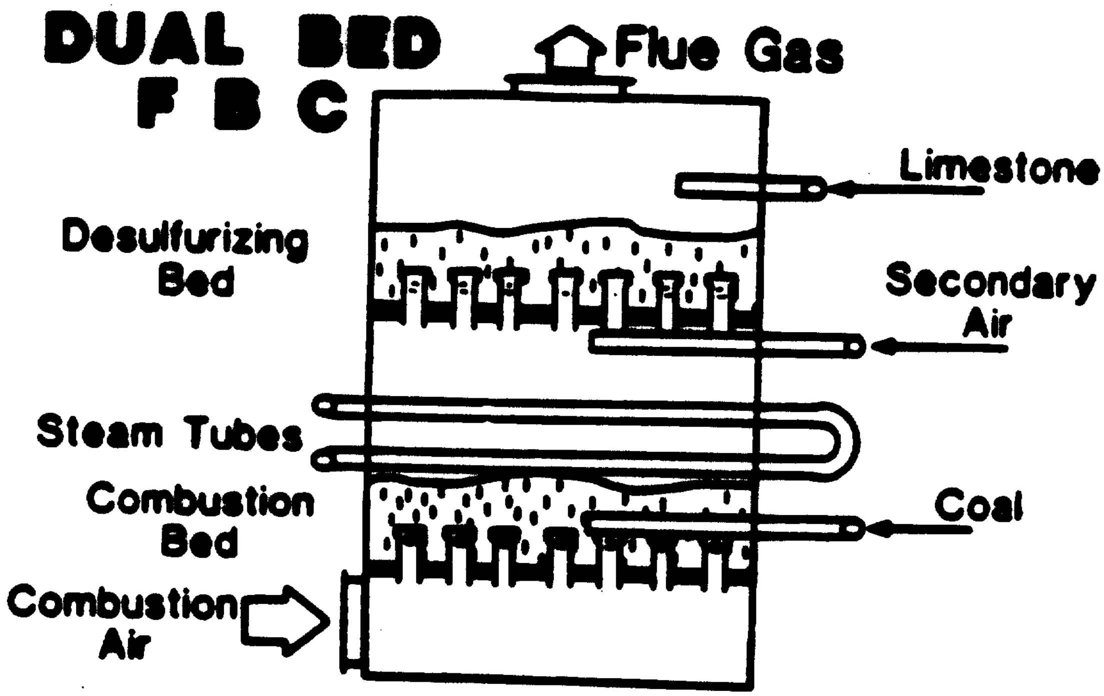


Figure 3-10. Staged bed AFBC boiler flowsheet.[117]

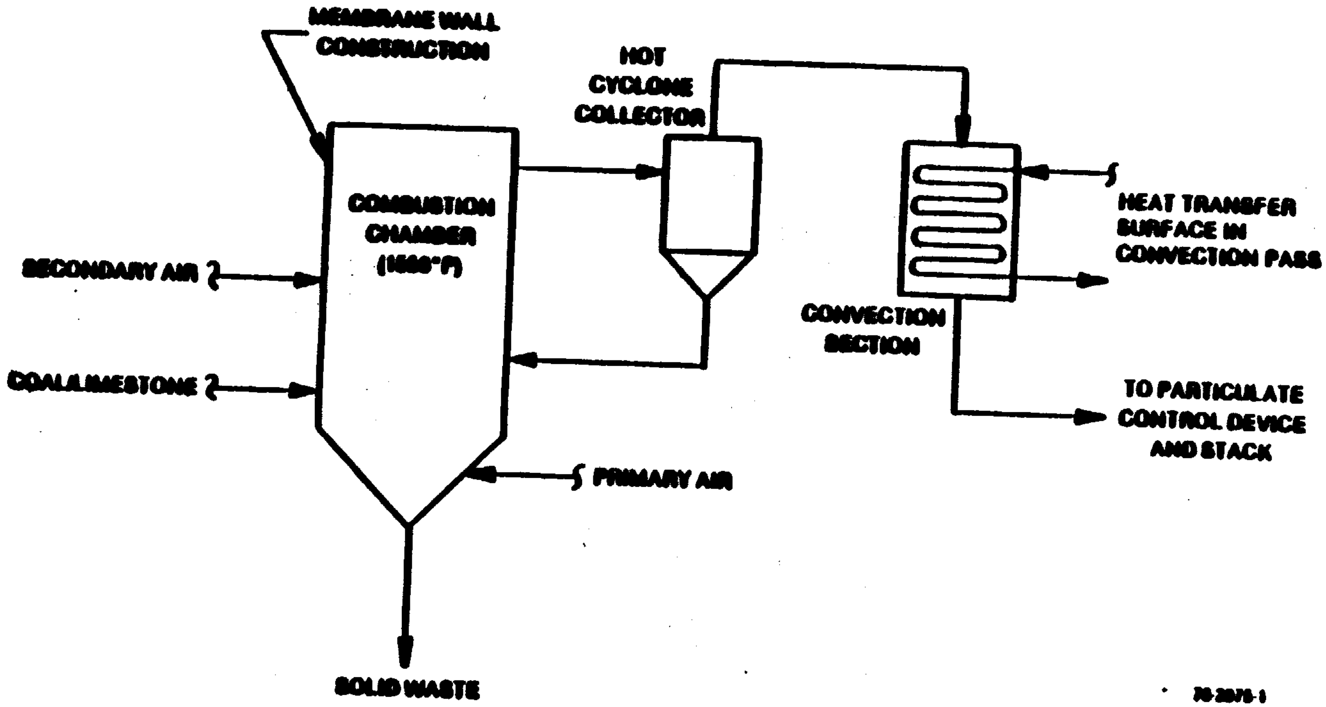


Figure 3-11. CFB boiler - Pyropower design.[118,119]

influencing SO_2 emissions are sorbent reactivity, bed temperature, feed mechanisms, and excess air. The impacts of the secondary factors on SO_2 emissions are not discussed in this section but have been discussed in other reports.[120,121]

3.2.4.2.1 Calcium to sulfur molar feed ratio. The Ca/S ratio is usually defined as the ratio of the molar feed of calcium in the limestone to the molar feed of sulfur in the coal. The Ca/S ratio is normally increased by increasing the limestone rate to the boiler instead of decreasing the coal feed rate.

As the Ca/S molar feed ratio is increased, higher SO_2 removal is achieved. The SO_2 removal rate increases rapidly as the Ca/S ratio increases in an essentially linear fashion up to a certain SO_2 removal level. According to the Westinghouse model, this level is about 75 percent SO_2 removal for limestone with a particle size of approximately 500 microns. Above 75 percent SO_2 removal, the SO_2 removal approaches 100 percent asymptotically with increasing Ca/S ratio. Figure 3-12 shows the trend graphically for various types of limestone.

As predicted by the Westinghouse model, the limestone utilization decreases when operating at higher SO_2 removals. Limestone utilization is defined as the ratio of the amount of limestone that is converted to $CaSO_4$ to the total amount of limestone fed. The decrease in utilization is expected at higher SO_2 removals because for every unit of increase in the Ca/S ratio, the increase in SO_2 removal becomes less as shown in Figure 3-12 for SO_2 removals above 75 percent.

3.2.4.2.2 Sorbent particle size. For a given mass of limestone, the smaller the mean particle size, the greater the net surface area. As the particle size decreases, calcium utilization increases. Therefore, higher SO_2 removals can be achieved at the same Ca/S ratio by using smaller rather than larger particle sizes. The increase in SO_2 removal for smaller particle sizes is due to the increase in the surface area of the particle being exposed to SO_2.[122] However, for very small particle sizes, the limestone particles can be elutriated from the bed before reaction with the

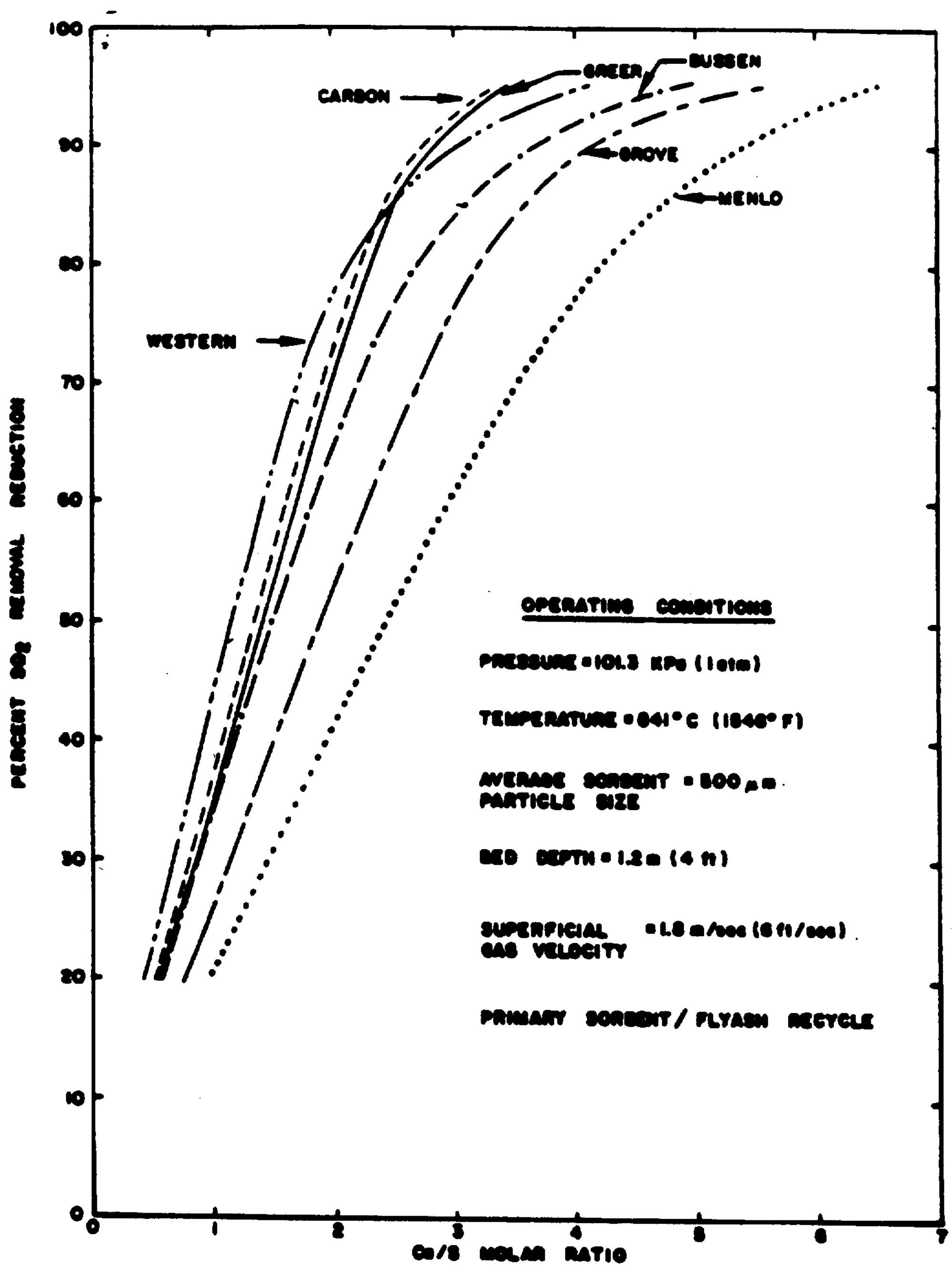


Figure 3-12. Projected desulfurization performance of atmospheric fluidized-bed coal combustor, based upon model developed by Westinghouse.[123]

sulfur has occurred, resulting in lower SO_2 removals and lower calcium utilization. The Westinghouse model predicts that for particle sizes below 500 microns, SO_2 removal will be significantly reduced for gas phase residence times below 0.7 seconds.[124]

3.2.4.2.3 Gas Phase Residence Time. The gas phase residence time is defined as the time that the volume of gas remains in the bed and is the ratio of the expanded bed height to the superficial gas velocity. As the gas phase residence time is increased, higher SO_2 removals are achieved at the same Ca/S ratio. The reaction time between SO_2 and calcium oxide (CaO) is increased allowing more SO_2 to react with CaO. The gas phase residence time can be increased by increasing the bed level, decreasing the coal feed rate, or decreasing the air flow rate (excess air).

3.2.5 SO_2 Emission Test Data for Oil-Fired Boilers

3.2.5.1 Low Sulfur Oil Test Data. Low sulfur oils include both those with naturally occurring low sulfur content and those that have had sulfur removed by HDS techniques. Sulfur constituents in a given fuel oil supply are distributed evenly throughout the fuel. Moreover, other factors such as refinery techniques, storage and transportation methods, and fuel handling at the steam generating unit site serve to make fuel oils relatively homogeneous with respect to fuel sulfur content. Thus, there is little variability in SO_2 emissions resulting from the combustion of a specific fuel oil supply and more than 95 percent of the fuel sulfur content is converted to SO_2.[125]

Air pollution emission correlations are available to estimate SO_2 emissions as a function of percent sulfur in the oil for firetube and watertube boilers 2.9 megawatt (MW) down to (10 million Btu/hour) heat input.[126] These correlations were developed from actual test data for uncontrolled oil-fired boilers and showed that SO_2 emissions increased proportionately as the percent sulfur in the oil increased. Assuming that low sulfur oils contain sulfur contents of 0.75 weight percent or less, the maximum SO_2 emissions for low sulfur oils are 344 ng/J (0.80 lb/10^6 Btu) for small boilers.[127]

3.2.5.2 Sodium Scrubbing Test Data. Table 3-12 presents SO_2 emissions data for 20 oil-fired steam generators equipped with sodium scrubbers and operated to produce steam for tertiary oil recovery. All SO_2 tests were short-term compliance tests (typically over a 3-hour period). Sulfur dioxide emissions were measured using either EPA Reference Method 8 or continuous emission monitors (CEM). The short-term CEM tests were performed using ultraviolet photometry. These tests were classified by the EPA as an alternative method to measure SO_2. From this table, it can be seen that SO_2 removal efficiency ranged from 87.5 to 99.5 percent on oils having sulfur contents ranging from 0.6 to 1.66 weight percent. Operating loads ranged from 67 to 108 percent of full load.

Table 3-13 summarizes the data in Table 3-12 and shows that the SO_2 removal efficiency averaged 95.2 percent for the 20 boilers equipped with sodium scrubbers. The average SO_2 outlet emissions were 30.1 ng/J (0.07 lb/10^6 Btu). The sulfur content of the oils and operating load for the 20 boilers averaged 1.21 weight percent and 87.5 percent of full load, respectively.

Because data presented on sodium scrubbing FGD systems on oil-fired boilers are from short-term testing, long-term SO_2 emission and reliability performance cannot be directly determined. One method of estimating the long-term SO_2 emission performance of sodium scrubbing systems on oil-fired boilers is to relate the short-term SO_2 emission results from oil-fired boilers to the long-term SO_2 emission performance of coal-fired boilers. Long-term SO_2 emission data were available and were analyzed for SO_2 reduction variability for one sodium scrubbing FGD system on a coal-fired boiler. The data will be discussed in Section 3.2.6.2. Because the sulfur content of residual oils is more consistent and less variable than the sulfur content of coals, the variability results using the long-term SO_2 emission data from this coal-fired boiler would be a conservative estimate of the emission variability for sodium scrubbers on oil-fired boilers.

TABLE 3-12. EMISSION DATA FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO OIL-FIRED SMALL STEAM GENERATORS

Boiler I.D.	Absorber type[a]	Boiler equivalent size, MW (10^6 Btu/hr) heat input	Oil sulfur content, percent	Percent of full load	Scrubber inlet pH	Blowdown pH	SO_2 removal efficiency, percent	Outlet SO_2 emissions, ng/J[g]	PM collecting efficiency, percent	Outlet PM emissions, ng/J	SO_2 test method/ no. of runs[j]	PM test method/ no. of runs[k]	References[l]
7	LJE	6.7 (23)	1.00	92[d]	NA[f]	NA	91.0	38.7	41	12.9[h]	EPA 8/3	Mod. EPA 8/2	128
8	LJE	8.1 (27.5)	1.00	75[d]	NA	NA	89.0	43.0	17	30.1[i]	EPA 8/3	Mod. EPA 8/2	128
12	LJE	14.7 (50)	1.65	92[e]	NA	NA	96.9	21.5	NA	30.1	EPA 8/3	Mod. EPA 8/2	32
30	LJE	14.7 (50)	1.34	96[e]	NA	NA	96.3	25.8	NA	38.7	EPA 8/3	Mod. EPA 8/2	32
6	SB	16.2 (55.2)	0.60	73[d]	NA	NA	95.0	17.2	35	12.9[i]	EPA 8/3	Mod. EPA 8/2	128
11	SB	7.3 (25)	1.00	95[d]	NA	NA	99.5	1.7	40	21.5[h]	EPA 8/3	Mod. EPA 8/2	128
U-24	SB	14.7 (50)	1.46	88[e]	NA	NA	98.1	12.9	NA	34.4	EPA 8/3	Mod. EPA 8/2	33
22-4	TA[b]	6.4 (22)	1.56	71	7.23	6.6	87.5	103	NA	90.3	CEM/4	UNK/2	129
22-41	TA	6.4 (22)	1.61	67	7.57	6.27	94.4	38.7	NA	NA	CEM/1	None	129
30-7	TA[b]	14.7 (50)	1.58	105	6.97	6.2	89.7	77.4	NA	77.4	CEM/5	UNK/2	129
30-71	TA	14.7 (50)	1.66	101	7.1	5.75	95.8	34.4	NA	68.8	CEM/1	UNK/2	129
1	VS	18.3 (62.5)	0.85	86[d]	NA	NA	97	17.2	30	30.1[h]	EPA 8/3	Mod. EPA 8/2	128
2	VS	18.3 (62.5)	1.15	91[d]	NA	NA	97.4	12.9	NA	17.2[h]	EPA 8/3	Mod. EPA 8/2	128
34	VS	18.3 (62.5)	1.00	84[d]	NA	NA	96	21.5	42	17.2[h]	EPA 8/3	Mod. EPA 8/2	128
38	VS	18.3 (62.5)	1.10	82[d]	NA	NA	96	17.2	27	25.8[h]	EPA 8/3	Mod. EPA 8/2	128
64	VS	18.3 (62.5)	1.10	82[d]	NA	NA	96	21.5	46	12.9[h]	EPA 8/3	Mod. EPA 8/2	128
4	ST	18.3 (62.5)	1.01	108[d]	NA	NA	98.0	12.9	56	12.9[i]	EPA 8/3	Mod. EPA 8/3	128
3	UNK[c]	18.3 (62.5)	0.80	94[d]	NA	NA	99.2	4.3	NA	12.9[h]	EPA 8/3	Mod. EPA 8/2	128
5	UNK	8.8 (30)	1.20	76[d]	NA	NA	93.5	30.1	50	12.9[i]	EPA 8/3	Mod. EPA 8/3	128
U-23	UNK	7.3 (25)	1.46	92[e]	NA	NA	98.1	12.9	NA	34.4	EPA 8/3	Mod. EPA 8/2	33

(Continued)

TABLE 3-12. EMISSION DATA FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO OIL-FIRED SMALL STEAM GENERATORS (CONTINUED)

[a] LJE = liquid jet eductor; SB = spray baffle; TA = tray absorber; VS = venturi scrubber; and ST = spray tower.

[b] Both sites use two tray absorbers. Two tray absorbers are known to have lower SO_2 removal efficiencies than those of three tray absorbers. The other two sites (#22-41 and #30-71) use three tray absorbers.

[c] UNK = unknown.

[d] The heat input during the test is determined by multiplying the oil flow rate to the boiler and an assumed heating value of 43,000 kJ/kg (18,500 Btu/lb). The results of the fuel analysis on heating value are not reported in the references.

[e] The heat input during the test is determined using the F-factor, the flue gas flow rate, and the oxygen content flue gas given in the references.

[f] NA = not available.

[g] Divide emissions by 430 to convert to $lb/10^6$ Btu.

[h] Particulate matter emissions are reported in lb/bbl in the references and have been converted to $lb/10^6$ Btu using the assumed heating value of 43,000 kJ/kg (18,500 Btu/lb).

[i] Particulate matter emissions are reported in lb/hr in the references and have been converted to $lb/10^6$ Btu using the calculated heat input as discussed in Footnote d.

[j] All tests were short-term (about 1 hour per run). EPA 8 = EPA Reference Method 8; CEM = continuous emission monitors.

[k] Mod EPA 8 = Modified EPA Reference Method 8 in accordance with California Air Resource Board specifications which measures both PM and SO_2 concentrations in stack gas.

[l] Test results in the above references are also presented in the Industrial Boiler SO_2 Technology Update Report (Reference 130).

TABLE 3-13. AVERAGE RESULTS FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO RESIDUAL OIL-FIRED SMALL STEAM GENERATORS[a]

SO_2 Removal Efficiencies, Percent	
Average Efficiency (± Standard Deviation)	95.2 ± 3.4
Outlet SO_2 Emissions, ng/J (lb/10^6 Btu)[b]	
Average SO_2 Outlet Emissions	30 ± 26 (0.07 ± 0.06)
Sulfur Content in Oil, Weight Percent	
Average Sulfur Content in Oil Fired	1.21 ± 0.31
Average Load, Percent of Full Load	87.5 ± 11.3

[a]Average results based on the data presented in Table 3-12.

[b]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

The results from this analysis of the coal-fired boiler data indicate that sodium scrubbers on residual oil-fired boilers could comply with a 90 percent SO_2 reduction specification using a 30-day rolling averaging period if the mean SO_2 reduction is 91 percent or greater. The SO_2 emission performance is expected to be better for oil than for coal because the sulfur variability of oil is lower than that of coal. The results of the data analysis from the coal-fired boiler are discussed in Section 3.2.6.2.

3.2.6 SO_2 Emission Test Data for Coal-Fired Boilers

3.2.6.1 Low Sulfur Coal Test Data. Low sulfur coals generally represent coals that can meet the existing NSPS for SO_2 of 516 ng/J (1.2 lb/10^6 Btu) for boilers greater than 73.3 MW (250 million Btu/hour) heat input. The variability and performance of low sulfur coal have been addressed in earlier reports in support of NSPS for industrial boilers.[131-133] The results from these references will be briefly summarized.

Unlike SO_2 emissions from oil combustion, those resulting from the combustion of coal vary considerably because the sulfur content of the coal is not homogeneous. Coal produced from a single seam at the same mine may vary substantially in sulfur content. In addition to sulfur content, the heat content of coal also varies. Therefore, when expressing fuel sulfur content on a heat content basis (ng/J or lb/10^6 Btu) and assuming that 100 percent of the sulfur is converted to SO_2, SO_2 emission variability is actually a measure of the joint variability of these two coal properties, heat content and sulfur content. Three other factors which affect the amount of SO_2 emission variability are:

- o the extent to which coal is cleaned prior to shipment (i.e., whether or not PCC is used),
- o coal handling practices at the mine, at the PCC plant, or at the boiler site, and
- o coal lot size, which is the quantity of coal consumed by a boiler in one day.

Coal blending decreases the variability in coal sulfur content by physically averaging the sulfur content of coals. The degree of reduction in variability, however, depends on the properties of the coals blended and the specific blending method.

To assess the performance of low sulfur coal as an emission control technique, SO_2 emission data were gathered from five industrial-commercial-institutional boilers and from six electric utility boilers.[134,135] Analyzing the data sets of these 11 boilers using a time series statistical model [AR(1) model], the model projected a ratio of 1.43 between the once-in-10-year maximum expected 30-day rolling average emission rate and the long-term average emission rate for a relative standard deviation (RSD) of 34 percent and an autocorrelation (AC) of 0.7. Such RSD and AC values are representative of SO_2 emission statistics for coal combustion in industrial boilers.[136] These variability statistics predict that a 0.75 weight percent sulfur coal with an average SO_2 emissions of 516 ng/J (1.2 lb/10^6 Btu) would exhibit a once-in-10-years maximum SO_2 emission rate of 731 ng/J (1.7 lb/10^6 Btu), as measured on a 30-day rolling average basis.

3.2.6.2 <u>Sodium Scrubbing Test Data</u>. Thirty days of certified CEM test data were gathered from a sodium scrubber applied to a pulverized coal-fired boiler rated at 55 MW (188 million Btu/hour) heat input (68,000 kg/hour [150,000 lb/hour] of steam).[137] The FGD system tested was a tray and quench liquid scrubber and consisted of a three-stage impingement tower with a Chevron mist eliminator. The scrubbing medium was a 50 percent aqueous NaOH solution. The makeup rate to the scrubber was 0.13 m^3/min (35 gal/min). The design SO_2 efficiency of this system was 90 percent at an inlet SO_2 concentration of 2,000 ppmv.[138]

Figure 3-13 shows consistently high SO_2 removal efficiencies, averaging 96.2 percent for the test period. The daily average outlet SO_2 emissions ranged from 56 to 267 ng/J (0.13 to .62 lb/10^6 Btu), averaging 87 ng/J (0.20 lb/10^6 Btu) for the 30-day test period. The scrubbing solution pH was consistently maintained at an average pH of 8.1. From Figure 3-13, it can be seen that the boiler operated at loads between 40 and 60 percent of full

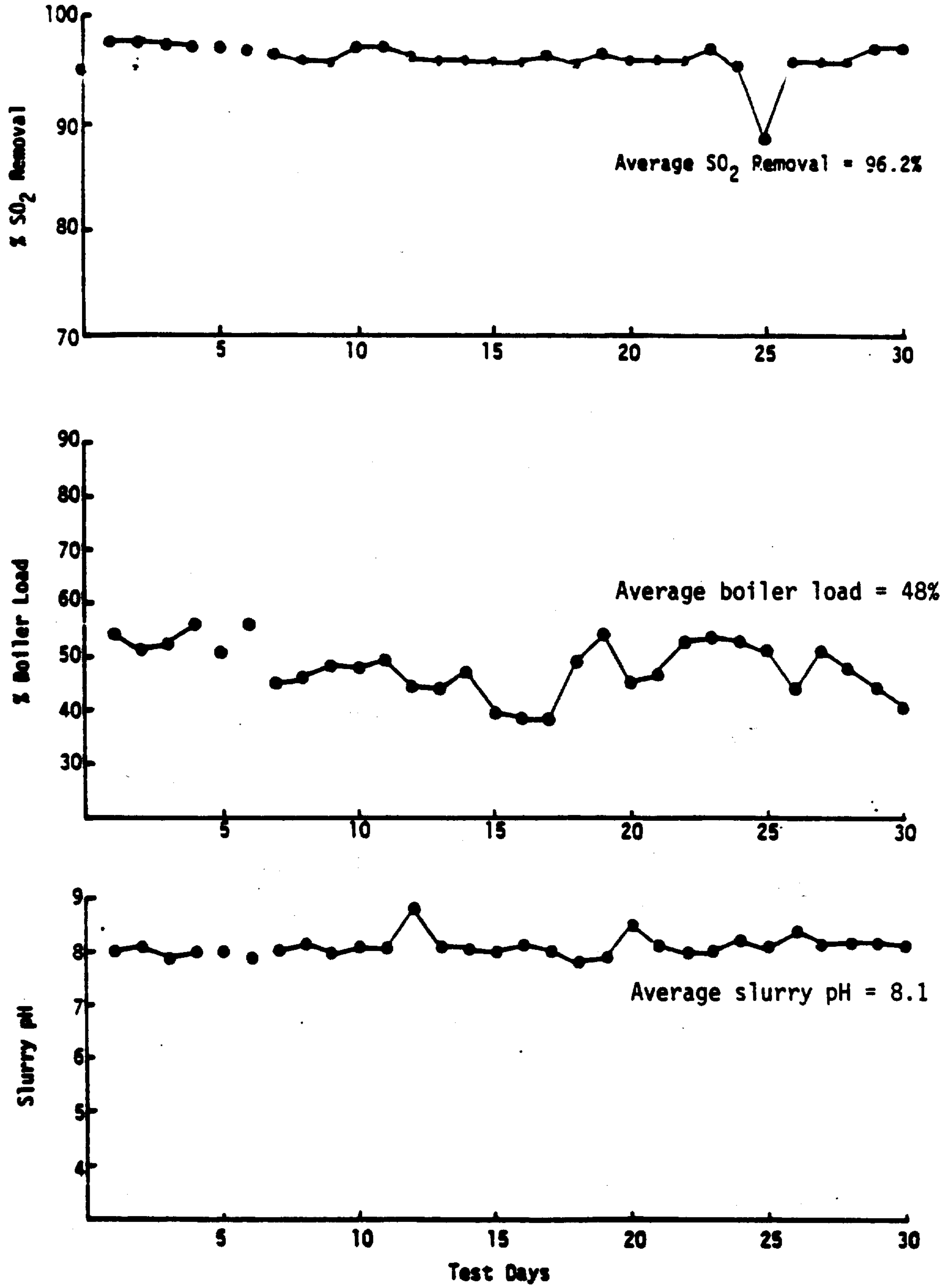


Figure 3-13. Daily average SO_2 removal, boiler load, and slurry pH for coal-fired boiler equipped with a sodium scrubber.[139]

load and averaged 48 percent of full load for the test duration. The sulfur content of the coal fired was 3.6 weight percent.

The long-term data from this FGD scrubber were analyzed for SO_2 emission reduction variability. The results of the variability analysis indicate that a long-term mean of 91 percent SO_2 reduction would be required to comply with a 90 percent SO_2 reduction limit based on a 30-day rolling average with no more than one exceedance every 10 years.[140] An RSD of 1.2 percent and an AC of 0.13 were determined from the SO_2 reduction data for this boiler.[141] If the mean SO_2 reduction performance of 94 percent were maintained over a long period of time at full load, then the sodium scrubber would be in compliance with a 90 percent SO_2 reduction specification using a 30-day rolling average.

It is also expected that if the inlet SO_2 concentrations are 2,000 ppmv or less and that FGD operating parameters (e.g., pH, TSC, and liquid-to-gas flow ratio) adjusted accordingly with increasing load, then the SO_2 removal efficiency for the FGD system of the tested boiler would meet at least the design SO_2 removal efficiency of 90 percent at full load. During the 30-day test, the inlet SO_2 emissions averaged about 1,800 ppm.[142]

Although the FGD scrubber is applied to a boiler rated above 29.3 MW (100 million Btu/hour) heat input, the test data on this scrubber are applicable to small boilers because SO_2 emissions on a heat input basis are independent of boiler type and size and are dependent only upon fuel type and sulfur content. In addition, FGD system design and operating characteristics do not vary significantly with size in this general size range.

3.2.6.3 Fluidized Bed Combustion Test Data. Table 3-14 presents SO_2 emission data for four bubbling bed and one circulating bed FBC boilers. Certified CEM or EPA Reference Methods were used to measure SO_2 emissions. Tests using EPA Methods were short-term tests (approximately three hour tests) except otherwise stated in Table 3-14, while tests using CEM's were long-term tests. The results from this table show that SO_2 removal efficiencies ranged from 86 to 99 percent for tests on the four bubbling bed boilers. The range of outlet SO_2 emissions is from 26 ng/J (0.16 lb/10^6

TABLE 3-14. FLUIDIZED BED COMBUSTION EMISSION TEST DATA

Plant owner/location	Type of unit[a]	Boiler size 10^6 Btu/hr heat input	Percent sulfur in coal	Percent of full load	Ca/S Ratio	Sorbent type	Sorbent size, mm	Bed temperature, °C	Recycle ratio	SO_2 Emissions Data: SO_2 removal efficiency, percent	SO_2 Emissions Data: Outlet SO_2 emissions, ng/J[h]	NO_x emissions, ng/J[h]	PM emissions, ng/J	Emission test methods (test duration)
Iowa Beef Processors,[143] Amarillo, TX	Pkg. Sb	26.4 (90)	4.2	59	3.1	Dolomite	16 x 21.7	878 (763)[b]	0	91	258	396	NM[c]	SO_2-CEM (1)[d] NO_x-CEM (1)
Idaho National[144] Engineering Labs Scoville, ID	Pkg. Bb	24.0 (82)	0.85	56	ND[e]	Limestone	3.2 x 0.8	NA[f]	0	86	69	NM	NM	SO_2-CEM (67)
Sohio Oil Corp.[145] Lima, OH	Pkg. Bb	28.4 (97)	3.6	72	NA	Limestone	6.3 x 0	NA	0	90	267	241	NM	SO_2-EPA-6 (3 hrs) NO_x-EPA-7 (3 hrs)
Summerside C.F.B.[146] Prince Edward Island, Canada	Pkg. Bb	14.7 (50)	6.0	72	3.7	Limestone	2.4 x 0.8	837	ND[g]	94	258	267	NM	SO_2-CEM (7.5) NO_x-CEM (7.5)
Summerside C.F.B.[146] Prince Edward Island, Canada	Pkg. Bb	14.7 (50)	6.5	66	4.5	Limestone	6.3 x 0	838	ND[g]	91	430	258	NM	SO_2-CEM (15 hrs) NO_x-CEM (15 hrs)
Summerside C.F.B.[146] Prince Edward Island, Canada	Pkg. Bb	14.7 (50)	5.7	56	7.2	Limestone	2.4 x 0.8	799	ND[g]	99	26	301	NM	SO_2-CEM (5 hrs) NO_x-CEM (5 hrs)
California Portland Cement Colton, California[147,148]	FE Cb	60.9 (208)	0.43	100	NA	Limestone	0.125 x 0.039	NA	by design	82	56	95	17	SO_2 - EPA-8 (3 hr PM - EPA-5 (3 hrs NO_x - CEM (3 hrs)

[a]Pkg. Sb = Packaged staged bubbling bed; Pkg. Bb = Packaged bubbling bed; and FE Cb = Field-erected circulating bed.

[b]Number in parentheses is the desulfurization bed temperature; number not in parentheses is the combustion bed temperature.

[c]NM = not measured.

[d]CEM = Certified continuous emission monitor. The number in parentheses represent the number of days unless otherwise specified for which emission data are reported in this table.

[e]ND = Not determined; the Ca/S ratio could not be determined at this site because the coal and limestone feed rates were inaccurate.

[f]NA = Not available.

[g]At this site, solids were recycled to the boiler but the rate of solids recycled was not determined for the above tests. However, the recycle ratio was estimated as 4.0 at test conditions similar to those for the 7.5-day test as reported in this table.

[h]Divide emissions by 430 to convert ng/J to lb/10^6 Btu.

Btu) for the bubbling bed boiler at Prince Edward Island firing a 5.7 percent sulfur coal and operating at a Ca/S ratio of 7.2 to 430 ng/J (0.98 $lb/10^6$ Btu) for the same boiler firing a 4.5 percent sulfur coal and operating at a Ca/S ratio of 4.5. For the only staged bed FBC boiler, the operating Ca/S ratio was 3.1, resulting in a 91 percent SO_2 removal efficiency. For the circulating bed FBC boiler firing a 0.43 percent sulfur coal, an SO_2 removal efficiency of 82 percent was achieved. Outlet SO_2 emissions from this boiler were 56 ng/J (0.13 $lb/10^6$ Btu).

The effects of sorbent particle size on SO_2 removal efficiency were examined on the boiler at Prince Edward Island. The results shown in Table 3-14 using two different sizes of limestone indicate that lower SO_2 removal efficiency was achieved while using the coarser limestone (particle sizes of 6.3 millimeters [mm] [0.25 inch] and less) compared to operation with the finer limestone (particle sizes between 2.4 mm and 0.8 mm [0.09 and 0.03 inch]). For the coarser limestone, an SO_2 removal efficiency of 91 percent was achieved by operating the boiler at a Ca/S ratio of 4.5. This compares with an SO_2 removal efficiency of 94 percent while operating with a Ca/S ratio of 3.7 and the finer limestone. Thus, even at the higher Ca/S ratio, the coarser limestone resulted in lower SO_2 removal performance than did the finer limestone. This lower performance can be attributed in part to the larger particle sizes but may also be attributed to the larger percentage of fines in this limestone which may have been readily elutriated from the bed. The particle size distribution analysis supports this contention.[149] Eleven percent of the coarser limestone contained particles smaller than 0.58 mm (0.023 inch) compared to only 2 percent for the finer limestone. Similarly, 23 percent of the coarser limestone contained particles larger than 3.3 mm (0.13 inch) compared to only 3.4 percent for the finer limestone. The calcium carbonate content of both limestones was about 98 weight percent.

In addition to the three test results reported in Table 3-14 for the boiler at Prince Edward Island, emission data were collected for the entire test period of 30 days. Figures 3-14 to 3-16 show the results of SO_2 removal efficiency, Ca/S molar ratio, and boiler load, respectively, for the entire test period. The results in these figures are based on daily

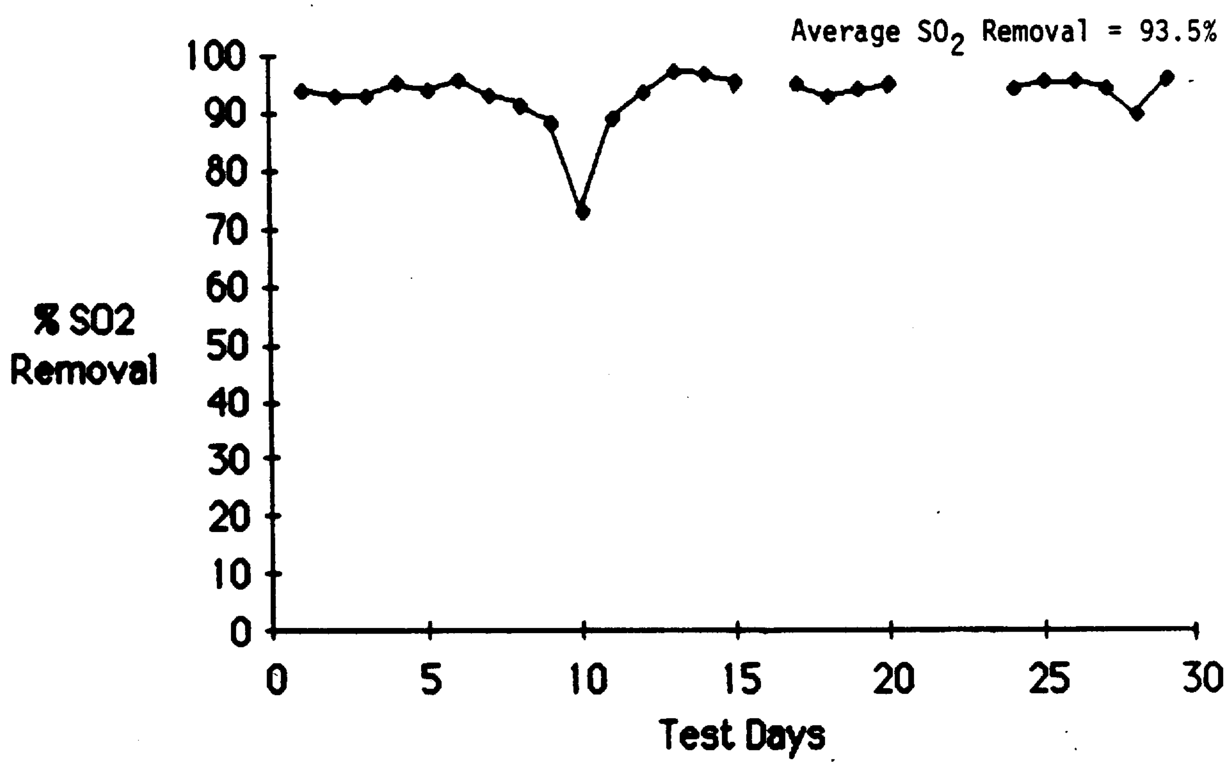


Figure 3-14. Daily average SO_2 removal efficiency for the FBC boiler at Prince Edward Island.[146]

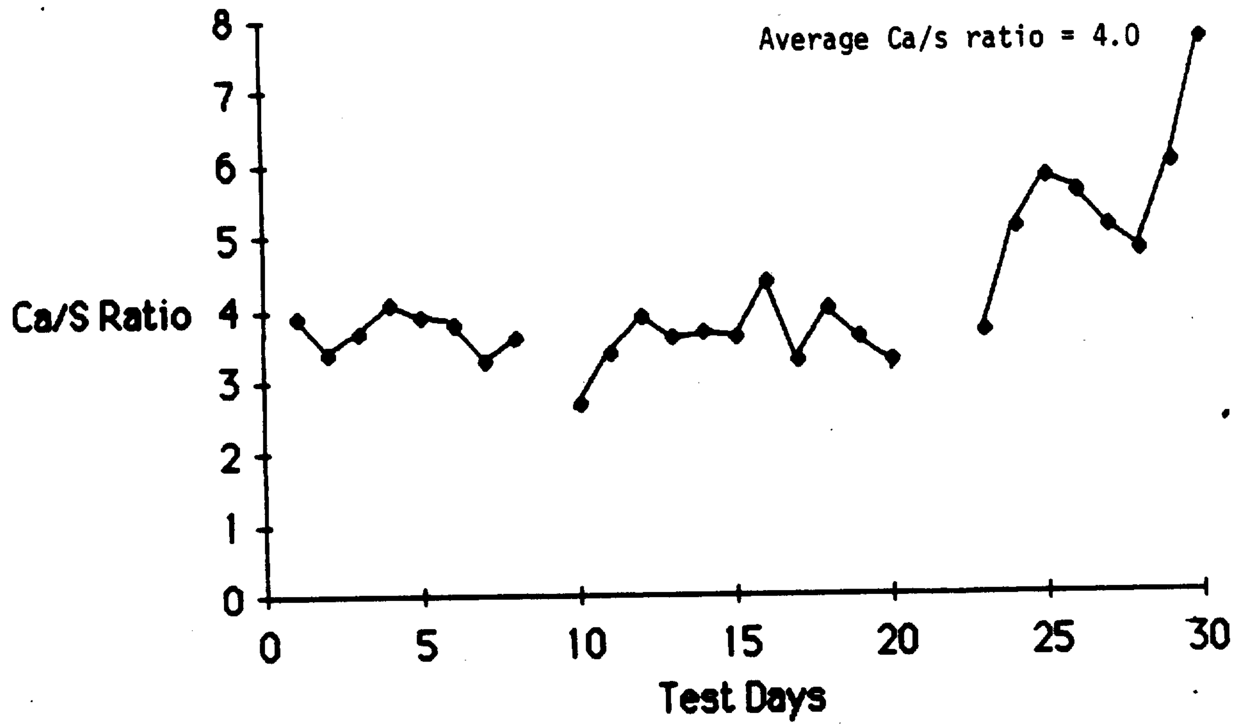


Figure 3-15. Daily average Ca/S molar feed ratio for the FBC boiler at Prince Edward Island.[146]

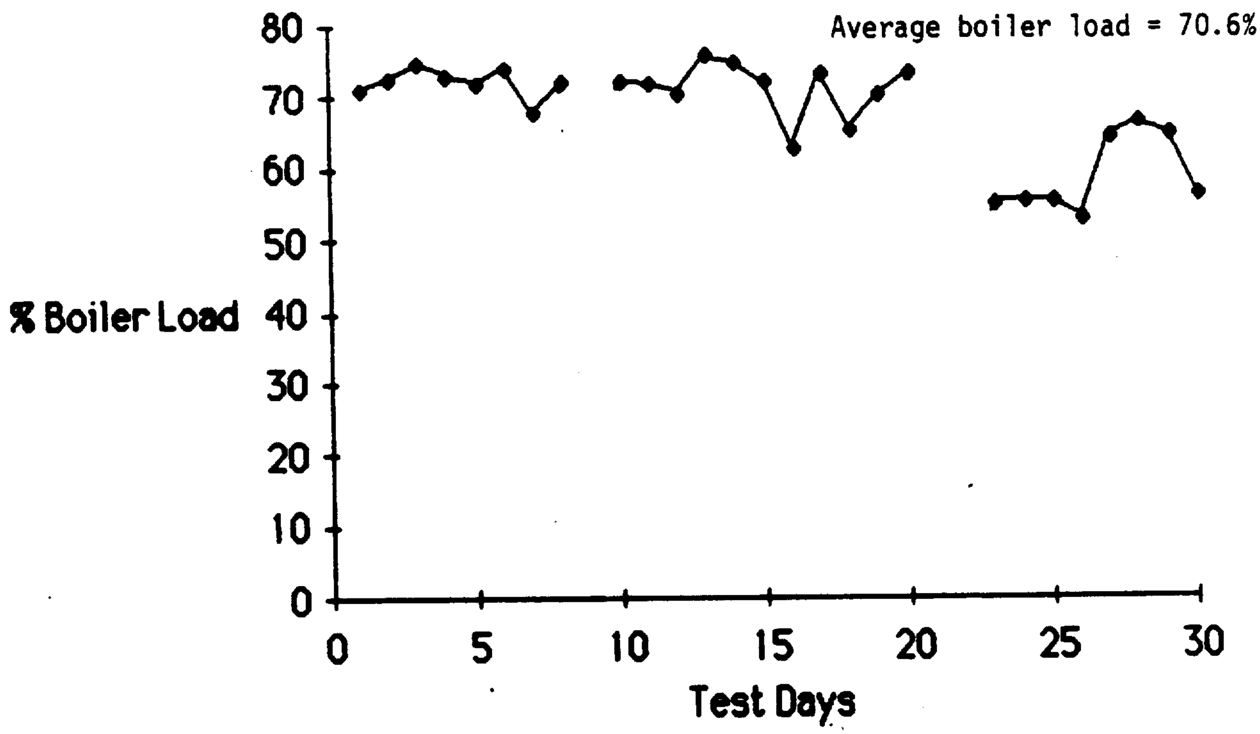


Figure 3-16. Daily average boiler load for the FBC boiler at Prince Edward Island.[146]

average data. The daily average SO_2 removal efficiency ranged from 73 to 97 percent, averaging 93.5 percent. The lower daily average SO_2 removal efficiency of 73 percent on day 10 in Figure 3-14 was attributed to operating the boiler at a low Ca/S ratio of 2.5. The Ca/S ratio was lowered on this day because of inclement weather conditions. The inclement weather forced the plant at the base to reduce ash removal rates since ash disposal trucks could not reach the base. With the exception of day 10, the Ca/S ratio ranged between 3 and 4 for the first 20 days as shown in Figure 3-15; however, because of parametric testing thereafter, the Ca/S ratio increased as high as 7.7. The Ca/S ratio for the entire test period averaged 4.0. Boiler load remained around 70 percent of full load for the first 19 days and then dropped to between 55 and 65 percent for the remainder of the test. Nevertheless, boiler load averaged 70.6 percent of full load for the entire period. It should be noted that the averages reported in Figures 3-14 to 3-16 were weighted averages with respect to the total number of hours of operation. The daily average datapoints in these figures were based on the hours of operation only, which for some days were less than 24 hours.

Emission data for the first 7.5 days of continuous operation from the FBC boiler at Prince Edward Island were analyzed for SO_2 emission reduction variability.[150] This time period represented the longest continuous operating period for which emission and operating data were collected. In view of the 94 percent mean SO_2 reduction efficiency achieved by the FBC unit for the 7.5 days, it is natural to compare this performance to the requirements of a 90 percent reduction specification. The results of the variability analysis indicate that a long-term mean of at least 91.3 percent SO_2 reduction would be required to comply with a 90 percent SO_2 reduction limit based on a 30-day rolling average with no more than one exceedance every 10 years.[151] Therefore, if 94 percent mean SO_2 reduction were maintained, the FBC boiler would be in compliance with a 90 percent SO_2 reduction specification using a 30-day rolling average.

3.3 NO_X CONTROL TECHNIQUES

3.3.1 Introduction

3.3.1.1 NO_X Formation and Control Theory. The term nitrogen oxides (NO_X) refers to the mixture of nitrogen oxide (NO) and nitrogen dioxide (NO_2) present in combustion gases; however, boilers produce predominantly NO due to kinetic limitations in the oxidation of NO to NO_2. Nitrogen oxides are formed by one of two mechanisms. "Thermal NO_X" is the result of the reaction between molecular nitrogen and molecular oxygen, both of which enter the combustion zone in the combustion air. "Fuel NO_X" results from the oxidation of atomic nitrogen which enters the combustion zone chemically bound within the fuel structure.

Natural gas and most distillate oils have little or no chemically bound fuel nitrogen and essentially all NO_X formed is thermal NO_X. Fuel-bound nitrogen content is typically less than 0.1 weight percent for distillate oil. Residual oils and coals both have fuel bound nitrogen and when these fuels are combusted, NO_X is formed by both pathways. The combustion of coals, and residual oils to a lesser extent, produces significant amounts of fuel NO_X since they are rich in nitrogen. Nitrogen content is typically 1.0 to 1.5 weight percent for coal and 0.2 to 0.7 weight percent for residual oil.

Although the detailed mechanism of thermal NO_X formation is not well understood, it is widely accepted that thermal fixation in the combustion zone is described by the Zeldovich equations:

$$N_2 + O \rightleftharpoons NO + N \qquad (3\text{-}10)$$

$$N + O_2 \rightleftharpoons NO + O \qquad (3\text{-}11)$$

The reaction rates of these equations are highly dependent upon both the mixture stoichiometric ratio (i.e., the molecular equivalent air-to-fuel ratio, with "rich and lean" describing the fuel amount) and the flame temperature as shown in Figures 3-17 and 3-18.

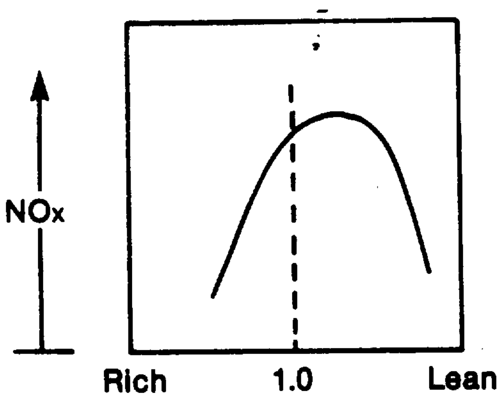


Figure 3-17. Stoichiometry.

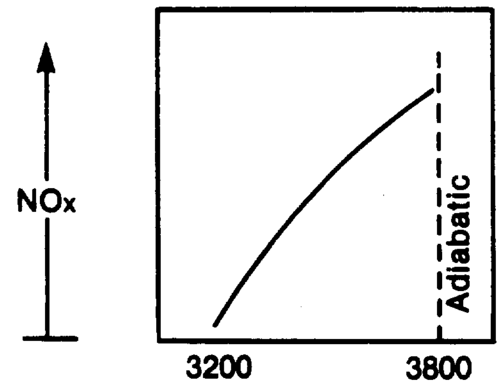


Figure 3-18. Flame temperature.

Figure 3-17[152] illustrates the very strong influence of stoichiometry on thermal NO_x generation. The maximum NO_x occurs at a slightly lean fuel mixture ratio due to the excess availability of oxygen for reaction within the hot flame zone. The very rapid decrease in NO_x for either rich or lean combustion indicates that control of local flame stoichiometry is critically important in achieving reductions in thermal NO_x.

The influence of flame temperature on thermal NO_x generation is shown in Figure 3-18.[153] For a given stoichiometry, the thermal NO_x generation decreases rapidly as the flame temperature drops below the adiabatic temperature. The local flame temperature decreases rapidly along the flame axis as heat is radiated out of the flame. Therefore, most of the thermal NO_x is generated in the flame core and little in the furnace combustion zone surrounding this flame core.

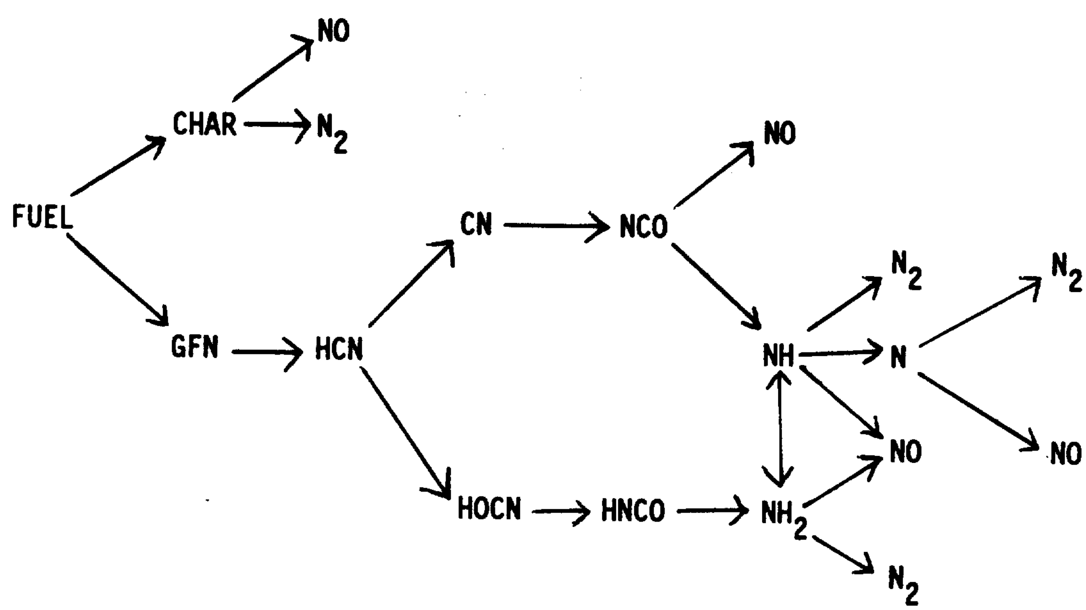
Localized control of the flame temperature is achieved by increasing the time during which combustion occurs and, more important, by decreasing the heat release rate. This is defined as the ratio of the boiler heat input, (MW, Btu/hr), to the heat transfer surface area (M^2, ft^2), or furnace volume (M^3, ft^3). For stokers, the heat release rate is based on the effective grate area.

Small combustion zones which generate high heat release rates and, consequently, high NO_x levels are typical in large, packaged industrial boilers whose furnace size is limited by shipping restrictions. This phenomenon is less of a problem for small boilers with heat inputs of 29.3 MW (100 million Btu/hour) or less. Boilers that are designed for low NO_x emissions generally have larger fireboxes in order to reduce peak flame temperatures.

The mechanisms by which nitrogen compounds (primarily organic) contained in liquid and solid fossil fuels evolve and react to form NO_x are much more complex than the Zeldovich model, and the empirical data are less conclusive. Nevertheless, several independent studies indicate that the fuel-bound nitrogen compounds react to form NO_x in two separate mechanisms: a solid-phase char nitrogen reaction (in solid fuels) and a homogeneous gas-phase reaction resulting from evolution and cracking of volatile compounds (solid and liquid fuels).

The char nitrogen reaction is not well understood and the empirical data are conflicting, although the data show that the char nitrogen conversion to NO_x is dependent on the flame temperature and stoichiometric ratio and on the char characteristics. The precise relations, however, are not known. Conversion rates to NO_x of 15 to 25 percent have been documented.[154]

The gas-phase reaction is postulated to include a number of intermediate reactions:[155]



where GFN is the gas phase nitrogen content of the volatiles.

These reactions have been shown to produce the intermediate species at rapid reaction rates. The decay rate of the intermediate species into N_2 (fuel rich) and NO_x (fuel lean) is slower by at least an order of magnitude. The rates are strongly dependent upon the stoichiometric ratio and the gas phase fuel nitrogen concentration, weakly dependent upon the flame temperature, and independent of the structure of the nitrogen compounds in the fuel. It is the weak influence of temperature on gas-phase fuel NO_x conversion that reduces the effectiveness of NO_x controls which rely on temperature effects in the combustion of nitrogen-bearing fuels.

Low NO_x operation for high nitrogen-containing fuels involves introducing the fuel with a substoichiometric amount of combustion air. In this situation, combustion initiates and fuel nitrogen is released in a reducing atmosphere which favors the reduction of fuel nitrogen to N_2 rather than the oxidation to NO_x. The balance of the combustion air is then injected in secondary and tertiary zones surrounding the fuel rich primary flame zone for ensuring complete combustion. Here, as with thermal NO_x, controlling excess oxygen (O_2) is an important part of controlling NO_x formation.

3.3.1.2 <u>NO_x Control Techniques Evaluated</u>. Table 3-15 lists the NO_x control techniques that are commercially available and applicable to small boilers.

Section 3.3.2 discusses low excess air (LEA) technology; Section 3.3.3 covers flue gas recirculation (FGR). Section 3.3.4 discusses overfire air (OFA) for watertube and FBC boilers. Section 3.3.5 discusses low NO_x burners (LNB) applied to natural gas- and oil-fired boilers.

Emission data and data analysis are presented in Sections 3.3.6, 3.3.7, 3.3.8, and 3.3.9 for natural gas-, distillate oil-, residual oil-, and coal-fired boilers, respectively, rated at 29.3 MW (100 million Btu/hour) or less. The NO_x control techniques of reduced air preheat (RAP) and combining OFA with FGR are presented and discussed in this chapter.

TABLE 3-15. SYSTEMS OF NO_x EMISSION REDUCTION: BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS

NO_x Control	Candidate Boilers	Availability
Low Excess Air (LEA)	Natural gas-, distillate oil-, and residual oil-fired boilers	Latest designed low excess air burner from Coen, Cleaver Brooks, and Peabody Engineering is available for small boilers.
	Coal-fired stoker boilers	Available.
Flue Gas Recirculation (FGR)	Natural gas- and distillate oil-fired boilers	Available from three boiler manufacturers (Keeler/Dorr Oliver, Coen, and Cleaver Brooks).
	Coal-fired spreader stoker boilers	Available from one boiler manufacturer (Zurn).
Overfire Air (OFA)	Natural gas-, distillate oil-, and residual oil-fired boilers	Available from four boiler manufacturers (Zurn, B&W, Keeler/Dorr-Oliver, and Cleaver Brooks).
Fluidized Bed Combustion (FBC)	Coal-fired boilers	Available from 17 U.S. manufacturers.[156]
Low NO_x Burners (LNB)	Natural gas-, distilate oil-, and residual oil-fired boilers	Two manufacturers (John Zink and B&W) are offering this burner to small industrial boilers. Two other manufacturers (Process Combustion, and North American) are offering this burner type to small oil-field steam generators. One manufacturer (Coen) is offering this burner to process heaters.

3.3.2 Low Excess Air

3.3.2.1 Process Description. Low excess air can be applied to all boilers between 2.9 and 29.3 MW (10 and 100 million Btu/hour) heat input. In this technique, the combustion air flow is reduced to the minimum amount needed for complete combustion. The level to which the excess air may be lowered is usually limited by the onset of carbon monoxide (CO) and smoke formation due to incomplete combustion.

Reducing the total excess air level reduces the local flame zone concentration of O_2, thus decreasing thermal NO_x emissions. The lower O_2 concentration in the flame zone also leads to lower fuel NO_x emissions, but fuel NO_x is also affected by the amount of mixing within the flame core. Fuel NO_x formation will be slowed by reducing the amount of mixing between the fuel and the air in the flame core. Low excess air operation generally does not reduce the fuel-to-air mixing in the flame core. Therefore, LEA will become less effective in reducing fuel NO_x emissions of higher nitrogen fuels such as coal or residual oil. Low excess air operation may be used as the primary NO_x control method or in combination with other NO_x controls such as LNB, OFA, or FGR.

Operation with LEA also presents an economic incentive to boiler operators since it results in increased boiler efficiency. Boiler efficiency is improved with LEA because less combustion air is heated and more heat of combustion is transferred for producing steam, thus lowering fuel requirements for the same steam output rate.

Firetube and watertube boilers can operate at lower excess air levels (at 10 percent excess air, or about 2 percent excess O_2 in the flue gas, and less) using two available types of control equipment. The first type uses an O_2 trim device on a conventional burner/boiler system to regulate the combustion air flow rate for achieving a desired excess O_2 level in the stack. This O_2 trim system is connected either to the air or to the fuel control instrumentation of the boiler for regulating air or fuel rates. In fact, the O_2 trim system can be linked to a burner management system for regulating both air and fuel rates. The O_2 sensor of the trim system is a continuous monitor which analyzes flue gas O_2 content in the boiler stack.

An O_2 trim system is needed for LEA operation to ensure that lower, yet sufficient, excess air levels are maintained under boiler load variations. The boiler can operate at lower excess air levels safely with an O_2 trim system and use of an O_2 trim system results in reduced fuel consumption.[157]

The second control equipment option for LEA operation is to combine an LEA burner and an O_2 trim system. This burner can operate at lower excess air levels than a conventional burner, typically between 1 and 2 percent excess O_2 (5 to 10 percent excess air) for gas or oil firing.[158-160]

It should be noted that the term "excess O_2" in this section and other sections of this report refers to the O_2 content of the stack gas. In the absence of air infiltration, this value is equivalent to the amount of O_2 in excess of that required for stoichiometric combustion.

For coal-fired stokers, low excess air is achieved by design and adjustment of the combustion air delivery system. Typical stack O_2 levels without LEA are about 6 percent (40 percent excess air) on newer units and about 5 percent (30 percent excess air) when LEA is applied.[161,162]

Coal-fired stoker boilers are generally balanced draft units, with both forced draft (FD) and induced draft (ID) fans. Often, these units control combustion air flow based on furnace draft pressure. The FD fan damper automatically adjusts to changes in furnace pressure, and the ID fan tracks the FD fan signal. By including an O_2 trim system, better O_2 control can be obtained in the boiler under extreme load variations.

3.3.2.2 <u>Factors Affecting Performance</u>. As discussed previously, lowering the excess air generally reduces NO_x emissions. Low excess air controls require more reliable combustion air control to ensure safe operation. Reducing the excess air level below stoichiometric air requirements can lead to a rapid increase in CO, hydrocarbon, and smoke emissions. Application of LEA controls requires not only the means of adjusting air flow at various loads, but also the installation of flue gas O_2 and CO monitors to provide feedback to the combustion air flow controller. For many cases, LEA is controlled automatically using an O_2 trim system. Also, proper burner design resulting in good fuel/air mixing is important for operating at lower excess air levels and for maintaining complete combustion.

3.3.3 Flue Gas Recirculation

3.3.3.1 Process Description. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with the combustion air prior to being fed to the burner or grate.

The FGR system reduces NO_x emissions formation by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone and lowers the peak flame temperature, thereby reducing the amount of thermal NO_x formation. To a lesser extent, FGR also reduces thermal NO_x formation by lowering the O_2 concentration in the primary flame zone. Flue gas recirculation is effective in reducing NO_x emissions in natural gas- and distillate oil-fired boilers, since nearly all of the NO_x generated during combustion of these fuels is thermal NO_x.

However, FGR is not as effective in reducing NO_x emissions from residual oil- and coal-fired boilers. This is due to the large fuel NO_x component of those fuels which is not reduced by the thermal NO_x control.

Flue gas recirculation systems have been applied primarily to packaged watertube boilers, although some FGR systems have been installed on firetube boilers. Typical layouts for an FGR system on a firetube and packaged watertube boiler are shown in Figures 3-19 and 3-20, respectively.

Major equipment items shown in Figures 3-19 and 3-20 are the FGR fan and motor and the FGR ducting from the stack to the windbox. In addition, one boiler manufacturer provides a shut off damper, a flowmeter, and controlled flow damper. For a boiler being retrofitted with FGR, modifications must be made to the stack and windbox to accommodate the FGR duct.

One boiler manufacturer recently introduced an FGR design for stokers, referred to as stoker gas recirculation. The Zurn process was developed by KVB and is shown schematically in Figure 3-21.

Stoker gas recirculation was designed as a technique for reducing excess air requirements and for improving boiler control. The system was not designed for, nor is it presently marketed as, a NO_x control system.

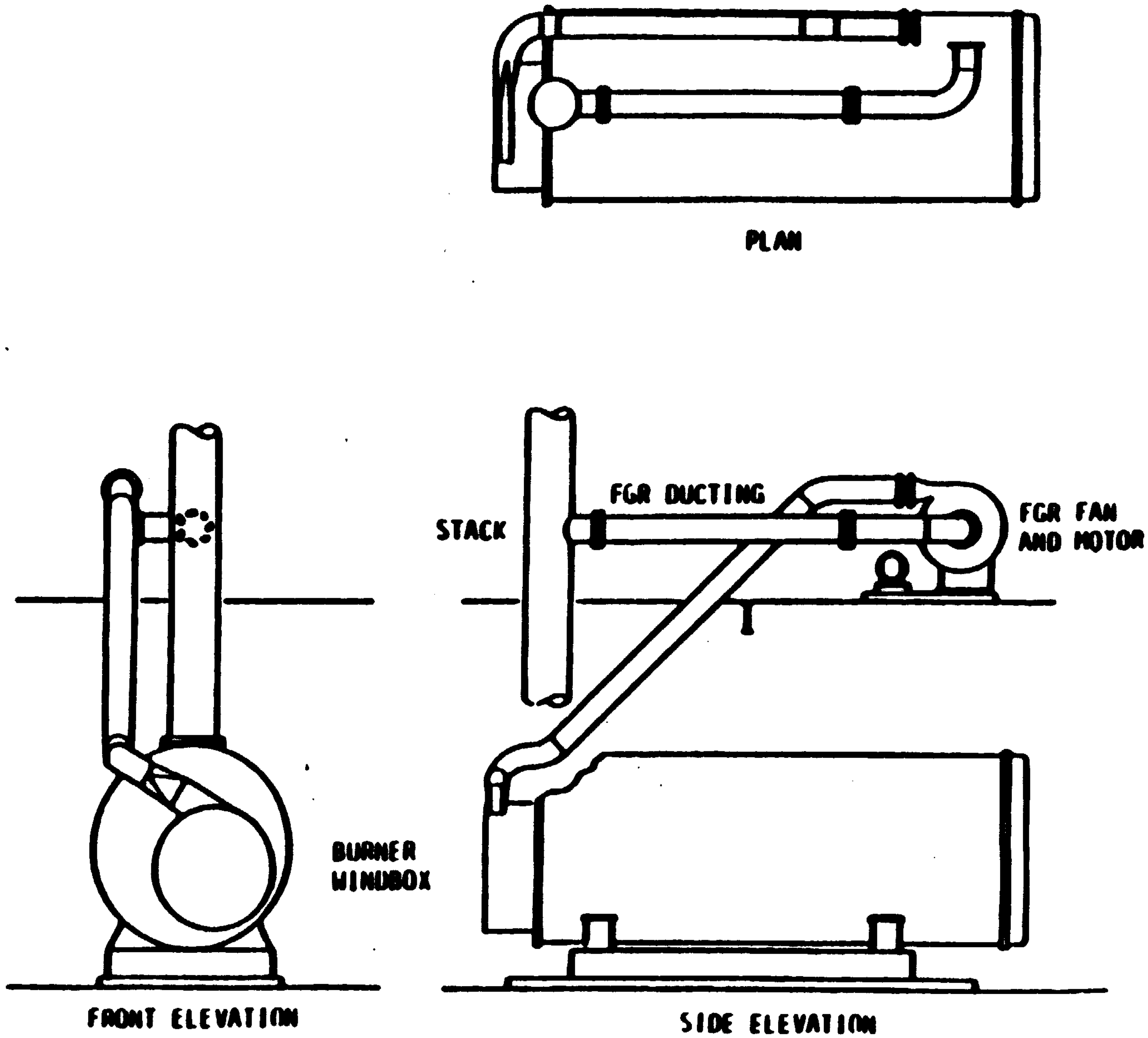
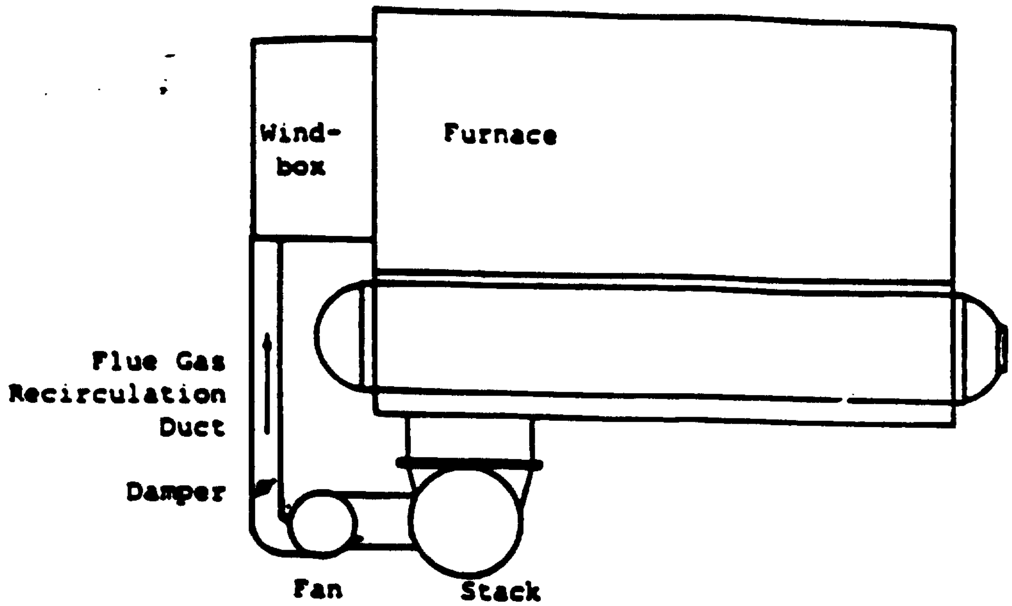
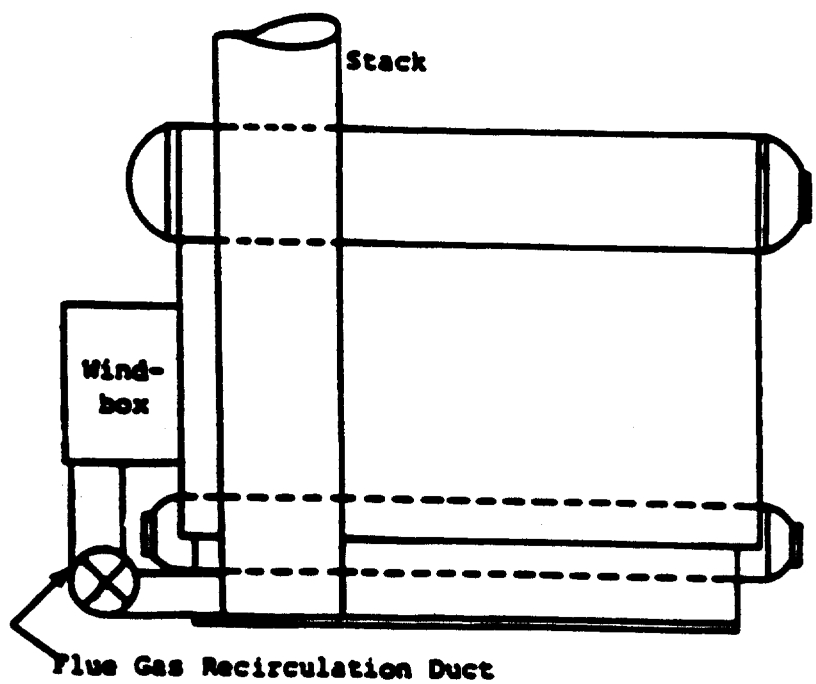


Figure 3-19. FGR system layout for firetube boiler.[163]



(a) Top View



(b) Side View

Figure 3-20. FGR system layout for packaged watertube boiler.[164]

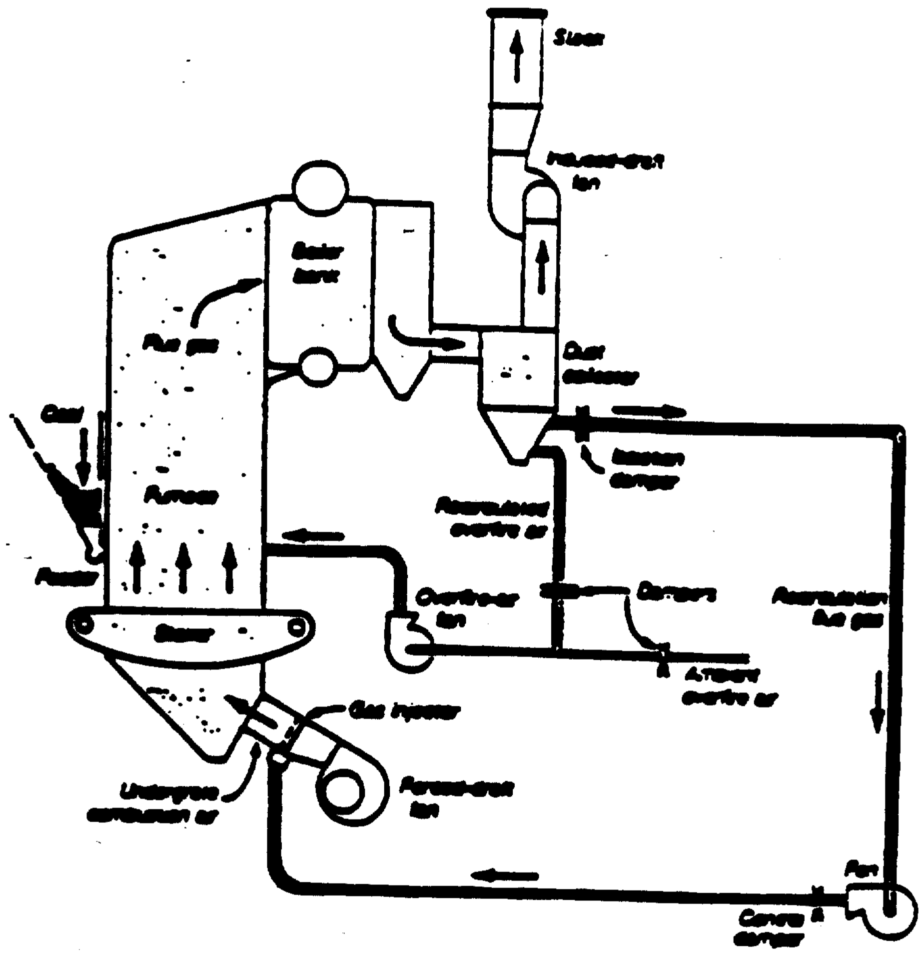


Figure 3-21. Stoker gas recirculation system for spreader stoker coal-fired boiler.[165]

With FGR, excess air can be reduced since the flue gas injected under the grate increases the gas flow through the bed and is of higher heat capacity, thus cooling the bed and avoiding clinker formation. Temperatures above the bed are reduced by as much as 120°C (250°F).[166] Lower excess air and the cooling effect tend to lower thermal NO_x emissions but have minimal impact on the more significant fuel-NO_x emissions.

3.3.3.2 <u>Factors Affecting Performance</u>. As the amount of flue gas recirculated to the boiler is increased, NO_x emissions will decrease. The effectiveness of FGR depends on the type of fuel being fired in the boiler and the boiler heat release rate. As discussed previously, FGR is effective in reducing thermal NO_x emissions; therefore, this technique is most effective in reducing NO_x emissions from boilers firing natural gas or distillate oil and is least effective for boilers firing residual oil or coal. Also, FGR is more effective in reducing NO_x emissions for high heat release rate boilers than for those with low heat release rates. By recirculating the flue gas to the combustion zone, the peak flame temperature is lowered, thereby lowering thermal NO_x emissions. Therefore, the potential for reducing NO_x emissions is greater for boilers having high heat release rates because the potential for reducing the peak flame temperature is greater.

As discussed above for LEA, increasing the FGR rate to the point where the delivered combustion air rate is below stoichiometric air requirements can lead to a rapid increase in CO, hydrocarbon, and smoke emissions. Proper flue gas, air, and fuel mixing is important for operating at high FGR rates and for maintaining complete combustion.

3.3.4 <u>Staged Combustion - Overfire Air</u>

3.3.4.1 <u>Process Description</u>.

3.3.4.1.1 <u>Firetube and watertube steam generators</u>. In staged combustion systems, conventional burners are used to introduce the fuel and sub-stoichiometric quantities of combustion air (primary air) into the boiler. The remaining combustion air (secondary air) is introduced approximately one-third of the distance down the furnace through overfire air (OFA) ports.

The OFA system reduces NO_x emissions formation by two mechanisms. Staging the combustion air partially delays the combustion process, resulting in a cooler flame and suppressing thermal NO_x formation. The staging of the combustion air also promotes a deprivation of O_2 and less complete mixing of fuel and air in the combustion region where fuel nitrogen evolves, thereby reducing fuel NO_x formation.

Overfire air systems have been applied mainly to watertube boilers rather than to firetube boilers. However, an OFA system was retrofitted on an experimental firetube boiler.[167] Figure 3-22 shows an overfire air system applied to a packaged watertube boiler.

The latest OFA system designs on watertube boilers incorporate high pressure injection of the overfire air. The high pressure injection promotes rapid and complete mixing of the remaining unburnt fuel with the secondary air. As a result, the secondary combustion reactions are rapid and complete, minimizing flame extension.

Coal-fired stokers achieve partial staged combustion by the nature of their design. Part of the fuel is combusted on the grate while the rest is burned in suspension above the grate. Combustion air can be split and introduced both below the grate and above the grate through OFA ports. Many stokers have OFA ports as smoke control devices. Therefore, the location of the OFA ports in the boiler may not be at the optimum location to achieve the greatest NO_x reductions. For stokers rated at heat inputs above 29.3 MW (100 million Btu/hr), NO_x reductions of 10 to 25 percent have been achieved.[168]

Reductions in NO_x are enhanced further by reducing the undergrate air flow and by increasing the air flow through the OFA ports. However, reducing the undergrate air flow to achieve a staging effect significantly greater than that which occurs naturally in stokers can result in serious operating problems.[169] Some of these problems are grate overheating, corrosion, and clinker formation. The effect of these operating problems

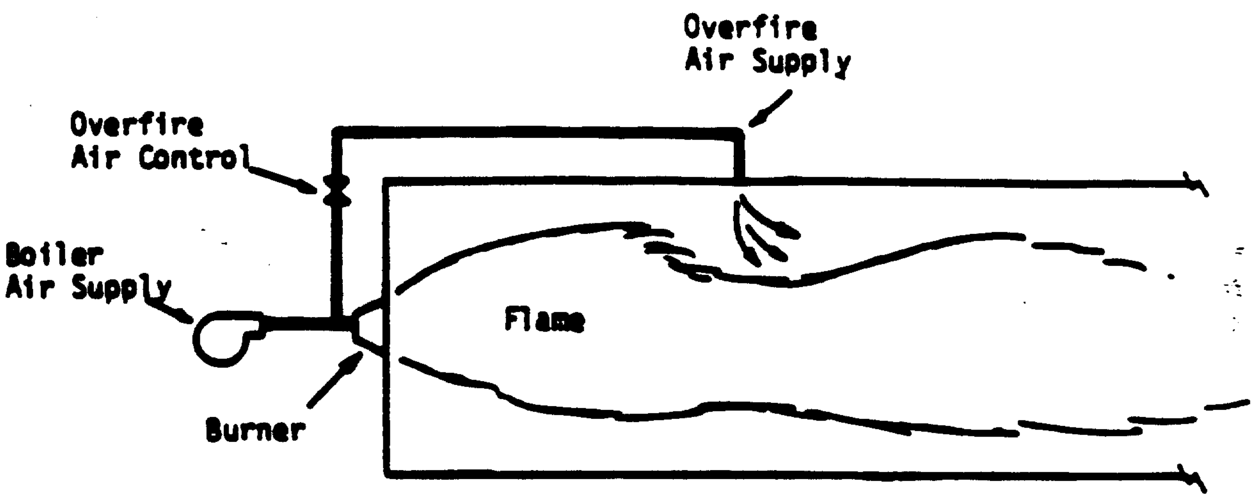


Figure 3-22. Overfire air system applied to a packaged boiler.

limits the use of this technology for NO_x control in coal-fired stokers. However, most of these problems can be eliminated by careful operator attention and adequate boiler control instrumentation (i.e., O_2 trim systems, CO and smoke monitors, better OFA controls, etc.).

3.3.4.1.2 Fluidized bed combustion boilers. Small boilers using FBC technology inherently produce NO_x emissions which are comparable to those from spreader stokers. The use of solids recycle can lead to reduction in NO_x emissions by the heterogeneous reactions between the carbon contained in the recycled solids and NO. Emissions of NO_x from FBC boilers can be reduced further by staging of the combustion air. A substoichiometric amount of air is added at the fluidizing air (primary air) injection point. The balance of the air needed to achieve adequate combustion efficiency is added above the bed. This allows combustion to be completed in the freeboard (i.e., space between the top of the fluidized bed and boiler outlet).

Bubbling bed boilers can be modified to operate with OFA ports. However, OFA ports are usually installed to improve combustion efficiency and SO_2 removal efficiency. One bubbling bed design which incorporates combustion air staging is the staged-bed FBC boiler. As discussed in Section 3.2.4.1, the total combustion air to this system is split between an upper bed where limestone is added for SO_2 control and a lower bed where optimum combustion temperatures are maintained to maximize boiler efficiency. However, this type of boiler is designed primarily for optimizing boiler efficiency and SO_2 removal with only secondary consideration to controlling NO_x emissions.

Circulating bed boilers are also designed with staging of the combustion air. Primary air is injected under the bottom of the combustion chamber creating a dense bed of large particles and a circulating entrained bed of fine particles. Secondary air is injected through air ports above the dense bed zone to improve combustion efficiency and reduce NO_x emissions.

3.3.4.2 Factors Affecting Performance. The variable having the greatest impact on NO_x emissions for staged combustion is the primary-to-stoichiometric air ratio, defined as the ratio of the air rate introduced either through a conventional burner for gas- and oil-firing or through the distributor plate for coal-firing to the calculated stoichiometric air rate. As the primary/stoichiometric air ratio is decreased, NO_x emissions will decrease. However, lowering the primary/stoichiometric air ratio in the boiler beyond its design capabilities will lead to operational problems such as high CO, hydrocarbon, and smoke emissions due to low primary air flow rates, creating incomplete combustion conditions.

Also, for natural gas- and oil-fired watertube boilers, a staged flame is larger and extends further into the furnace than an unstaged flame. This could lead to flame impingement on the rear furnace wall (or side walls) causing premature tube failures and/or refractory damage. These factors diminish the applicability of staging techniques for boilers with high heat release rates [greater than 426 kJ/sec-m^2 (135,000 Btu/hr-ft^2) based on radiant surface area or greater than 828 kJ/sec-m^3 (80,000 Btu/hr-ft^3) based on furnace volume].[170, 171] Small watertube boilers have heat release rates generally below 828 kJ/sec-m^3 (80,000 Btu/hr-ft^3).[172]

Using staged combustion in combination with LEA in small boilers will lead to further improvements in NO_x reduction. The amount of staging and the amount of the excess air reduction required to optimize NO_x emission reduction will depend upon boiler design, operational practices, and the fuel being fired. For most steam generators, decreasing the total excess air at the same primary-to-stoichiometric air ratio will decrease NO_x emissions.

3.3.5 Staged Combustion - Low NO_x Burners

3.3.5.1 Process Description. Staged combustion with LNB reduces NO_x formation by carrying out the combustion, as the name implies, in stages. The staging technique is similar to that of the OFA system except that the combustion staging is achieved at and within the burner rather than further up in the furnace.

As with OFA, the burner staging delays combustion and reduces the peak flame temperature, thus reducing the amount of thermal NO_x. For this reason, LNB should be as effective as OFA in controlling NO_x emissions from boilers burning low nitrogen fuels such as natural gas and distillate oil.

The substoichiometric O_2 levels (introduced with the primary combustion air into the high temperature, fuel nitrogen evolution zones of the flame core) reduce fuel NO_x formation. This makes LNB effective in controlling NO_x emissions from boilers burning high nitrogen fuels such as residual oil or pulverized coal.

Although pulverized coal-fired boilers are not expected to be employed in the small boiler size range, much of the LNB technology was developed on pilot plant units (with less than 29.3 MW [100 million Btu/hour] heat input capacity) for application to pulverized coal-fired utility boilers. Low-NO_x burners have been applied to watertube boilers. One burner manufacturer is testing a ceramic fiber LNB for natural gas-fired firetube boilers.[173] However, this burner is available commercially for natural gas-fired firetube boilers rated at 1.2 MW (4 million Btu/hour) heat input or less. The manufacturer of this burner indicates that they plan to scale-up the burner for larger firetube boilers in the near future.[174]

3.3.5.2 Types of low NO_x burners. There are basically four types of LNB's applied to small watertube boilers: staged air burners, staged air burners with internal recirculation, staged fuel burners, and split-flame burners. The staged air and staged fuel burners are the only LNB types that are commercially available at present for small boiler application. However, the other two LNB types are discussed in this section since they could possibly be developed for small watertube boiler application in the future. With the exception of the radiant flame LNB, no LNB's are available for firetube boilers.

3.3.5.2.1 Staged air burner. Staged air burners can be designed to combust natural gas either alone or in conjunction with a wide range of liquid fuels ranging from light distillate oil to heavy residual oils. To allow flexibility, most staged air burners are designed for multiple fuel capabilities.

The cross-sectional view of one type of staged air burner is shown in Figure 3-23. Only a portion of the combustion air is introduced with the fuel at the point of fuel injection. This air is designated as primary combustion air. A substantial amount of secondary combustion air is introduced in the burner throat. Finally, the remaining combustion air (if any), designated as tertiary air, is introduced at the burner face and is directed down the boiler walls in such a manner that it does not mix with the flame until it reaches zones deeper into the firebox.

The staged air burner reduces NO_x formation by two mechanisms. Staging the combustion air elongates the flame and delays combustion. This results in a cooler flame and reduces thermal NO_x formation. Secondly, with proper combustion air staging, low O_2 levels can be maintained in the specific combustion regions where fuel nitrogen is evolved from the fuel, thus suppressing fuel NO_x formation.

At present, the staged air LNB is being offered by five manufacturers for applications to gas- and oil-fired boilers. Two manufacturers have applied the staged air burner to boilers between 6.4 and 29.3 MW (25 and 100 million Btu/hour) heat input.[175,176] Two other manufacturers have applied this burner type to oil-field steam generators rated between 6.4 and 29.3 MW (22 and 100 million Btu/hour) heat input.[177,178] One additional manufacturer has applied this burner type to process heaters.[179]

3.3.5.2.2 Staged Fuel Burner. Staged fuel burners are designed for the combustion of gaseous fuels such as natural gas. The cross-sectional view of a staged fuel burner is shown in Figure 3-24. This burner achieves staged combustion by introducing the fuel into two combustion zones.

In the primary combustion zone, the fuel is combusted with an excess of air. This continues until the flame front reaches the second combustion zone which is located downstream of the burner face. At this point the secondary fuel contacts the main flame at such a rate as to keep the entire burner operating within proper stoichiometric limits. The resulting flame is partitioned into almost two separate flames.

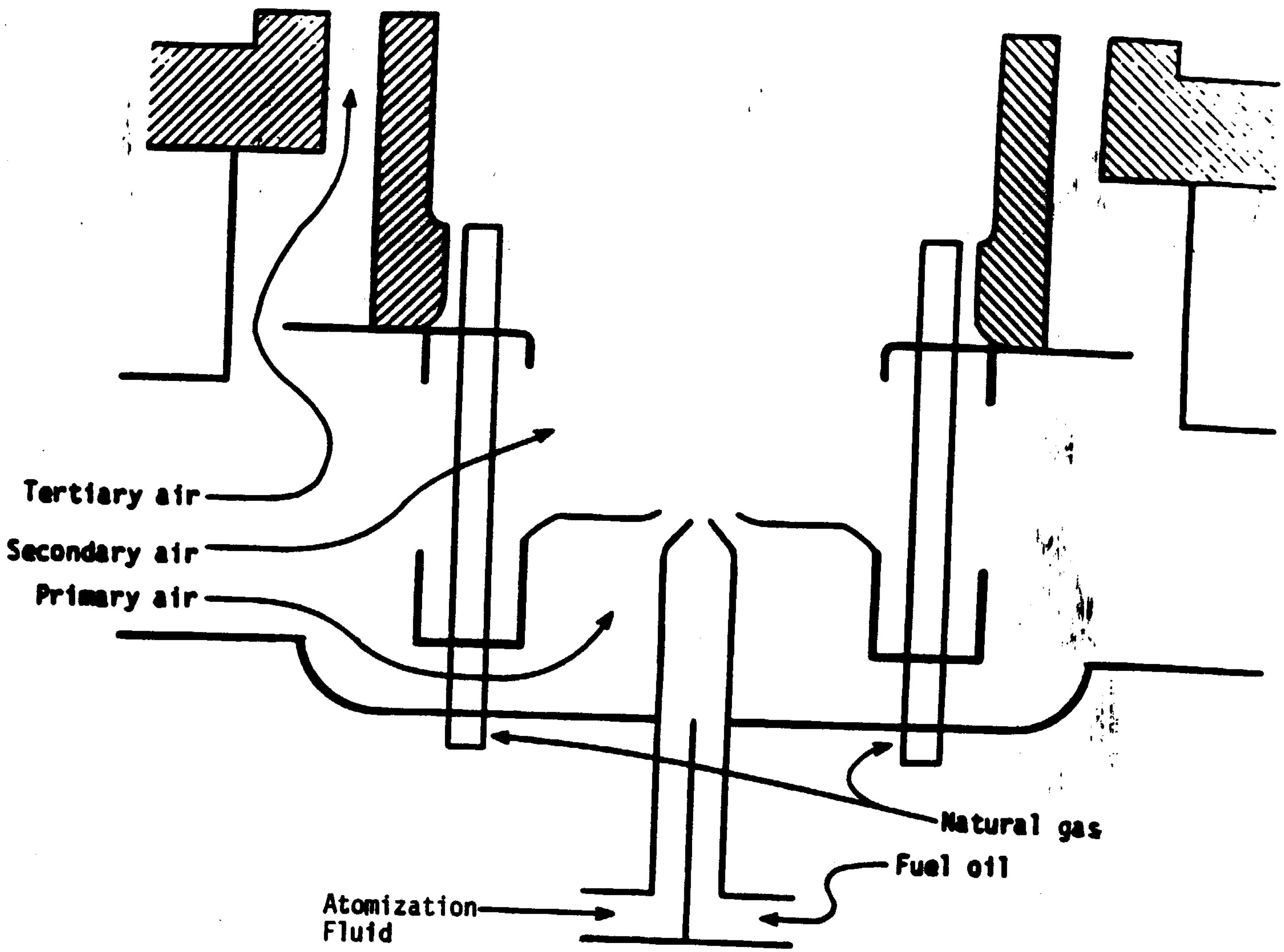


Figure 3-23. Staged air burner.

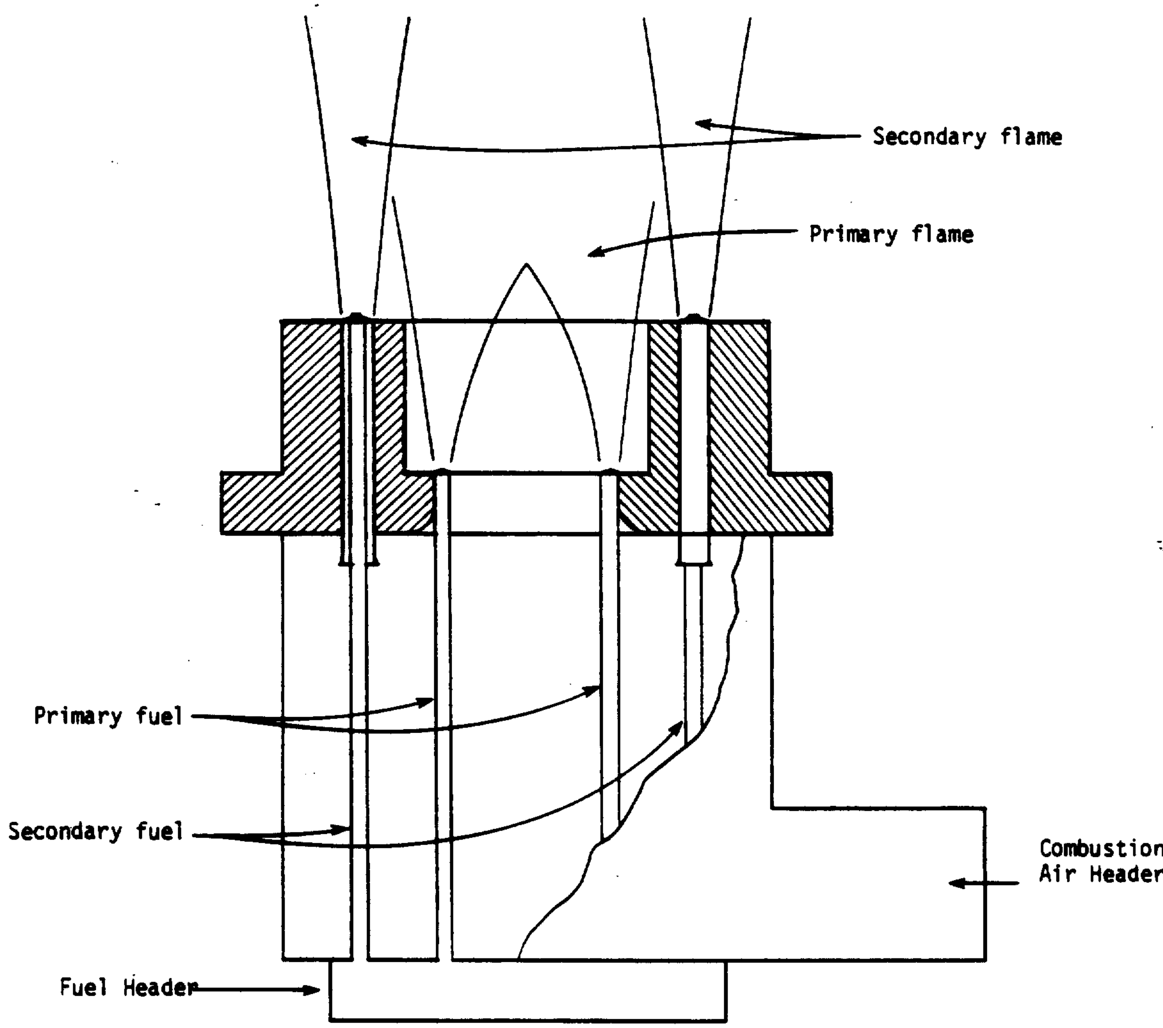


Figure 3-24. Staged fuel burner.

Thermal NO_x emissions are reduced in the primary flame zone because less fuel is available for combustion. Therefore, less heat will be generated in the primary zone reducing the peak flame temperature. In addition, the fuel in the primary flame zone is exposed to very high excess air levels.[180] At these very high excess air levels, the inerts of the air (primarily nitrogen) in the primary combustion zone will cool or quench the flame resulting in further thermal NO_x reduction. Thermal NO_x emissions are also reduced in the secondary combustion zone from the buildup of inerts present in the primary combustion zone. The buildup of the inerts will also reduce the peak flame temperature in the secondary combustion zone as well as dilute the secondary combustion zone's oxygen content.[181]

The staged fuel burner is being offered by one manufacturer for gaseous fuels.[182] This manufacturer plans to develop a staged fuel burner for liquid fuels. At this time, the staged fuel burner has been applied mostly to process heaters and to some industrial boilers.

3.3.5.2.3 <u>Internal Recirculation/Staged Air Burner</u>. The internal recirculation/staged air burner is designed for the combustion of gaseous and liquid fuels in boilers. It combines the advantages of a staged air burner with a limited amount of FGR. Figure 3-25 shows the cross-section of an internal recirculation/staged air burner. As with other staging burners, only a portion of the combustion air is introduced with the fuel as primary air.

The internal recirculation/staged air burner reduces NO_x formation from natural gas combustion by the same two mechanisms described above for staged air burners. In addition, the internal recirculation/staged air burner reduces thermal NO_x by diluting the O_2 in the combustion zone with recirculated combustion products.

Although actively marketed for use in natural gas-fired industrial boilers, internal recirculation/staged air burners have been applied only on small oil-fired steam generators for tertiary oil recovery to date.[183]

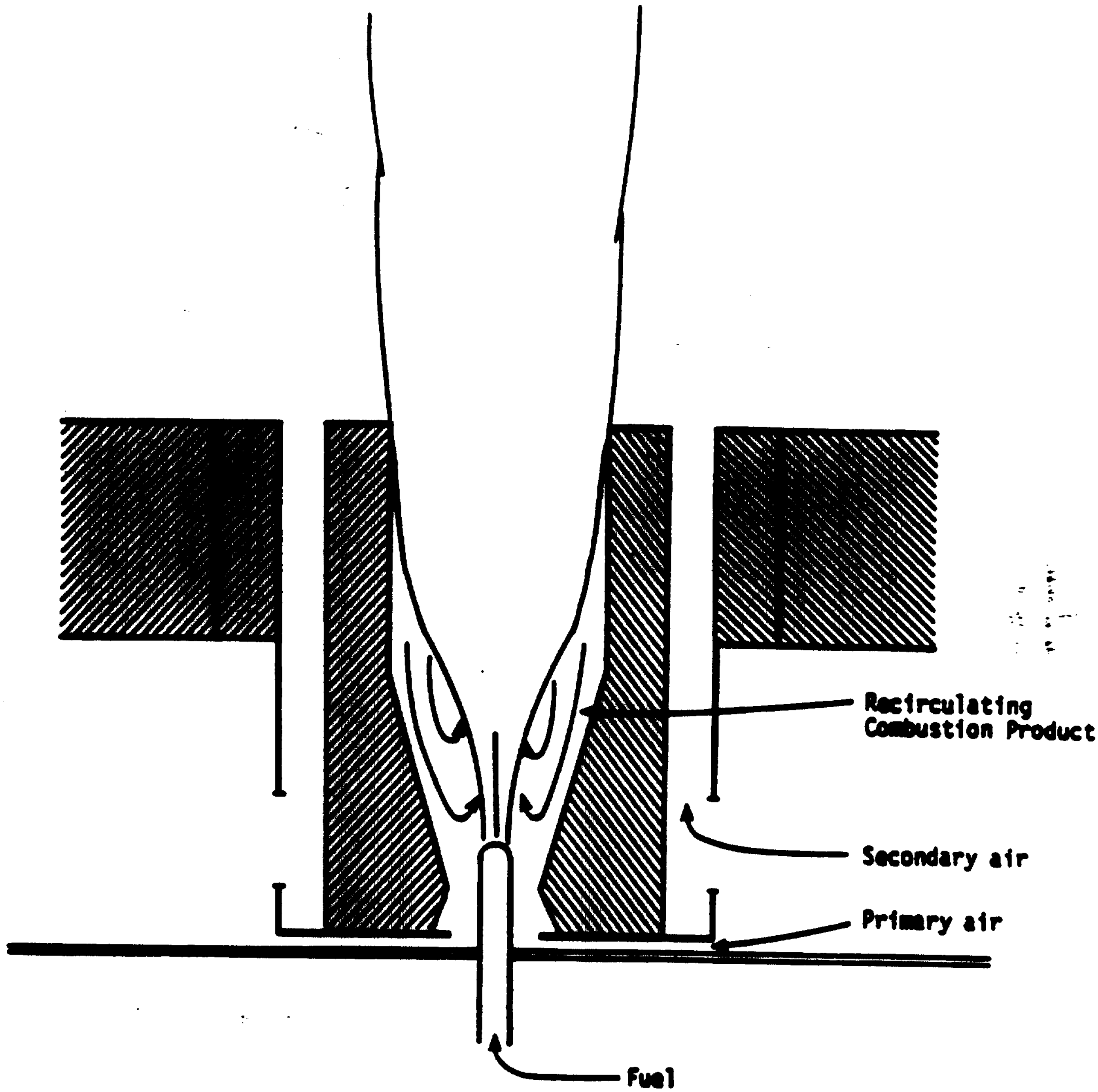


Figure 3-25. Internal recirculation/staged air burner.

3.3.5.2.4 Split Flame Burner. The split flame LNB has been developed for application to large industrial and utility pulverized coal boilers. While not directly applicable to small boilers at present, this burner is an example of the current state-of-the-art commercial LNB, and it could possibly be applied to residual oil-fired watertube boilers. The split flame burner is shown in Figure 3-26.

The controlled-flow, split-flame burner achieves a triple staging effect by dividing the secondary air flow with dual series registers and concentrating the coal flow into four streams. The concentrated split flames reduce fuel NO_x by operating fuel rich. Thermal NO_x is reduced by the lower flame temperatures resulting from the increased flame surface area and heat dissipation.

3.3.5.3 Factors Affecting Performance. As similarly discussed in Section 3.3.4.2 for OFA, the primary-to-stoichiometric air ratio is the major operating factor affecting NO_x emission performance for boilers using LNB. For LNB, this ratio is defined as the air introduced in the primary zone of the burner to the calculated stoichiometric air. The influence of the primary-to-stoichiometric ratio on NO_x emissions for boilers using LNB is the same as discussed for those generators using OFA (refer to Section 3.3.4.2). Reducing this ratio will reduce NO_x emission formation. Additionally, reducing the total excess air for most boilers using LNB will further reduce NO_x emissions. However, operating the boiler beyond its design capabilities will lead to operational problems such as high CO, hydrocarbons, and smoke emissions.

3.3.6 NO_x Emissions Test Data From Natural Gas-Fired Steam Generators

3.3.6.1 LEA Test Data.

3.3.6.1.1 Actual or non-normalized NO_x emissions data. Table 3-16 presents NO_x emission data from tests on 14 natural gas-fired small boilers using LEA. Emission data are available on five firetube and nine watertube

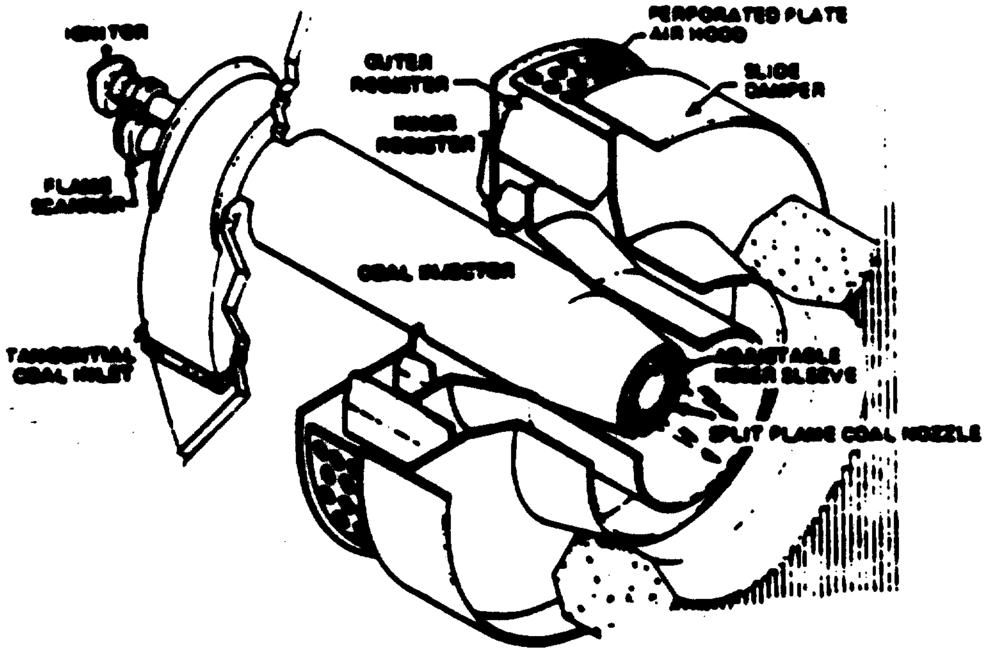


Figure 3-26. Split flame burner.[184]

TABLE 3-16. EMISSIONS DATA ON NATURAL GAS-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING LOW EXCESS AIR

Site and Boiler Data				Test Data							
Site I.D.	Boiler type[a]	Full load heat release rate 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	NOx reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/control	Reference[g]
3-2	FT	152 (329)	3.8 (13)	50	8.0/3.6	Amb[d]	0.122/0.080	34	13/0	NR/84	24
4-4	FT	236 (532)	7.3 (25)	70	6.8/4.8	Amb	0.132/0.111	16	NR/NR[f]	80/NR	24
5-248-1	FT	152 (323)	2.9 (10)	80	11.0/5.5	Amb	0.076/0.072	5	0/145	NR/NR	24
26-1	FT	108 (138)	6.7 (2.3)	96	7.2/2.7	Amb	0.071/0.093	(31)[e]	15/59	82/84	24
Site 6	FT	NR (NR)	2.3 (8)	33	8.3/7.2	Amb	0.105/0.072	31	28/117	NR/NR	187
1-1	WT, PKG	68 (48)	11 (36)	80	4.5/1.9	Amb	0.101/0.079	22	6/114	NR/NR	24
1-2	WT, PKG	68 (48)	11 (36)	59	4.7/2.2	Amb	0.101/0.095	6	10/67	NR/79	24
1-3	WT, PKG	73 (58)	11 (38)	80	4.5/2.7	Amb	0.117/0.094	19	0/0	78/79	24
5-716-3	WT, PKG	NR (NR)	9.1 (31)	65	5.8/4.1	Amb	0.097/0.079	19	0/0	NR/NR	24
10-4	WT, PKG	92 (66)	22 (75)	82	5.2/3.9	Amb	0.127/0.132	(4)[e]	0/42	80/NR	24
19-2	WT, PKG	67 (56)	6.5 (22)	93	3.2/2.0	Amb	0.075/0.066	12	10/71	80/NR	24
9-BC-1	WT, PKG	70 (32)	22 (75)	79	3.3/2.6	204 (400)	0.307/0.294	4	0/20	NR/79	24
28-1	WT, PKG	78 (32)	26 (88)	41	5.7/3.7	168 (335)	0.257/0.202	21	0/21	83/85	24
38-2	WT, PKG	84 (36)	16 (56)	89	3.2/1.9	288 (550)	0.268/0.222	17	0/0	81/82	24

[a]FT = Firetube; WT = Watertube; and PKG = Packaged.

[b]Numbers in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]NO_x emissions were measured by Thermo Electron Chemilluminescent analyzer. All tests were short-term (<3 hours) except at Site 6. 30-day tests were performed on the boiler at Site 6. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d]Amb = Ambient temperature [assume 27°C (80°F)].

[e]Numbers in parenthesis indicate a NO_x emission increase from baseline using LEA.

[f]NR = Not reported.

[g]Test results from Reference 24 also reported in Reference 188.

boilers. The data in this table were not corrected or normalized to any specific operating conditions. In addition to NO_x emission data, this table presents site and boiler information and operating conditions for baseline and LEA tests. Baseline conditions represented the normal operating conditions of each boiler and differed for each boiler tested. The average test load and combustion air temperature data indicated for each boiler in this table were held constant during baseline and LEA testing of the 14 natural gas-fired boilers.

Four of the five firetube boilers were tested for NO_x emissions using continuous emission monitors (CEM) over a short time period. Long-term (30 days) CEM tests were performed on the boiler at Site 6. Reduction efficiencies of NO_x ranged from 5 to 34 percent excluding one test that showed increased NO_x emissions. Emissions of NO_x from the five firetube boilers using LEA ranged from 31.0 to 47.7 ng/J (0.072 to 0.111 lb/10^6 Btu). The boilers operated at loads ranging from 33 to 90 percent of full load. Excess O_2 levels during LEA operation ranged from 2.7 to 7.2 percent, and from 6.8 to 11 percent during baseline operation. Only one firetube boiler (#26-1) produced higher NO_x emissions using LEA than during baseline testing. An explanation was not given for this observation in the emission test report on this boiler.[185]

All watertube boilers in Table 3-16 were tested for NO_x emissions using CEM's over a short time period. For the six packaged watertube boilers using no air preheat, reduction efficiencies of NO_x ranged from 6 to 22 percent excluding one test that showed increased NO_x emissions. NO_x emissions from these boilers using LEA ranged from 28.4 to 56.8 ng/J (0.066 to 0.132 lb/10^6 Btu). Excess O_2 levels varied from 1.9 to 4.1 percent during LEA operation and from 3.2 to 5.8 percent during baseline operation. The six boilers operated at loads ranging from 59 to 93 percent of full load. LEA-controlled NO_x emissions from only one boiler (#10-4) were higher than baseline NO_x emissions. Again, no explanation was given for this observation in the emission test report on this boiler.[186]

For the three package watertube boilers with preheated combustion air, reduction efficiencies of NO_x ranged from 4 to 21 percent. LEA-controlled

NO_x emissions ranged from 86.9 to 126 ng/J (0.202 to 0.294 lb/10^6 Btu). Excess O_2 levels ranged from 1.9 to 3.7 percent during LEA operation and between 3.2 to 5.7 percent during baseline operation. Test loads varied from 41 to 89 percent.

To examine the effects of combustion air preheat temperature on NO_x emissions, test data on one boiler (#38-2) with reduced combustion air preheat firing natural gas and No. 6 fuel oil separately are shown in Table 3-17. The results of these tests indicate that reducing combustion air temperature reduces NO_x emissions for both these fuels. However, most boilers in the small boiler size range do not have air preheaters. Therefore, reduced air preheat is not generally available as a NO_x control technique for small steam generators.

Table 3-16 also presents CO emissions and boiler efficiency data from test on boilers operating at baseline and LEA conditions. Carbon monoxide emissions were measured from 13 of the 14 boilers and ranged from 0 to 145 ppm. Nine of these 13 boilers produced higher CO emissions operating with LEA than operating at baseline conditions. However, the increase in CO emissions from these boilers operating with LEA was not significant enough to cause a reduction in combustion efficiency. In fact, for two boilers (#26-1 and #28-1) which produced higher CO emissions during LEA operation than during baseline operation, the boiler efficiency of both boilers increased 2 percent during LEA operation compared to baseline conditions. Three boilers produced no detectable CO emissions during either baseline or LEA operations, and one boiler (#3-2) emitted no detectable CO emissions during LEA operation only.

Boiler efficiency was determined for LEA and baseline conditions on four boilers (#1-3, #26-1, #28-1, and #38-2). These boilers operated at roughly 1 to 2 percent higher efficiency at LEA than at baseline. Boiler efficiency for the four boilers using LEA ranged from 79 to 85 percent.

3.3.6.1.2 Normalized NO_x emission data. As shown in Table 3-16, NO_x emission data were obtained from 14 small boilers operating at various baseline and LEA conditions. Nitrogen oxides emissions from natural

TABLE 3-17. NO_x EMISSION DATA FROM NATURAL GAS-FIRED BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING REDUCED COMBUSTION AIR PREHEAT

Site and Boiler Data				Test Data							
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity MW (10^6 Btu/hr) heat input	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x Emissions lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO Emissions ppm @ 3% O_2 baseline/controlled[e]	Boiler efficiency, percent baseline/controlled	Reference number[e]
38-2	WT,PKG	84 (36)	16 (56)	87	3.2/1.6	288 (550)/ 207 (405)[c]	0.268/0.151	44	0/30	82/79	24

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Baseline air temperature/reduced air temperature.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]Test results from Reference 24 are also presented in Reference 188.

gas-fired industrial boilers have been shown to be affected by load (or heat release rate), combustion air temperature, and excess O_2 level.[189] To isolate the impacts of lower excess air operation on NO_x emissions, the small boiler NO_x emission data presented in Table 3-16 were normalized with respect to heat release rate, combustion air temperature, and excess O_2 level using the 1985 industrial boiler NO_x emission predictive (regression) algorithm for watertube natural gas-fired boilers.[190] This technique eliminates the contribution of those operating factors to NO_x emissions by correcting the data to a "common basis." The NO_x predictive algorithm was developed from data on both industrial small boilers (presented in Table 3-16, excluding the firetube NO_x emission data). For this reason, the normalized NO_x emissions of the firetube boilers calculated by this algorithm are considered to be rough approximations.

Emissions of NO_x for each boiler in Table 3-16 were normalized to full load condition (i.e., at its design heat release rate) and at an ambient combustion air temperature of 27°C (80°F). The chosen combustion air temperature was assumed to be typical for a packaged firetube and watertube boiler without an air preheater. If heat recovery is desirable for small boilers, then an economizer can be used instead of an air preheater to improve boiler efficiency. Using an economizer, which preheats only the boiler feedwater by exchanging heat with the flue gas, will not increase NO_x emissions as would using an air preheater. For correcting baseline NO_x emissions with respect to excess O_2 level, a baseline O_2 level of 6 percent was chosen. Similarly, an LEA O_2 level of 2 percent was chosen to correct the LEA controlled NO_x emissions. Both O_2 levels can be achieved from examining data collected from natural gas- and oil-fired boilers presented in this chapter.

The normalization equations used for correcting the NO_x emission data to the full load heat release rate and ambient combustion air temperature are as follows:

For baseline,

$$En = E \left(\frac{H_F}{H}\right)^{0.24} \left(\frac{540}{T}\right)^{1.08} \left(\frac{6.0}{A}\right)^{0.14}$$

For LEA,

$$En = E \left(\frac{H_F}{H}\right)^{0.24} \left(\frac{540}{T}\right)^{1.08} \left(\frac{2.0}{A}\right)^{0.14}$$

where: En = Normalized NO_x emissions, ng/J or $lb/10^6$ Btu
E = Actual or unnormalized NO_x emissions, ng/J or $lb/10^6$ Btu
H_F = Full load combustion zone heat release rate, 10^3 Btu/hr-ft^2 surface
H = Test load combustion zone heat release rate, 10^3 Btu/hr-ft^2 surface
T = Combustion air preheat temperature, ^oR
A = Excess O_2 level, percent.

For two boilers (#6 and #5-716-3) in which no full load heat release rates were reported in the source test report, NO_x emissions were normalized with respect to heat release rate using the ratio of full to operating test loads. This ratio is the same as the ratio of the full load heat release rate to the test load heat release rate.

Table 3-18 presents the normalized NO_x emission data from 14 boilers, 5 of which are firetubes and 9 are watertubes. For the firetube boilers, NO_x reductions from baseline ranged from -28.6 percent for boiler #26-1 to 39.7 percent for the boiler at Site 6. The negative NO_x reduction from boiler #28-1 implies that LEA-controlled NO_x emissions were higher than baseline NO_x emissions. For the watertube boilers, NO_x reductions ranged from 7.4 percent for boiler #10-4 to 28.8 percent for boiler #28-1.

Figures 3-27 and 3-28 show the baseline normalized NO_x emissions as a function of boiler size at full load and full load heat release rate, respectively. Also, superimposed on both figures is the normalized NO_x

TABLE 3-18. NORMALIZED NO_x EMISSION DATA ON NATURAL GAS-FIRED BOILERS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS

				Baseline Results		LEA Results			
Site I.D.	Boiler type[a]	Test load heat release rate, 10^3 Btu/ft^2-hr[b]	Combustion air temperature, °C (°F)	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[e]	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[f]	NO_x reductions from baseline, percent	Reference[h]
3-2	FT	76	Amb[d]	6.0	0.138	2.0	0.087	37.0	24
4-4	FT	165	Amb	6.0	0.141	2.0	0.107	24.1	24
5-248-1	FT	122	Amb	6.0	0.073	2.0	0.066	9.6	24
26-1	FT	104	Amb	6.0	0.070	2.0	0.090	(28.6)[g]	24
Site 6	FT	NA[c]	Amb	6.0	0.131	2.0	0.079	39.7	187
1-1	WT	54	Amb	6.0	0.111	2.0	0.084	24.3	24
1-2	WT	40	Amb	6.0	0.119	2.0	0.107	10.1	24
1-3	WT	58	Amb	6.0	0.128	2.0	0.095	25.8	24
5-716-3	WT	NA	Amb	6.0	0.109	2.0	0.080	26.6	24
10-4	WT	75	Amb	6.0	0.136	2.0	0.126	7.4	24
19-2	WT	62	Amb	6.0	0.083	2.0	0.067	19.3	24
9-BC-1	WT	55	Amb	6.0	0.216	2.0	0.181	16.2	24
28-1	WT	32	Amb	6.0	0.212	2.0	0.151	28.8	24
38-2	WT	75	Amb	6.0	0.153	2.0	0.117	23.5	24

[a]FT = Firetube; WT = Watertube

[b]NO_x emission data were normalized to the full load heat release rate of each boiler as reported in Table 4.3-2. To convert to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[c]NA = Not Available.

[d]Amb = Ambient air temperature [assume 27°C (80°F)].

[e]Baseline NO_x emissions for each boiler were normalized to full load conditions and adjusted to a baseline O_2 level of 6.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]LEA-controlled NO_x emissions for each boiler were normalized to full load conditions and adjusted to a LEA O_2 level of 2.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]The number in parentheses indicates a NO_x emission increase from baseline using LEA.

[h]Test results from Reference 24 are also presented in Reference 188.

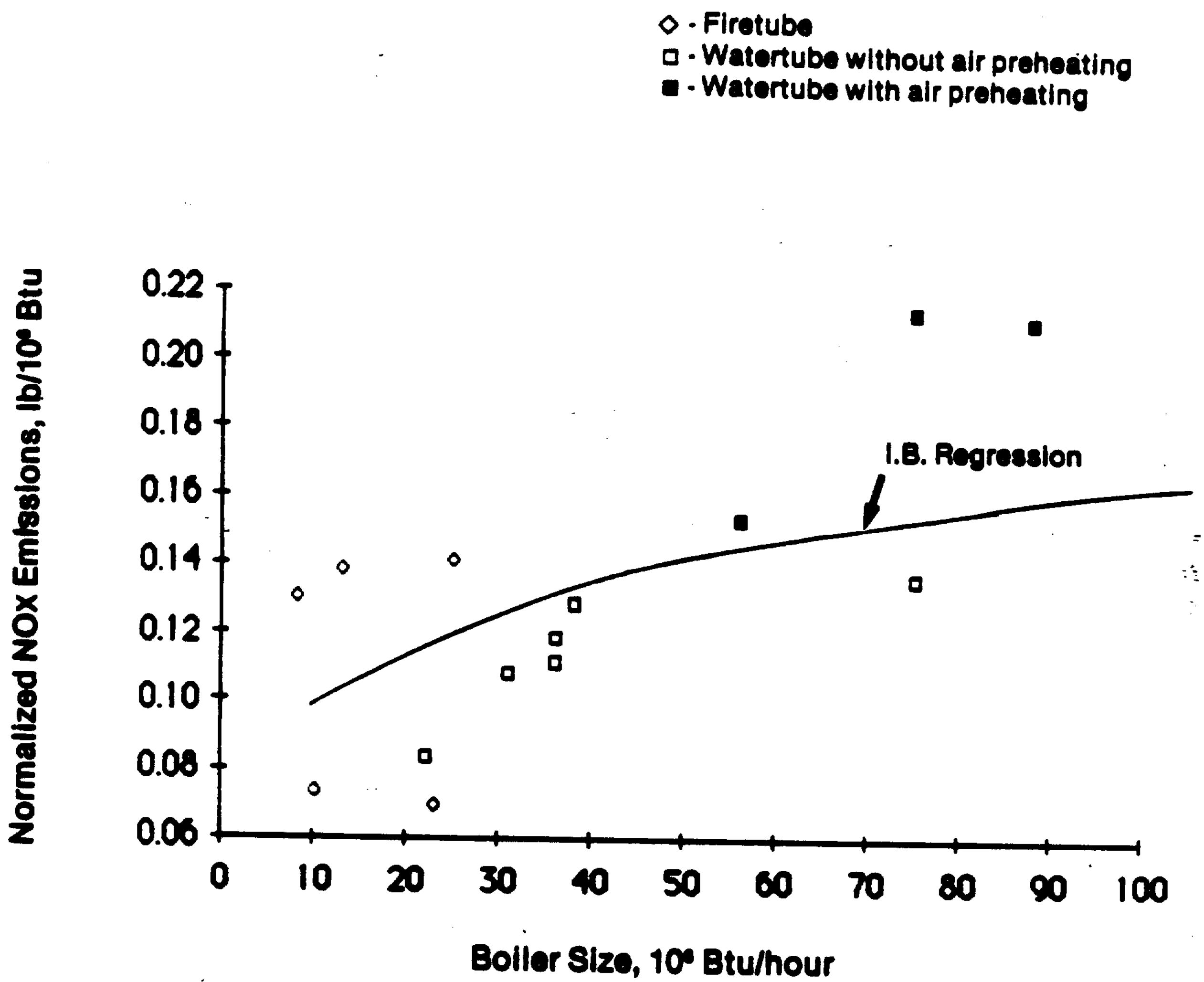


Figure 3-27. Normalized baseline NO_x emissions as a function of boiler size for natural gas-fired small boilers.

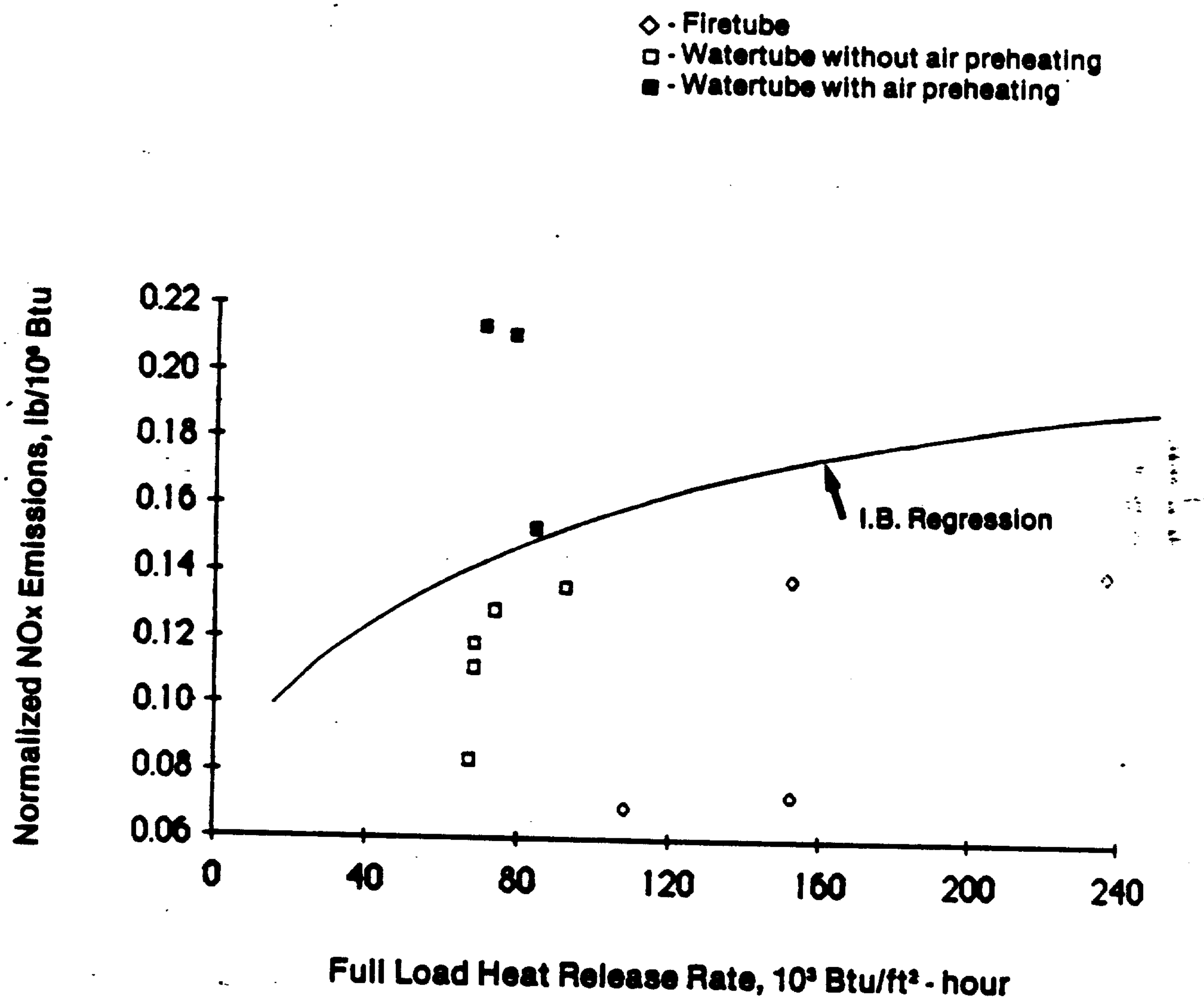


Figure 3-28. Normalized baseline NO_x emission as a function of full load heat release rate for natural gas-fired small boilers.

emission curve of the industrial boiler predictive algorithm. The curve shown in Figure 3-27 is based on typical full load heat release rates for each boiler size determined from a regression algorithm relating boiler size to heat release rate.[191] This algorithm is presented as follows:

$$HRR = 1.606 * \text{Boiler Size} - 00381 * (\text{Boiler Size})^2$$

where:

HRR = Full load heat release rate, 10^3 Btu/hour-ft^2
Boiler Size = Full load heat input capacity, 10^6 Btu/hour

From the data presented in both figures, boilers rated between 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input (or heat release rates between 16,000 and 38,000 Btu/ft^2-hour) can achieve baseline NO_x emissions of 60.2 ng/J (0.14 lb/10^6 Btu) or less. Using the industrial boiler regression curve for a boiler rated at 14.7 MW (50 million Btu/hour) heat input, boilers rated between 7.6 and 14.7 MW (26 and 50 million Btu/hour) heat input (or heat release rates between 50 and 120 kJ/m^2-sec [16,000 and 38,000 Btu/ft^2 hour]) can achieve a baseline NO_x emission level of 64.5 ng/J (0.15 lb/10^6 Btu). For boilers rated between 14.9 and 29.3 MW (51 and 100 million Btu/hour) heat input, baseline NO_x emissions of 71 ng/J (0.165 lb/10^6 Btu) or less was obtained using the industrial boiler regression curve at a heat input of 29.3 MW (100 million Btu/hour). It also should be noted that this analysis excludes the NO_x emission data from watertube boilers using combustion air preheating, since very few small natural gas-fired boilers are equipped with air preheaters. The industrial boiler regression curve shown in both figures was used to cover any data gaps present in the small boiler emission database.

By the same token, Figures 3-29 and 3-30 show the normalized NO_x emissions for LEA as function of boiler size at full load and full load heat release rate, respectively. By analyzing both figures, LEA-controlled NO_x emissions of 38.1 ng/J (0.09 lb/10^6 Btu) and 47.3 ng/J (0.11 lb/10^6 Btu) can

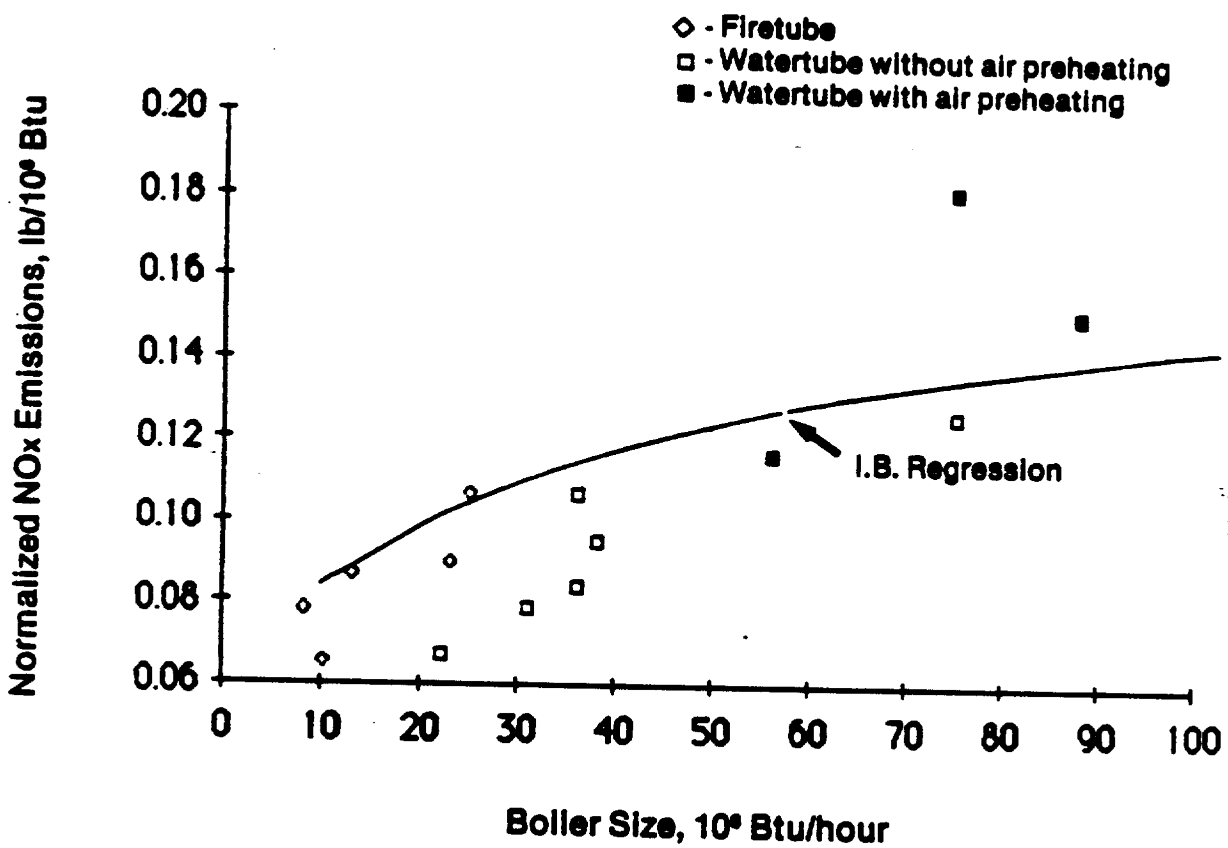


Figure 3-29. Normalized LEA-controlled NO_x emissions as a function of boiler size for natural gas-fired small boilers.

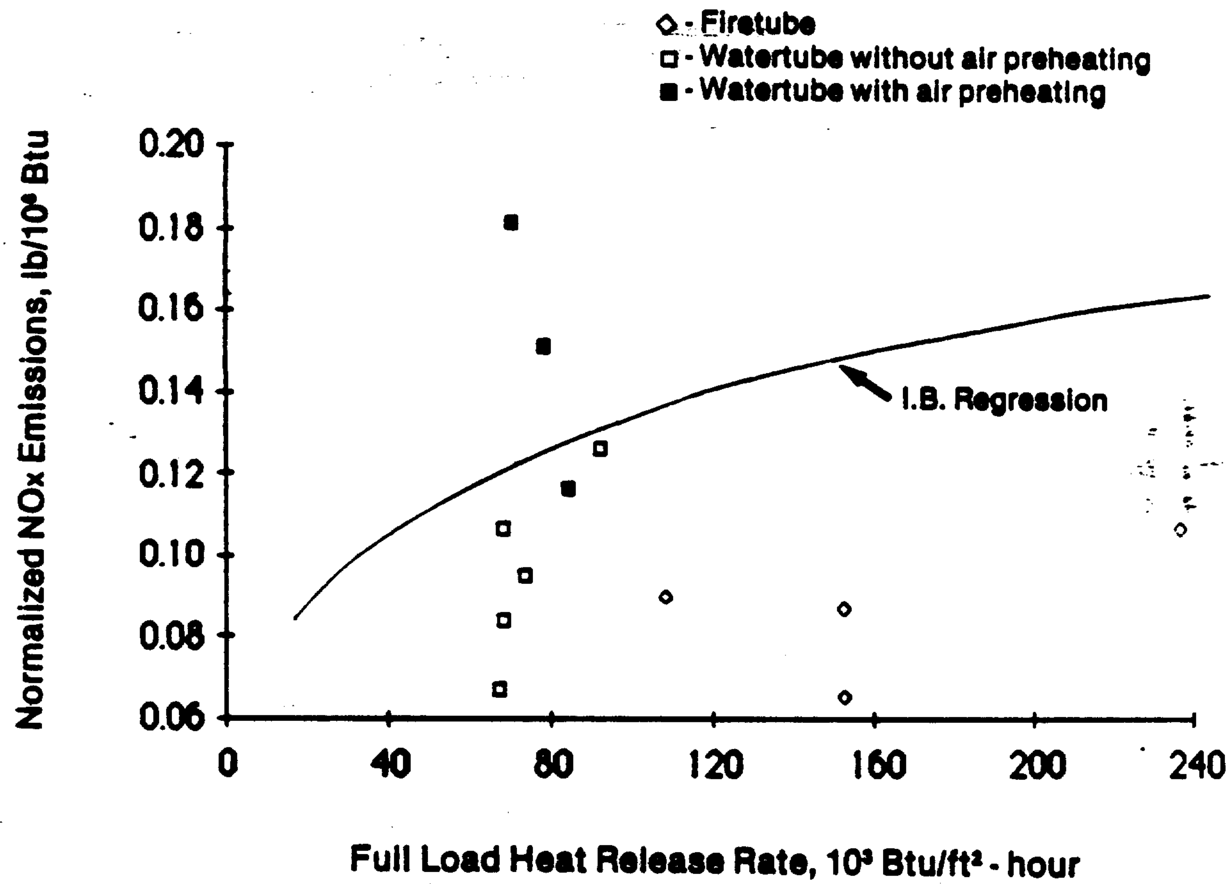


Figure 3-30. Normalized LEA-controlled NO_x emissions as a function of full load heat release rate for natural gas-fired small boilers.

be achieved for natural gas-fired boilers rated at 2.9 MW and 7.3 MW (10 and 25 million Btu/hour) heat input, respectively. These NO_x emissions were obtained by examining both emission test datapoints and the industrial boiler regression curve for both boiler sizes. For natural gas-fired boilers rated 7.6 and 14.7 MW (26 and 50 million Btu/hour) heat input, LEA-controlled NO_x emissions of 53.8 ng/J (0.125 lb/10^6 Btu) or less can be achieved using the industrial boiler regression curve for a 14.7 MW (50 million Btu/hour) boiler with a heat release rate of 224 kJ/m^2-sec (71,000 Btu/ft^2-hour). Finally, LEA-controlled NO_x emissions of 60.2 ng/J (0.14 lb/10^6 Btu) or less can be achieved for small natural gas-fired boilers rated between 14.9 and 29.3 MW (51 and 100 million Btu/hour) heat input. Again, the industrial boiler regression curve was used to estimate this NO_x emission level for this size range based on 29.3 MW (100 million Btu/hour) boiler. This analysis also excluded NO_x emission data from boilers using air preheaters.

3.3.6.2 FGR Test Data. Table 3-19 presents NO_x emissions data from tests on six natural gas-fired watertube boilers equipped with FGR. This table provides site and boiler-specific data and test data on baseline and FGR tests for each boiler. Baseline conditions are the normal operating conditions of the boiler with no FGR. All NO_x tests reported in Table 3-19 were short-term (i.e., 3-hour) CEM tests. The test load was held at the same level during both FGR and baseline operation for each boiler.

Of the six watertube boilers tested, FGR operation resulted in NO_x emission reductions ranging from 49 percent for boiler #6 operating at a 10 percent recirculation rate to 77 percent for the boiler #ECCC operating at 26 percent recirculation. Emissions of NO_x ranged from 6.9 to 24.9 ng/J (0.016 to 0.058 lb/10^6 Btu) from the six boilers using FGR. The six boilers operated at loads ranging from 30 to 100 percent.

Nitrogen oxides emission tests were conducted at different recirculation rates for boiler #6 and the boiler at Location 19 both operating at constant loads. The results from Table 3-19 show that increasing the recirculation rate further reduces NO_x emissions. For boiler

TABLE 3-19. NO_x EMISSIONS DATA ON NATURAL GAS-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING FLUE GAS RECIRCULATION

Site and Boiler Data				Test Data							
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, 10^6 Btu/hr heat input	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °F	NO_x emissions, lb/10^6 Btu baseline/controlled[e]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference[f]
#3	WT, PKG	NR (62)	13 (43)	12	93	2.1/2.0	Amb[d]	0.102/0.036	65	0/57	84/84	193, 194
#5	WT, PKG	95 (54)	16 (56)	16	60	3.6/3.1	Amb	0.078/0.027	65	182/85	NR/NR	195
#6	WT, PKG	91 (53)	13 (45)	10	100	2.3/1.7	Amb	0.079/0.040	49	NR/NR	84/84	194, 196
#6	WT, PKG	91 (53)	13 (45)	14	100	2.3/1.5	Amb	0.079/0.030	62	NR/NR	84/84	194, 196
MOD	WT, PKG	NR (76)	47(162)	NR	100	NA[d]/3.0	Amb	NA/0.058	NA	NA/<5	NA/NR	197, 198
MOD	WT, PKG	NR (76)	47(162)	NR	80	NA/3.5	Amb	NA/0.047	NA	NA/<10	NA/NR	197, 198
ECCC	WT, PKG	NR (NR)	9.1 (31)	22	39	3.1/2.6	Amb	0.056/0.022	61	20/20	NR/NR	199
ECCC	WT, PKG	NR (NR)	9.1 (31)	26	30	3.5/1.2	Amb	0.069/0.016	77	10/55	NR/NR	199
Loc.19	WT, PKG	67 (56)	6.5 (22)	17	79	3.2/3.3	Amb	0.110/0.032	71	19/16	78/79	26
Loc.19	WT, PKG	67 (56)	6.5 (22)	20	80	3.2/3.2	Amb	0.110/0.029	74	19/20	78/79	26
Loc.19	WT, PKG	67 (56)	6.5 (22)	20	83	3.2/2.5	Amb	0.110/0.027	75	19/16	78/78	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parentheses indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to boiler.

[d]NA = Not Available; NR = Not Reported; Amb = Ambient temperature [assume 27°C (80°F)].

[e]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer; all tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]Test results from References 26 and 199 are also presented in Reference 188.

0.001 - .063

#6, NO_x emission reduction increased from 49 to 62 percent as the FGR rate increased from 10 to 14 percent. Similarly, for the boiler at Location 19 operating at 79 to 80 percent of full load, NO_x emission reduction only increased from 71 to 74 percent as the FGR rate increased from 17 to 20 percent. The results from both boilers show that the increase in precentage NO_x emission reductions diminishes at ever increasing recirculation rates.

Nitrogen oxides emission data were not available on FGR-equipped firetube boilers rated above 2.9 MW (10 million Btu/hour) heat input. However, NO_x emission data are available from one experimental firetube boiler rated at 1.5 MW (5 million Btu/hour) heat input using FGR.[192] The test results from this boiler operating at 95 percent of full load indicated that NO_x emissions with and without 15 percent FGR rate were 12.9 ng/J (0.03 lb/10^6 Btu or 25 ppm at 3 percent O_2) and 34.4 ng/J (0.08 lb/10^6 Btu or 66 ppm at 3 percent O_2) , respectively. Flue gas recirculation reduced NO_x emissions by 62 percent over baseline for this boiler operating at a 15 percent FGR rate.

Table 3-19 also presents CO emissions on four boilers and boiler efficiency data on three boilers equipped with FGR. Carbon monoxide emissions measured during FGR tests were about the same as those measured during the baseline tests for two of four boilers tested (ECCC and Loc. 19). The differences in CO emissions were small between baseline and controlled conditions for a boiler operating at close to the same excess O_2 level during both tests. For one boiler (ECCC) operating at different excess O_2 levels during both tests, CO emissions increased slightly at lower O_2 levels. Emissions of CO from boiler ECCC were 10 ppm during baseline operation at 3.5 percent O_2 and were 55 ppm during FGR test at 1.2 percent O_2. Increasing the FGR rate from 0 to 12 percent for boiler #3 increased CO emissions from 0 to 57 ppm.

For the fourth boiler (#5), CO emissions were lower during FGR than during baseline operations. Baseline CO emissions were 182 ppm, while CO emissions measured during FGR testing were 82 ppm. The excess O_2 level during FGR testing was slightly below that during baseline tests.

Boiler efficiency was determined during baseline and FGR operations from three boilers. Boiler efficiency of those boilers either remained the same or increased by about 1 percent from the baseline boiler efficiency.

Unlike the LEA data discussed in Section 3.3.6.1, no predictive regression equation exists to normalize the NO_x emission data from boilers using FGR to compensate for the NO_x emission effects of other operating parameters.

The data indicate that FGR can achieve a 50 percent NO_x reductions between 49 and 77 percent on small natural gas-fired boilers operating at recirculation rates between 10 and 26 percent. FGR-controlled NO_x emissions ranged from 6.9 ng/J (0.016 lb/10^6 Btu) to 24.9 ng/J (0.058 lb/10^6 Btu).

3.3.6.3 OFA Test Data. Table 3-20 presents NO_x emissions data on three natural gas-fired small boilers equipped with OFA ports (#19-2, #38-2, and Loc. 38). Reductions in NO_x from baseline emissions ranged from 13 percent for boiler #19-2 to 40 percent for boiler #38-2 when OFA was used. OFA-controlled NO_x emissions ranged from 31.4 to 61.1 ng/J (0.073 to 0.142 lb/10^6 Btu) for these three boilers. These boilers operated at loads ranging from 83 to 89 percent and at excess O_2 levels varying from 1.5 to 3.2 percent.

Carbon monoxide emissions and boiler efficiency results are also presented in Table 3-20 for these three boilers equipped with OFA ports. Emissions of CO were measured during the baseline and OFA tests. For boilers #19-2 and #38-2, CO emissions were higher during the OFA tests than during baseline tests. Boiler #38-2 emitted only 28 ppm of CO when using OFA. This compares to no detectable CO being emitted from the same boiler during the baseline test. For boiler #19-2, CO emissions were 185 ppm during the OFA test compared to no detectable CO being emitted during the baseline test. The large increase in CO emissions during the OFA test from boiler #19-2 may be partially attributed to operating at a lower excess O_2 level (1.5 percent) during this test compared to baseline (3.2 percent). Emissions of CO measured from the boiler at location 38 during the OFA tests were essentially the same as baseline.

TABLE 3-20. NO_x EMISSIONS DATA FROM NATURAL GAS-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING OVERFIRE AIR

Site and Boiler Data				Test Data							
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x Emissions, lb/10^6 Btu baseline/controlled[c]	NO_x Reduction, percent	CO Emissions, ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference[f]
19-2	WT, PKG	67 (56)	6.5 (22)	83	3.2/1.5	Amb[d]	0.084/0.073	13	0/185	NR/NR	24
38-2	WT, PKG	84 (36)	16 (56)	89	1.9/3.2	NR[d]	0.268/0.073	73	0/28	82/80	24
Loc. 38	WT, PKG	84 (36)	16 (56)	88	1.6/3.2	NR	0.206[e]/0.142[e]	31	140/122	81/81	26

[a] WT = Watertube; PKG = Packaged.

[b] Number in parentheses indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c] NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d] Amb = Ambient temperature [assume 27°C (80°F)]; NR = Not reported.

[e] Estimate only, only NO_x values assume NO_2 is 5% of the total (only NO was measured).

[f] Test results from References 24 and 26 are also presented in Reference 188.

Boiler efficiency was determined for two boilers (#38-2 and Loc. 38). For the boiler at Location 38, the boiler operated at 81 percent efficiency during both OFA and baseline tests. However, boiler efficiency dropped 2 percent during OFA operation on boiler #38-2. Boiler #38-2 was 82 percent efficient during baseline operation and 80 percent efficient during OFA operation.

Table 3-21 presents NO_x emission data on one boiler (Loc. 19) combining both FGR and OFA. From examining the data in this table and in Table 3-19, no improvement is gained in NO_x reduction over FGR alone when both NO_x control techniques are applied. In fact, this boiler was modified to operate with both techniques primarily as a means of evaluating each technique on the same boiler during experimental testing only. Combining both FGR and OFA on boilers is not at present used in commercial or industrial applications.

No predictive algorithm exists to normalize the NO_x emission data from boilers using OFA for correcting other operating parameters' effects on NO_x emissions. Based on the data presented in Table 3-20, the amount of NO_x emission reduction attributed to OFA alone cannot be determined, since the excess O_2 for the above boilers tested were not at the same O_2 level during baseline and OFA conditions.

3.3.6.4 LNB Test Data. Table 3-22 presents NO_x emissions data on three natural gas-fired boilers (#3, CA, and Site 5) using LNB. Baseline tests were not available on these boilers using conventional burners.

Emissions of NO_x ranged from 30.1 ng/J (0.07 lb/10^6 Btu) for boiler #3 to 38.7 ng/J (0.09 lb/10^6 Btu) for the California (CA) boiler. The boiler at Site 5 was tested continually for 39 days. Emissions of NO_x averaged 38.3 ng/J (0.089 lb/10^6 Btu) for 39 days, based on the daily average data. This boiler operated at an average load of 44 percent of rated capacity. For the other boilers, boiler #3 operated at 86 percent load and the CA boiler operated at 40 percent load.

TABLE 3-21. NO_x EMISSION DATA FROM NATURAL GAS-FIRED BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING BOTH FLUE GAS RECIRCULATION AND OVERFIRE AIR

Site and Boiler Data				Test Data								
Site I.D.	Boiler Type[a]	Full load heat release Rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity MW (10^6 Btu/hr) heat input	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference[f]
Loc. 19	WT,PKG	67 (56)	6.5 (22)	18	79	3.2/4.8	Amb	0.110/0.027	75	19/1	NR/NR[e]	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to the boiler.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NR = Not reported.

[f]Test results from Reference 26 are also presented in Reference 188.

TABLE 3-22. NO_x EMISSIONS DATA FROM NATURAL GAS-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING LOW NO_x BURNERS

Site and Boiler Data				Test Data						
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	CO emissions, ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference
CA	WT, PKG	NR (NR)	18 (63)	40	NA[d]/4.0	Amb[d]	NA/0.090	NA/NR[d]	NR/NR	200
#3	WT, PKG	72 (NR)	22 (75)	86	NA/4.3	Amb	NA/0.070	NA/744[e]	NA/NR	201
Site 5	WT, PKG	NR (NR)	31 (106)	44	NA/5.8	Amb	NA/0.089	NA/82	NA/NR	202

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[a]WT = Watertube; PKG = Packaged.

[b]Number in parentheses indicate volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (≤3 hours) except for Site 5. Thirty nine day continuous emissions testing was performed at Site 5. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d]NA = Not available; Amb = Ambient temperature [assume 27°C (80°F)]; NR = Not reported.

[e]This test was demonstrated intentionally at the lowest possible NO_x emissions for this boiler. However, this CO emissions level met the CO regulation of the county's air pollution control district.

Carbon monoxide emissions were measured from the boiler at Site 5 and from boiler #3. The boiler at Site 5 emitted 82 ppm CO on the average during the 39-day test, while boiler #3 emitted 744 ppm CO. As noted in Table 3-22, the test on boiler #3 was intentionally run at the lowest possible NO_x emissions. Although the CO emissions were high, this boiler still met the CO regulation of the county's air pollution control district. However, most boiler operators tend to operate their boilers below 200 ppm CO.

No predictive algorithm exists to normalize the NO_x emission data from boilers using LNB for correcting the operating parameters' effects on NO_x emissions, such as heat release rate and combustion air temperature.

The data indicate that LNB can achieve a NO_x emission levels of 30.1 to 38.7 ng/J (0.07 to 0.09 lb/10^6 Btu) on small natural gas-fired boilers.

3.3.7 NO_x Emission Test Data on Distillate Oil-Fired Boilers

3.3.7.1 LEA Test Data.

3.3.7.1.1 Actual or non-normalized NO_x emission data. Table 3-23 presents NO_x emission data on six distillate oil-fired small boilers operating with LEA. This table also presents site and boiler related data as well as test data from baseline and LEA tests on each boiler. Nitrogen oxides emission data are available from tests on two firetube and four watertube boilers. Baseline conditions are as defined in Section 3.3.6.1. The average test load and combustion air temperature for each boiler in Table 3-23 were held constant during baseline and LEA testing. All NO_x tests were short-term CEM tests.

For the two firetube boilers (#3-2 and #4-4), LEA-controlled NO_x emissions were lower than baseline NO_x emissions. Emission reductions were 11 and 17 percent for boilers #3-2 and #4-4, respectively. LEA-controlled NO_x emissions were 84.7 and 80.0 ng/J (0.197 and 0.186 lb/10^6Btu) for boilers #3-2 and #4-4, respectively. Excess O_2 levels during the LEA tests were 2.7 percent for boiler #4-4 and 3.6 percent for boiler #3-2. By

TABLE 3-23. NO_x EMISSIONS DATA FROM DISTILLATE OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING LOW EXCESS AIR

Site and Boiler Data					Test Data								
Site I.D.	Boiler type[b]	Full load heat release rate, 10^3 Btu/ft^2-hr[c]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Average test load, percent	Stack O_2, percent, baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference[f]
3-2	FT	152 (329)	3.8 (13)	NA[e]	50	5.6/3.6	Amb[e]	0.221/0.197	11	0/0	0.04/NR	NR/86	24
4-4	FT	236 (532)	7.3 (25)	NA	47	5.2/2.7	Amb	0.224/0.186	17	NR/NR[e]	0.03/NR	85/NR	24
1-2	WT, PKG	68 (48)	11 (36)	0.045	50	8.2/5.1	Amb	0.136/0.118	13	NR/NR	NR/NR	NR/NR	24
19-1 (Steam)[a]	WT, PKG	67 (56)	6.4 (22)	0.006	80	4.3/3.6	Amb	0.098/0.088	10	0/49	NR/0.04	NR/85	24
19-1 (Air)[a]	WT, PKG	67 (56)	6.4 (22)	0.006	80	4.3/2.5	Amb	0.134/0.125	7	0/0	NR/NR	84/NR	24
19-1 (Mech)[a]	WT, PKG	67 (56)	6.4 (22)	0.006	66	6.2/3.7	Amb	0.107/0.105	2	0/0	NR/NR	NR/86	24
Loc. 19	WT, PKG	67 (56)	6.4 (22)	0.004	83	3.2/1.1	Amb	0.154/0.125	19	4/181	0.06/0.04	82/83	26
1-3	WT, PKG	73 (58)	11 (38)	0.045	79	5.9/2.8	177 (350)	0.158/0.134	15	0/17	0.04/NR	81/83	24

[a]Indicates type of oil atomization. Mech = mechanical.

[b]FT = Firetube; WT = Watertube; PKG = Package.

[c]Number in parentheses indicates volumetric heat release rate in units of 10^3 Btu/ft^3 hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NA = Not available; NR = Not reported; Amb = Ambient temperature.

[f]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from References 24 and 26 are also presented in Reference 188.

comparison, excess O_2 levels during the baseline tests were 5.2 and 5.6 percent for boilers #4-4 and #3-2, respectively.

LEA-controlled NO_x emissions were lower than baseline NO_x emissions on the four packaged watertube boilers. For the three boilers (#1-2, #19-1, and Loc. 19) using no air preheating, emission reductions ranged from 2 to 19 percent. LEA-controlled NO_x emissions ranged from 37.8 to 53.8 ng/J (0.088 to 0.125 lb/10^6 Btu). Low excess air NO_x emissions were 57.6 ng/J (0.134 lb/10^6 Btu) for boiler #1-3 with air preheating. Emission reduction for this boiler using LEA was 15 percent. Excess O_2 ranged from 1.1 to 5.1 percent for the four boilers during the LEA tests and from 3.2 to 8.2 percent during the baseline tests. The four boilers operated at loads ranging from 50 to 80 percent of full load.

Carbon monoxide and PM emissions and boiler efficiency data are also presented in Table 3-23 for distillate oil-fired boilers operating at LEA and baseline conditions. Carbon monoxide emissions were measured from only four boilers (three watertube and one firetube) tested at both LEA and baseline conditions. From three of the four boilers using LEA (#1-3, #19-1, and Loc. 19), CO emissions were slightly higher than at baseline conditions. For boiler #19-1 using either air or mechanical atomization, no detectable CO emissions were measured during the baseline and LEA tests. Similarly, boiler #3-2 emitted no CO emissions during either test. Carbon monoxide emissions from the four boilers using LEA ranged from 0 to 181 ppm.

Emissions of PM were measured during both baseline and LEA tests from one boiler (Loc. 19). Emissions of PM from this using LEA were lower than baseline PM emissions, producing PM emissions of 0.04 lb/10^6 Btu during LEA operation compared to 0.06 lb/10^6 Btu during baseline operation.

Finally, boiler efficiency was determined on three boilers (#1-3, #19-1, and Loc. 19) during operation at LEA and baseline conditions. Boiler efficiencies increased 1 to 2 percent for LEA operation relative to the baseline efficiencies on these boilers.

3.3.7.1.2 <u>Normalized NO_x emission data</u>. The methodology to normalize the NO_x emission data for the distillate oil-fired boilers is similar to that discussed in Section 3.3.6.1.2 for the natural gas-fired boiler data. The equations used to normalize the NO_x emission data presented in Table 3-23 with respect to heat release rate, combustion air temperature, excess O_2, and fuel nitrogen content are:

For baseline,

$$En = E \left[TF \left(\frac{H_F}{H}\right)^{0.46} \left(\frac{540}{T}\right)^{0.81} \left(\frac{0.06}{A}\right)^{0.35} + FF \left(\frac{0.019}{N}\right)^{0.91} \right]$$

For LEA,

$$En = E \left[TF \left(\frac{H_F}{H}\right)^{0.46} \left(\frac{540}{T}\right)^{0.81} \left(\frac{0.06}{A}\right)^{0.35} + FF \left(\frac{0.019}{N}\right)^{0.91} \right]$$

where:

- En = Normalized NO_x emissions, ng/J or lb/10^6 Btu
- E = Actual or unnormalized NO_x emissions, ng/J or lb/10^6 Btu
- H_F = Full load combustion zone heat release rate, 10^3 Btu/hour-ft^2 surface
- H = Test load combustion zone heat release rate, 10^3 Btu/hour-ft^2 surface
- T = Combustion air preheat temperature, ^oR
- A = Excess O_2 level, fraction
- N = Fuel nitrogen content, weight percent

$$TF = \frac{3.53 \times 10^{-4} H^{0.46} T^{0.81} A^{0.35}}{3.53 \times 10^{-4} H^{0.46} T^{0.81} A^{0.35} + 0.655 N^{0.91}}$$

$$FF = \frac{0.655 N^{0.91}}{3.53 \times 10^{-4} H^{0.46} T^{0.81} A^{0.35} + 0.655 N^{0.91}}$$

Both equations shown were derived using the industrial boiler NO_x predictive algorithm for oil-fired watertube boilers.[203] In order to normalize the emissions data with respect to fuel nitrogen content, a fuel nitrogen content of 0.019 weight percent was used for correcting the emission data for fuel nitrogen effects. This value was determined by averaging the fuel nitrogen contents of the distillate oils presented in Table 3-23. The same method discussed for normalizing the natural gas data was used to correct the distillate oil NO_x emission data with respect to full load conditions, excess O_2 level, and ambient combustion air temperature of 27°C (80°F). Baseline NO_x emissions were corrected to 6 percent O_2, and LEA-controlled NO_x emissions were corrected to 2 percent O_2.

Table 3-24 presents the normalized NO_x emission data for six boilers, two of which are firetubes and four are watertubes. For the two firetube boilers, NO_x reductions from baseline were 27.8 percent for boiler #3-2 and 28.5 percent for boiler #4-4. The normalized NO_x emissions presented for the firetube boilers in Table 3-24 are considered as only estimates since the average fuel nitrogen content of 0.019 weight percent was assumed for correcting these data for fuel nitrogen effects. Fuel nitrogen content was not measured for the oils fired in these boilers. Reductions in NO_x ranged from 16.8 to 31.8 percent for the four watertube boilers.

One watertube boiler (#19-1) was tested for NO_x emissions using three different oil atomization techniques; NO_x reductions from baseline for this boiler using LEA ranged from 16.8 percent using mechanical atomization to 31.8 percent using steam atomization. Also, steam atomization produced the lowest NO_x emissions on this boiler during both baseline and LEA testing compared to the other two atomization techniques. Based on these results, steam atomization by itself produced the lowest NO_x emissions from the boiler compared to the other two atomization techniques.

Figures 3-31 and 3-32 show the baseline normalized NO_x emissions from Table 3-24 corrected to 6 percent O_2 as a function of both boiler size at full load and full load heat release rate, respectively. Also, superimposed on both figures is the normalized NO_x emission curve from the industrial boiler predictive algorithm. Again, the curve shown in Figure 3-31 is based on typical full load heat release rates for each boiler size.[204] For

TABLE 3-24. NORMALIZED NO_x EMISSIONS DATA ON DISTILLATE OIL-FIRED BOILERS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS

					Baseline Results		LEA Results			
Site I.D.	Boiler type[a]	Test load heat release rate, 10^3 Btu/ft^2-hr[b]	Combustion air temperature, °C (°F)	Oil nitrogen content, percent	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[e]	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[f]	NO_x reduction from baseline, percent	Reference[g]
3-2	FT	76	Amb[c]	0.019[d]	6.0	0.302	2.0	0.218	27.8	24
4-4	FT	111	Amb	0.019[d]	6.0	0.323	2.0	0.231	28.5	24
1-2	WT	34	Amb	0.019	6.0	0.142	2.0	0.100	29.6	24
19-1 (Steam)	WT	54	Amb	0.019	6.0	0.129	2.0	0.088	31.8	24
19-1 (Air)	WT	54	Amb	0.019	6.0	0.177	2.0	0.141	20.3	24
19-1 (Mechanical)	WT	44	Amb	0.019	6.0	0.137	2.0	0.114	16.8	24
Loc. 19	WT	56	Amb	0.019	6.0	0.224	2.0	0.186	17.0	26
1-3	WT	58	Amb	0.019	6.0	0.118	2.0	0.088	25.4	24

[a]FT = Firetube; WT = Watertube.

[b]NO_x emission data were normalized to a full load heat release rate of each boiler as reported in Table 3-23. To convert to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[c]Amb = Ambient air temperature [assume 27°C (80°F)].

[d]Assume average nitrogen content for this boiler calculated from the database presented in Table 3-23. Fuel nitrogen content was not available in this boiler's test report.

[e]Baseline-normalized NO_x emissions for each boiler were calculated to full load conditions and adjusted to a baseline O_2 level of 6.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]LEA-normalized NO_x emissions for each boiler were calculated to full load conditions and adjusted to a LEA O_2 level of 2.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from References 24 and 26 are also presented in Reference 188.

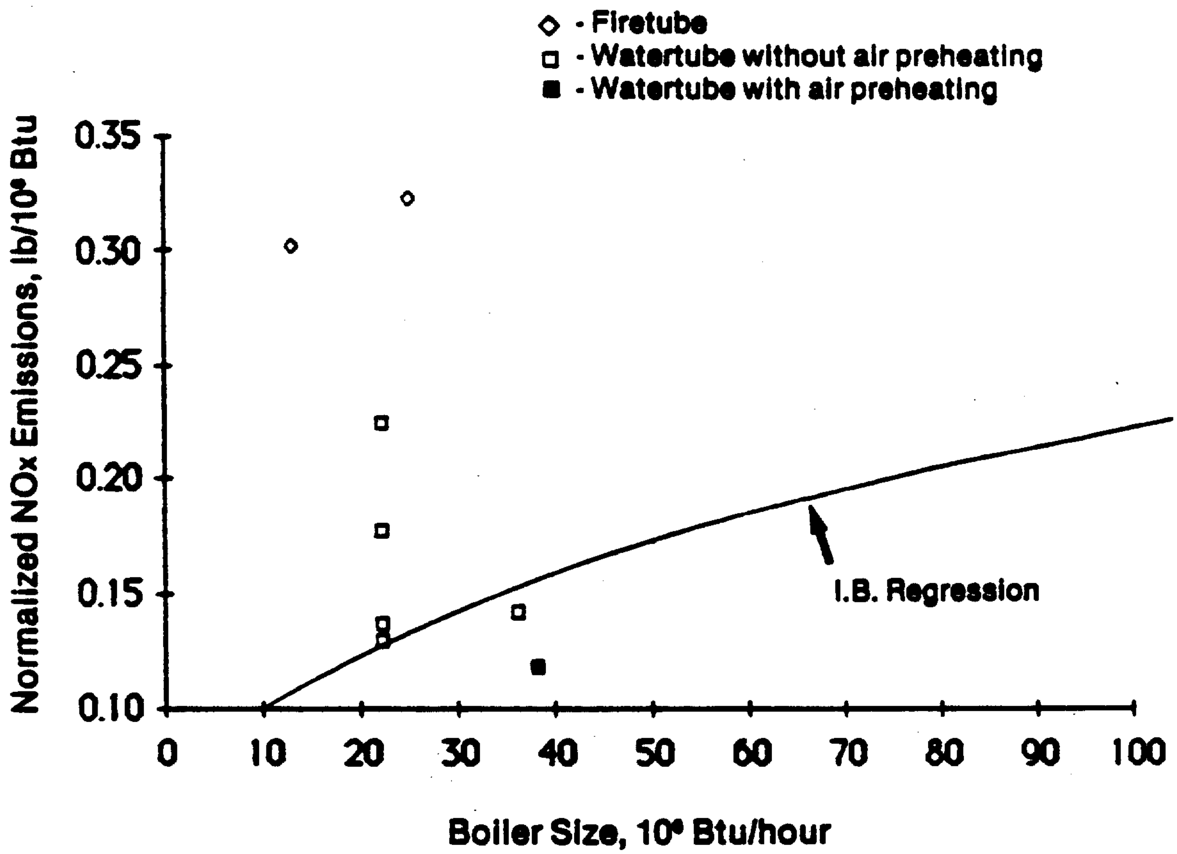

Figure 3-31. Normalized baseline NO_x emissions as a function of boiler size for distillate oil-fired small boilers.

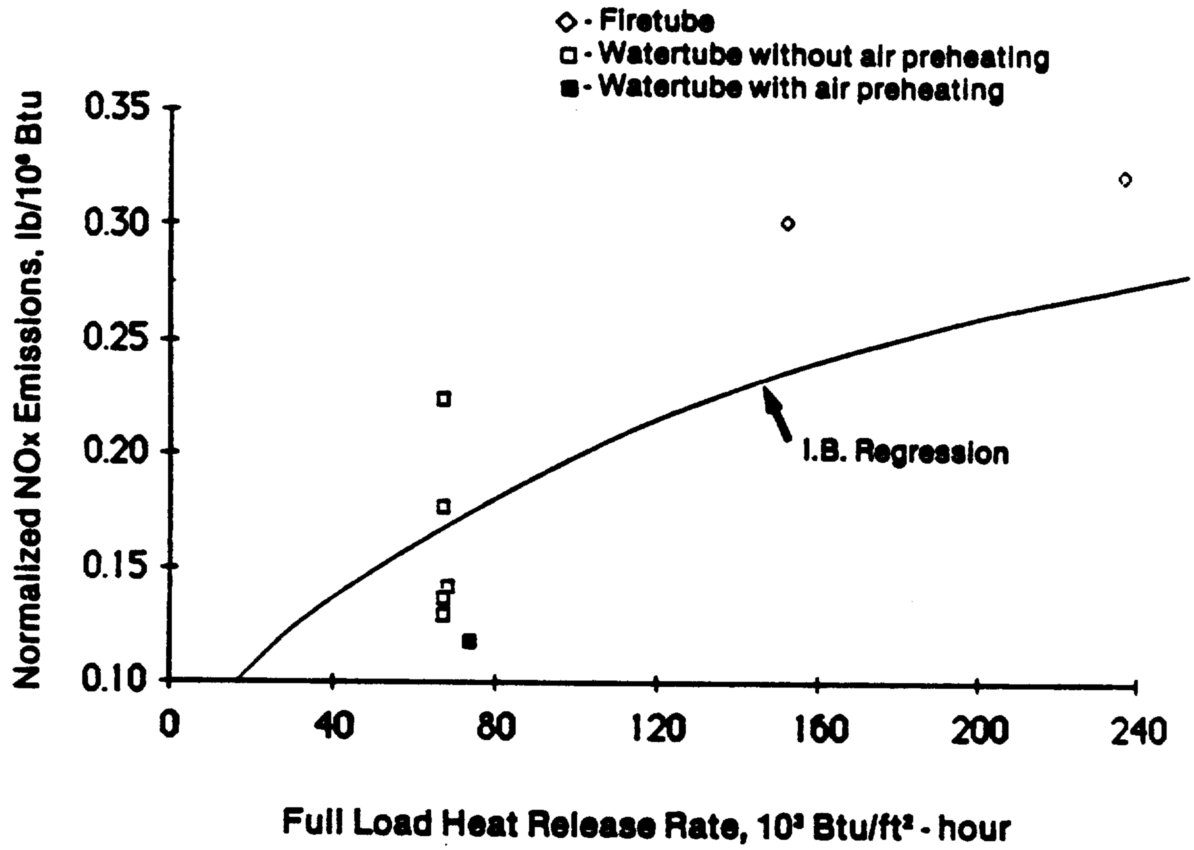

Figure 3-32. Normalized baseline NO_x emissions as a function of full load heat release rate for distillate oil-fired small boilers.

boilers between 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input, baseline NO_x emissions of 118 ng/J (0.275 lb/10^6 Btu) or less can be achieved. Because the firetube data are considered only as estimates, the industrial boiler curve in Figure 3-32 was used to estimate the NO_x emissions of 118 ng/J for that size range at the highest full load heat release rates for the firetube data given in Table 3-23 [i.e., up to a heat release rate of 743 KJ/m^2 -sec (236,000 Btu/ft^2-hour)]. In the same manner, for watertube boilers rated between 7.6 and 29.3 MW (26 and 100 million Btu/hour) heat input, a baseline NO_x emissions of 94.6 ng/J (0.22 lb/10^6 Btu) or less can be achieved based on the industrial boiler regression curve shown in both figures for a watertube boiler rated at 29.3 MW (100 million Btu/hour) heat input with a full load heat release rate of 387 kJ/m^2-sec (123,000 Btu/ft^2-hour).

Figures 3-33 and 3-34 show the LEA-controlled normalized NO_x emissions from Table 3-24 corrected to 2 percent O_2 as a function of boiler size at full load and full load heat release rate, respectively. Using the same approach discussed previously for estimating the baseline NO_x emissions, LEA-controlled NO_x emissions of 86 ng/J (0.20 lb/10^6 Btu) or less can be achieved for distillate oil-fired boilers between 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input. The industrial boiler regression curve in Figure 3-34 was used to estimate the NO_x emissions of 86 ng/J (0.20 lb/10^6 Btu) for that size range at a heat release rate of 743 kJ/m^2-sec (236,000 Btu/ft^2-hour). This heat release rate of 743 kJ/m^2-sec corresponds to the maximum heat release rate for a firetube boiler available from the normalized data in Table 3-24. Emissions of NO_x of 66.7 ng/J (0.155 lb/10^6 Btu) or less can be achieved for natural gas-fired watertube boilers using LEA rated between 7.6 and 27.3 MW (26 and 100 million Btu/hour) heat input as shown in both figures. This NO_x emissions level for the larger size range was obtained for a boiler rated at 29.3 MW (100 million Btu/hour) with a heat release rate of 387 kJ/m^2-sec (123,000 Btu/ft^2-hour) using the industrial boiler regression curve.

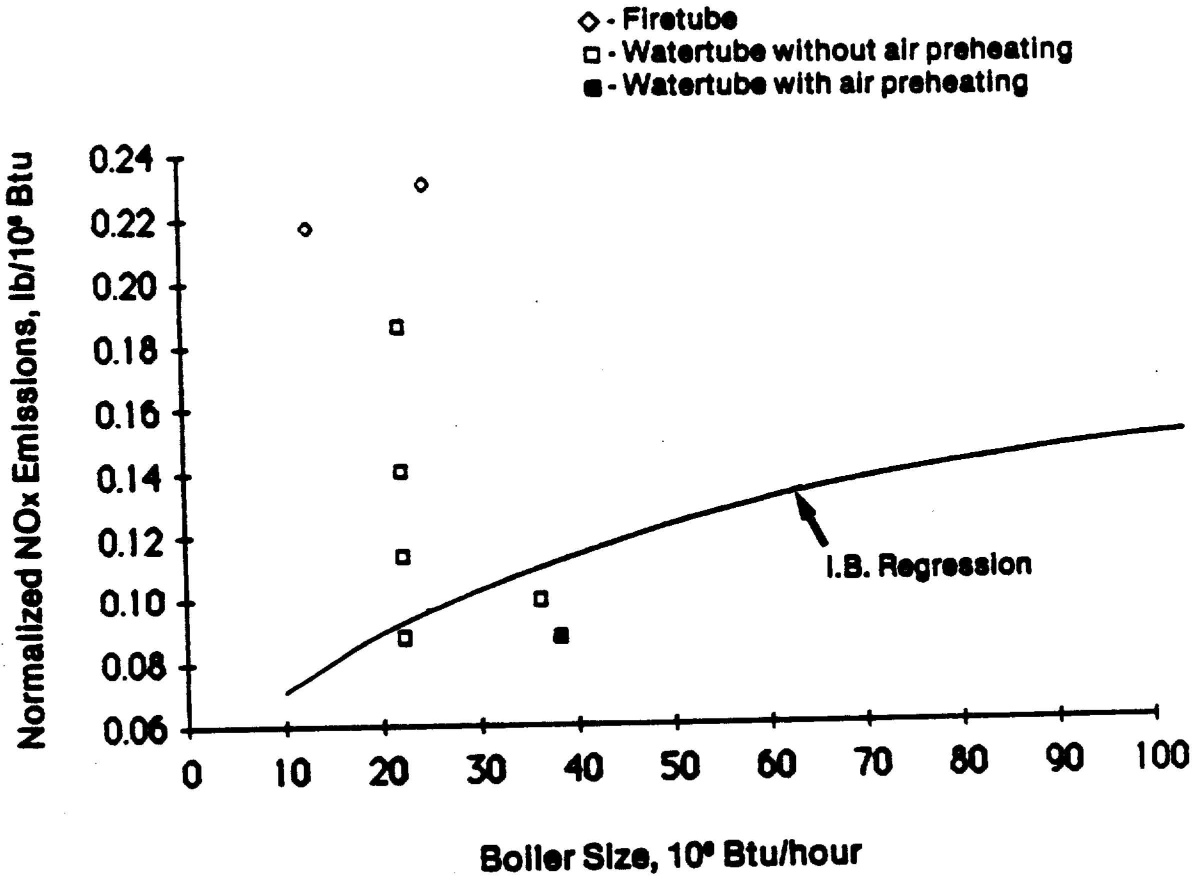

Figure 3-33. Normalized LEA-controlled NO_x emissions as a function of boiler size for distillate oil-fired small boilers.

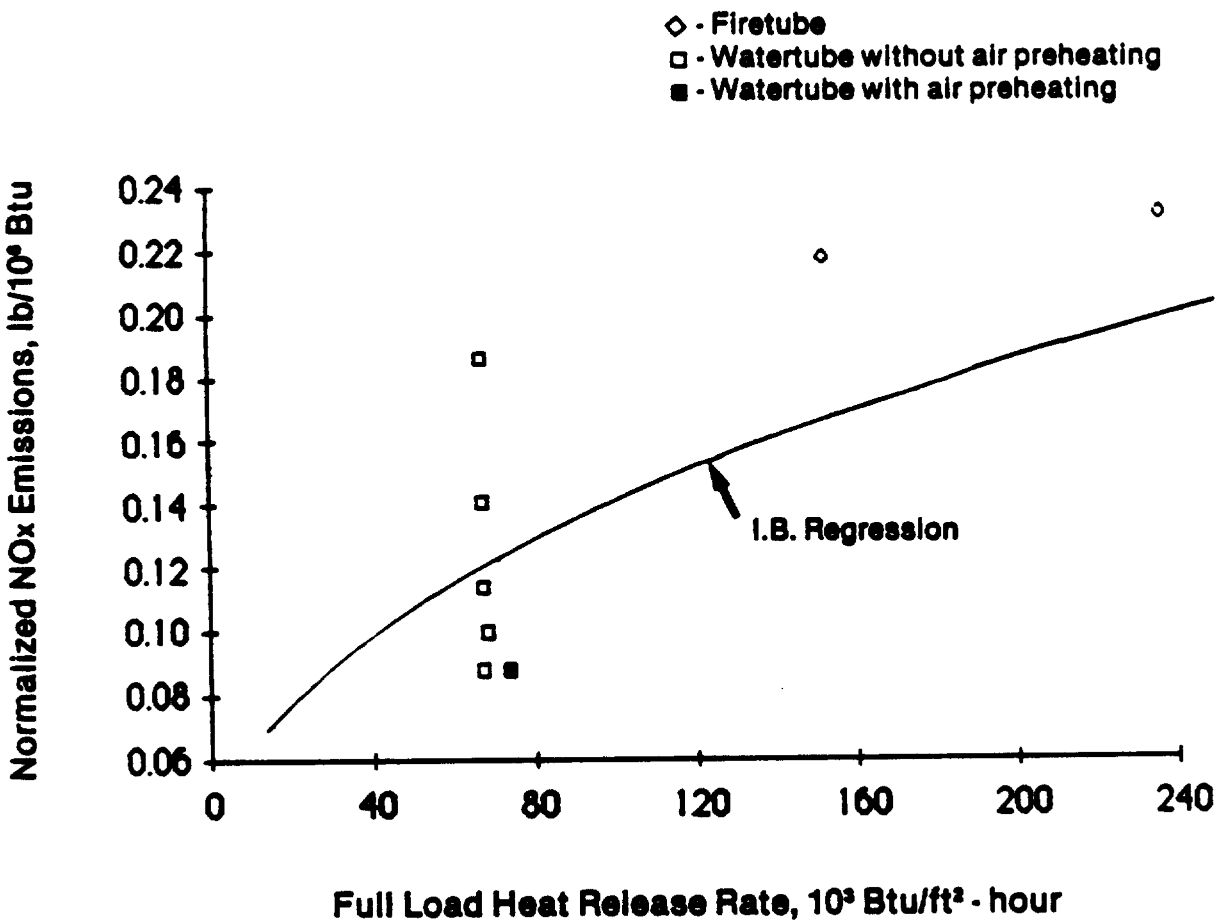

Figure 3-34. Normalized LEA-controlled NO_x emissions as a function of full load heat release rate for distillate oil-fired boilers.

3.3.7.2 FGR Test Data. Emissions data for NO_x from tests on two packaged watertube boilers (#5 and Loc. 19) equipped with FGR are summarized in Table 3-25. Baseline conditions are the normal operating conditions of the boiler with no FGR. All NO_x tests reported in Table 3-25 were short-term (less than 3 hours) CEM tests.

FGR-controlled NO_x emissions were 65.4 ng/J (0.152 lb/10^6 Btu) for boiler #5 operating at a 10 percent recirculation rate. At this recirculation rate, baseline NO_x emissions were reduced by 18 percent. Boiler #5 operated at full load and at roughly 3.5 percent excess O_2, for both baseline and FGR tests.

For the boiler at Location 19 operating at a 28 percent recirculation rate, NO_x emissions decreased to 17.6 ng/J (0.041 lb/10^6 Btu) from a baseline level of 66.2 ng/J (0.154 lb/10^6 Btu), resulting in a 73 percent NO_x reduction. The high reduction in NO_x emissions during the FGR test can be attributed to two factors. First, the recirculation rate was higher (28 percent) for this boiler than for boiler #5. Secondly, the excess O_2 was lower (0.8 percent) during the FGR test than during baseline test (3.2 percent). As discussed before, lowering the excess air generally tends to reduce NO_x emissions.

Nitrogen oxides emission data were not available for a boiler operating at a constant load with varying recirculation rates. Therefore, the relationship between NO_x emissions and the amount of flue gas recirculation cannot be directly determined for a small distillate oil-fired boilers. However, data presented for the natural gas-fired boilers in Section 3.3.6.2 show that NO_x emissions decrease as the flue gas recirculation rate increases. It follows that this trend, observed for the natural gas-fired boilers, should be similar for distillate oil-fired boilers since both fuels contain little or no fuel-bound nitrogen. As discussed in Section 3.3.3.1, FGR is more effective in reducing NO_x emissions for boilers firing low nitrogen fuels such as natural gas and distillate oil than high nitrogen fuels such as coal and residual oil.

Nitrogen oxides emission data were not available on firetube boilers rated above 2.9 MW (10 million Btu/hour) heat input. However, NO_x emission data are available from one experimental firetube boiler using FGR rated at

TABLE 3-25. NO_x EMISSIONS DATA FROM DISTILLATE OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING FLUE GAS RECIRCULATION

Site and Boiler Data					Test Data									
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °F	NO_x emissions, lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu percent baseline/controlled	Boiler efficiency percent baseline/controlled[f]	Reference[g]
#5	WT, PKG	95 (54)	16 (56)	NA[e]	10	100	3.5/3.4	Amb[e]	0.185/0.152	18	20/24	NR/NR[e]	NR/NR	195
Loc. 19	WT, PKG	87 (56)	6.5 (22)	0.004	28	83	3.2/0.8	Amb	0.154/0.041	73	4/46	0.06/0.01	82/82	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat relase rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to boiler.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NA = Not available; Amb = Ambient temperature [assume 27°C (80°F)]; NR = Not reported

[f]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from Reference 26 are also presented in Reference 180.

1.5 MW (5 million Btu/hour) heat input.[205] The test results from this boiler operating at 95 percent of full load indicated that NO_x emissions with and without a 15 percent FGR rate were 33.1 ng/J (0.077 lb/10^6 Btu or 60 ppm at 3 percent O_2) and 63.2 ng/J (0.147 lb/10^6 Btu or 115 ppm at 3 percent O_2), respectively. Flue gas recirculation reduced baseline NO_x emissions by 48 percent for this boiler operating at a 15 percent FGR rate.

Table 3-25 presents data on CO and PM emissions and boiler efficiency from tests on these two distillate oil-fired boilers. Carbon monoxide emissions were low (less than 50 ppm) from both boilers tested at baseline and at FGR. The boiler at Location 19 emitted more CO emissions during the FGR test because the excess O_2 was lower than the baseline excess O_2 (0.8 percent O_2 at FGR versus 3.2 percent at baseline conditions).

Examination of PM emissions data from the boiler at Location 19 shows that this boiler produced lower PM emissions during FGR tests than during baseline operation. Emissions of PM dropped from a baseline of 25.8 ng/J (0.06 lb/10^6 Btu) to 4.3 ng/J (0.01 to lb/10^6 Btu) when 28 percent of the flue gas was recirculated to the boiler. This decline in PM emissions indicates that some of the carbonaceous particulate matter returning to the boiler may either have been combusted or that the recycled ash may have been removed as bottom ash from the boiler.

Finally, boiler efficiency was the same, at 82 percent, for the boiler at Location 19 during the baseline and FGR tests. No predictive NO_x emissions regression is available to normalize the above FGR data.

The data indicate that FGR can achieve NO_x emission reductions from 18 to 73 percent for small distillate oil-fired boilers operating at recirculation rates between 10 and 28 percent. Based on the performance of the small firetube boilers using FGR, FGR can achieve a 50 percent NO_x reduction for this boiler operating at a 15 percent recirculation rate.

3.3.7.3 <u>OFA Test Data</u>. Table 3-26 presents NO_x emission data from one distillate oil-fired small boiler (Loc. 19) equipped with OFA. This boiler emitted 53.8 ng/J (0.125 lb/10^6 Btu) of NO_x during OFA operation and 66.2 ng/J (0.154 lb/10^6 Btu) of NO_x during baseline operation resulting in a 19

TABLE 3-26. NO_x EMISSIONS DATA FROM DISTILLATE OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING OVERFIRE AIR

Site and Boiler Data					Test Data									
Site I.D.	Boiler type[a]	Full load heat release rate 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, Percent	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	NO_x reduction, percent	CO Emissions, ppm @ 3% O_2 baseline/controlled	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[e]	Boiler efficiency, percent baseline/controlled	Reference[f]
Loc. 19	WT, PKG	67 (56)	6.5 (22)	0.004	83	3.2/3.1	Amb[d]	0.154/0.125	19	4/29	4/29	0.06/0.03	82/83	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d]Amb = Ambient temperature [assume 27°C (80°F)].

[e]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]Test results from Reference 26 are presented in Reference 180.

percent reduction in NO_x emissions over baseline. The boiler operated at 83 percent load and about 3.2 percent O_2 for both baseline and OFA conditions.

Table 3-26 also presents boiler efficiency, CO, and PM emissions data on the boiler at Location 19 during baseline and OFA tests. Carbon monoxide emissions increased slightly from 4 ppm at baseline to 29 ppm during OFA operation for this boiler. Emissions of PM were 25.8 ng/J (0.06 lb/10^6 Btu) and 12.9 ng/J (0.03 lb/10^6 Btu) during the baseline and OFA tests, respectively. Boiler efficiency increased roughly one percent during OFA operation (83 percent) from the baseline boiler efficiency of 82 percent.

Table 3-27 presents NO_x emission data on the boiler at location 19 when combining both FGR and OFA. From examining the data from this table and Table 3-25, no improvement is gained on NO_x reduction over FGR alone when both techniques are applied.

The data indicate that OFA can achieve 20 percent NO_x emission reduction on one small distillate oil-fired boiler. Outlet NO_x emissions were 53.8 ng/J (0.125 lb/10^6 Btu).

3.3.7.4 <u>LNB Test Data</u>. The results of a NO_x test on one distillate oil-fired small boiler (#3) using a staged combustion air burner are presented in Table 3-28. Emissions of NO_x measured from this boiler were 47.3 ng/J (0.110 lb/10^6 Btu) during low NO_x operation. Boiler #3 operated at 84 percent load and 1.9 percent O_2 during the test. From Table 3-28, this boiler emitted 91 ppm CO during low NO_x testing. Particulate matter emissions were not measured during the test.

The data indicate that LNB can achieve NO_x emission level of 47.3 ng/J (0.11 lb/10^6 Btu) on one small distillate oil-fired boiler.

3.3.8 <u>NO_x Emission Test Data on Residual Oil-Fired Steam Generators</u>

3.3.8.1 <u>LEA Test Data</u>.

3.3.8.1.1 <u>Actual or non-normalized NO_x emission data</u>. Table 3-29 presents NO_x emission data from tests on 14 residual oil-fired small steam generators. Of the 14 generators, NO_x emission data were collected on 3

TABLE 3-27. NO_x EMISSION DATA FROM DISTILLATE OIL-FIRED BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING BOTH FLUE GAS RECIRCULATION AND OVERFIRE AIR

Site and Boiler Data					Test Data									
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[e]	Boiler efficiency, percent baseline/controlled	Reference[g]
Loc. 19	WT,PKG	67 (56)	6.5 (22)	NR[f]	26	82	3.2/3.5	Amb	0.154/0.042	73	4/18	0.06/0.01	82/81	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to the boiler.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]NR = Not reported.

[g]Test results from Reference 26 are also presented in Reference 108.

TABLE 3-28. NO_x EMISSIONS DATA FROM DISTILLATE OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING LOW NO_x BURNERS

Site and Boiler Data				Test Data						
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °F	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	CO emissions, ppm @ 3% O_2 baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference
#3	WT, PKG	72 (NR)	22 (75)	84	NA[d]/1.9	Amb[d]	NA/0.110	NA/91	NR/NR[d]	201

[a]WT = Watertube; PKG = Packaged. 46,000 Btu/hr ft³

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d]NA = Not Available; Amb = Ambient Temperature [assume 27°C (80°F)]; NR = Not Reported.

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TABLE 3-29. NO_x EMISSIONS DATA FROM RESIDUAL OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING LOW EXCESS AIR

Site and Boiler Data					Test Data								
Site I.D.	Boiler type[b]	Full load heat release rate, 10^3 Btu/ft^2-hr[c]	Boiler capacity, 10^6 Btu/hr heat input	Fuel nitrogen, percent	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[g]	Boiler efficiency, percent baseline/controlled	Reference[h]
23-1	FT	133 (282)	2.6 (9)	0.27	96	5.4/3.9	Amb[e]	0.389/0.328	16	21/26	NR/NR	88/NR	24
24-TV	FT	NR[e] (NR)	3.8 (13)	1.30	104	3.2/1.9	Amb	0.239/0.227	5	0/113	0.09.NR	85/NR	24
26-1	FT	108 (138)	6.7 (23)	0.03	94	6.9/3.8	Amb	0.213/0.201	6	13/21	0.08/NR	86/87	24
2-4	WT, FE	58 (24)	24 (81)	0.38	80	5.7/3.4	Amb	0.641/0.572	11	0/0	NR/NR	NR/81	24
16-2	WT, PKG	85 (40)	24 (81)	0.29	83	4.9/3.7	Amb	0.256/0.236	8	0/0	NR/NR	85/88	24
Loc. 19	WT, PKG	67 (56)	6.5 (22)	0.25	80	2.9/1.6	Amb	0.278/0.193	31	4/183	0.08/0.07	83/84	26
19-1 (Steam)[a]	WT, PKG	67 (56)	6.5 (22)	0.44	83	4.0/2.6	Amb	0.459/0.438	5	0/90	0.03/NR	84/85	24
19-1 (Air)[a]	WT, PKG	67 (56)	6.5 (22)	0.44	83	4.4/2.8	Amb	0.436/0.368	16	0/NR	NR/NR	85/85	24
19-2	WT, PKG	67 (56)	6.5 (22)	0.14	81	3.1/0.9	Amb	0.217/0.159	27	19/58	NR/0.15	85/86	24
20-4	WT, PKG	137 (60)	29 (100)	0.37	64	5.7/4.0	Amb	0.398/0.356	11	0/82	0.09/NR	80/NR	24
ECCC	WT, PKG	NR (NR)	9.1 (31)	0.19	78	5.5/3.6	Amb	0.200/0.145	28	<10/<10	NR/NR	NR/NR	199
28-1	WT, PKG	78 (32)	26 (88)	NR	41	5.3/4.9	174 (345)	0.263/0.231	12	0/45	NR/NR	86/87	24
37-2	WT, PKG	101 (32)	15 (50)	0.30	81	4.3/3.8	110 (230)	0.251/0.230	8	0/0	0.14/NR	85/NR	24
Loc. 38	WT, PKG	84 (36)	16 (56)	0.14	85	3.1/0.9	138 (280)	0.386[f]/0.305[f]	21	22/65	0.15/0.11	85/86	26
38-2	WT, PKG	84 (36)	16 (56)	0.49	81	3.0/1.6	157 (315)	0.419/0.312	26	0/120	0.11/NR	87/87	24

[a]Indicates type of oil atomization.

[b]FT = Firetube; WT = Watertube; PKG = Packaged; and FE = Field Erected.

[c]Number in parentheses indicates volumetric heat release rate in units of 10^3 Btu/ft^3 hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3/ft^3-hr by 10.35.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NR = Not reported; Amb = Ambient temperature [assume 27°C (80°F)].

[f]Estimate only, NO_x values assume NO_2 is 5% of the total (only NO was measured).

[g]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[h]Test results from References 24, 26, and 199 are also presented in Reference 188.

firetube and 11 watertube boilers. The average test load and combustion air temperature for each boiler in Table 3-29 were the same during baseline and LEA testing. All NO_x tests were short-term CEM tests.

For the three firetube boilers (#23-1, #24-TV, and #28-1),LEA-controlled NO_x emissions were lower than baseline NO_x emissions. Emission reductions ranged from 5 to 16 percent. LEA-controlled NO_x emissions ranged from 86.4 to 141 ng/J (0.201 to 0.328 lb/10^6 Btu) for the three boilers. Excess O_2 levels during LEA operation ranged from 1.9 to 3.9 percent. The three boilers operated at loads ranging from 94 to 104 percent of full load.

Of the 11 watertube boilers listed in Table 3-29, NO_x emission data were collected from tests on 6 packaged watertube boilers without air preheating. LEA-controlled NO_x emissions for these boilers were lower than the baseline NO_x emissions and ranged from 62.4 to 188 ng/J (0.145 to 0.438 lb/10^6 Btu). Emission reductions ranged from 5 to 31 percent for the six watertube boilers. During the LEA tests, excess O_2 levels ranged from 0.9 to 4.0 percent. Baseline O_2 levels were between 2.9 and 5.9 percent. These boilers operated at loads ranging from 64 to 83 percent of full load. To examine the effects of combustion air preheat temperature on NO_x emissions, Table 3-30 presents data on two boilers (#37-2 and #38-2) using reduced air preheat. Test data from these two boilers indicate that reducing combustion air temperature reduces NO_x emissions from 13 to 49 percent.

Nitrogen oxide emissions data were collected from tests on four packaged boilers (#28-1, #37-2, #38-2, and Loc. 38) using combustion air preheating. LEA-controlled NO_x emissions were lower than baseline and ranged from 98.9 to 134 ng/J (0.230 to 0.312 lb/10^6 Btu) for these four boilers. Emission reductions ranged from 8 to 25 percent. Excess O_2 levels for the boilers tested with LEA ranged from 0.9 to 4.9 percent. This compares with baseline O_2 levels ranging from 3.0 to 5.3 percent. Loads ranged from 41 to 85 percent.

One field-erected boiler (#2-4) was tested for NO_x emissions. The results are also shown in Table 3-29. Emission reductions of 11 percent were achieved for this boiler using LEA. LEA-controlled NO_x emissions were 246 ng/J (0.572 lb/10^6 Btu). Excess O_2 levels during LEA and baseline

TABLE 3-30. NO_x EMISSION DATA FROM RESIDUAL OIL-FIRED BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING REDUCED COMBUSTION AIR PREHEAT

Site and Boiler Data					Test Data								
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Average test load, percent	Stack O_2, percent baseline/ controlled	Combustion air temperature, °C (°F)[c]	NO_x emissions lb/10^6 Btu baseline/ controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/ controlled	PM emissions, lb/10^6 Btu baseline/ controlled	Boiler efficiency, percent baseline/ controlled	Reference[f]
37-2	WT,PKG	101 (35)	15 (50)	0.30	79	4.3/4.5	108 (227)/ 46 (115)	0.251/0.129	49	0/38	0.14/NR[e]	85/83	24
38-2	WT,PKG	84 (36)	16 (56)	0.49	77	3.0/2.7	157 (315)/ 77 (171)	0.419/0.364	13	0/0	0.11/NR	87/85	24

[a] WT = Watertube; PKG = Packaged.

[b] Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c] Baseline air temperature/reduced air temperature.

[d] NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e] NR = Not reported.

[f] Test results from Reference 24 are also presented in Reference 188.

operation were 3.4 and 5.7, respectively. This boiler operated at 80 percent load.

Table 3-29 also presents CO and PM emissions and boiler efficiency data from tests on 14 residual oil-fired small boilers operating with LEA and at baseline conditions. Carbon monoxide emissions from these boilers operating with LEA ranged from 0 to 183 ppm. Ten of the 14 residual oil boilers listed in Table 3-29 emitted slightly higher CO emissions at LEA than at baseline conditions. Furthermore, four boilers (#2-4, #26-1, #37-2, and ECCC) could have operated at lower excess O_2 levels since no CO emissions were measured from these boilers during operation with LEA.

Only two boilers (Loc. 19 and Loc. 38) have data on PM emissions from both baseline and LEA tests. Both boilers emitted less PM during the LEA tests. For the LEA tests, PM emissions were 30.1 ng/J (0.07 lb/10^6/Btu) from the boiler at Location #19 and 47.2 ng/J (0.11 lb/10^6 Btu) from the boiler at Location #38. For the baseline tests, PM emissions from all boilers in Table 3-29 ranged from 12.9 ng/J (0.03 lb/10^6 Btu) from boiler #19-1 using steam atomization to 60.2 ng/J (0.14 lb/10^6 Btu) from boiler #37-2.

Boiler efficiencies from baseline and LEA tests were determined from tests on nine boilers. For seven boilers (#16-2, #19-1 using steam atomization, #19-2, #26-1, #28-1, Loc. 19, and Loc. 38), operating the boiler at LEA increased the boiler efficiency roughly 1 percent. Three boilers (#26-2, #19-1 using air atomization, and #38-2) operated at the same efficiency at both LEA and baseline conditions.

3.3.8.1.2 Normalized NO_x emission data. The methodology used to normalize the NO_x emission data for the residual oil-fired boilers is similar to that discussed in Section 3.3.6.1.2 for the natural gas-fired boiler data. The equations used to normalize the NO_x emission data in Table 3-29 with respect to heat release rate, combustion air temperature, excess O_2, and fuel nitrogen content are:

For baseline,

$$En = E\left[TF\left(\frac{HF}{H}\right)^{0.46}\left(\frac{540}{T}\right)^{0.81}\left(\frac{0.06}{A}\right)^{0.35} + FF\left(\frac{0.36}{N}\right)^{0.91}\right]$$

For LEA,

$$En = E\left[TF\left(\frac{HF}{H}\right)^{0.46}\left(\frac{540}{T}\right)^{0.81}\left(\frac{0.02}{A}\right)^{0.35} + FF\left(\frac{0.36}{N}\right)^{0.91}\right]$$

A description of the variables used in the above equations are presented in Section 3.3.7.1.2. As discussed in Section 3.3.7.1.2, the form of the above equation is derived from the industrial boiler NO_x regression equation for oil-fired watertube boilers.[206]

In order to normalize the emission data with respect to fuel nitrogen content, the emission data were corrected using a fuel nitrogen content of 0.36 weight percent. This value was determined by averaging the fuel nitrogen contents of the residual oils in Table 3-29. The rationale for using the average nitrogen content was that the average value, based on the data collected for small boilers, would be more representative of a typical nitrogen content for residual oil available to small boiler users than any other fuel nitrogen content. The same methodology was used to correct the NO_x emission data of each boiler with respect to full load heat release rate, excess O_2 level of 6 percent for baseline and 2 percent for LEA, and ambient combustion air temperature of 27°C (80°F) as those used in normalizing the natural gas NO_x emission data.

Table 3-31 presents the normalized NO_x emissions from 12 boilers, 2 of which are firetubes and 10 are watertubes. Emissions of NO_x could not be normalized with respect to heat release rate from data on two boilers (#24-TV and ECCC) because heat release rate information was not available. The nitrogen content of the oil fired in boiler #28-1 was not measured during the test; it was assumed to equal the average nitrogen content of the database for the purposes of normalization.[207] For this reason, the normalized NO_x emissions from this boiler can only be considered as an estimate.

For the two firetube boilers reported in Table 3-31, NO_x reductions from baseline were 2.1 percent for boiler #26-1 and 23.5 percent for boiler #23-1. Reductions in NO_x ranged from 12.4 to 34.1 percent for the 10 watertube boilers.

TABLE 3-31. NORMALIZED NO_x EMISSIONS DATA ON RESIDUAL OIL-FIRED BOILERS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS

					Baseline Results		LEA Results			
Site I.D.	Boiler type[a]	Test load heat release rate, 10^3 Btu/ft^2-hr[b]	Combustion air temperature, °C (°F)	Oil nitrogen content, percent	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[e]	Stack O_2, percent	Full load normalized NO_x emissions, lb/10^6 Btu[f]	NO_x reduction over baseline, percent	Reference[g]
23-1	FT	128	Amb[c]	0.36	6.0	0.459	2.0	0.351	23.5	24
26-1	FT	102	Amb	0.36	6.0	0.436	2.0	0.427	2.1	24
2-4	WT	46	Amb	0.36	6.0	0.646	2.0	0.540	16.4	24
16-2	WT	71	Amb	0.36	6.0	0.306	2.0	0.257	16.0	24
Loc. 19	WT	54	Amb	0.36	6.0	0.390	2.0	0.257	34.1	26
19-1 (Steam)	WT	56	Amb	0.36	6.0	0.436	2.0	0.382	12.4	24
19-1 (Air)	WT	56	Amb	0.35	6.0	0.410	2.0	0.319	22.2	24
19-2	WT	54	Amb	0.36	6.0	0.408	2.0	0.320	21.6	24
20-4	WT	88	Amb	0.36	6.0	0.430	2.0	0.346	19.5	24
28-1	WT	32	Amb	0.36[d]	6.0	0.276	2.0	0.215	22.1	24
37-2	WT	82	Amb	0.36	6.0	0.278	2.0	0.225	19.1	24
Loc. 38	WT	71	Amb	0.36	6.0	0.615	2.0	0.536	12.8	26
38-2	WT	68	Amb	0.36	6.0	0.355	2.0	0.247	30.4	24

[a]FT = Firetube; WT = Watertube.

[b]NO_x emission data were corrected to full load heat release rate of each boiler as reported in Table 3-30. To convert to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[c]Amb = Ambient air temperature [assume 27°C (80°F)].

[d]Assume average nitrogen content for this boiler calculated from the database presented in Table 3-30. Fuel nitrogen content was not measured.

[e]Baseline-normalized NO_x emissions for each boiler were calculated to full load conditions and adjusted to a baseline O_2 level of 6.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Bty by 430.

[f]LEA-normalized NO_x emissions for each boiler were calculated to full load conditions and adjusted to a LEA O_2 level of 2.0 percent using EPA's NO_x predictive algorithm. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from References 24 and 26 are also presented in Reference 188.

One watertube boiler (#19-1) was tested for NO_x emissions using two oil atomization techniques (steam and air atomization). When this boiler operated with LEA, NO_x reductions from baseline were 12.4 percent using steam atomization and 22.2 percent using air atomization. In addition, this boiler emitted lower baseline and LEA-controlled NO_x emissions using air atomization than using steam atomization. Essentially the same excess O_2 levels were maintained during baseline and LEA operations for this boiler using both atomization techniques. By contrast, steam atomization produced lower NO_x emissions than air atomization for the small boiler firing distillate oil, as discussed in Section 3.3.7.1.2. The results from testing of this boiler while firing both types of oil indicate that proper atomization is also important for reducing NO_x emissions. One type of atomization may be more conducive to reducing NO_x emissions when firing one fuel but not another fuel.

Figures 3-35 and 3-36 show the baseline normalized NO_x emissions from Table 3-31 corrected to 6 percent O_2 and the normalized NO_x emission curve of the industrial boiler NO_x regression curve as a function of boiler size at full load and full load heat release rate, respectively. The curve shown in Figure 3-35 is based on typical full load heat release rates for each boiler size.[208] From datapoints presented in both figures, a baseline NO_x emissions level of 198 ng/J (0.46 lb/10^6 Btu) or less can be met for firetube and watertube boilers rated at 7.3 MW (25 million Btu/hour) heat input or less. This same NO_x emission level of 198 ng/J (0.46 lb/10^6 Btu) or less can also be achieved by watertube boilers between 7.6 and 29.3 MW (26 and 100 million Btu/hour) heat input based on the industrial boiler regression curve for a 29.3 MW (100 million Btu/hour) boiler [i.e., boiler #20-4 with a full load heat release rate of 432 KJ/m^2-sec (137,000 Btu/ft^2-hr)]. This analysis excludes data from field-erected boilers and package watertube boilers using combustion air preheating, since these boiler types are atypical of small boilers rated at 29.3 MW (100 million Btu/hour) heat input or less.

In a similar fashion, Figures 3-37 and 3-38 show the LEA-controlled normalized NO_x emissions from Table 3-31 as a function of boiler size at full load and full load heat release rate, respectively. Using the same

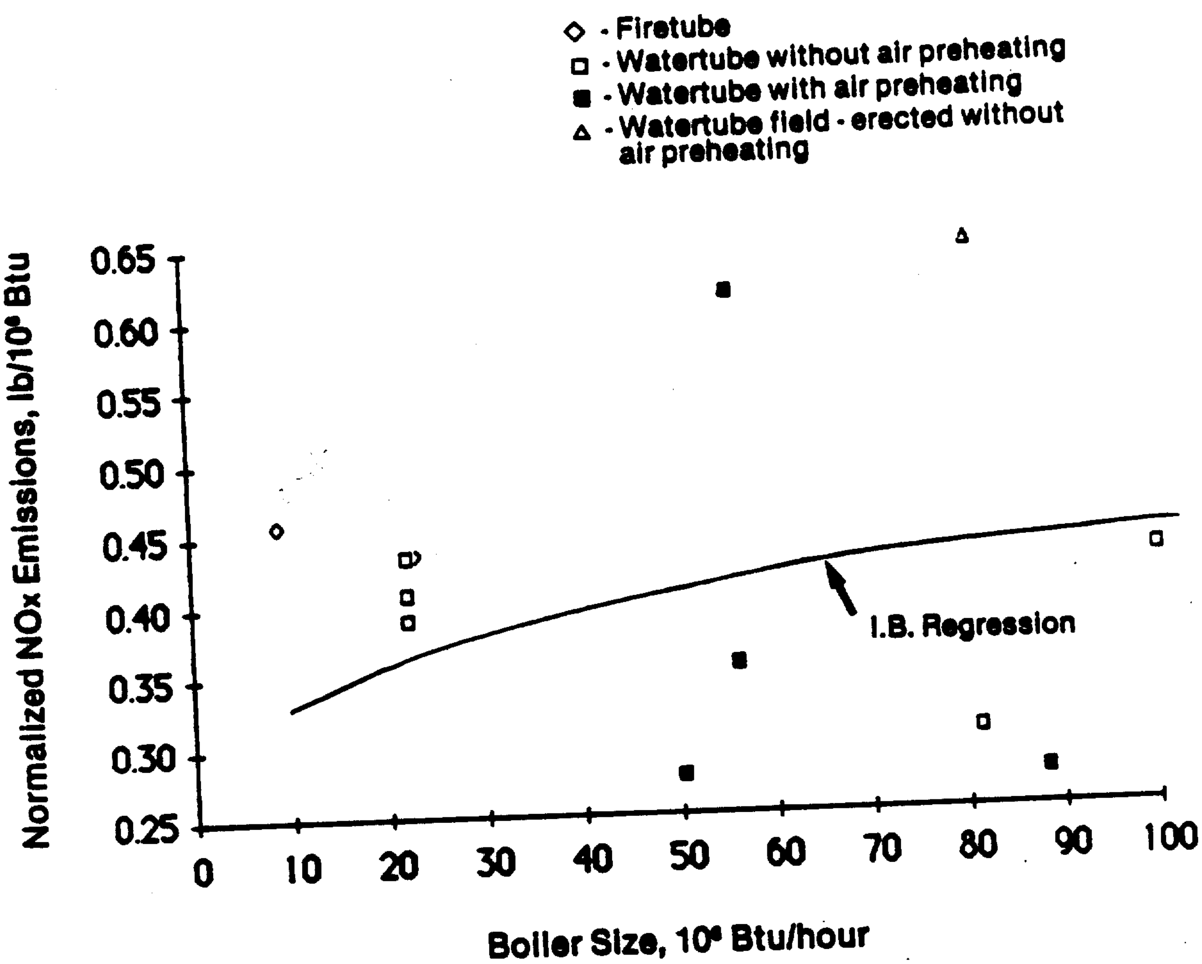

Figure 3-35. Normalized baseline NO_x emissions as a function of boiler size for residual oil-fired small boilers.

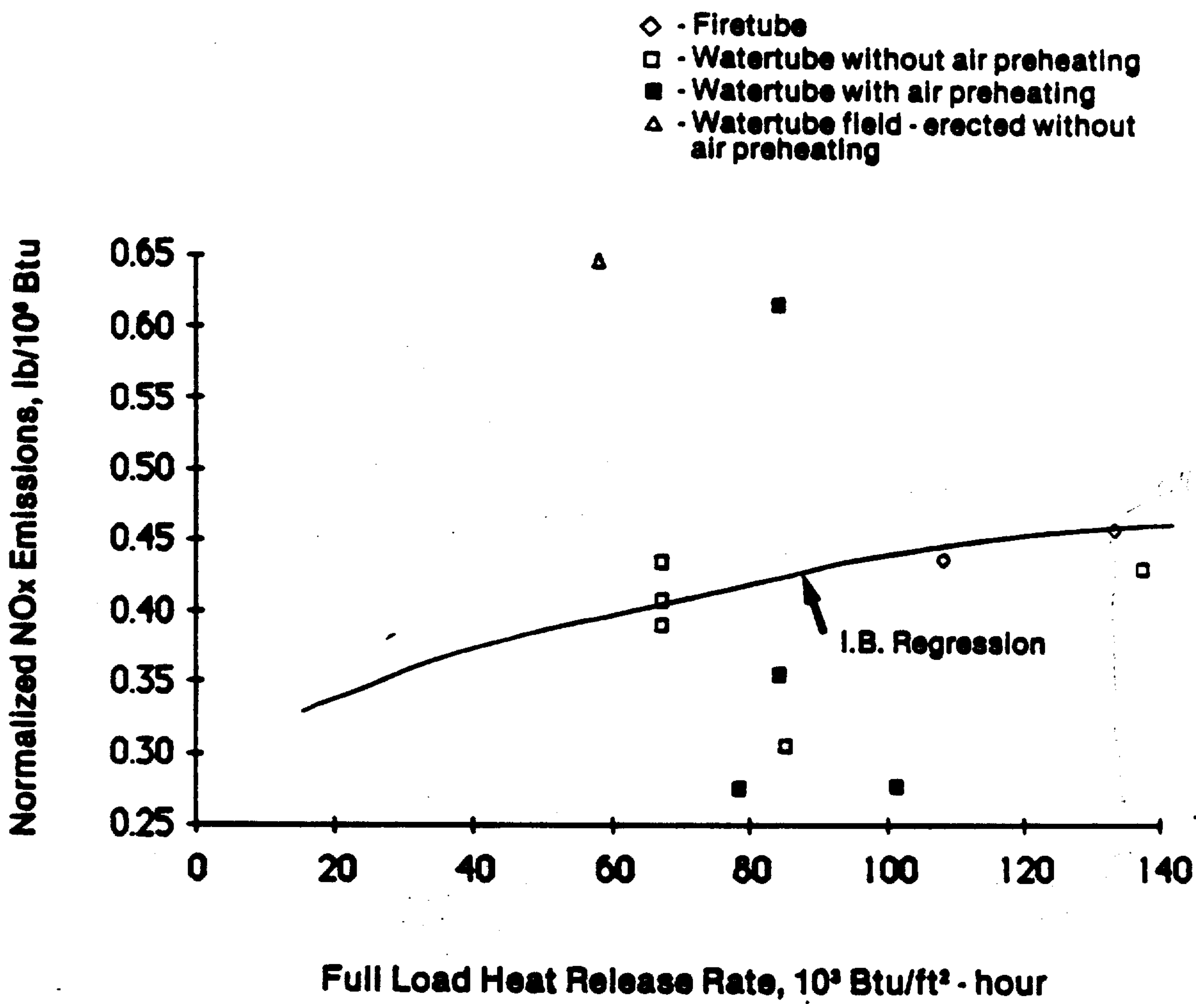

Figure 3-36. Normalized baseline NO_x emissions as a function of full load heat release rate for residual oil-fired small boilers.

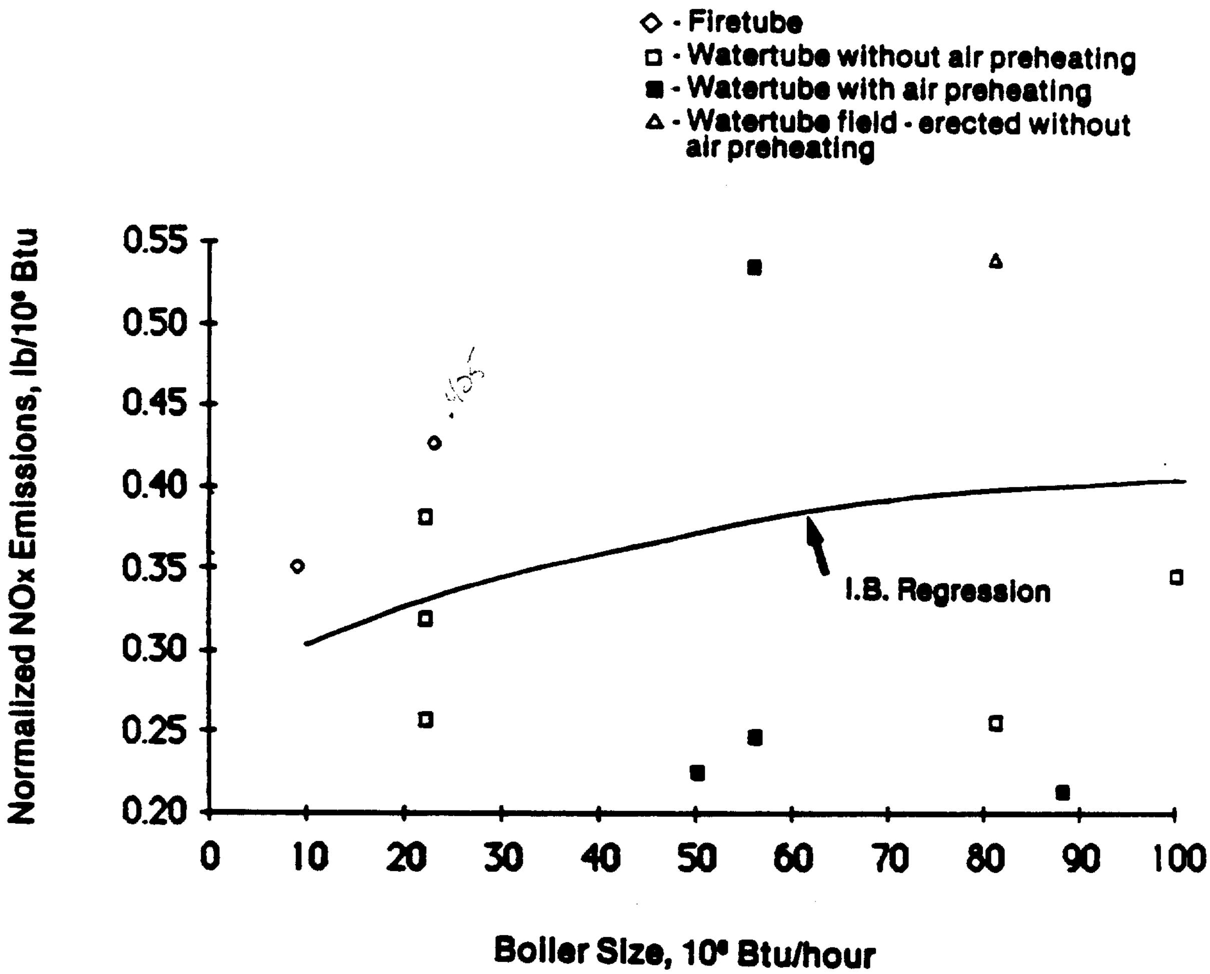

Figure 3-37. Normalized LEA-controlled NO_x emissions as a function of boiler size for residual oil-fired small boilers.

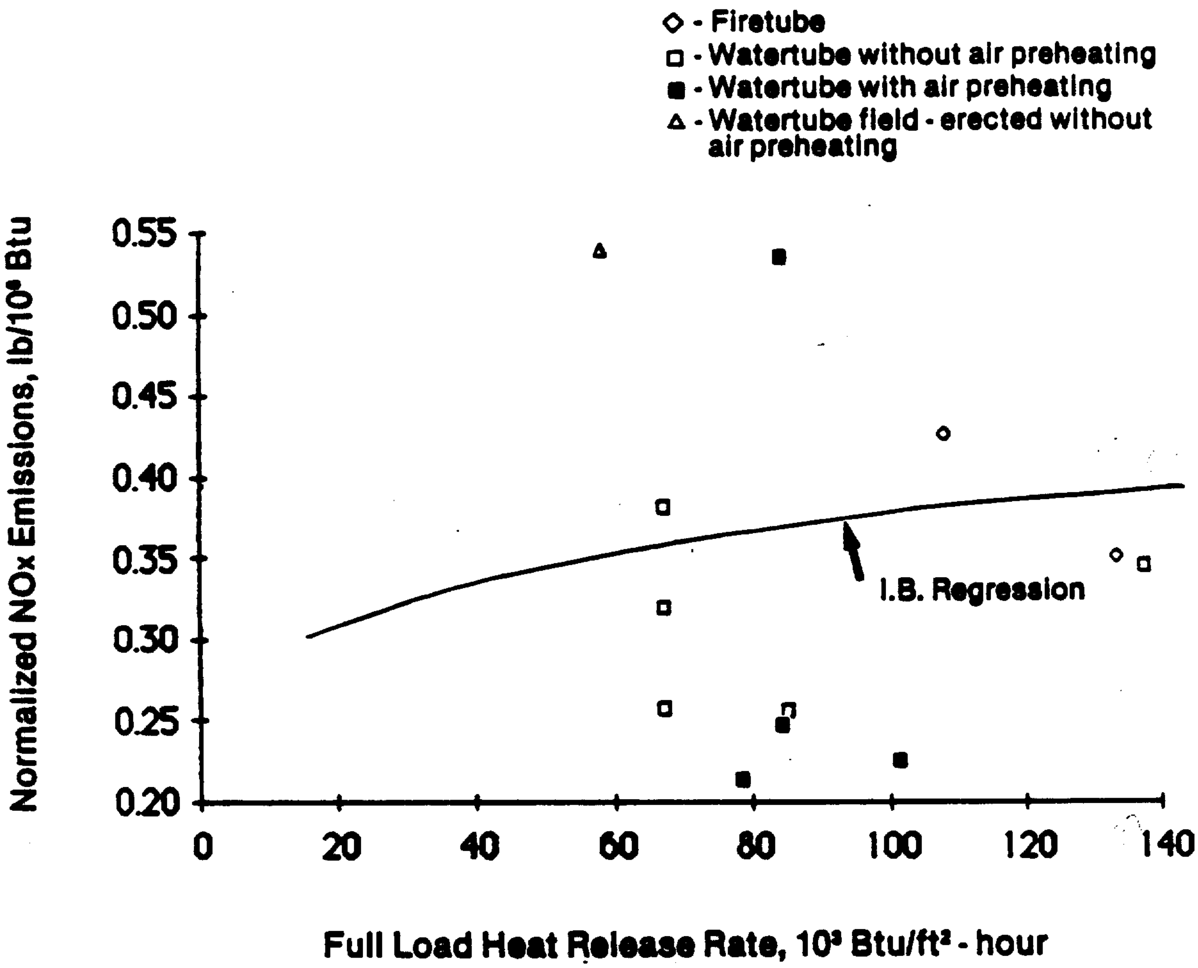

Figure 3-38. Normalized LEA-controlled NO_x emissions as a function of full load heat release rate for residual oil-fired small boilers.

approach discussed previously, LEA-controlled NO_x emissions of 183 ng/J (0.425 lb/10^6 Btu) or less can be achieved for residual oil-fired boilers rated at 7.3 MW (25 million Btu/hour) heat input or less. For watertube packaged residual oil-fired boilers rated at 7.6 to 29.3 MW (26 to 100 million Btu/hour) heat input LEA-controlled NO_x emissions of 172 ng/J (0.400 lb/10^6 Btu) or less can be achieved. These NO_x levels apply to residual oils with 0.36 weight percent nitrogen or less.

3.3.8.2 <u>FGR Test Data</u>. Table 3-32 summarizes test data collected on two residual oil-fired watertube boilers (ECCC and Loc. 19) equipped with FGR. All NO_x tests were short term CEM tests. Nitrogen oxides emission data for FGR operation were not available on firetube boilers rated above 2.9 MW (10 million Btu/hour) heat input. However, NO_x emission data are available from one experimental firetube boiler using FGR rated at 1.5 MW (5 million Btu/hour) heat input and firing a 0.26 weight percent nitrogen oil.[209] The test results from this boiler operating at 95 percent of full load indicated that NO_x emissions with and without a 15 percent FGR rate were 94.6 ng/J (0.22 lb/10^6 Btu or 170 ppm at 3 percent O_2) and 151 ng/J (0.35 lb/10^6 Btu or 275 ppm at 3 percent O_2), respectively. Flue gas recirculation reduced baseline NO_x emissions by 38 percent.

The FGR-controlled NO_x emissions presented in Table 3-32 were lower than baseline NO_x emissions. The more flue gas that is recirculated to the boiler, the greater the NO_x reduction. For example, only a 3 percent reduction in NO_x emissions was achieved in boiler ECCC operating at a 7 percent FGR. Reduction of NO_x emissions increased to 30 percent when 19 percent of the flue gas was recirculated in the same boiler. However, some of the reduction in NO_x emissions can be attributed to lower excess O_2 levels achieved during FGR operation compared to baseline operation. For the boiler at Location 19, 31 percent NO_x reduction was obtained at 25 percent FGR. Again, the excess O_2 level during FGR operation was lower than during baseline O_2 level, resulting in some reduction which should be attributed to lower excess air operation. Emissions of NO_x from the two watertube boilers using FGR ranged from 48.2 to 83 ng/J (0.112 to 0.193 lb/10^6 Btu).

TABLE 3-32. NO_X EMISSIONS DATA FROM RESIDUAL OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING FLUE GAS RECIRCULATION

Site and Boiler Data					Test Data									
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[d]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[f]	Boiler efficiency, percent baseline/controlled	Reference[g]
ECCC	WT,PKG	NR[e] (NR)	9.1 (31)	0.19	7	67	4.4/4.5	Amb[e]	0.161/0.157	3	20/20	NR/NR	NR/NR	199
ECCC	WT,PKG	NR (NR)	9.1 (31)	0.19	19	67	4.4/2.0	Amb	0.161/0.112	30	10/145	NR/NR	NR/NR	199
Loc. 19	WT,PKG	67 (56)	6.5 (22)	0.25	25	81	3.1/1.8	Amb	0.278/0.193	31	4/90	0.08/0.08	83/82	26

[a]WT = Watertube, PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to boiler.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NR = Not reported; Amb = Ambient temperature [assume 27°C (80°F)].

[f]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from Reference 26 and 198 are also presented in Reference 188.

Table 3-32 also presents data on CO and PM emissions and boiler efficiency from tests on two residual oil-fired boilers (ECCC and Loc. 19) equipped with FGR. Carbon monoxide emissions were higher during the FGR tests than at baseline from both boilers operating at lower excess O_2 levels during the FGR tests. For the boiler at Location 19 operating at 25 percent FGR, CO emissions increased from 4 to 90 ppm when the excess O_2 was lowered from 3.1 to 1.8 percent O_2. Similarly, CO emissions from boiler ECCC increased from 20 to 145 ppm when the O_2 was lowered from 4.4 to 2.0 percent. Carbon monoxide emissions from boiler ECCC with 7 percent FGR were the same as baseline CO emissions. At this recirculation rate, the excess O_2 was about the same as baseline excess O_2 level.

Particulate matter emissions were measured from only one boiler (Loc. 19) operating with FGR. Particulate matter emissions measured from this boiler were the same, 34.4 ng/J (0.08 lb/10^6 Btu), at both baseline and FGR conditions.

Boiler efficiency during FGR operation was determined from tests on only one boiler (Loc. 19). The boiler at Location 19 operated at 83 percent efficiency during the baseline test and at 82 percent efficiency during the FGR test.

The data indicate that FGR can achieve NO_x emissions reduction from 3 to 31 percent on small residual fired-boilers firing up to a 0.25 weight percent nitrogen oil and operating at recirculation rates between 7 and 25 percent. Outlet NO_x emissions ranged from 48.2 to 83 ng/J (from 0.112 to 0.193 lb/10^6 Btu).

3.3.8.3 <u>OFA Test Data</u>. Table 3-33 presents NO_x emission data on four residual oil-fired watertube boilers equipped with OFA ports. Two boilers (#19-2 and Loc. 19) operated without combustion air preheating, while the other two boilers (#38-2 and Loc. 38) operated with combustion air preheating.

For boilers #19-2 and Location 19, OFA-controlled NO_x emissions were lower than the baseline emissions. Reductions in NO_x ranged from 24 percent for boiler #19-2 using OFA at the same baseline excess O_2 level to 35 percent for the same boiler operating at a lower excess O_2 level of 2.4

TABLE 3-33. NO_x EMISSIONS DATA FROM RESIDUAL OIL-FIRED STEAM GENERATORS RATED AT 29.3 MW (100 MILLION BTU/HOUR) OR LESS USING OVERFIRE AIR

Site and Boiler Data					Test Data								
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[f]	Boiler efficiency percent baseline/controlled	Reference[g]
19-2	WT,PKG	67 (56)	6.5 (22)	0.14	80	3.1/3.1	Amb[d]	0.217/0.166	24	0/0	0.03/NR[d]	84/82	24
19-2	WT,PKG	67 (56)	6.5 (22)	0.44	80	3.1/2.4	Amb	0.217/0.141	35	0/190	0.03/NR	84/82	24
Loc. 19	WT,PKG	67 (56)	6.5 (22)	0.44	79	3.1/2.4	Amb	0.278/0.194	30	4/24	0.08/0.07	83/83	26
38-2	WT,PKG	84 (36)	16 (56)	0.49	80	3.0/2.9	157 (315)	0.419/0.222	47	0/55	0.11/0.14	87/87	24
Loc. 38	WT,PKG	84 (36)	16 (56)	0.31	85	2.9/3.3	138 (280)	0.386[e]/0.245[e]	37	22/62	0.15/0.12	85/85	26

[a]WT = Watertube, PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[d]Amb = Ambient temperature [assume 27°C (80°F)]; NR = Not reported.

[e]Estimate only. NO_x values assume NO_2 is 5% of the total (only NO was measured).

[f]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[g]Test results from Reference 24 and 26 are also presented in Reference 100.

percent for the OFA test (compared to the baseline O_2 level of 3.1 percent). Therefore, reducing the excess O_2 level from 3.1 to 2.4 percent in boiler #19-2 during the OFA tests reduced NO_2 emissions by an additional 11 percent. For the three tests conducted on these two boilers, OFA-controlled NO_x emissions ranged from 60.6 to 83.4 ng/J (0.141 to 0.194 lb/10^6 Btu).

Two other boilers (#38-2 and Loc. 38) using combustion air preheating also produced lower NO_x emissions during the OFA tests than during baseline tests. The OFA-controlled NO_x emissions from boiler #38-2 were 47 percent lower than baseline emissions, while OFA-controlled NO_x emissions from the boiler at Location 38 were 37 percent lower. Boiler #38-2 and the boiler at Location 38 emitted 45.5 and 105 ng NO_x/J (0.222 and 0.245 lb NO_x/10^6 Btu) during OFA operation, respectively. Boiler #38-2 operated at 80 percent of full load, and the boiler at Location 38 operated at 85 percent of full load.

Table 3-33 also presents boiler efficiency, CO, and PM emissions data on the four residual oil-fired boilers using OFA. In general, CO emissions were slightly higher from these boilers during OFA operation than during baseline operation. For boiler #19-2, CO emissions increased from 0 ppm at baseline to 190 ppm with OFA as excess O_2 dropped from 3.1 to 2.4 percent. In contrast, no detectable CO emissions were measured from this boiler during the other tests when operated at 3.1 percent O_2.

Particulate matter emissions were measured during baseline and OFA tests for three boilers (#38-2, Loc. 19, and Loc. 38). During OFA operation, PM emissions were lower than baseline PM emissions for two boilers (Loc. 19 and Loc. 38). The other boiler (#38-2) emitted more PM during OFA than during baseline operation. Emission ranged from 30.1 to 60.2 ng PM/J (0.07 to 0.14 lb PM/10^6 Btu) for the three boilers operating with OFA.

Boiler efficiency was determined during both baseline and OFA tests on all four boilers; boiler efficiencies ranged from 82 to 87. For boilers at Locations 38, 19, and #38-2, boiler efficiency was the same during baseline and OFA operation. For boiler #19-2, the boiler efficiency was two percent lower (82 percent) during OFA operation compared to baseline operation.

Table 3-34 presents NO_x emission data from one boiler (Loc. 19) combining both FGR and OFA. Examination of the data in this table and the data in Tables 3-31, 3-32, and 3-33 for this same boiler using only FGR indicates that no improvement is gained in NO_x reduction when both NO_x control techniques are applied compared to FGR alone. It should be reiterated that this boiler was modified to operate with both techniques as a means primarily of evaluating each technique during experimental testing only. Combining both FGR and OFA on the same boiler is not presently used in small boiler applications for controlling NO_x emissions.

From the above data presented for small residual oil-fired boilers using OFA with and without preheated air, NO_x emissions can be reduced from 24 to 35 percent below baseline NO_x emissions. Outlet NO_x emissions for these boilers ranged from 60.6 to 105 ng/J (from 0.141 to 0.245 lb/10^6 Btu). This applies to boilers firing residual oil containing 0.49 weight percent nitrogen or less.

3.3.8.4 LNB Test Data. Emission data are not available from residual oil-fired boilers rated below 29.3 MW (100 million Btu/hour) heat input using LNB's. In addition, no emission data are available from residual oil-fired industrial package boilers rated above 29.3 MW (100 million Btu/hour) using LNB's. However, one LNB manufacturer will guarantee NO_x emissions between 125 and 129 ng/J (0.29 and 0.30 lb/10^6 Btu) for their LNB's applied to residual oil-fired boilers having a maximum heat release rate of 518 kJ/m^3-sec (50,000 Btu/ft^3-hour) and firing oils containing 0.45 weight percent nitrogen or less.[210] The largest package watertube boiler that can be built having a maximum heat release rate of 518 kJ/m^3-sec (50,000 Btu/ft^3-hour) is typically rated at 17.6 MW (60 million Btu/hour) heat input.[211]

3.3.9 NO_x Emission Test Data on Coal-Fired Steam Generators

3.3.9.1 LEA Test Data

TABLE 3-34. NO_x EMISSION DATA FROM RESIDUAL OIL-FIRED BOILERS WITH CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) HEAT INPUT OR LESS USING BOTH FLUE GAS RECIRCULATION AND OVERFIRE AIR

Site and Boiler Data					Test Data									
Site I.D.	Boiler type[a]	Full load heat release rate, 10^3 Btu/ft^2-hr[b]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Percent FGR[c]	Average test load, percent	Stack O_2, percent baseline/controlled	Combustion air temperature, °C (°F)	NO emissions, lb/10^6 Btu baseline/controlled[d]	NO reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled[e]	Boiler efficiency, percent baseline/controlled	Reference[f]
Loc. 19	WT,PKG	67 (56)	6.5 (22)	0.25	23	81	3.1/4.2	Amb	0.278/0.207	26	4/27	0.08/0.07	83/81	26

[a]WT = Watertube; PKG = Packaged.

[b]Number in parenthesis indicates volumetric heat release rate in units of 10^3 Btu/ft^3-hr. To convert surface area heat release rate to kJ/m^2-sec, multiply heat release rate in 10^3 Btu/ft^2-hr by 3.15. To convert volumetric heat release rate to kJ/m^3-sec, multiply heat release rate in 10^3 Btu/ft^3-hr by 10.35.

[c]Percent of flue gas mass recirculated to the boiler.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[f]Test results from Reference 26 are also presented in Reference 180.

3.3.9.1.1 Actual or non-normalized NO_x emission data. Table 3-35 presents NO_x emissions data from tests on 12 coal-fired stokers using LEA. Data were collected from six spreader, three overfeed, two underfeed, and one vibrating grate stoker. All NO_x tests reported in Table 3-35 were short-term CEM tests.

For the six spreader stokers, LEA-controlled NO_x emissions were lower than baseline NO_x emissions. Emission reductions of NO_x ranged from 1 to 30 percent. LEA-controlled NO_x emissions ranged from 13.4 to 211 ng/J(0.312 to 0.491 lb/10^6 Btu). Excess O_2 levels for these boilers varied from 3.0 to 7.8 percent during the LEA tests and from 6.0 to 9.9 percent during the baseline tests. The coals fired in the six boilers had nitrogen contents ranging from 0.5 to 1.6 percent by weight.

For the three overfeed stokers using LEA listed in Table 3-35, NO_x emissions were lower than baseline emissions. Emission reductions of NO_x ranged from 4 to 29 percent. Emissions of NO_x from these three boilers ranged from 90.7 to 136 ng/J (0.211 to 0.316 lb $NO_x/10^6$ Btu). Excess O_2 levels were 5.0 to 7.5 percent during the LEA tests and 7.7 to 9.3 percent during the baseline tests. These boilers operated at roughly 100 percent load and the coals fired had nitrogen contents ranging from 1.4 to 1.8 percent by weight.

Emissions of NO_x were reduced from baseline on two underfeed stoker boilers using LEA. Low excess air operation reduced baseline NO_x emissions by 28 percent from 157 to 113 ng/J (0.364 to 0.263 lb/10^6 Btu) on boiler #15-32-10 by lowering excess O_2 from 6.6 to 4.9 percent. For the other underfeed stoker boiler (#15-32-13), NO_x emissions decreased by 17 percent from 186 to 155 ng/J (0.433 to 0.361 lb/10^6 Btu) when the excess O_2 was lowered from 10.3 to 8.0 percent. Both boilers were tested at 77 percent load. The coals fired in these boilers contained 1.4 percent nitrogen by weight.

For the only vibrating grate stoker (UM-Stout #2), LEA-controlled NO_x emissions were 89.9 ng/J (0.209 lb/10^6 Btu), compared with baseline NO_x emissions of 119 ng/J (0.277 lb/10^6 Btu). Emission reduction was 25 percent when LEA was applied. Excess O_2 level was lowered from 9.3 to 5.2 percent.

TABLE 3-35. NO_x EMISSIONS DATA FROM COAL-FIRED STOKER BOILERS USING LOW EXCESS AIR[a]

Site and Boiler Data						Test Data							
Site I.D.	Boiler type[b]	Full load grate heat release rate, 10^3 Btu/ft^2-hr	Boiler capacity, MW (10^6 Btu/hr) heat input	Moisture in fuel, weight percent	Fuel nitrogen, percent	Average test load percent	Stack O_2, percent baseline/controlled	NO_x emissions, lb/10^6 Btu baseline/controlled[c]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled[d]	PM emissions, lb/10^6 Btu baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference[i]
#5	SS	710	33 (113)	6.0	1.6	100	NA[e]/4.5	NA/0.435	NA	NA/42	NA/NA	NA/NA	212
#5	SS	710	33 (113)	6.0	1.6	75	6.0/3.0	0.390/0.385	1	22/28	NA/NA	NA/NA	212
#21-2	SS	471	18 (63)	2.1	1.5	81	8.0/5.8	0.635/0.452	29	35/42	NR/0.55	81/82	24
#21-3	SS	451	28 (94)	1.6	1.4	84	7.8/5.5	0.634/0.491	23	122/104	0.24/NR	76/NR	24
Site G	SS	714	29 (99)	4.3	1.0	99	7.2/5.0	0.540/0.412	24	NR/NR	6.3[h]/NR	74/NR	213
Site G	SS	714	29 (99)	4.8	1.0	99	7.5/4.0	0.572/0.401	30	NR/NR	4.8[h]/NR	75/NR	213
Site F	SS	688	29 (98)	3.3	1.2	75	8.9/7.8	0.468/0.443	5	146/137	NR/NR	NR/NR	214
Site F	SS	688	29 (98)	4.7	1.1	75	9.9/6.2	0.454/0.312	31	139/96	NR/NR	NR/NR	214
Fairmont #3	SS	NR[e]	29 (100)	7.3	1.1	75	8.0/6.5	0.506[e]/0.405[e]	20	47/155	1.8[h]/2.6[h]	NR/80	215
Fairmont #3	SS	NR	29 (100)	14.2	0.5	76	8.0/7.0	0.483[e]/0.418[e]	13	83/75	2.8[h]/2.6[h]	76/78	215
15-32-10	UFS	NR	22 (75)	10.5	1.4	77	6.6/4.9	0.364/0.263	28	0/0	NR/NR	76/77	24
15-32-13	UFS	NR	22 (75)	10.5	1.4	77	10.3/8.0	0.433/0.361	17	0/0	1.3/NR	72/NR	24
Site I	OFS	377	28 (95)	3.1	1.8	104	8.3/5.0	0.400/0.283	29	NR/NR	1.0[h]/NR	77/NR	216
Site I	OFS	377	28 (95)	2.3	1.4	102	7.7/5.9	0.229/0.211	8	NR/NR	1.4[h]/NR	NR/NR	216
Site J	OFS	360	23 (77)	3.1	1.7	100	9.1/7.5	0.353/0.316	10	NR/NR	NR/NR	NR/NR	217
Site K	OFS	NR	18 (63)	6.5	1.6	101	7.9/7.0	0.324/0.310	4	139/130	0.71[h]/0.69[h]	76/80	218
UW-Stout #2	VGS	NR	16 (56)	21.5	0.9	57	9.3/5.2	0.277/0.209	25	30/111	0.72/0.56	NR/NR	215

[a]All boilers used no air preheat.

[b]SS = Spreader stoker; UFS = Underfeed stoker; OFS = Overfeed stoker; and VGS = Vibrating grate stoker.

[c]To convert to kJ/m^2-sec, multiply grate heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[d]NO_x emissions were measured by Thermo Electron Chemiluminescent Analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[e]NR = Not reported; NA = Not available.

[f]Estimate only; NO_x values assume NO_2 is 5% of the total (only NO was measured).

[g]To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[h]PM emissions were taken from inlet to the PM control device (uncontrolled emissions).

[i]Test results from References 24 and 212-217 are also presented in Reference 188.

Table 3-35 also presents data on CO and PM emissions and boiler efficiency from tests on 12 stokers using LEA. Carbon monoxide emission data are available from 9 of the 12 stokers, and the results are mixed. Four of 9 stokers (#21-2, Fairmont #3 boiler firing a 1.1 percent nitrogen coal, #5, and (UM-Stout #2) emitted slightly higher CO emissions during the LEA tests than during baseline tests. Four stokers (including Fairmont #3 boiler firing a 0.5 percent nitrogen coal, #21-3, Site F and Site K) emitted lower CO emissions at LEA than at baseline, and 2 stokers (#15-32-10 and #15-32-13) emitted no CO emissions during either the baseline or LEA tests. The excess O_2 could have been lowered further during the LEA tests for the three stokers emitting less CO at LEA than at baseline conditions and for the two boilers emitting no CO during the LEA tests.

Particulate matter emissions were measured during both the baseline and LEA tests on three stokers (Fairmont #3, Site K, and UM-Stout #2). Emissions of PM were measured at the inlet to the PM control device for the Fairmont #3 and Site K boilers. From Table 3-35, emissions of PM from both boilers decreased as the excess air was lowered. Particulate matter emissions also decreased as the excess air was lowered for the Fairmont #3 boiler firing a coal containing 1.1 percent nitrogen, but PM emissions increased as the excess air was lowered for this boiler firing a coal with 0.5 percent nitrogen.

Boiler efficiency was determined during both baseline and LEA tests on four stokers (#15-32-10, #21-2, Fairmont #3, and Site K). Operating at LEA on these stokers increased boiler efficiency from 1 to 4 percent above baseline efficiencies.

3.3.9.1.2 Normalized NO_x emission test data. Emissions of NO_x were normalized with respect to full load grate heat release rate and excess air for three spreader stokers presented in Table 3-36 (#21-2, Site F and Site G). Boiler-specific regression models were developed from data on these boilers for predicting NO_x emissions as a function of grate heat release rate and excess air level.[219] The boiler-specific models were of the following general form:

TABLE 3-36. NORMALIZED NO_x EMISSION DATA ON COAL-FIRED SPREADER STOKERS USING LEA

Site I.D.	Test load grate heat release rate, 10^3 Btu/ft^2-hr[a]	Nitrogen content in coal, percent	Moisture content in coal, percent	Baseline Results: Stack air, percent	Baseline Results: Full load normalized NO_x emissions, lb/10^6 Btu[b]	LEA Results: Stack air, percent	LEA Results: Full load normalized NO_x emissions, lb/10^6 Btu[b]	LEA Results: NO_x reduction over baseline, percent	Reference
21-2	382	1.5	2.1	60	0.664	35	0.490	26.2	24
Site G	707	1.0	4.3	60	0.581	35	0.432	25.6	213
Site G	707	1.0	4.8	60	0.600	35	0.444	26.0	213
Site F	516	1.2	3.3	60	0.511	35	0.443	13.3	214
Site F	516	1.1	4.7	60	0.445	35	0.361	18.9	214

[a] To convert to kJ/m^2-sec, multiply grate heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[b] Baseline NO_x emissions for each boiler were normalized to full load conditions (i.e., to the full load heat release rate of each boiler) and adjusted to a baseline excess air level of 60 percent using EPA's boiler specific NO_x predictive algorithms. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

[c] LEA-controlled NO_x emissions for each boiler were normalized to full load conditions (i.e., to the full load heat release rate of each boiler) and adjusted to a LEA excess air level of 35 percent using EPA's boiler specific NO_x predictive algorithms. To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

$$NO_x = C_1 + C_2 * EA + C_3 * GHRR$$

where:

C_1, C_2, and C_3 are boiler-specific linear regression coefficients
NO_x = NO_x emissions
EA = excess air levels
GHRR = grate heat release rate.

The coefficients of determination (R^2) for the best-fit stoker boiler-specific models were 0.46 for the boiler at Site G, 0.79 for boiler #21-2, and 0.81 for the boiler at Site F.[220] The data from the other small spreader stokers in Table 3-35 were not fitted to any regression models. For the three small spreader stoker boilers, the baseline NO_x emissions were corrected to full load and 60 percent excess air (7.8 percent O_2), while the LEA-controlled NO_x emissions were corrected to full load and 35 percent excess air (5.4 percent O_2). Most boilers presented in Table 3-36 are capable of operating at both baseline and LEA excess air levels.

Table 3-36 presents the normalized NO_x emission data for the three spreader stokers. Reductions from baseline NO_x emissions ranged from 13.3 to 26.2 percent. The NO_x emission data for baseline and LEA conditions in this table are shown in Figure 3-39 as a function of full load grate heat release rate. Also, shown in this figure is the LEA-controlled NO_x emission data point for spreader stoker boiler #5 at full load, but not corrected to 35 percent excess air. This boiler operated at 27 percent excess air during LEA testing.

Based on these data, the above spreader stokers can achieve baseline NO_x emissions of 286 ng/J (0.665 lb/10^6 Btu) or less and LEA-controlled NO_x emissions of 204 ng/J (0.475 lb/10^6 Btu) or less at 60 and 35 percent excess air, respectively.

The overfeed, underfeed, and vibrating grate NO_x emission data could not be normalized in the same manner as the above spreader stokers because no regression models were available. Nevertheless, data from the three overfeed stokers (Sites I, J, and K) operating at full load indicate that

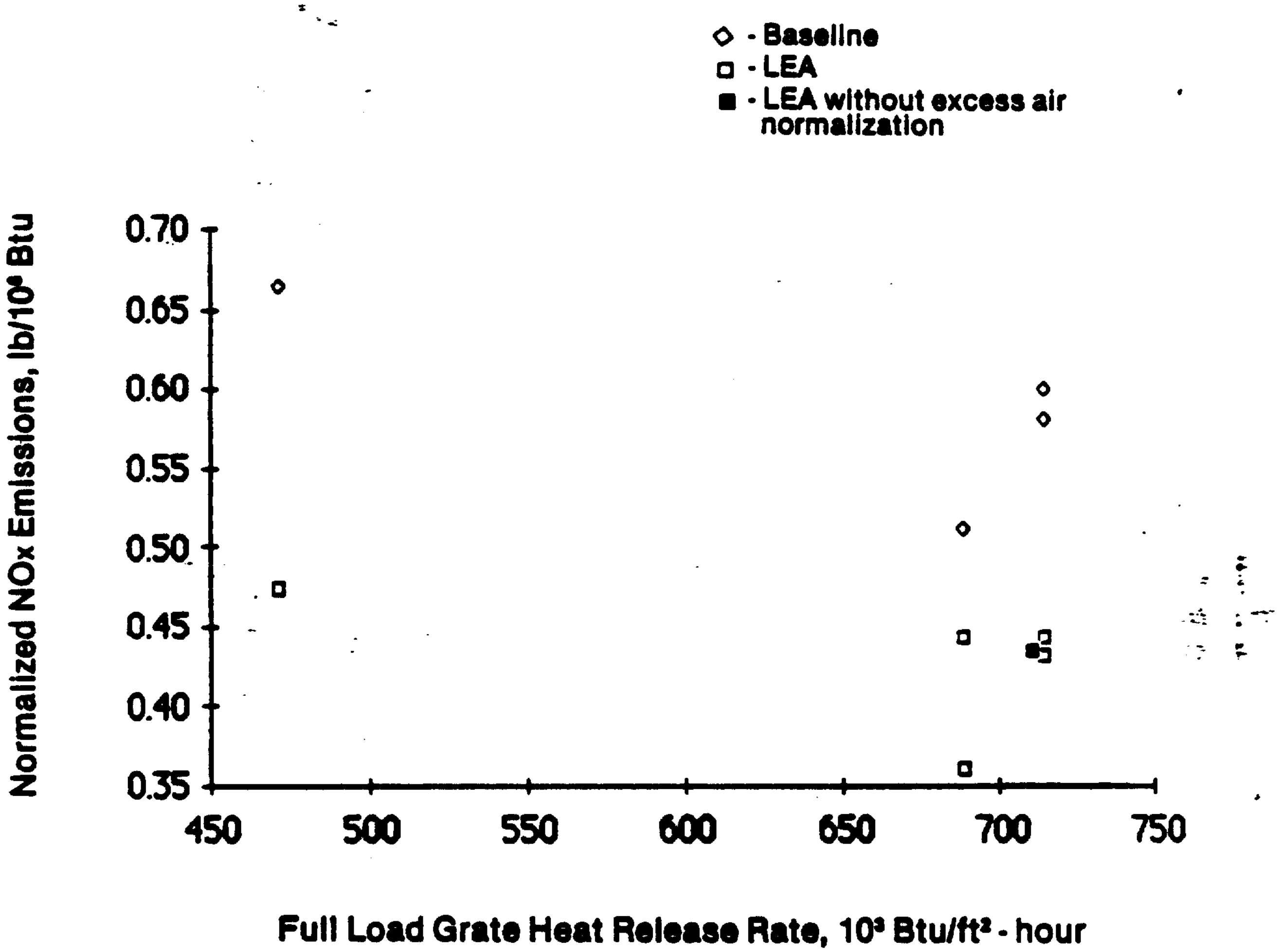

Figure 3-39. Normalized NO_x emissions as a function of full load heat release rate for coal-fired spreader stokers.

baseline NO_x emissions of 172 ng/J (0.40 lb/10^6 Btu) or less and LEA-controlled NO_x emissions of 138 ng/J (0.32 lb/10^6 Btu) or less can be achieved. It is expected that the two underfeed and one vibrating grate stokers shown in Table 3-35 will be able to achieve the same NO_x emissions at full load if baseline and LEA excess air levels are operated at 60 and 35 percent, respectively. Underfeed and vibrating grate stokers tend to produce about the same NO_x emissions as overfeed stokers because all three stoker types have similar grate heat release rates.

Based on these data, all types of small mass feed stokers using LEA can achieve a NO_x emission level of 138 ng/J (0.32 lb/10^6 Btu) or less.

3.3.9.2 FGR Test Data. Table 3-37 presents NO_x emissions data from tests on one spreader stoker (#5) equipped with stoker gas recirculation (SGR), which is the stoker equivalent of FGR. Although boiler #5 is rated slightly above 29.3 MW (100 million Btu/hour) heat input, the design and operating characteristics of this boiler were not significantly different from those of smaller spreader stokers.

For boiler #5 operating at full load, NO_x emissions were reduced 15 percent from baseline NO_x emissions using FGR. Baseline emissions were 187 ng/J (0.435 lb/10^6 Btu) compared to 160 ng/J (0.371 lb/10^6 Btu) at 20 percent SGR. Excess O_2 was 3.0 percent (18 percent excess air) during the SGR test and was 4.5 percent (30 percent excess air) during the baseline test. The baseline test of this boiler can be considered to be a LEA test, since LEA excess air levels are typically around 35 percent.

At 75 percent of full load, NO_x emissions from the same boiler were reduced by 8 percent from baseline during FGR operation. Emissions of NO_x were 166 ng/J (0.385 lb/10^6 Btu) at baseline and 153 ng/J (0.355 lb NO_x/10^6 Btu) with SGR operation. Excess O_2 was about the same during both tests (3.0 percent O_2 at baseline and 2.8 percent O_2 with SGR operation). Again, the above baseline O_2 levels of both tests at 100 and 75 percent of full load are considered to be LEA conditions for most stokers.

Carbon monoxide emissions were the only secondary emissions that were measured from boiler #5 during baseline and FGR tests. Table 3-37 presents the CO emissions results on this boiler. Operating at full load, boiler #5

TABLE 3-37. NO_x EMISSIONS DATA FROM COAL-FIRED STOKER BOILERS USING FLUE GAS RECIRCULATION

Site and Boiler Data					Test Data								
Site I.D.	Boiler type[b]	Full load grate heat release rate, 10^3 Btu/ft^2-hr[c]	Boiler capacity, MW (10^6 Btu/hr) heat input	Fuel nitrogen, percent	Percent FGR[d]	Average test load, percent	Stack O_2, percent baseline/controlled	NO_x emissions, lb/10^6 Btu baseline/controlled[f]	NO_x reduction, percent	CO emissions, ppm @ 3% O_2 baseline/controlled	PM emissions, lb/10^6 Btu baseline/controlled	Boiler efficiency, percent baseline/controlled	Reference
#5[a]	SS	710	33 (113)	1.6	20	100	4.5/3.0	0.435/0.371	15	42/42	NR/NR	NR/NR	212
#5	SS	710	33 (113)	1.6	NR[e]	75	3.0/2.8	0.385/0.355	8	28/43	NR/NR	NR/NR	212

[a]This boiler used no air preheat.

[b]SS = Spreader stoker.

[c]To convert to kJ/m^2-sec, multiply grate heat release rate in 10^3 Btu/ft^2-hr by 3.15.

[d]Percent of flue gas mass recirculated to boiler.

[e]NR = Not Reported.

[f]NO_x emissions were measured by Thermo Electron Chemiluminescent Analyzer. All tests were short-term (<3 hours). To convert to ng/J, multiply emissions in lb/10^6 Btu by 430.

emitted 42 ppm of CO during both baseline and FGR operation. At 75 percent full load, CO emissions during baseline and FGR operation for this boiler were 28 and 42 ppm, respectively. Carbon monoxide emissions were slightly higher during FGR operation than baseline operation at this load.

The data demonstrate that FGR can reduce LEA-controlled NO_x emissions from 8 to 15 percent for one small coal-fired spreader stoker. At full load and operating with 20 percent FGR, this boiler can achieve 15 percent NO_x reduction using FGR. Outlet NO_x emissions for this boilers operating at both loads ranged from 153 to 160 ng/J (from 0.355 to 0.371 lb/10^6 Btu).

3.3.9.3. <u>OFA Test Data</u>. Emission data are not available on coal-fired stokers rated less than 29.3 MW (100 million Btu/hour) heat input using OFA in the current database. However, NO_x emission data are available on two spreader stokers rated above 29.3 MW (100 million Btu/hour) heat input.[221,222] For one spreader stoker rated at 46.9 MW (160 million Btu/hour), NO_x emissions measured with OFA operation were 233 ng/J (0.542 lb/10^6 Btu) compared to 236 ng/J (0.549 lb/10^6 Btu) at baseline operation. Overfire air reduced the baseline NO_x emission by only 1 percent. Excess O_2 levels and loads were maintained at 9 percent and 66 percent of full load, respectively, during both operations. For the other boiler (rated at 58.6 MW [200 million Btu/hour], heat input) OFA-controlled NO_x emissions were 35 percent lower than the baseline NO_x emissions. Nitrogen oxides emissions during OFA were 215 ng/J (0.499 lb/10^6 Btu) compared to 330 ng/J (0.767 lb/10^6 Btu) during baseline. Excess O_2 levels and loads were maintained at 11 percent and 75 percent of full load, respectively, during both tests.

Nitrogen oxides emission data are also presented in Table 3-14 of Section 3.2.6.3 for FBC boilers without OFA ports. This table shows NO_x emission data from three FBC boilers. Emissions of NO_x from these boilers ranged from 241 to 396 ng/J (0.56 to 0.92 lb/10^6 Btu). Measured NO_x emissions were 396 ng/J (0.92 lb/10^6 Btu) for the staged bed boiler at Iowa Beef Processors operating for one day without OFA. Additional NO_x emission data not reported in Table 3-14 but collected over 2.5 days of operation at the Iowa Beef Processors FBC boiler are: average NO^x emissions of 258 ng/J

(0.6 lb/10^6 Btu) with OFA compared to average emissions of 378 ng/J (0.88 lb/10^6 Btu) without OFA.[223] This resulted in about a 32 percent NO_x reduction for this FBC boiler using OFA. During the OFA test on the staged bed boiler, approximately 10 percent of the total combustion air was introduced as secondary air below the desulfurization bed.[224]

From the data above, the amount of NO_x emission reduction from coal-fired spreader stokers using OFA can not be accurately determined because of the large differences in NO_x reduction for the two spreader stokers. However, the data do indicate that OFA can reduce baseline NO_x emissions by up to 32 percent on small FBC boilers.

3.3.9.4 <u>LNB Test Data</u>. Emission data are not available on coal-fired small boilers using LNB in the database.

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4.0 MODEL BOILERS AND CONTROL ALTERNATIVES

Model boilers and their control alternatives for new small steam generating units (i.e., boilers) with heat inputs of 29.3 MW (100 million Btu/hour) or less are discussed in this section. These model boilers will serve as a basis to assess the incremental environmental, energy, and cost impacts of alternative emission levels applied to various types and sizes of small boilers.

A three-step approach was used in selecting model boilers. First, a preliminary set of model boilers was developed to represent the anticipated new small boiler population. Second, control alternatives for reducing sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) emissions were selected for each model boiler as suggested by the performance and emission data presented in Sections 3.1 to 3.3. Finally, the model boilers were combined with the selected control alternatives to form the basis for subsequent cost and emission impact analyses.

4.1 SELECTION OF MODEL BOILERS

4.1.1 Overview of Model Boilers

Table 4-1 presents 34 uncontrolled boilers selected as representative of new small boilers in terms of design types, fuel usage, and boiler sizes. In this table, model boilers are segregated into five size categories of 2.9, 7.3, 14.7, 22.0, and 29.3 MW (10, 25, 50, 75, and 100 million Btu/hour) heat input. Seven model boilers were selected in the 2.9 MW (10 million Btu/hour) size category, 11 in 7.3 MW (25 million Btu/hour) category, 7 in the 14.7 MW (50 million Btu/hour) category, 4 in the 22.0 MW (75 million Btu/hour) category, and 5 in the 29.3 MW (100 million Btu/hour) category. Seventeen model boilers firing gas and oils, 13 firing coal, 2 firing wood and 2 firing solid waste were selected.

The selection of model boilers was based primarily on the information presented in Section 2.1 related to boiler classifications and uses. The

TABLE 4-1. SMALL MODEL BOILERS SELECTED FOR EVALUATION

Boiler type	Fuel[a]	Boiler size category, MW (10^6 Btu/hour) heat input 2.9 (10)	7.3 (25)	14.7 (50)	22.0 (75)	29.3 (100)
Firetube, packaged	NG	X[b]	X	-[c]	NA[d]	NA
Firetube, packaged	DO	X	X	-[c]	NA	NA
Firetube, packaged	RO	X	X	X	NA	NA
Watertube, packaged	NG	X	X	X	-[c]	X
Watertube, packaged	DO	X	X	X	-[c]	-[c]
Watertube, packaged	RO	NA	X	X	-[c]	X
Underfeed Firetube	Coal	X	X	-	NA	NA
Underfeed Stoker, Watertube	Coal	X	X	-[c]	NA	NA
Massfeed Stoker, Watertube	Coal	NA	-[c]	X	X	X
Spreader Stoker, Watertube	Coal	NA	-[c]	X	X	X
Fluidized Bed Combustor	Coal	-[c]	X	X	-[c]	X
Massfeed Stoker, Watertube	Wood	NA	X	-[c]	-[c]	-[c]
Spreader Stoker, Watertube	Wood	NA	-[c]	-[c]	X	-[c]
Incinerator, Small Modular	Solid Waste	-[c]	X	-	NA	NA
Massfeed Stoker, Watertube	Solid Waste	NA	-[c]	-[c]	X	-[c]

NOTES:

[a]NG = Natural Gas DO = Distillate Oil RO = Residual Oil

[b]"X" designates a category which was selected to be represented by a model boiler.

[c]These sizes are available for the respective boiler types, but they are not included in the model boiler set because they are less representative than other selected model boilers.

[d]NA = Not generally available or used in this size category.

reader is referred to this section and the Industrial Boiler Background Information Document for further details.[1] In addition, American Boiler Manufacturers Association (ABMA) personnel assisted in the selection of typical small boiler types, fuel usage, and boiler sizes based on their experience and recent sales trends. The final selection of model boilers incorporates ABMA and EPA comments.[2,3]

4.1.2 Rationale in Selecting Model Boilers

Model boilers were selected to represent the expected new small boiler population. Boiler characteristics such as design type, size, and fuel usage are necessary to identify each model boiler. Information from the small boiler manufacturers survey reports and information developed in support of the industrial boiler new source performance standards (NSPS) (40 CFR Part 60) were used to define the model boilers.[4-10]

Cast-iron boilers were not included in the model boiler selection. These boilers range in size from 0.0009 to 2.93 MW (0.003 to 10 million Btu/hour) heat input. However, most new cast-iron boilers have capacities below 0.12 MW (0.4 million Btu/hour) heat input.[11] Cast-iron boilers primarily fire natural gas or distillate oil.[12] Since these boilers fire relatively clean fuels, and are not commonly used in industrial-commercial-institutional applications, no model boilers were selected to represent cast-iron boilers.

4.1.2.1 Firetube Boilers. Two firetube boilers firing natural gas and two firing distillate oil at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat inputs were selected to represent the smallest sizes of firetube boilers. For residual oil-fired firetube boilers, three model boilers were selected at 2.9, 7.3, and 14.7 MW (10, 25, and 50 million Btu/hour) heat inputs. Furthermore, two model firetube boilers were selected to represent coal-fired underfeed firetube boilers at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat inputs.

Due to the similarities between Scotch Marine and firebox firetube boilers, it was not necessary to identify separate model firetube boilers for each type. The model firetube boiler specified in Table 4-1, and the costs and emission impacts developed in later sections, apply equally to both types.

4.1.2.2 Natural Gas and Oil-Fired Packaged Watertube Boilers. Four packaged watertube boilers firing natural gas were selected as model boilers at 2.9, 7.3, 14.7, and 29.3 MW (10, 25, 50, and 100 million Btu/hour) heat inputs. For distillate oil firing, model boilers were selected with heat inputs of 2.9, 7.3, and 14.7 MW (10, 25, and 50 million Btu/hour). Another three model boilers were selected to represent residual oil-fired boilers at 7.3, 14.7, and 29.3 MW (25, 50, and 100 million Btu/hour) heat inputs.

Most watertube boilers rated below 29.3 MW (100 million Btu/hour) heat input are shop-assembled, or packaged, units. Some design types for these boilers are available in sizes as low as 0.3 MW (1 million Btu/hour), but most packaged watertube boilers are typically available down to only 2.9 MW (10 million Btu/hour) heat input.[13]

4.1.2.3 Coal-Fired Watertube Boilers (Stokers). Stokers are classified into three general types: underfeed, massfeed (or overfeed), and spreader. Model boilers were selected for each type. For the underfeed stokers, two model boilers were selected at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input to cover the smallest-sized stokers. Three massfeed and three spreader stoker model boilers were selected as representative of these types at 14.7, 22.0, and 29.3 MW (50, 75, and 100 million Btu/hour) heat inputs.

Stoker boilers are expected to account for most of the new small coal-fired boilers installed in the near future. Stoker boilers currently account for about 95 percent of the coal-fired industrial boiler capacity between 2.9 and 73.3 MW (10 and 250 million Btu/hour) heat input.[14] One can also expect that stokers will predominate among the commercial and institutional boilers between 2.9 and 29.3 MW (10 and 100 million Btu/hour) heat input. The size breakdown of coal-fired model boilers among underfeed, massfeed, and spreader stokers in Table 4-1 was based on information supplied by ABMA and from the industrial boiler NSPS project work.[15]

4.1.2.4 Fluidized Bed Combustion Units. For boiler sizes at 7.3, 14.7, and 29.3 MW (25, 50, and 100 million Btu/hour) heat input, three coal-fired fluidized bed combustion (FBC) units were chosen as model boilers. Fluidized bed combustion units are becoming more popular with industry because NO_x and SO_2 emissions can be reduced in the furnace, eliminating the need for scrubbers, low-sulfur coal, or elaborate combustion modifications. Most boiler manufacturers who make FBC units for coal manufacture these units in sizes as small as 5.9 MW (20 million Btu/hour) heat input.[16]

4.1.2.5 Wood-fired Watertube Boilers (Stokers). Two model boilers firing wood were selected as model boilers. For the massfeed (or overfeed) units, a model boiler was selected at 7.3 MW (25 million Btu/hour) heat input to cover the smallest size stoker. For the larger spreader stokers, a 22.0 MW (75 million Btu/hour) heat input boiler was selected as representative.

The firing mechanisms for the majority of new wood-fired boilers are similar across the capacity range. These units are primarily overfeed or spreader stokers with the major differences being in the type of grate selected.[17] Some other firing methods used at times to fire wood include Dutch ovens, fuel cells, and fluidized beds. However, Dutch ovens have been phased out for new construction due to high costs, low efficiencies, and inability to follow load swings. Particulate emission rates for the other firing mechanisms are usually less than from spreader stokers.[18]

4.1.2.6 Solid Waste-Fired Boilers. Municipal solid waste-fired (MSW-fired) boilers are used to represent the general class of boilers combusting solid waste. These MSW-fired boilers fall into two distinct design types based on heat input capacity. Small municipal incinerators with heat recovery are usually installed in modules, the number and size of which are determined by the amount of waste to be burned. These modular devices often use two combustion chambers with substoichiometric air delivered to the first chamber. The larger MSW-fired boilers burn waste as it is received on moving grates.[19] These boilers are mass feed stokers.

Model boilers were selected for each of these types. For the small modular incinerators (SMI), one model boiler was selected at 7.3 MW (25 million Btu/hour). One massfeed stoker model boiler was selected as representative of the type at 22.0 MW (75 million Btu/hour) heat input.

4.2 SELECTION OF CONTROL ALTERNATIVES

Control alternatives are defined as the application of control technologies, or techniques, to model (uncontrolled) boilers so as to achieve specified emission levels and/or percent reduction requirements for NO_x, SO_2, or PM emissions. Control alternatives include both baseline emission levels/controls as well as more stringent control techniques to reduce emissions below baseline levels. The control alternatives for the model boilers discussed above are presented in this section.

Baseline emission levels discussed here are consistent with the baseline emission analysis presented in Section 2.3. The emission levels and/or reduction requirements associated with more stringent control alternatives are based on the emissions and performance data presented in Sections 3.1 to 3.3. These control levels are used in subsequent sections to estimate the cost and emission impacts of lower levels of emissions relative to the baseline emissions.

4.2.1 Alternative PM Emission Levels and Control Techniques

4.2.1.1 Oil- and Coal-Fired Boilers. Particulate matter control techniques for oil and coal-fired model boilers were examined for a baseline level of control and for two alternative levels of control. Table 4-2

TABLE 4-2. PM EMISSION LEVELS AND CONTROLS FOR RESIDUAL OIL- AND COAL-FIRED MODEL BOILERS

Fuel/ control level	PM emission level, ng/J (lb/10^6 Btu)[a]	Fuel type, ng SO_2/J (lb SO_2/10^6 Btu)	Control device
Residual oil	PM and SO_2 control		
- Baseline	77 (0.18)	1,010 (2.34) Oil	Uncontrolled
- Level 1	34 (0.08)	344 (0.8) Oil	Uncontrolled
- Level 2	17 (0.3) 0.04?	129 (0.3) Oil	Uncontrolled
Residual oil	PM control only		
- Baseline	77 (0.18)	1,010 (2.34) Oil	Uncontrolled
- Level 1	34 (0.08)	688 (1.6) Oil	Mechanical collector
- Level 2	17 (0.04)	344 (0.8) Oil	Mechanical collector
Coal	PM control only		
- Baseline	194/258 (0.45/0.6)[a]	1,230 (2.86) Coal	Mechanical collector
- Level 1	108 (0.25)	1,230 (2.86) Coal	Side stream separator
- Level 2	22 (0.05)	1,230 (2.86) Coal	Fabric filter

[a]Baseline PM emission levels are 194 ng PM/J (0.45 lb PM/10^6 Btu) for mass feed stoker boilers and 258 ng PM/J (0.6 lb PM/10^6 Btu) for spreader stoker boilers.

presents the control levels selected for analysis and the control technique used to meet each of these levels.

Emission levels of 77, 34, and 17 ng PM/J (0.18, 0.08, and 0.04 lb PM/10^6 Btu) were selected to evaluate PM control techniques for residual oil-fired small boilers. The baseline level of 77 ng/J is based on uncontrolled firing of a high sulfur oil (1,020 ng SO_2/J or 2.35 lb $SO_2/10^6$ Btu). The 34 ng PM/J (0.08 lb PM/10^6 Btu) level can be met by firing a low sulfur oil or by firing a medium sulfur oil and installing a mechanical collector. The 17 ng PM/J (0.04 lb PM/10^6 Btu) level can be met by firing a very low sulfur oil or by firing a low sulfur oil and installing a mechanical collector. Since Levels 1 and 2 can be met by several alternative control methods, the control technique chosen by actual boiler operators will likely be the lowest cost option. If SO_2 control is required concurrent with PM control for small boilers, then the lowest cost option for PM control would be firing low sulfur oil. In this case, all of the additional fuel cost (i.e., fuel sulfur premium) would be attributed to the SO_2 control cost. Thus, the PM control levels would be achieved at effectively zero additional cost. On the other hand, if only PM control is required for small residual oil-fired boilers, then the lowest cost option would be to fire a medium sulfur oil and install a mechanical collector.

A baseline PM emission level of 258 ng/J (0.6 lb/10^6 Btu) for spreader stoker and 194 ng/J (0.45 lb/10^6 Btu) for underfeed stoker coal-fired units can be met by installing a mechanical collector. Side stream separators are able to meet an emission level (Level 1) of 108 ng PM/J (0.25 lb PM/10^6 Btu) operating with 20 percent flow or less to the baghouse. The Level 2 control is 22 ng PM/J (0.05 lb PM/10^6 Btu) which can be met by operating a fabric filter at an air-to-cloth ratio of 0.61 m^3/m^2-min (2 acfm/ft^2) or less.

4.2.1.2. <u>Wood- and Solid Waste- Fired Boilers</u>. Particulate matter control techniques for wood- and solid waste-fired model boilers were examined for a baseline PM emission level and for two alternative control levels. Table 4-3 presents the control levels selected for analysis and the control techniques used to meet each of these levels.

The baseline emission levels of 172 and 159 ng PM/J (0.40 and 0.37 lb PM/10^6 Btu) were selected for wood-fired boilers less than 14.7 MW (50 million Btu/hour) heat input and for wood-fired boilers with heat inputs from 14.7 to 29.3 MW (50 to 100 million Btu/hour), respectively. The less than 14.7 MW (50 million Btu/hour) size category is represented by a 7.3 MW (25 million Btu/hour) heat input wood-fired boiler and the 14.7 to 29.3 MW (50 to 100 million Btu/hour) category is represented by a 22 MW (75 million Btu/hour) heat input wood-fired boiler. An alternative emission control level of 86 ng PM/J (0.20 lb/10^6 Btu) can be met with the use of a venturi scrubber operated at a 5 kPa (20 inches of water) pressure differential for both size categories. The strictest alternative control level, 43 ng/J (0.10 lb/10^6 Btu), can be met by using an electrostatic precipitator (ESP) control system with a specific collection area (SCA) of 523 and 2070 m^2/(1,000 m^3/s) (160 and 634 ft^2/1,000 acfm) for cold- and hot-side units, respectively.

The baseline PM emission levels for solid waste-fired boilers represent uncontrolled emissions from small modular incinerators and the Subpart E emission level for massfeed stoker boilers. The baseline emission level of 73 ng/J (0.17 lb/10^6 Btu) for the massfeed stoker requires an ESP with a 525 m^2/(1000 m^3/s) (160 ft^2/1000 acfm) SCA. The alternative emission control levels of 43 and 22 ng/J (0.10 and 0.05 lb/10^6 Btu) can be met with the use of an ESP with an SCA of 820 and 1210 m^2/(1000 m^3/s) (250 and 370 ft^2/1000 acfm), respectively.

4.2.2 Alternative SO_2 Emission Levels and Control Techniques

4.2.2.1. Oil-Fired Boilers. Sulfur dioxide control techniques for oil- and coal-fired model boilers were examined for a baseline level of control and for two alternative levels of control. The control levels selected for analysis and the corresponding SO_2 control technique used to meet these levels are presented in Table 4-4.

TABLE 4-3. PM EMISSION LEVELS AND CONTROLS FOR WOOD- AND SOLID WASTE-FIRED MODEL BOILERS

Fuel	Model boiler size, MW (10^6 Btu/hr) heat input	Model boiler type[a]	PM emissions, ng/J (lb/10^6 Btu)			Baseline PM control device[b]	Level 1 PM control device	Level 2 PM control device
			Baseline	Level 1	Level 2			
Wood	7.3 (25)	OFS	172 (0.40)	86 (0.20)	43 (0.10)	DM	VS	ESP
Wood	22.0 (75)	SS	159 (0.37)	86 (0.20)	43 (0.10)	DM	VS	ESP
Solid Waste	7.3 (25)	SMI	129 (0.30)	43 (0.10)	22 (0.05)	UNC	ESP[c]	ESP[d]
Solid Waste	22.0 (75)	MS	73 (0.17)	43 (0.10)	22 (0.05)	ESP[e]	ESP[c]	ESP[d]

[a]OFS = Overfeed Stokers; SS = Spreader Stokers; SMI = Small Modular Incinerators; MS = Massfeed Stoker.

[b]DM = Dual Mechanical Collector; VS = Venturi Scrubber; ESP = Electrostatic Precipitator; UNC = Uncontrolled.

[c]A specific collection area of 820 m^2/1,000 m^3/min (250 ft^2/acfm) is required to achieve the PM emissions of 43 ng/J (0.10 lb/10^6 Btu).

[d]A specific collection area of 1210 m^2/1,000 m^3/min (370 ft^2/acfm) is required to achieve the PM emissions of 22 ng/J (0.05 lb/10^6 Btu).

[e]A specific collection area of 525 m^2/1,000 m^3/min (160 ft^2/acfm) is required to achieve the PM emissions of 73 ng/J (0.17 lb/10^6 Btu).

TABLE 4-4. SO_2 EMISSION LEVELS AND CONTROLS FOR OIL- AND COAL-FIRED MODEL BOILERS

Fuel	Region	SO_2 emission level, ng/J (lb/10^6 Btu)	Fuel type ng SO_2/J (lb SO_2/10^6 Btu)		Control device
Oil	Region V	Baseline - 1,010 (2.35)	1,010 (2.35) Oil		Uncontrolled
		Level 1 - 344 (0.8)	344 (0.8) Oil		Uncontrolled
		Level 2 - 129 (0.3)	129 (0.3) Oil	or	Uncontrolled
			1,290 (3.0) Oil		90% FGD[a]
Coal	Region V	Baseline - 1,460 (3.4)	1,226 (2.85) Coal		Uncontrolled
		Level 1 - 516 (1.2)	409 (0.95) Coal		Uncontrolled
		Level 2 - 258 (0.6)	2,382 (5.54) Coal	or	90% FGD
			2,382 (5.54) Coal		90% FBC[a]
	Region VIII	Baseline - 1,460 (3.4)	903 (2.10) Coal		Uncontrolled[b]
		Level 1 - 516 (1.2)	409 (0.95) Coal		Uncontrolled
		Level 2 - 258 (0.6)	903 (2.10) Coal	or	75% FGD
			903 (2.10) Coal		75% FBC

[a]FGD = flue gas desulfurization using sodium scrubbing; FBC = fluidized bed combustor. The percent number indicates the percent of SO_2 reduced by the control device.

[b]903 ng SO_2/J coal is the highest sulfur coal available in Region VIII. Therefore, firing 903 ng SO_2/J coal uncontrolled results in emissions much lower than the 1,462 ng SO_2/J baseline.

For oil-fired boilers, a baseline SO_2 emissions level of 1,010 ng/J (2.35 lb/10^6 Btu) is based on the uncontrolled firing of medium sulfur oil. Level 1 emissions of 344 ng/J (0.8 lb/10^6 Btu) are based on the uncontrolled firing of a low sulfur oil; Level 2 emissions of 129 ng/J (0.3 lb/10^6 Btu) are based on the uncontrolled firing of a very low sulfur oil or 90 percent removal efficiency on a high sulfur oil using a sodium scrubber operating at inlet scrubber pH between 7.1 and 7.6.

4.2.2.2 <u>Coal-Fired Boilers</u>. The baseline SO_2 emissions level of 1,460 ng/J (3.4 lb/10^6 Btu) for coal-fired units is based on uncontrolled firing of a a medium sulfur coal. The basis for the 516 ng/J (1.2 lb/10^6 Btu) emission level (Level 1) is the firing of an uncontrolled low sulfur coal. The medium and low sulfur coals selected reflect the average fuel sulfur content of a class of coals that would consistently meet a given emissions limit. An emissions level of 258 ng/J (0.6 lb/10^6 Btu) (Level 2) is based on achieving 90 percent SO_2 removal efficiency on a high sulfur coal in EPA Region V and 75 percent SO_2 removal efficiency on a medium sulfur coal in EPA Region VIII. These SO_2 emission reductions can be achieved either using a sodium scrubber operating at a pH of 8, or an FBC unit operating with a calcium to sulfur (Ca/S) ratio of 4.5.

4.2.3 <u>Alternative NO_x Emission Levels and Control Techniques</u>

Nitrogen oxide control techniques for natural gas-, distillate oil-, residual oil-, and coal-fired model boilers are examined for a baseline NO_x emission level and one alternative NO_x emission control level. The control levels selected for analysis and the corresponding NO_x control techniques used to meet these levels are presented in Table 4-5. Based on the limited amount of NO_x emission data on FGR, OFA, and LNB and the inability to correct these data to full load conditions, emission levels were not selected for NO_x control stricter than LEA emission levels.

4.2.3.1 <u>Natural Gas-Fired Boilers</u>. The baseline NO_x emission levels for natural gas-fired units are based on the analysis of the normalized baseline NO_x emission data presented in Section 3.3.6.1.2. As discussed in this section, model boilers rated at 2.9 and 7.3 MW (10 and 25 million

TABLE 4-5. NO_x EMISSION LEVELS FOR SMALL MODEL BOILERS

Fuel	Model boiler size, MW (10^6 Btu/hr)	Model boiler type[a]	NO_x Emissions, ng/J (lb/10^6 Btu)	
			Baseline[b]	Level 1[c]
Natural Gas	2.9 (10)	FT	60.2 (0.140)	38.7 (0.090)
	7.3 (25)	FT	60.2 (0.140)	47.3 (0.110)
	14.7 (50)	WT	64.5 (0.150)	53.8 (0.125)
	29.3 (100)	WT	71.0 (0.165)	60.2 (0.140)
Distillate Oil	2.9 (10)	FT	118 (0.275)	86.0 (0.200)
	7.3 (25)	FT/WT	118 (0.275)	86.0 (0.200)
	14.7 (50)	WT	94.6 (0.220)	66.7 (0.155)
Residual Oil	2.9 (10)	FT	198 (0.460)	183 (0.425)
	7.3 (25)	FT/WT	198 (0.460)	183 (0.425)
	14.7 (50)	WT	198 (0.460)	172 (0.400)
	29.3 (100)	WT	198 (0.460)	172 (0.400)
Coal	2.9 (10)	UFS	172 (0.400)	138 (0.320)
	7.3 (25)	UFS	172 (0.400)	138 (0.320)
	14.7 (50)	OFS	172 (0.400)	138 (0.320)
	22.0 (75)	SS	286 (0.665)	204 (0.475)
	29.3 (100)	SS	286 (0.665)	204 (0.475)

[a] FT = Firetube; WT = Watertube; UFS = Underfeed Stoker; OFS = Overfeed Stoker; SS = Spreader Stoker.

[b] Baseline NO_x emissions of natural gas- and oil-fired boilers were determined from analysis of small boiler NO_x data sets at 6 percent O_2. For coal-fired small boilers, baseline NO_x emissions were determined at 60 percent excess air (7.8 percent O_2).

[c] Level 1 NO_x emissions of natural gas- and oil-fired boilers are based on LEA control at 2 percent O_2 from NO_x emissions data sets on small boilers. For coal-fired small boilers, Level 1 NO_x emissions are based on NO_x emission data at 35 percent excess air (5.4 percent O_2).

Btu/hour) heat input have characteristic baseline NO_x emissions of 60.2 ng/J (0.14 lb/10^6 Btu) at 6 percent oxygen (O_2). For boilers rated at 14.7 and 29.3 MW (50 and 100 million Btu/hour), baseline NO_x emissions of 64.5 ng/J (0.15 lb/10^6 Btu) and 71.0 ng/J (0.165 lb/10^6 Btu) are representative, respectively, at this same O_2 level. Similarly, emission levels for Level 1 control based on the use of low excess air (LEA) at 2 percent O_2 were determined by averaging the normalized LEA-controlled NO_x emission data presented in Section 3.3.6.1.2. LEA-controlled NO_x emissions of 38.7 ng/J (0.09 lb/10^6 Btu) and 47.3 ng/J (0.11 lb/10^6 Btu) can be met for the 2.9 MW (10 million Btu/hour) and the 7.3 MW (25 million Btu/hour) heat input boilers, respectively. Model boilers using LEA rated at 14.7 and 29.3 MW (50 and 100 million Btu/hour) heat input can meet NO_x emissions of 53.8 ng/J (0.125 lb/10^6 Btu) and 60.2 ng/J (0.14 lb/10^6 Btu), respectively.

4.2.3.2 Distillate Oil-Fired Boilers. The baseline NO_x emission levels for the distillate oil-fired units are based on the analysis of the normalized baseline NO_x emission data presented in Section 3.3.7.1.2. Operating at 6 percent O_2, model boilers rated at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input have characteristic NO_x emissions of 86.0 ng/J (0.275 lb/10^6 Btu); while the 14.7 MW (50 million Btu/hour) boiler has NO_x emission levels of 94.6 ng/J (0.22 lb/10^6 Btu). The higher baseline NO_x emissions for the smaller model boiler sizes are attributed to the very high heat release rates characteristic of firetube boilers. Emissions of NO_x are generally higher for boilers having higher heat release rates. For the same reason, NO_x emission levels for Level 1 control based on the use of LEA at 2 percent O_2 were higher for the 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input boilers than for the 14.7 MW (50 million Btu/hour). As discussed in Section 3.3.7.1.2, NO_x emissions levels of 86 ng/J (0.2 lb/10^6 Btu) can be achieved for the 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input boilers with LEA, and 66.7 ng/J (0.155 lb/10^6 Btu) emission levels can be achieved for the 14.7 MW (25 million Btu/hour) heat input boiler. The emission levels were based on a fuel nitrogen content of 0.019 weight percent.

4.2.3.3 Residual Oil-Fired Boilers. The baseline and Level 1 (LEA) NO_x emission levels for residual oil-fired boilers are based on the analysis of the normalized NO_x emission data presented in Section 3.3.8.1.2. As discussed in this section, all boilers between 2.9 and 29.3 MW (10 and 100 million Btu/hour) heat inputs have characteristic baseline NO_x emissions of 198 ng/J (0.46 lb/10^6 Btu) based on a 6 percent O_2 operation. For Level 1, NO_x emissions of 183 ng/J (0.425 lb/10^6 Btu) can be achieved for model boilers rated at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input and 172 ng/J (0.40 lb/10^6 Btu) for boilers rated at 14.7 and 29.3 MW (50 and 100 million Btu/hour) heat input when operating at 2 percent O_2. These emission levels are also based on fuel nitrogen contents of 0.36 weight percent or less.

4.2.3.4 Coal-Fired Boilers. Baseline and Level 1 (based on LEA) NO_x emission levels for coal-fired boilers are based on the analysis of the normalized NO_x emission data as presented in Section 3.3.9.1.2. Based on full load test data for the overfeed stokers, baseline (7.8 percent O_2 operation) and Level 1 (5.4 percent O_2 operation) NO_x emission levels of 172 ng/J (0.40 lb/10^6 Btu) and 138 ng/J (0.32 lb/10^6 Btu) can be achieved for model boilers rated between 2.9 and 14.7 MW (10 and 50 million Btu/hour) heat input, respectively. For spreader stokers, NO_x emission levels for the baseline and LEA conditions specified above are 286 ng/J (0.665 lb/10^6 Btu) and 204 (0.475 lb/10^6 Btu) for stokers rated at 22 MW (75 million Btu/hour) and 29.3 MW (100 million Btu/hour) heat input.

4.3 SUMMARY OF MODEL CONTROL SYSTEMS AND BOILERS

Table 4-6 summarizes control technologies for PM, SO_2, and NO_x emissions by fuel type and control level. Level 1 controls generally are those which can provide a degree of emission control greater than that currently obtained under existing regulations. Level 2 controls are those which achieve the greatest degree of emission reduction using commercially available control technology.

TABLE 4-6. CONTROL SYSTEMS FOR SO_2, PM AND NO_x EMISSIONS FROM SMALL BOILERS

Fuel	SO_2		PM		NO_x
	Level 1	Level 2	Level 1	Level 2	Level 1
Natural Gas/Distillate Oil	-[a]	-[a]	-[a]	-[a]	LEA
Residual Oil	LSO	FGD or LSO	LSO	ESP or LSO	LEA
Coal	LSC	FGD	SSS	FF	LEA
Wood	-[a]	-[a]	VS	ESP	-[a]
Solid Waste	-[a]	-[a]	ESP	ESP	-[a]

[a]Not applicable.

LSO = Low sulfur oil
LSC = Low sulfur coal
FGD = Flue gas desulfurization
SSS = Side stream separator
FF = Fabric filter
ESP = Electrostatic precipitator
VS = Venturi scrubber
LEA = Low excess air

Flue gas desulfurization (FGD) using sodium scrubbing is a commercially available SO_2 control system that is capable of offering the greatest SO_2 emission reductions for small residual oil- and coal-fired boilers. Flue gas desulfurization is an established technology currently being applied to small boilers. Therefore, FGD was selected as the system that could achieve Level 2 control. Low sulfur fuel was selected for achieving Level 1 control.

Two levels of PM controls were identified. The type of control depends on the fuel fired. For small boilers firing oil, very low sulfur oil or low sulfur oil along with a mechanical collector was selected for meeting the Level 2 PM emission level. For small boilers firing coal, side-stream separators were selected for Level 1 and fabric filters were selected for achieving the Level 2 emission level. Electrostatic precipitators were selected for solid waste- and wood-fired boilers.

The type of system selected for controlling NO_x emissions again depends on the fuel fired and the boiler type. Low excess air was selected for meeting the Level 1 NO_x emission levels for natural gas-, oil-, and coal-fired small boilers.

4.4 REFERENCES

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5.0 MODEL BOILER COST IMPACTS

5.1 COSTING APPROACH

The cost impacts of requiring particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) control devices on various types and sizes of small steam generating units (boilers) are assessed in this section through an analysis of "model boilers." For wood- and municipal solid waste (MSW)-fired boilers, only PM costs are assessed. The costs of each model boiler can be separated into three major cost categories:

- Capital costs (total capital investment required to construct and make operational a boiler and emission control system),
- Operation and maintenance (O & M) costs (total annual costs necessary to operate and maintain a boiler and emission control system), and
- Annualized costs (total O & M costs plus annualized capital-related charges).

As discussed in Section 4, model boilers were selected to represent the population of new small boilers expected to be built in the future, and thus cover a range of boiler sizes, fuel types, and control devices. Applicable emission control technologies for small boilers were evaluated in Section 3.

Capital and operating costs for those controls have been estimated. The cost estimates for fossil fuel-fired boilers were prepared using the industrial boiler fossil fuel cost algorithms, supplemented by data from manufacturers and published cost manuals for cases where the algorithms were not applicable.[1,2] For estimating the costs of nonfossil fuel-fired boilers, the model boiler costs were obtained using the cost algorithms developed specifically for those boilers.[3] The PM control device costs for nonfossil fuel-fired boilers were calculated from PM cost algorithms applied to coal-fired boilers. Process and emission characteristics typical of wood- and solid waste-fired boilers were incorporated into the PM cost algorithms. The capital and operating costs presented in this section are budgetary-type estimates with an overall accuracy level of $\pm$ 30 percent. All costs are 1995 "first year" costs presented in January 1983 dollars. Costs in this chapter are based on annual capacity factors of 0.3, 0.6, and 0.9.

Tables 5-1 and 5-2 present the Region V and Region VIII fuel costs and specifications used in each analysis for oil and coal, respectively. These fuel costs represent projected 1995 prices in 1983 dollars. Table 5-3 presents Region V costs and specifications for wood. In this analysis, it was assumed that wood and MSW have a zero cost. In some cases, wood may be purchased off site and thus have an associated fuel cost. However, since costs are presented only for PM controls, the cost of wood does not affect the cost of the PM control device. Municipal solid waste units are paid a tipping fee to burn the waste. Thus, as these units burn more waste, they earn more money from tipping fees. The mean tipping fees by region and by process type are presented in Table 5-4. Credits from tipping fees were included in the costs of MSW-fired boilers.

Costs for PM, SO_2, and NO_x emissions control are presented in Sections 5.2.1, 5.2.2, and 5.2.3, respectively. The cost analysis for each pollutant focuses primarily on those costs associated with a 0.3 capacity factor since this was shown in Section 2.2.1 to be the most representative value. Boilers used for space heating and for some industrial applications such as food processing typically operate at such a capacity factor.[4] Food processing industries typically rely on their boilers to operate at full load for only a short period of time (e.g., 24 hours/day for 3 months of the year). The remainder of the time, these boilers are either shut down or operated at low loads for space heating (representing about 5 to 6 percent of the total steam demands for many food processing plants).[5] Other commercial, industrial, and institutional applications may require their small boilers to operate at annual capacity factors above 0.3. For example, some hospitals will operate one boiler approximately 60 percent of the time

TABLE 5-1. SPECIFICATIONS FOR RESIDUAL OILS DELIVERED TO EPA REGION V[6,7]

Sulfur content ng SO_2/J (lb $SO_2/10^6$ Btu)	Fuel price \$/kJ (\$/10^6 Btu)[a]	Heating value kJ/kg (Btu/lb)	Ash content, (wt. %)	Nitrogen content, (wt. %)
Region V:				
129 (0.3)	6.94 (7.32)	43,000 (18,500)	0.10	0.04
344 (0.8)	6.55 (6.91)	43,000 (18,500)	0.10	0.12
688 (1.6)	6.18 (6.51)	43,000 (18,500)	0.10	0.23
1,290 (3.0)	5.85 (6.17)	43,000 (18,500)	0.10	0.44

[a]Projected 1995 fuel price in 1983 dollars.

TABLE 5-2. SPECIFICATIONS FOR COAL DELIVERED TO EPA REGION V AND REGION VIII[8,9]

Coal type[a]	Sulfur content,[b,c] ng SO_2/J Range	Average	Fuel price,[d] \$/kJ (\$/10^6 Btu)	Heating value, kJ/kg (Btu/lb)	Sulfur content, wt. %	Ash content, wt. %
Region V:						
B-Sub	34.4-464	(409)	3.22 (3.39)	20,500 (8,825)	0.42	6.9
D-Sub	464-718	(624)	3.17 (3.34)	20,500 (8,825)	0.64	6.9
E-Sub	718-1,080	(903)	3.16 (3.33)	20,500 (8,825)	0.93	6.9
B-Bit	34.4-464	(409)	3.23 (3.40)	29,100 (12,500)	0.60	11.0
D-Bit	464-718	(624)	3.11 (3.28)	29,300 (12,600)	0.91	11.0
E-Bit	718-1,080	(903)	2.98 (3.14)	27,400 (11,800)	1.24	10.5
F-Bit	1,080-1,430	(1,230)	2.85 (3.00)	26,700 (11,500)	1.64	10.9
G-Bit	1,430-2,150	(1,780)	2.60 (2.74)	26,700 (11,500)	2.38	12.2
H-Bit	>2,150	(2,380)	2.42 (2.55)	27,200 (11,700)	3.23	12.0
Region VIII:						
B-Sub	34.4-464	(409)	1.37 (1.44)	20,400 (8,770)	0.42	8.4
D-Sub	464-718	(624)	1.38 (1.45)	20,000 (8,620)	0.63	6.9
E-Sub	718-1,080	(903)	1.24 (1.31)	20,000 (8,620)	0.91	6.9
B-Bit	34.4-464	(409)	1.92 (2.02)	25,400 (10,900)	0.52	10.0
D-Bit	464-718	(624)	1.84 (1.94)	24,000 (10,300)	0.75	10.0
E-Bit	718-1,080	(903)	1.82 (1.92)	24,000 (10,300)	1.08	10.0

[a]Sub = subbituminous; Bit = bituminous

[b]Value in parenthesis represents "average" sulfur content for coal type.

[c]Divide ng/J by 430 to convert to lb/10^6 Btu.

[d]Projected 1995 price in 1983 dollars.

TABLE 5-3. SPECIFICATIONS FOR WOOD AND MUNICIPAL SOLID WASTE (MSW) DELIVERED TO EPA REGION V[10]

Fuel type	Fuel price ($\$/10^6$ Btu)	Heating value, (Btu/lb)	Sulfur content, (wt. %)	Ash content, (wt. %)
Wood	0[a]	4,560	0.02	1.00
MSW	0[a]	4,875	0.12	22.38

[a]This analysis assumes zero cost for wood and MSW.

TABLE 5-4. MEAN TIPPING FEES BY REGION AND PROCESS TYPE[11] ($/Mg OF WASTE)[a,b]

Process	Northeast	South	North central	West	Average
Mass-burning except modular	22.02 (13)	20.28 (9)	18.79 (5)	12.46 (5)	19.53 (32)
Modular Mass-burning	12.85 (8)	9.40 (9)	14.97 (3)	13.78 (2)	11.82 (22)
RDF (All)	13.68 (8)	14.68 (7)	10.42 (4)	13.01 (5)	13.28 (24)
Total	17.20	14.79	15.05	12.91	15.43

[a]To convert tipping fees to $/ton, multiply by 0.9072.

[b]Numbers in parentheses indicate number of plants in each subgroup.

and have up to 2 boilers as backup.[12] A recent survey on resource recovery plants indicates that the average resource recovery plant has an annual capacity of 0.82.[13] For this reason, capacity factors of 0.6 and 0.9 were chosen to represent these energy-intensive applications.

5.2 ANALYSIS OF COST IMPACTS

5.2.1 PM Control Cost Impacts

For the purposes of this analysis, model boilers with heat input capacities of 2.9, 7.3, 14.7, 22.0, and 29.3 MW (10, 25, 50, 75, and 100 million Btu/hour) were chosen for the coal and residual oil-fired units. Costs for model boilers have been developed on the basis of construction and operation in the midwest region (EPA Region V) of the U.S. Although the absolute costs for model boilers and various PM control alternatives will vary from region to region, the incremental costs of the various control alternatives over the baseline will not differ significantly on a regional basis.

In order to examine the potential overall cost of PM control on oil-, coal-, wood-, and solid waste-fired small boilers, it is necessary to consider the compliance costs associated with meeting each alternative emission level. Therefore, for each alternative control level, costs were estimated both with and without an opacity monitor. The additional costs associated with this monitor were $57,000 for capital cost, $8,000/year for O & M costs, and $15,000/year for annualized costs.[14,15] The baseline control level does not include opacity monitors since they are not commonly required on new small boilers.

5.2.1.1 Residual Oil-Fired Model Boilers. Table 5-5 presents the PM control costs for residual oil-fired small boilers operating at a 0.3 capacity factor without monitors, assuming that SO_2 control will not be required. If SO_2 control is required (e.g., burning a low sulfur oil), then PM emissions could be controlled at zero cost. This table presents capital

TABLE 5-5. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[b]				Annualized costs ($1,000/yr)			
		Boiler	PM	Total	Boiler	PM	Fuel	Total	Boiler	PM	Fuel	Total
2.9 MW (10 million Btu/hr)												
HSO/Unc[c] - 77.4 (0.18)	2.1 (2.4)	439	-	439	169	-	166	335	240	-	166	406
MSO/MC[d] - 34.4 (0.08)	1.0 (1.1)	440	35	475	169	15	171	355	240	21	171	432
LSO/MC[e] - 17.2 (0.04)	0.45 (0.5)	440	35	475	169	15	182	366	240	21	182	443
7.3 MW (25 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	5.4 (5.9)	728	-	728	225	-	416	641	342	-	416	758
MSO/MC - 34.4 (0.08)	2.4 (2.6)	730	67	797	225	17	428	670	342	28	428	798
LSO/MC - 17.2 (0.04)	1.2 (1.3)	732	67	799	225	17	454	696	343	28	454	825
14.7 MW (50 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	10.7 (11.8)	1,470	-	1,470	267	-	832	1,100	508	-	832	1,340
MSO/MC - 34.4 (0.08)	4.8 (5.3)	1,480	111	1,590	268	21	855	1,140	509	39	855	1,400
LSO/MC - 17.2 (0.04)	2.4 (2.6)	1,480	111	1,590	268	21	908	1,200	509	39	908	1,460
22.0 MW (75 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	16.1 (17.7)	1,900	-	1,900	310	-	1,250	1,560	620	-	1,250	1,870
MSO/MC - 34.4 (0.08)	7.2 (7.9)	1,900	150	2,050	311	24	1,280	1,620	621	49	1,280	1,950
LSO/MC - 17.2 (0.04)	3.6 (3.9)	1,910	150	2,060	311	24	1,360	1,700	622	49	1,360	2,030
29.3 MW (100 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	21.5 (23.7)	2,280	-	2,280	352	-	1,660	2,010	724	-	1,660	2,380
MSO/MC - 34.4 (0.08)	9.5 (10.5)	2,290	186	2,480	353	27	1,710	2,090	725	58	1,710	2,490
LSO/MC - 17.2 (0.04)	4.8 (5.3)	2,300	186	2,490	353	27	1,820	2,200	726	58	1,820	2,600

[a]Costs rounded to three significant figures.

[b]O & M = Operating and maintenance.

[c]HSO/Unc = High sulfur oil/uncontrolled.

[d]MSO/MC = Medium sulfur oil with mechanical collector.

[e]LSO/MC = Low sulfur oil with mechanical collector.

costs, O & M costs, and annualized costs for each model boiler and control level examined.

Table 5-5 shows that the capital costs increase about 8.3 percent over the baseline to meet a PM emission level of 34.4 ng/J (0.08 $lb/10^6$ Btu). For a PM control level of 17.2 ng/J (0.04 $lb/10^6$ Btu), the capital costs increase approximately 8.6 percent over the baseline. Table 5-5 also shows that the annualized costs increase about 5.1 percent to meet control Level 1 and approximately 8.9 percent to meet control level 2.

Similarly, PM control costs are presented in Tables 5-6 and 5-7 for oil-fired boilers without monitors operating at 0.6 and 0.9 capacity factors, respectively. Table 5-8 shows the variation of boiler and PM control costs with capacity factor. The capital costs do not vary with capacity factor, but the operating and maintenance costs are sensitive to capacity factor. Thus, as capacity factor increases, the annualized costs also increase.

5.2.1.2 <u>Coal-Fired Model Boilers</u>. Table 5-9 presents the PM control costs for coal-fired boilers operating at a 0.3 capacity factor in Region V without monitors. This table shows the annual emissions, capital costs, O & M costs, and annualized costs for each model boiler and emission control level examined.

Table 5-9 shows that the capital costs increase about 2 percent over the baseline when a side stream separator is used to meet a PM emission level of 108 ng/J (0.25 $lb/10^6$ Btu). When a fabric filter is installed to meet an emission level of 22 ng PM/J (0.05 lb $PM/10^6$ Btu), the capital costs increase by 3 to 8 percent.

Table 5-9 also shows that the increased annualized costs over the baseline associated with the use of side stream separators range from 1.5 to 1.8 percent. The annualized costs associated with the use of a fabric filter range from 4.6 to 6.7 percent higher than the baseline costs. The PM control costs for coal-fired boilers in Region V without monitors for boilers operating at a 0.6 and 0.9 capacity factor are presented in Tables 5-10 and 5-11, respectively.

TABLE 5-6. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[b]				Annualized costs ($1,000/yr)			
		Boiler	PM	Total	Boiler	PM	Fuel	Total	Boiler	PM	Fuel	Total
2.9 MW (10 million Btu/hr)												
HSO/Unc[c] - 77.4 (0.18)	4.3 (4.7)	467	-	467	249	-	333	582	322	-	333	655
MSO/MC[d] - 34.4 (0.08)	1.9 (2.1)	468	36	504	250	23	342	615	323	29	333	694
LSO/MC[e] - 17.2 (0.04)	1.0 (1.1)	470	36	506	250	23	363	636	323	29	363	715
7.3 MW (25 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	10.7 (11.8)	783	-	783	328	-	832	1,160	448	-	832	1,280
MSO/MC - 34.4 (0.08)	4.8 (5.3)	785	69	854	329	26	855	1,210	457	38	855	1,350
LSO/MC - 17.2 (0.04)	2.4 (2.6)	790	69	858	326	26	908	1,260	454	38	908	1,400
14.7 MW (50 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	21.5 (23.7)	1,570	-	1,570	340	-	1,660	2,000	640	-	1,660	2,300
MSO/MC - 34.4 (0.08)	9.5 (10.5)	1,570	113	1,680	388	32	1,710	2,130	640	50	1,710	2,400
LSO/MC - 17.2 (0.04)	4.8 (5.3)	1,580	113	1,690	389	31	1,810	2,230	640	50	1,810	2,500
22.0 MW (75 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	32.2 (35.5)	2,030	-	2,030	450	-	2,490	2,940	770	-	2,490	3,260
MSO/MC - 34.4 (0.08)	14.3 (15.8)	2,030	152	2,190	453	37	2,560	3,050	778	62	2,560	3,400
LSO/MC - 17.2 (0.04)	7.2 (7.9)	2,050	152	2,200	453	37	2,720	3,210	778	62	2,720	3,560
29.3 MW (100 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	42.9 (47.3)	2,450	-	2,450	500	-	3,330	3,830	890	-	3,330	4,220
MSO/MC - 34.4 (0.08)	19.1 (21.0)	2,460	188	2,650	508	42	3,420	3,970	896	74	3,420	4,390
LSO/MC - 17.2 (0.04)	9.5 (10.5)	2,470	188	2,660	508	42	3,630	4,180	897	73	3,630	4,600

[a]Costs rounded to three significant figures.

[b]O & M = operating and maintenance.

[c]HSO/Unc = High sulfur oil/uncontrolled.

[d]MSO/MC = Medium sulfur oil with mechanical collector.

[e]LSO/MC = Low sulfur oil with mechanical collector.

TABLE 5-7. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[b]				Annualized costs ($1,000/yr)			
		Boiler	PM	Total	Boiler	PM	Fuel	Total	Boiler	PM	Fuel	Total
2.9 MW (10 million Btu/hr)												
HSO/Unc[c] - 77.4 (0.18)	6.4 (7.1)	496	-	496	329	-	499	828	406	-	499	905
MSO/MC[d] - 34.4 (0.08)	2.9 (3.2)	497	38	535	329	31	513	873	406	37	513	956
LSO/MC[e] - 17.2 (0.04)	1.4 (1.6)	499	38	537	329	31	545	905	406	37	545	988
7.3 MW (25 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	16.1 (17.7)	837	-	837	430	-	1,250	1,680	560	-	1,250	1,810
MSO/MC - 34.4 (0.08)	7.2 (7.9)	841	70	911	435	35	1,280	1,750	563	47	1,280	1,890
LSO/MC - 17.2 (0.04)	3.6 (3.9)	847	70	917	435	35	1,360	1,830	563	47	1,360	1,970
14.7 MW (50 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	32.2 (35.5)	1,660	-	1,660	500	-	2,500	3,000	760	-	2,500	3,260
MSO/MC - 34.4 (0.08)	14.3 (15.8)	1,670	115	1,790	507	43	2,570	3,110	768	62	2,560	3,390
LSO/MC - 17.2 (0.04)	7.2 (7.9)	1,680	115	1,790	508	42	2,720	3,270	769	61	2,720	3,550
22.0 MW (75 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	48.3 (53.2)	2,160	-	2,160	580	-	3,740	4,320	920	-	3,740	4,660
MSO/MC - 34.4 (0.08)	21.5 (23.7)	2,170	155	2,320	580	50	3,850	4,480	920	75	3,850	4,840
LSO/MC - 17.2 (0.04)	10.7 (11.8)	2,190	155	2,340	590	50	4,080	4,720	925	75	4,080	5,080
29.3 MW (100 million Btu/hr)												
HSO/Unc - 77.4 (0.18)	64.4 (71.0)	2,620	-	2,620	660	-	4,990	5,650	1,070	-	4,990	6,060
MSO/MC - 34.4 (0.08)	28.6 (31.5)	2,630	191	2,820	663	57	5,130	5,850	1,070	89	5,130	6,290
LSO/MC - 17.2 (0.04)	14.3 (15.8)	2,660	191	2,850	663	57	5,450	6,170	1,070	89	5,450	6,610

[a]Costs rounded to three significant figures.

[b]O & M = operating and maintenance.

[c]HSO/Unc = High sulfur oil/uncontrolled.

[d]MSO/MC = Medium sulfur oil with mechanical collector.

[e]LSO/MC = Low sulfur oil with mechanical collector.

TABLE 5-8. VARIATION OF PM CONTROL COSTS ON RESIDUAL OIL-FIRED BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
HSO/Unc[b] - 77.4 (0.18)	406	406	2.1 (2.4)	655	655	4.3 (4.7)	905	905	6.4 (7.1)
MSO/MC[c] - 34.4 (0.08)	447	432	1.0 (1.1)	694	679	1.9 (2.1)	956	941	2.9 (3.2)
LSO/MC[d] - 17.2 (0.04)	458	443	0.45 (0.5)	715	700	1.0 (1.1)	988	973	1.4 (1.6)
7.3 MW (25 million Btu/hr)									
HSO/Unc - 77.4 (0.18)	753	753	5.4 (5.9)	1,280	1,280	10.7 (11.8)	1,810	1,810	16.1 (17.7)
MSO/MC - 34.4 (0.08)	813	798	2.4 (2.6)	1,370	1,350	4.8 (5.3)	1,910	1,890	7.2 (7.9)
LSO/MC - 17.2 (0.04)	840	825	1.2 (1.3)	1,420	1,400	2.4 (2.6)	1,990	1,920	3.6 (3.9)
14.7 MW (50 million Btu/hr)									
HSO/Unc - 77.4 (0.18)	1,340	1,340	10.7 (11.8)	2,300	2,300	21.5 (23.7)	3,260	3,260	32.2 (35.5)
MSO/MC - 34.4 (0.08)	1,420	1,400	4.8 (5.3)	2,420	2,400	9.5 (10.5)	3,410	3,390	14.3 (15.8)
LSO/MC - 17.2 (0.04)	1,470	1,460	2.4 (2.6)	2,520	2,500	4.8 (5.3)	3,570	3,550	7.2 (7.9)
22.0 MW (75 million Btu/hr)									
HSO/Unc - 77.4 (0.18)	1,870	1,870	16.1 (17.7)	3,260	3,260	32.2 (35.5)	4,660	4,660	48.3 (53.2)
MSO/MC - 34.4 (0.08)	1,970	1,950	7.2 (7.9)	3,420	3,400	14.3 (15.8)	4,860	4,840	21.5 (23.7)
LSO/MC - 17.2 (0.04)	2,050	2,030	3.6 (3.9)	3,580	3,560	7.2 (7.9)	5,100	5,080	10.7 (11.8)
29.3 MW (100 million Btu/hr)									
HSO/Unc - 77.4 (0.18)	2,380	2,380	21.5 (23.7)	4,220	4,220	42.9 (47.3)	6,060	6,060	64.4 (71.0)
MSO/MC - 34.4 (0.08)	2,510	2,490	9.5 (10.5)	4,410	4,390	19.1 (21.0)	6,300	6,290	28.6 (31.5)
LSO/MC - 17.2 (0.04)	2,620	2,600	4.8 (5.3)	4,620	4,600	9.5 (10.5)	6,620	6,610	14.3 (15.8)

[a]Costs rounded to three significant figures.

[b]HSO/Unc = High sulfur oil/uncontrolled.

[c]MSO/MC = Medium sulfur oil with mechanical collector.

[d]LSO/MC = Low sulfur oil with mechanical collector.

TABLE 5-9. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[d]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
2.9 MW (10 million Btu/hr)										
Type F-Bit[b] - MC[c]	5.4 (5.9)	1,470	40	1,510	341	16	356	583	22	605
Type F-Bit - SSS	3.0 (3.3)	1,470	67	1,540	341	22	363	583	33	616
Type F-Bit - FF	0.6 (0.7)	1,470	164	1,630	341	31	372	583	57	640
7.3 MW (25 million Btu/hr)										
Type F-Bit - MC	13.4 (14.8)	2,630	77	2,710	562	18	579	998	31	1,030
Type F-Bit - SSS	7.5 (8.2)	2,630	135	2,770	562	26	588	998	49	1,050
Type F-Bit - FF	1.5 (1.6)	2,630	219	2,850	562	37	599	998	71	1,070
14.7 MW (50 million Btu/hr)										
Type F-Bit - MC	35.8 (39.4)	4,690	130	4,820	946	24	971	1,720	46	1,770
Type F-Bit - SSS	14.9 (16.4)	4,690	231	4,920	946	36	982	1,720	74	1,790
Type F-Bit - FF	3.0 (3.3)	4,690	308	5,000	946	53	999	1,720	102	1,820
22.0 MW (75 million Btu/hr)										
Type F-Bit - MC	53.6 (59.1)	6,750	175	6,930	1,210	29	1,240	2,330	58	2,390
Type F-Bit - SSS	22.4 (24.6)	6,750	316	7,070	1,210	43	1,250	2,330	97	2,430
Type F-Bit - FF	4.5 (4.9)	6,750	397	7,150	1,210	65	1,280	2,330	128	2,460
29.3 MW (100 million Btu/hr)										
Type F-Bit - MC	71.5 (78.8)	8,670	217	8,890	1,480	34	1,510	2,920	70	2,990
Type F-Bit - SSS	29.8 (32.9)	8,670	396	9,070	1,480	52	1,530	2,920	118	3,040
Type F-Bit - FF	6.0 (6.6)	8,670	486	9,160	1,480	79	1,560	2,920	156	3,080

[a]Costs rounded to three significant figures.

[b]Coal type is defined in Table 6.1-2.

[c]MC = mechanical collector; SSS = side stream separators; and FF = fabric filter

[d]O & M = operating and maintenance.

TABLE 5-10. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[d]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
2.9 MW (10 million Btu/hr)										
Type F-Bit[b] - MC[c]	10.7 (11.8)	1,490	42	1,530	531	24	555	776	30	806
Type F-Bit - SSS	6.0 (6.6)	1,490	70	1,560	531	33	564	776	45	821
Type F-Bit - FF	1.2 (1.3)	1,490	166	1,660	531	46	577	776	72	848
7.3 MW (25 million Btu/hr)										
Type F-Bit - MC	26.8 (29.6)	2,680	79	2,760	910	27	937	1,350	40	1,390
Type F-Bit - SSS	14.9 (16.4)	2,680	140	2,820	910	40	950	1,350	60	1,410
Type F-Bit - FF	3.0 (3.3)	2,680	223	2,900	910	57	967	1,350	92	1,440
14.7 MW (50 million Btu/hr)										
Type F-Bit - MC	71.5 (78.7)	4,760	133	4,890	1,560	38	1,600	2,340	60	2,400
Type F-Bit - SSS	29.8 (32.9)	4,760	230	4,990	1,560	50	1,610	2,340	100	2,440
Type F-Bit - FF	6.0 (6.6)	4,760	316	5,080	1,560	79	1,640	2,340	127	2,470
22.0 MW (75 million Btu/hr)										
Type F-Bit - MC	107 (118)	6,840	179	7,020	2,040	47	2,090	3,170	77	3,250
Type F-Bit - SSS	44.7 (49.3)	6,840	320	7,160	2,040	70	2,110	3,170	120	3,290
Type F-Bit - FF	8.9 (9.9)	6,840	406	7,250	2,040	99	2,140	3,170	162	3,330
29.3 MW (100 million Btu/hr)										
Type F-Bit - MC	143 (158)	8,780	222	9,000	2,530	56	2,590	3,980	93	4,070
Type F-Bit - SSS	59.6 (65.7)	8,780	400	9,180	2,530	80	2,610	3,980	150	4,130
Type F-Bit - FF	11.9 (13.1)	8,780	496	9,280	2,530	119	2,650	3,980	196	4,180

[a]Costs rounded to three significant figures.

[b]Coal type is defined in Table 5-2.

[c]MC = mechanical collector; SSS = side stream separators; and FF = fabric filter.

[d]O & M = operating and maintenance.

TABLE 5-11. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[d]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
2.9 MW (10 million Btu/hr)										
Type F-Bit[b] - MC[c]	16.1 (17.7)	1,520	43	1,560	721	32	752	968	38	1,010
Type F-Bit - SSS	8.9 (9.9)	1,520	70	1,590	721	45	766	968	62	1,030
Type F-Bit - FF	1.8 (2.0)	1,520	169	1,690	721	61	782	968	87	1,050
7.3 MW (25 million Btu/hr)										
Type F-Bit - MC	40.2 (44.3)	2,720	81	2,800	1,260	36	1,300	1,700	50	1,750
Type F-Bit - SSS	22.4 (24.6)	2,720	140	2,860	1,260	50	1,310	1,700	80	1,780
Type F-Bit - FF	4.5 (4.9)	2,720	209	2,930	1,260	75	1,340	1,700	110	1,810
14.7 MW (50 million Btu/hr)										
Type F-Bit - MC	107 (118)	4,830	136	4,670	2,170	53	2,220	2,960	75	3,040
Type F-Bit - SSS	44.7 (49.3)	4,830	240	5,070	2,170	80	2,250	2,960	120	3,080
Type F-Bit - FF	8.9 (9.9)	4,830	321	5,150	2,170	106	2,280	2,960	155	3,120
22.0 MW (75 million Btu/hr)										
Type F-Bit - MC	161 (177)	6,930	183	7,110	2,870	65	2,930	4,000	95	4,100
Type F-Bit - SSS	67.1 (73.9)	6,930	330	7,260	2,870	90	2,960	4,000	150	4,150
Type F-Bit - FF	13.4 (14.8)	6,930	413	7,340	2,870	132	3,000	4,000	195	4,200
29.3 MW (100 million Btu/hr)										
Type F-Bit - MC	215 (236)	8,900	226	9,130	3,570	78	3,650	5,040	115	5,150
Type F-Bit - SSS	89.4 (98.6)	8,900	410	9,310	3,570	120	3,690	5,040	180	5,220
Type F-Bit - FF	17.9 (19.7)	8,900	504	9,400	3,570	159	3,730	5,040	236	5,280

[a]Costs rounded to three significant figures.

[b]Coal type is defined in Table 5-2.

[c]MC = mechanical collector; SSS = side stream separator; and FF = fabric filter

[d]O & M = operating and maintenance.

Table 5-12 summarizes the annualized costs and emissions for coal-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Also shown are the costs for operation with and without monitors. The results show that as the boiler capacity factor increases, the annualized cost of PM control also increases. This is due to the fact that operating and maintenance costs are directly related to the capacity factor, even though capital costs are not affected by capacity factor differences.

5.2.1.3 Wood-Fired Model Boilers. Table 5-13 presents the costs of PM control for wood-fired boilers without monitors. This table shows the capital, operating, and annualized costs and emissions for the control alternatives considered with the boiler costs.

Table 5-13 shows that for level 1 control, the capital costs increase about 3 percent over the baseline when a venturi scrubber is used to meet an emission level of 86 ng PM/J (0.20 lb PM/10^6 Btu). When an electrostatic precipitator (ESP) is installed to meet a 43 ng PM/J (0.10 lb PM/10^6 Btu) level, the capital costs rise an additional 20 to 25 percent. Table 5-13 also shows that for level 1 control, the increased annualized cost over the baseline is about 2.5 percent. Annualized costs increase about 11 percent over the baseline when an ESP is installed to meet a 43 ng PM/J (0.10 lb PM/10^6 Btu) emission limit. Table 5-14 presents the annualized costs for each model boiler at varying capacity factors of 0.3, 0.6 and 0.9. This table shows that the annual costs increase with increasing capacity factor.

5.2.1.4 Municipal Solid Waste-Fired Model Boilers. Table 5-15 presents the PM control costs for MSW-fired boilers in Region V without monitors. This table shows the annual emissions, capital costs, O & M costs, and annualized costs for each of the model boilers and emission control levels examined for a boiler operating at a 0.3 capacity factor. capacity factor. The costs to control PM emissions from other forms of solid waste would be comparable.

Table 5-15 shows that the capital costs increase about 2 to 18 percent over the baseline when an ESP is used to meet a PM emission level of 43 ng/J

TABLE 5-12. VARIATION OF PM CONTROL COSTS ON COAL-FIRED BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
Baseline - 194 (0.45)	605	605	5.4 (5.9)	806	806	10.7 (11.8)	1,010	1,010	16.1 (17.7)
Level 1 - 108 (0.25)	631	616	3.0 (3.3)	836	821	6.0 (6.6)	1,050	1,030	8.9 (9.9)
Level 2 - 22 (0.05)	655	640	0.6 (0.7)	863	848	1.2 (1.3)	1,070	1,050	1.8 (2.0)
7.3 MW (25 million Btu/hr)									
Baseline - 194 (0.45)	1,030	1,030	13.4 (14.8)	1,390	1,390	26.8 (29.6)	1,750	1,750	40.2 (44.3)
Level 1 - 108 (0.25)	1,080	1,050	7.5 (8.2)	1,430	1,410	14.9 (16.4)	1,800	1,780	22.4 (24.6)
Level 2 - 22 (0.05)	1,080	1,070	1.5 (1.6)	1,460	1,440	3.0 (3.3)	1,830	1,810	4.5 (4.9)
14.7 MW (50 million Btu/hr)									
Baseline - 258 (0.60)	1,770	1,770	35.5 (39.4)	2,400	2,400	71.5 (78.7)	3,040	3,040	107 (118)
Level 1 - 108 (0.25)	1,810	1,790	14.9 (16.4)	2,460	2,440	29.8 (32.9)	3,100	3,080	44.7 (49.3)
Level 2 - 22 (0.05)	1,840	1,820	3.0 (3.3)	2,480	2,470	6.0 (6.6)	3,130	3,120	8.9 (9.9)
22.0 MW (75 million Btu/hr)									
Baseline - 258 (0.60)	2,390	2,390	53.6 (59.1)	3,250	3,250	107 (118)	4,100	4,100	161 (177)
Level 1 - 108 (0.25)	2,440	2,430	22.4 (24.6)	3,310	3,290	44.7 (49.3)	4,170	4,150	67.1 (73.9)
Level 2 - 22 (0.05)	2,470	2,460	4.5 (4.9)	3,350	3,330	8.9 (9.9)	4,210	4,200	13.4 (14.8)
29.3 MW (100 million Btu/hr)									
Baseline - 258 (0.60)	2,990	2,990	71.5 (78.8)	4,070	4,070	143 (158)	5,150	5,150	215 (236)
Level 1 - 108 (0.25)	3,050	3,040	29.8 (32.9)	4,150	4,130	59.6 (65.7)	5,240	5,220	89.4 (98.6)
Level 2 - 22 (0.05)	3,090	2,080	6.0 (6.6)	4,190	4,180	11.9 (13.1)	5,290	5,280	17.9 (19.7)

[a]Costs rounded to three significant figures.

TABLE 5-13. BOILER AND PM CONTROL COSTS WITHOUT MONITORS FOR WOOD-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M Costs ($1,000/yr)[c]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
7.3 MW (25 million Btu/hr)										
DM[b] - 172 (0.40)	11.9 (13.1)	2,330	127	2,460	820	19	839	1,150	40	1,200
VS - 86 (0.20)	6.0 (6.6)	2,330	222	2,550	820	35	855	1,150	72	1,230
ESP - 43 (0.10)	3.0 (3.3)	2,330	874	3,200	820	38	858	1,150	186	1,340
22.0 MW (75 million Btu/hr)										
DM - 159 (0.37)	33.1 (36.5)	5,330	307	5,640	1,340	29	1,370	2,200	81	2,280
VS - 86 (0.20)	17.9 (19.7)	5,330	456	5,790	1,340	61	1,400	2,200	137	2,340
ESP - 43 (0.10)	9.0 (9.9)	5,330	1,640	6,970	1,340	53	1,400	2,200	331	2,530

[a]All costs are presented in 1983 dollars rounded to three significant figures.

[b]DM = Dual Mechanical Collector; VS = Venturi Scrubber; ESP = Electrostatic Precipitator.

[c]O & M = operating and maintenance.

TABLE 5-14. VARIATION OF PM CONTROL COSTS ON WOOD-FIRED BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb PM/10^6 Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
7.3 MW (25 million Btu/hr)									
DM[b] - 172 (0.40)	1,190	1,190	11.9 (13.1)	1,230	1,230	23.8 (26.2)	1,260	1,260	35.7 (39.3)
VS - 86 (0.20)	1,240	1,230	6.0 (6.6)	1,280	1,270	12.0 (13.2)	1,320	1,300	18.0 (19.8)
ESP - 43 (0.10)	1,360	1,340	3.0 (3.3)	1,400	1,390	6.0 (6.6)	1,440	1,420	9.0 (9.9)
22.0 MW (75 million Btu/hr)									
DM - 159 (0.37)	2,280	2,280	33.1 (36.5)	2,350	2,350	66.2 (73.0)	2,400	2,400	99.1 (109)
VS - 86 (0.20)	2,350	2,340	17.9 (19.7)	2,430	2,410	35.8 (39.4)	2,490	2,480	53.7 (59.1)
ESP - 43 (0.10)	2,550	2,530	9.0 (9.9)	2,620	2,600	18.0 (19.8)	2,690	2,670	27.0 (29.7)

[a]Costs rounded to three significant figures.

[b]DM = dual mechanical collector; VS = venturi scrubber; and ESP = electrostatic precipitator.

TABLE 5-15. BOILERS AND PM CONTROL COSTS WITHOUT MONITORS FOR MUNICIPAL SOLID WASTE-FIRED MODEL BOILERS IN REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/ control level,[b] ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[c]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
7.3 MW (25 million Btu/hr)										
UNC - 129 (0.30)	8.9 (9.9)	2,790	0	2,790	735	0	735	1,170	0	1,170
ESP - 43 (0.10)	3.0 (3.3)	2,790	495	3,290	735	34	769	1,170	118	1,290
ESP - 22 (0.05)	1.5 (1.6)	2,790	640	3,430	735	36	771	1,170	144	1,310
22.0 MW (75 million Btu/hr)										
ESP - 73 (0.17)	15.2 (16.8)	13,900	845	14,750	966	52	1,020	2,990	195	3,190
ESP - 43 (0.10)	8.9 (9.9)	13,900	1,070	15,000	966	55	1,020	2,990	236	3,230
ESP - 22 (0.05)	4.5 (4.9)	13,900	1,315	15,200	966	58	1,020	2,990	281	3,270

[a]All costs are presented in 1983 dollars rounded to three significant figures.

[b]UNC = Uncontrolled; ESP = Electrostatic Precipitator.

[c]O & M = Operating and Maintenance.

(0.10 lb/10^6 Btu). When an ESP is installed to meet an emission level of 22 ng PM/J (0.05 lb PM/10^6 Btu), the capital costs increase 3 to 23 percent.

Table 5-15 also shows that the increased annual costs over the baseline range from 2 to 12 percent using an ESP to meet the 43 ng/J (0.10 lb/10^6 Btu) PM level. The annualized costs associated with the use of a ESP at the 22 ng/J (0.05 lb/10^6 Btu) PM level range from 2 to 12 percent higher than the baseline costs. The PM control costs for MSW-fired boilers in Region V without monitors for boilers operating at a 0.6 and 0.9 capacity factor are presented in Tables 5-16 and 5-17.

Table 5-18 summarizes the annualized costs for MSW-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. The results show that as the boiler capacity factor increases, the total annualized cost decreases. The reason for this anomaly is that a waste disposal credit is allowed for MSW-fired boilers based on the amount of fuel/waste combusted. As capacity factor increases, the waste disposal credit also increases but at a faster rate than the O & M costs associated with PM control. As a result, a net decrease in total annualized costs is observed as capacity factor increases.

5.2.2 SO_2 Control Cost Impacts

For the purposes of this analysis, model boilers with heat input capacities of 2.9, 7.3, 14.7, 22.0, and 29.3 MW (10, 25, 50, 75, and 100 million Btu/hour) were chosen for the coal-fired units and model sizes of 2.9, 7.3, 14.7, and 29.3 MW (10, 25, 50, and 100 million Btu/hour) were chosen for oil-fired units. As stated in Section 3.2, SO_2 emissions reductions can be achieved through the use of low sulfur fuels, flue gas desulfurization (FGD), or fluidized bed combustion (FBC). In order to compare the costs of these control techniques, the cost of the boiler, fuel, and add-on SO_2 control device were examined.

Costs for residual oil-fired model boilers are estimated for boilers operating in Region V only since the difference in price between various sulfur content oils does not vary by region. Costs and specifications for residual oils in Region V are presented in Table 5-1. Costs for coal-fired

TABLE 5-16. BOILERS AND PM CONTROL COSTS WITHOUT MONITORS FOR MUNICIPAL SOLID WASTE-FIRED MODEL BOILERS IN REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/ control level,[b] ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[c]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
7.3 MW (25 million Btu/hr)										
UNC - 129 (0.30)	17.9 (19.7)	2,780	0	2,780	704	0	704	1,140	0	1,140
ESP - 43 (0.10)	6.0 (6.6)	2,780	498	3,280	704	50	754	1,140	134	1,270
ESP - 22 (0.05)	3.0 (3.3)	2,780	643	3,420	704	52	752	1,140	161	1,300
22.0 MW (75 million Btu/hr)										
ESP - 73 (0.17)	30.4 (33.5)	13,900	850	14,700	776	80	856	2,800	224	3,020
ESP - 43 (0.10)	17.9 (19.7)	13,900	1,076	15,000	776	84	860	2,800	266	3,070
ESP - 22 (0.05)	8.9 (9.9)	13,900	1,322	15,200	776	89	865	2,800	313	3,110

[a]All costs are presented in 1983 dollars rounded to three significant figures.

[b]UNC = Uncontrolled; ESP = Electrostatic Precipitator.

[c]O & M = Operating and Maintenance.

TABLE 5-17. BOILERS AND PM CONTROL COSTS WITHOUT MONITORS FOR MUNICIPAL SOLID WASTE-FIRED MODEL BOILERS IN REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/ control level,[b] ng/J (lb PM/10^6 Btu)	Annual PM emissions Mg/yr (tons/yr)	Capital costs ($1,000)			O & M costs ($1,000/yr)[c]			Annualized costs ($1,000/yr)		
		Boiler	PM	Total	Boiler	PM	Total	Boiler	PM	Total
7.3 MW (25 million Btu/hr)										
UNC - 129 (0.30)	26.8 (29.6)	2,770	0	2,770	672	0	672	1,110	0	1,110
ESP - 43 (0.10)	8.9 (9.9)	2,770	501	3,270	672	66	738	1,110	150	1,260
ESP - 22 (0.05)	4.5 (4.9)	2,770	646	3,420	672	69	741	1,110	178	1,290
22.0 MW (75 million Btu/hr)										
ESP - 73 (0.17)	45.6 (50.3)	13,800	856	14,700	586	108	694	2,600	252	2,850
ESP - 43 (0.10)	26.8 (29.6)	13,800	1,080	14,900	586	113	699	2,600	295	2,900
ESP - 22 (0.05)	13.4 (14.8)	13,800	1,330	15,100	586	120	706	2,600	344	2,940

[a]All costs are presented in 1983 dollars rounded to three significant figures.

[b]UNC = Uncontrolled; ESP = Electrostatic Precipitator.

[c]O & M = Operating and Maintenance.

TABLE 5-18. VARIATION OF PM CONTROL COSTS WITH CAPACITY FACTOR FOR MUNICIPAL SOLID WASTE-FIRED SMALL MODULAR MODEL BOILERS[a]

Boiler size/ control level,[b] ng/J (lb PM/10^6 Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
7.3 MW (25 million Btu/hr)									
UNC - 129 (0.30)	1,170	1,170	8.9 (9.9)	1,140	1,140	17.9 (19.7)	1,110	1,110	26.8 (29.6)
ESP - 43 (0.10)	1,300	1,290	3.0 (3.3)	1,300	1,270	6.0 (6.6)	1,270	1,260	8.9 (9.9)
ESP - 22 (0.05)	1,320	1,310	1.5 (1.6)	1,320	1,300	3.0 (3.3)	1,300	1,290	4.5 (4.9)
22.0 MW (75 million Btu/hr)									
UNC - 129 (0.30)	3,190	3,190	15.2 (16.8)	3,020	3,020	30.4 (33.5)	2,850	2,850	45.6 (50.3)
ESP - 43 (0.10)	3,230	3,230	8.9 (9.9)	3,080	3,070	17.9 (19.7)	2,910	2,900	26.8 (29.6)
ESP - 22 (0.05)	3,280	3,270	4.5 (4.9)	3,130	3,110	8.9 (9.9)	3,000	2,940	13.4 (14.8)

[a]Costs rounded to three significant figures.

[b]UNC = Uncontrolled; ESP = Electrostatic Precipitator.

model boilers are estimated for boilers operating in both EPA Regions V and VIII. Region V was chosen because the prices and types of coal available there are generally representative of those in Regions I through VII, as can be seen in Table 5-19. Region VIII was selected because it has significantly lower coal prices than any other region in the U.S. Costs and specifications for coals in Region V and VIII are presented in Table 5-2. For control levels which require FGD, the costs for a sodium scrubbing FGD system were estimated since this is the most widely applied FGD system among small boilers.

In order to examine the overall costs of SO_2 control on oil- and coal-fired boilers, it was necessary to examine the costs of ensuring compliance with an alternative emission level. Therefore, the costs associated with continuous emission monitors (CEM's) have been considered for each alternative emission level required to show compliance. For control levels which require low sulfur fuels, it is assumed that an SO_2 CEM and a carbon dioxide/oxygen (CO_2/O_2) diluent monitor are required at the outlet. It should be noted that there may be alternative approaches to ensuring compliance with emission levels based on the use of low sulfur fuels. For example, fuel sampling by the boiler operator or fuel supplier could be used. For Level 2 control where an FGD system is required, both an inlet and outlet SO_2 monitor is specified in addition to the CO_2/O_2 diluent monitor. The additional costs for required CEM's are presented in Table 5-20. These additional costs have been added to the SO_2 control costs for Levels 1 and 2 to obtain the cost of SO_2 controls with monitors. The baseline control level does not include monitors since they are not commonly required on new small boilers.

5.2.2.1 Oil-Fired Boilers. Table 5-21 presents the costs of SO_2 control for oil-fired boilers operating at a capacity factor of 0.3 in Region V without monitors. This table also presents the annual emissions, capital costs, O & M costs, and annualized costs for each of the model boilers and emission control levels examined.

TABLE 5-19. PROJECTED 1995 FUEL PRICES FOR ICI BOILERS WITH HEAT INPUT CAPACITIES OF 29.3 MW (100 MILLION BTU/HOUR) OR LESS[a]

Fuel type	Sulfur content (ng SO_2/J)[b]	EPA Regions I	II	III	IV	V	VI	VII	VIII	IX	X
Natural Gas	0	7.29	7.30	7.26	7.49	7.31	6.80	6.96	6.34	7.00	6.90
Distillate Oil	0	7.57	7.59	7.54	7.78	7.60	7.09	7.25	6.62	7.29	7.18
Residual Oil											
-	129	6.80	6.79	6.79	6.77	6.94	6.79	6.91	6.61	6.40	6.37
-	344	6.43	6.42	6.42	6.40	6.55	6.42	6.53	6.23	6.06	6.02
-	688	6.05	6.04	6.04	6.02	6.18	6.04	6.15	5.86	5.65	5.62
-	1,290	5.73	5.72	5.72	5.70	5.85	5.72	5.82	5.54	5.32	5.28
Coal											
Bituminous											
Type B	34.4 - 464	3.63	3.37	3.04	3.13	3.23	3.27	3.04	1.92	2.67	3.03
Type D	464 - 718	3.60	3.34	2.86	2.95	3.11	3.16	2.94	1.84	2.81	2.89
Type E	718 - 1,080	3.53	3.18	2.79	2.93	2.98	3.15	2.91	1.82	2.72	2.74
Type F	1,080 - 1,430	3.33	3.02	2.68	2.84	2.85	3.09	2.84	-	-	-
Type G	1,430 - 2,150	3.13	2.82	2.37	2.72	2.60	3.00	2.49	-	-	-
Type H	>2,150	3.15	2.80	2.35	2.53	2.42	2.84	2.36	-	-	-
Subbituminous											
Type B	34.4 - 464	-	-	-	-	3.22	3.35	2.63	1.37	2.74	2.53
Type D	464 - 718	-	-	-	-	3.17	3.23	2.57	1.38	2.64	2.50
Type E	718 - 1,080	-	-	-	-	3.16	3.19	2.59	1.24	2.51	2.01

[a]Projected 1995 fuel prices in \$/kJ presented in January 1983 dollars. To convert fuel prices to \$/10^6 Btu, divide the fuel costs in \$/kJ by 0.9486. References 6 and 7.

[b]To convert to lb/10^6 Btu, divide emissions in nanograms per joule (ng/J) by 430.

TABLE 5-20. CONTINUOUS EMISSION MEASUREMENT COSTS (JANUARY 1983 $)[16,17]

System	Capital cost ($1,000)	O & M cost ($1,000/yr)	Annualized cost ($1,000/yr)
SO_2 (outlet only)	44	36	42
SO_2 (inlet and outlet)	64	72	81
O_2/CO_2 (outlet only)	9	8	9
O_2/CO_2 (inlet and outlet)	18	15	18

TABLE 5-21. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[c]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[d]	Total	
2.9 MW (10 million Btu/hr)						
1,010 ng SO_2/J oil[b]	28.0 (30.9)	439	166	169	335	406
344 ng SO_2/J oil	9.5 (10.5)	440	182	169	351	422
129 ng SO_2/J oil	3.6 (3.9)	441	192	169	362	433
1,290 ng SO_2/J oil and 90% FGD[e]	3.6 (3.9)	613	162	231	393	493
7.3 MW (25 million Btu/hr)						
1,010 ng SO_2/J oil	70.0 (77.2)	729	416	225	641	758
344 ng SO_2/J oil	23.8 (26.3)	732	454	225	679	797
129 ng SO_2/J oil	8.9 (9.9)	735	481	225	706	824
1,290 ng SO_2/J oil and 90% FGD	8.9 (9.9)	1,000	405	312	717	880
14.7 MW (50 million Btu/hr)						
1,010 ng SO_2/J oil	140 (154)	1,470	832	267	1,100	1,340
344 ng SO_2/J oil	47.7 (52.6)	1,480	908	267	1,180	1,420
129 ng SO_2/J oil	17.9 (19.7)	1,480	962	267	1,230	1,470
1,290 ng SO_2/J oil and 90% FGD	17.9 (19.7)	1,860	811	383	1,200	1,510
29.3 MW (100 million Btu/hr)						
1,010 ng SO_2/J oil	280 (309)	2,280	1,660	353	2,010	2,390
344 ng SO_2/J oil	95.4 (105)	2,300	1,820	353	2,170	2,540
129 ng SO_2/J oil	35.8 (39.4)	2,300	1,920	353	2,270	2,650
1,290 ng SO_2/J oil and 90% FGD	35.8 (39.4)	2,840	1,620	539	2,160	2,630

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]To convert to $lb/10^6$ Btu, divide nanograms per joule (ng/J) by 430.

[c]Emissions based on actual fuel sulfur contents.

[d]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[e]90% FGD = 90% SO_2 removal using an FGD.

Table 5-21 shows that when monitors are not included, there is a slight increase in the capital costs for emission levels based on the use of low sulfur oils over the baseline cost. This increase is attributed to a slight increase in working capital requirements resulting from the higher fuel price of low sulfur oil over the baseline oil. The increased capital costs of sodium scrubbing over the baseline range from 40 percent for a 2.9 MW (10 million Btu/hour) heat input boiler to 25 percent for a 29.3 MW (100 million Btu/hour) boiler.

Table 5-21 shows that the increased annualized cost over the baseline for an emission level based on the use of the low sulfur 344 ng/J (0.8 lb/10^6 Btu) oil is less than 8.5 percent for all boilers. The increase in annualized cost over the baseline for the very low sulfur 129 ng/J (0.3 lb/10^6 Btu) oil is less than 13 percent for all boilers. The annualized cost increases over the baseline associated with the use of FGD range from 23 percent for the 2.9 MW (10 million Btu/hour) heat input boiler to 12 percent for a 29.3 MW (100 million Btu/hour) boiler.

The SO_2 control costs for residual oil-fired boilers in Region V without monitors for boilers operating at 0.6 and 0.9 capacity factors are presented in Tables 5-22 and 5-23, respectively. As discussed previously in this section, the slight increase in capital costs for boilers firing low sulfur oils is attributed to a slight increase in working capital requirements resulting from a higher fuel price for low sulfur oil compared to the baseline oil. Table 5-24 summarizes the annualized costs and emissions for oil-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Shown in the table are the SO_2 control costs including and excluding the costs for monitors.

5.2.2.2 Coal-Fired Model Boilers. Table 5-25 presents the costs of SO_2 control for coal-fired boilers operating at a capacity factor of 0.3 in Region V without monitors. As shown, annualized costs increase with increasing capacity factor due to increases in O & M costs. All emission levels are based on the average fuel sulfur contents of representative coals. The table shows that, when monitoring costs are not included, there

TABLE 5-22. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[c]	Capital costs ($1,000)	O & M Costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[d]	Total	
2.9 MW (10 million Btu/hr)						
1,010 ng/J oil[b]	56.0 (61.8)	467	333	249	582	655
344 ng/J oil	19.1 (21.0)	470	363	249	612	686
129 ng/J oil	7.2 (7.9)	472	385	249	634	708
1,290 ng/J oil and 90% FGD[e]	7.2 (7.9)	643	324	321	645	748
7.3 MW (25 million Btu/hr)						
1,010 ng/J oil	140 (154)	783	832	328	1,160	1,280
344 ng/J oil	47.7 (52.6)	790	908	332	1,240	1,360
129 ng/J oil	17.9 (19.7)	794	962	328	1,290	1,410
1,290 ng/J oil and 90% FGD	17.9 (19.7)	1,060	811	439	1,250	1,420
14.7 MW (50 million Btu/hr)						
1,010 ng/J oil	280 (309)	1,570	1,660	390	2,050	2,300
344 ng/J oil	95.4 (105)	1,580	1,820	380	2,200	2,450
129 ng/J oil	35.8 (39.4)	1,590	1,920	388	2,310	2,560
1,290 ng/J oil and 90% FGD	35.8 (39.4)	1,970	1,620	556	2,180	2,490
29.3 MW (100 million Btu/hr)						
1,010 ng/J oil	560 (618)	2,450	3,320	510	3,830	4,220
344 ng/J oil	191 (210)	3,020	3,630	370	4,000	4,490
129 ng/J oil	71.5 (78.8)	2,490	3,850	500	4,350	4,750
1,290 ng/J oil and 90% FGD	71.5 (78.8)	3,030	3,240	790	4,030	4,510

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]To convert to lb/10^6, divide nanograms per joule (ng/J) by 430.

[c]Emissions based on actual fuel sulfur contents.

[d]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[e]90% FGD = 90% SO_2 removal using an FGD.

TABLE 5-23. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[c]	Capital costs ($1,000)	O & M costs ($1,000/yr) Fuel	Nonfuel[d]	Total	Annualized costs ($1,000/yr)
2.9 MW (10 million Btu/hr)						
1,010 ng/J oil[b]	84.0 (92.6)	496	499	329	828	905
344 ng/J oil	28.6 (31.5)	499	545	329	874	951
129 ng/J oil	10.7 (11.8)	502	577	329	906	983
1,290 ng/J oil and 90% FGD[e]	10.7 (11.8)	674	486	411	897	1,000
7.3 MW (25 million Btu/hr)						
1,010 ng/J oil	210 (232)	837	1,250	430	1,680	1,810
344 ng/J oil	71.5 (78.8)	847	1,360	430	1,790	1,930
129 ng/J oil	26.8 (29.6)	854	1,440	430	1,870	2,010
1,290 ng/J oil and 90% FGD	26.8 (29.6)	1,120	1,220	560	1,780	1,960
14.7 MW (50 million Btu/hr)						
1,010 ng/J oil	420 (463)	1,660	2,440	560	3,000	3,260
344 ng/J oil	143 (158)	2,060	2,430	700	3,130	3,460
129 ng/J oil	53.6 (59.1)	1,690	2,890	500	3,390	3,650
1,290 ng/J oil and 90% FGD	53.6 (59.1)	2,070	2,430	720	3,150	3,480
29.3 MW (100 million Btu/hr)						
1,010 ng/J oil	840 (926)	2,620	4,990	660	5,650	6,060
344 ng/J oil	286 (315)	3,210	4,860	1,000	5,860	6,360
129 ng/J oil	107 (118)	2,680	5,770	660	6,430	6,840
1,290 ng/J oil and 90% FGD	107 (118)	3,220	4,860	1,040	5,900	6,410

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]To convert to lb/10^6, divide nanograms per joule (ng/J) by 430.

[c]Emissions based on actual fuel sulfur contents.

[d]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[e]90% FGD = 90% SO_2 removal using an FGD.

TABLE 5-24. VARIATION OF SO_2 CONTROL COSTS ON RESIDUAL OIL-FIRED BOILERS IN EPA REGION V WITH CAPACITY FACTORS[a,b,c]

Boiler size/ control level, ng/J (lb $SO_2/10^6$ Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
Baseline - 1,010 (2.35)	406	406	28.0 (30.9)	665	665	56.0 (61.8)	905	905	84.0 (92.6)
Level 1 - 344 (0.80)	473	422	9.5 (10.5)	737	686	19.1 (21.0)	1,010	951	28.6 (31.5)
Level 2 - 129 (0.30)	484	433	3.6 (3.9)	759	708	7.2 (7.9)	1,030	983	10.7 (11.8)
7.3 MW (25 million Btu/hr)									
Baseline - 1,010 (2.35)	758	758	70.0 (77.2)	1,280	1,280	140 (154)	1,810	1,810	210 (232)
Level 1 - 344 (0.80)	848	797	23.8 (26.3)	1,410	1,360	47.7 (52.6)	1,980[d]	1,930[d]	71.5 (78.8)
Level 2 - 129 (0.30)	875	824	8.9 (9.9)	1,460	1,410	17.9 (19.7)	2,060[d]	1,960[d]	26.8 (29.6)
14.7 MW (50 million Btu/hr)									
Baseline - 1,010 (2.35)	1,340	1,340	140 (154)	2,300	2,300	280 (309)	3,260	3,260	420 (463)
Level 1 - 344 (0.80)	1,470	1,420	47.7 (52.6)	2,500[d]	2,450[d]	95.4 (105)	3,510[d]	3,460[d]	143 (158)
Level 2 - 129 (0.30)	1,520	1,470	17.9 (19.7)	2,590[d]	2,490[d]	35.8 (39.4)	3,580[d]	3,480[d]	53.6 (59.1)
29.3 MW (100 million Btu/hr)									
Baseline - 1,010 (2.35)	2,390	2,390	280 (309)	4,220	4,220	560 (618)	6,060	6,060	840 (926)
Level 1 - 344 (0.80)	2,590[d]	2,540[d]	95.4 (105)	4,540[d]	4,490[d]	191 (210)	6,460[d]	6,360[d]	286 (315)
Level 2 - 129 (0.30)	2,730[d]	2,630[d]	35.8 (39.4)	4,610[d]	4,510[d]	71.5 (78.8)	6,510[d]	6,410[d]	107 (118)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Unless otherwise indicated, annualized costs and annual emissions are based on the following:
Baseline - 1,010 ng/J (2.35 lb $SO_2/10^6$ Btu oil)
Level 1 - 344 ng/J (0.8 lb $SO_2/10^6$ Btu oil)
Level 2 - 129 ng/J (0.3 lb $SO_2/10^6$ Btu oil)

[d]Annualized costs for level 2 are based on a boiler firing a 1,290 ng SO_2/J (3.0 lb/10^6 Btu) coal and an FGD removing 90 percent of the SO_2. These costs are presented for less expensive Level 2 control option.

TABLE 5-25. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr) Fuel	Nonfuel[e]	Total	Annualized costs ($1,000/yr)
2.9 MW (10 million Btu/hr)						
Type F-Bit[c]	34.0 (37.4)	1,470	79	262	341	583
Type B-Bit	11.3 (12.5)	1,470	89	262	351	593
Type H-Bit and 90% FGD[c]	6.6 (7.2)	1,670	67	334	401	678
Type H-Bit and 90% FBC[c,d]	-	-	-	-	-	-
7.3 MW (25 million Btu/hr)						
Type F-Bit	84.9 (93.6)	2,630	197	365	562	998
Type B-Bit	28.3 (31.2)	2,640	223	365	588	1,020
Type H-Bit and 90% FGD	16.4 (18.1)	2,960	168	473	641	1,130
Type H-Bit and 90% FBC[d]	-	-	-	-	-	-
14.7 MW (50 million Btu/hr)						
Type F-Bit	170 (187)	4,690	394	552	946	1,720
Type B-Bit	56.6 (62.4)	4,690	447	552	999	1,780
Type H-Bit and 90% FGD	32.8 (36.1)	5,150	335	714	1,050	1,900
Type H-Bit and 90% FBC	32.7 (36.1)	5,890	335	614	949	1,930
22.0 MW (75 Million Btu/hr)						
Type F-Bit	255 (281)	6,750	591	618	1,210	2,330
Type B-Bit	84.9 (93.6)	6,750	670	618	1,290	2,410
Type H-Bit and 90% FGD	49.2 (54.2)	7,320	503	830	1,330	2,550
Type H-Bit and 90% FBC	49.2 (54.2)	8,710	503	872	1,380	2,820
29.3 MW (100 million Btu/hr)						
Type F-Bit	340 (375)	8,670	788	690	1,480	2,920
Type B-Bit	113 (125)	8,670	894	690	1,580	3,030
Type H-Bit and 90% FGD	65.6 (72.3)	9,340	670	953	1,620	3,180
Type H-Bit and 90% FBC	65.6 (72.3)	11,200	670	1,020	1,690	3,560

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Coal types are defined in Table 5-2. 90% FGD = 90% SO_2 removal using FGD; 90% FBC = 90% SO_2 removal using FBC.

[d]Outside FBC algorithm range.

[e]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

is no increase in capital cost over the baseline cost for emission levels based on the use of low sulfur coal. The increased capital costs of sodium scrubbing over the baseline range from 14 percent for a 2.9 MW (10 million Btu/hour) heat input boiler to 8 percent for a 29.3 MW (100 million Btu/hour) boiler. The capital cost of FBC is approximately 26 to 29 percent higher than the baseline cost.

Table 5-25 shows that the increased annualized cost over the baseline for an emission level based on the use of low sulfur coal is less than 2 percent for all boiler sizes. The annualized cost increases over the baseline associated with the use of FGD range from 15 percent for a 2.9 MW (10 million Btu/hour) heat input boiler to 7 percent for a 29.3 MW (100 million Btu/hour) boiler. Table 5-25 shows that the annualized costs of FBC are approximately 12 to 22 percent higher than the baseline costs in this size range. The SO_2 control costs for coal-fired boilers without monitors in Region V for a boiler operating at 0.6 and 0.9 capacity factors are presented in Tables 5-26 and 5-27, respectively.

Table 5-28 presents the costs of SO_2 control for coal-fired boilers without monitors in Region VIII. This table presents the annual emissions, capital costs, O & M costs, and annualized costs for each of the model boilers and emission control levels examined. All costs are based on a capacity factor of 0.3 and all emissions are based on the average fuel sulfur contents of representative coals. It should be noted that the capital cost of a boiler in Region VIII is greater than in Region V because of the lower heating value of subbituminous coal. The lower heating value requires a larger solids handling system and combustion chamber in order to meet the desired rated capacity.

Table 5-28 shows that when monitoring costs are not included, there is no increase in capital cost over the baseline cost for emission levels based on the use of low sulfur coal. The increased capital costs of sodium scrubbing over the baseline range from 9 percent for a 2.9 MW (10 million Btu/hour) heat input boiler to 6 percent for a 29.3 MW (100 million Btu/hour) boiler. In all cases shown in Table 5-28, the capital cost of FBC is approximately 13 to 16 percent higher than the baseline costs. Table

TABLE 5-26. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[e]	Total	
2.9 MW (10 million Btu/hr)						
Type F-Bit[c]	67.9 (74.9)	1,490	158	373	531	776
Type B-Bit	22.6 (25.0)	1,500	178	373	551	796
Type H-Bit and 90% FGD[c]	13.1 (14.5)	1,710	134	462	596	876
Type H-Bit and 90% FBC[c,d]	13.1 (14.5)	2,310	134	584	718	1,100
7.3 MW (25 million Btu/hr)						
Type F-Bit	170 (187)	2,680	394	516	910	1,350
Type B-Bit	56.6 (62.4)	2,680	445	517	962	1,400
Type H-Bit and 90% FGD	32.8 (36.1)	3,010	335	665	1,000	1,500
Type H-Bit and 90% FBC[d]	32.8 (36.1)	2,500	335	675	1,010	1,420
14.7 MW (50 million Btu/hr)						
Type F-Bit	340 (374)	4,760	788	772	1,560	2,340
Type B-Bit	113 (125)	4,770	891	769	1,660	2,450
Type H-Bit and 90% FGD	65.6 (72.3)	5,240	670	1,010	1,680	2,550
Type H-Bit and 90% FBC	65.6 (72.3)	5,970	671	889	1,560	2,550
22.0 MW (75 Million Btu/hr)						
Type F-Bit	510 (562)	6,840	1,180	860	2,040	3,170
Type B-Bit	170 (187)	6,850	1,340	850	2,190	3,320
Type H-Bit and 90% FGD	98.3 (108)	7,440	1,010	1,180	2,190	3,420
Type H-Bit and 90% FBC	98.3 (108)	8,830	1,010	1,280	2,290	3,750
29.3 MW (100 million Btu/hr)						
Type F-Bit	680 (749)	8,780	1,580	950	2,530	3,980
Type B-Bit	227 (150)	8,800	1,780	950	2,730	4,190
Type H-Bit and 90% FGD	131 (145)	9,490	1,340	1,370	2,710	4,280
Type H-Bit and 90% FBC	131 (145)	11,400	1,340	1,520	2,860	4,740

[a] All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b] Emissions based on actual fuel sulfur contents.

[c] Coal types are defined in Table 5-2. 90% FGD = 90% SO_2 removal using FGD; FBC = 90% SO_2 removal using FBC

[d] Outside FBC algorithm range.

[e] Nonfuel O & M costs = direct labor + supervision laor + maintenance labor + spare parts + electricity + water + overhead.

TABLE 5-27. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[e]	Total	
2.9 MW (10 million Btu/hr)						
Type F-Bit[c]	102 (112)	1,520	237	484	721	968
Type B-Bit	34.0 (37.4)	1,520	267	485	752	999
Type H-Bit and 90% FGD[c]	19.7 (21.7)	1,740	201	589	790	1,070
Type H-Bit and 90% FBC[c,d]	19.7 (21.7)	2,340	201	743	944	1,330
7.3 MW (25 million Btu/hr)						
Type F-Bit	255 (281)	2,720	591	669	1,260	1,700
Type B-Bit	84.9 (93.6)	2,730	668	672	1,340	1,780
Type H-Bit and 90% FGD	49.2 (54.2)	3,070	503	857	1,360	1,860
Type H-Bit and 90% FBC[d]	49.2 (54.2)	2,560	503	887	1,390	1,800
14.7 MW (50 million Btu/hr)						
Type F-Bit	510 (562)	4,830	1,180	990	2,170	2,960
Type B-Bit	170 (187)	4,850	1,340	980	2,320	3,120
Type H-Bit and 90% FGD	98.3 (108)	5,330	1,010	1,310	2,320	3,190
Type H-Bit and 90% FBC	98.3 (108)	6,060	1,010	1,170	2,180	3,170
22.0 MW (75 Million Btu/hr)						
Type F-Bit	765 (843)	6,930	1,770	1,100	2,870	4,010
Type B-Bit	255 (281)	6,950	2,010	1,080	3,090	4,240
Type H-Bit and 90% FGD	148 (163)	7,560	1,510	1,540	3,050	4,290
Type H-Bit and 90% FBC	148 (163)	8,960	1,510	1,700	3,210	4,680
29.3 MW (100 million Btu/hr)						
Type F-Bit	1,020 (1,120)	8,900	2,370	1,200	3,570	5,040
Type B-Bit	340 (374)	8,920	2,670	1,210	3,880	5,350
Type H-Bit and 90% FGD	197 (217)	9,630	2,010	1,800	3,810	5,390
Type H-Bit and 90% FBC	197 (217)	11,500	2,010	2,010	4,020	5,920

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Coal types are defined in Table 5-2. 90% FGD = 90% SO_2 removal using FGD; 90% FBC = 90% SO_2 removal using FBC.

[d]Outside FBC algorithm range.

[e]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

TABLE 5-28. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION VIII OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[e]	Total	
2.9 MW (10 million Btu/hr)						
Type E-Sub[c]	25.0 (27.6)	1,870	34	281	315	625
Type B-Sub	11.3 (12.5)	1,870	38	281	320	630
Type E-Sub and 75% FGD[c]	6.3 (6.9)	2,040	34	339	373	712
Type E-Sub 75% and FBC[c,d]	-	-	-	-	-	-
7.3 MW (25 million Btu/hr)						
Type E-Sub	62.6 (69.0)	3,360	86	397	483	1,040
Type B-Sub	28.3 (31.2)	3,360	95	392	494	1,050
Type E-Sub and 75% FGD	15.6 (17.2)	3,630	86	474	560	1,160
Type E-Sub and 75% FBC[d]	-	-	-	-	-	-
14.7 MW (50 million Btu/hr)						
Type E-Sub	125 (138)	5,110	172	552	724	1,580
Type B-Sub	56.6 (62.4)	5,120	189	552	742	1,590
Type E-Sub and 75% FGD	31.3 (34.5)	5,500	172	653	825	1,740
Type E-Sub and 75% FBC	31.3 (34.5)	5,820	172	616	788	1,760
22.0 MW (75 Million Btu/hr)						
Type E-Sub	188 (207)	7,360	258	617	875	2,100
Type B-Sub	84.9 (93.6)	7,370	284	617	901	2,130
Type E-Sub and 75% FGD	46.9 (51.7)	7,840	258	741	999	2,310
Type E-Sub and 75% FBC	46.9 (51.7)	8,500	258	864	1,120	2,540
29.3 MW (100 million Btu/hr)						
Type E-Sub	251 (276)	9,460	344	689	1,030	2,610
Type B-Sub	113 (125)	9,460	378	689	1,070	2,650
Type E-Sub and 75% FGD	62.6 (69.0)	10,000	344	836	1,180	2,850
Type E-Sub and 75% FBC	62.6 (69.0)	10,700	344	1,010	1,350	3,140

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Coal types defined in Table 5-2. 75% FGD = 75% SO_2 removal using FGD; 75% FBC = 75% SO_2 removal using FBC.

[d]Outside FBC algorithm range.

[e]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

5-28 also shows that the different fuel characteristics of subbituminous and bituminous coal (see Table 5-21) result in higher capital costs in Region VIII than in Region V for the same SO_2 control option. This is due to the fact that subbituminous coals generate more flue gas (on a thermal input basis) than bituminous coals resulting in a larger, and more expensive, SO_2 absorber.

Table 5-28 shows that the increased annualized cost over the baseline for an emission level based on the use of low sulfur coal is less than 1.5 percent for all boiler sizes. The annualized cost increases over the baseline associated with the use of FGD range from 14 percent for the 2.9 MW (10 million Btu/hour) heat input boiler to 10 percent for a 29.3 MW (100 million Btu/hour) boiler. Table 5-28 shows that the annualized costs of FBC are 11 to 21 percent higher than the baseline costs in this size range. The SO_2 control cost for coal-fired boilers in Region VIII without monitors for boilers operating at 0.6 and 0.9 capacity factors are presented in Tables 5-29 and 5-30, respectively.

Tables 5-31 and 5-32 summarize the annualized costs and emissions for coal-fired boilers in Regions V and VIII, respectively, operating at capacity factors of 0.3, 0.6, and 0.9. These tables also present the costs for operation both with and without monitors. All emissions shown are based on the actual average fuel sulfur contents of the representative coals.

For all of the costs shown, as the boiler capacity factor increases, annualized costs also increase. The costs increase because certain O & M costs (e.g., fuel, water, electricity, waste disposal) are directly related to capacity factor. Capital costs are not affected by differences in capacity factor.

5.2.3 NO_x Control Cost Impacts

This section presents the costs of NO_x controls for model boilers firing natural gas, distillate oil, residual oil, and coal in EPA Region V. Costs were estimated for the same model boiler sizes as those presented for SO_2 control costs in Section 5.2.2. All costs include the cost of the

TABLE 5-29. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION VIII OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[e]	Total	
2.9 MW (10 million Btu/hr)						
Type E-Sub[c]	50.1 (55.2)	1,890	69	394	463	775
Type B-Sub	22.6 (25.0)	1,900	76	396	472	784
Type E-Sub and 75% FGD[c]	12.5 (13.8)	2,070	69	457	526	867
Type E-Sub and 75% FBC[c,d]	12.5 (13.8)	2,330	69	602	671	1,050
7.3 MW (25 million Btu/hr)						
Type E-Sub	125 (138)	3,390	172	553	725	1,290
Type B-Sub	56.6 (62.4)	3,390	189	557	746	1,310
Type E-Sub and 75% FGD	31.3 (34.5)	3,670	172	643	815	1,420
Type E-Sub and 75% FBC[d]	31.3 (34.5)	2,410	172	662	834	1,230
14.7 MW (50 million Btu/hr)						
Type E-Sub	251 (276)	5,170	344	766	1,110	1,970
Type B-Sub	113 (125)	5,170	378	772	1,150	2,010
Type E-Sub and 75% FGD	62.6 (69.0)	5,560	344	896	1,240	2,160
Type E-Sub and 75% FBC	62.6 (69.0)	5,870	344	836	1,180	2,150
22.0 MW (75 Million Btu/hr)						
Type E-Sub	376 (414)	7,430	516	854	1,370	2,600
Type B-Sub	170 (187)	7,430	568	852	1,420	2,660
Type E-Sub and 75% FGD	93.9 (103)	7,920	516	1,020	1,540	2,850
Type E-Sub and 75% FBC	93.9 (103)	8,590	517	1,193	1,710	3,130
29.3 MW (100 million Btu/hr)						
Type E-Sub	502 (552)	9,540	689	951	1,640	3,220
Type B-Sub	227 (250)	9,540	757	953	1,710	3,290
Type E-Sub and 75% FGD	125 (138)	10,100	689	1,150	1,840	3,520
Type E-Sub and 75% FBC	125 (138)	10,800	689	1,380	2,070	3,870

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Coal types are defined in Table 5-2. 75% FGD = 75% SO_2 removal using FGD; 75% FBC = 75% SO_2 removal using FBC.

[d]Outside FBC algorithm range.

[e]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

TABLE 5-30. BOILER AND SO_2 CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED MODEL BOILERS IN EPA REGION VIII OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size/control	Annual SO_2 emissions Mg/yr (tons/yr)[b]	Capital costs ($1,000)	O & M costs ($1,000/yr)			Annualized costs ($1,000/yr)
			Fuel	Nonfuel[e]	Total	
2.9 MW (10 million Btu/hr)						
Type E-Sub[c]	75.1 (82.8)	1,920	103	507	610	925
Type B-Sub	34.0 (37.4)	1,920	114	510	624	939
Type E-Sub and 75% FGD[c]	18.8 (20.7)	2,090	103	576	679	1,020
Type E-Sub and 75% FBC[c,d]	18.8 (20.7)	2,360	103	749	852	1,240
7.3 MW (25 million Btu/hr)						
Type E-Sub	188 (207)	3,430	258	708	966	1,530
Type B-Sub	84.9 (93.6)	3,430	284	714	998	1,560
Type E-Sub and 75% FGD	46.9 (51.7)	3,710	258	812	1,070	1,680
Type E-Sub and 75% FBC[d]	46.9 (51.7)	2,450	258	832	1,090	1,490
14.7 MW (50 million Btu/hr)						
Type E-Sub	376 (414)	5,220	516	984	1,500	2,370
Type B-Sub	170 (187)	5,230	568	992	1,560	2,420
Type E-Sub and 75% FGD	93.9 (103)	5,620	516	1,140	1,660	2,590
Type E-Sub and 75% FBC	93.9 (103)	5,930	517	1,050	1,570	2,550
22.0 MW (75 Million Btu/hr)						
Type E-Sub	563 (621)	7,490	775	1,090	1,850	3,100
Type B-Sub	255 (281)	7,500	851	1,090	1,940	3,180
Type E-Sub and 75% FGD	141 (155)	7,990	775	1,300	2,080	3,390
Type E-Sub and 75% FBC	141 (155)	8,680	775	1,520	2,300	3,720
29.3 MW (100 million Btu/hr)						
Type E-Sub	751 (828)	9,620	1,030	1,210	2,240	3,830
Type B-Sub	340 (374)	9,630	1,130	1,220	2,350	3,940
Type E-Sub and 75% FGD	188 (207)	10,200	1,030	1,470	2,500	4,190
Type E-Sub and 75% FBC	188 (207)	11,100	1,030	1,760	2,790	4,600

[a]All costs are 1995 "first-year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Coal types are defined in Table 5-2. 75% FGD = 75% SO_2 removal using FGD; 75% FBC = 75% SO_2 removal using FBC.

[d]Outside FBC algorithm range.

[e]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

TABLE 5-31. VARIATION OF SO_2 CONTROL COSTS ON COAL-FIRED BOILERS IN EPA REGION V WITH CAPACITY FACTOR[a,b,c]

Boiler size/ control level, ng/J ($lb/10^6$ Btu)	Capacity factor = 0.3: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.3: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.3: Annual emissions, Mg/yr (tons/yr)	Capacity factor = 0.6: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.6: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.6: Annual emissions, Mg/yr (tons/yr)	Capacity factor = 0.9: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.9: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.9: Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
Baseline - 1,460 (3.4)	583	583	34.0 (37.4)	776	776	67.9 (74.9)	968	968	102 (112)
Level 1 - 516 (1.2)	644	593	11.3 (12.5)	847	796	22.6 (25.0)	1,050	999	34.0 (37.4)
Level 2 - 258 (0.6)	777	678	6.6 (7.2)	975	876	13.1 (14.5)	1,170	1,070	19.7 (21.7)
7.3 MW (25 million Btu/hr)									
Baseline - 1,460 (3.4)	998	998	84.9 (93.6)	1,350	1,350	170 (187)	1,700	1,700	255 (281)
Level 1 - 516 (1.2)	1,075	1,020	28.3 (31.2)	1,450	1,400	56.6 (62.4)	1,830	1,780	84.9 (93.6)
Level 2 - 258 (0.6)	1,230	1,130	16.4 (18.1)	1,600	1,500	32.8 (36.1)	1,960	1,860	49.2 (54.2)
14.7 MW (50 million Btu/hr)									
Baseline - 1,460 (3.4)	1,720	1,720	170 (187)	2,340	2,340	340 (374)	2,960	2,960	510 (562)
Level 1 - 516 (1.2)	1,830	1,780	56.6 (62.4)	2,500	2,450	113 (125)	3,170	3,120	170 (187)
Level 2 - 258 (0.6)	2,000	1,900	32.7 (36.1)	2,650	2,550	65.6 (72.3)	3,290	3,190	98.3 (108)
22.0 MW (75 million Btu/hr)									
Baseline - 1,460 (3.4)	2,330	2,330	255 (281)	3,170	3,170	510 (562)	4,010	4,010	765 (843)
Level 1 - 516 (1.2)	2,460	2,410	84.9 (93.6)	3,370	3,320	170 (187)	4,290	4,240	255 (281)
Level 2 - 258 (0.6)	2,650	2,550	49.2 (54.2)	3,520	3,420	98.3 (108)	4,390	4,290	148 (163)
29.3 MW (100 million Btu/hr)									
Baseline - 1,460 (3.4)	2,920	2,920	340 (375)	3,980	3,980	680 (749)	5,040	5,040	1,020 (1,120)
Level 1 - 516 (1.2)	3,080	3,030	113 (125)	4,240	4,190	227 (250)	5,400	5,350	340 (374)
Level 2 - 258 (0.6)	3,280	3,180	65.6 (72.3)	4,380	4,280	131 (145)	5,490	5,390	197 (217)

[a] All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b] Emissions based on actual fuel sulfur contents.

[c] Unless otherwise indicated, annualized costs and annual emissions are based on the following:
Baseline - Type F-Bit coal 1,230 nanograms per joule (ng/J) (2.85 lb $SO_2/10^6$ Btu)
Level 1 - Type B-Bit coal 409 ng/J (0.95 lb $SO_2/10^6$ Btu)
Level 2 - 90% SO_2 removal using FGD on Type H-Bit coal 2,380 ng/J (5.54 lb $SO_2/10^6$ Btu)

TABLE 5-32. VARIATION OF SO_2 CONTROL COSTS ON COAL-FIRED BOILERS IN EPA REGION VIII WITH CAPACITY FACTOR[a,b,c]

Boiler size/ control level, ng/J ($lb/10^6$ Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
Baseline - 1,460 (3.4)	625	625	25.0 (27.6)	775	775	50.1 (55.2)	925	925	75.1 (82.8)
Level 1 - 516 (1.2)	681	630	11.3 (12.5)	835	784	22.6 (25.0)	990	939	34.0 (37.4)
Level 2 - 258 (0.6)	811	712	6.3 (6.9)	960	867	12.5 (13.8)	1,120	1,020	18.8 (20.7)
7.3 MW (25 million Btu/hr)									
Baseline - 1,460 (3.4)	1,040	1,040	62.6 (69.0)	1,290	1,290	125 (138)	1,530	1,530	188 (207)
Level 1 - 516 (1.2)	1,100	1,050	28.3 (31.2)	1,360	1,310	56.6 (62.4)	1,610	1,560	84.9 (93.6)
Level 2 - 258 (0.6)	1,260	1,160	15.6 (17.2)	1,520	1,420	31.3 (34.5)	1,780	1,680	46.9 (51.7)
14.7 MW (50 million Btu/hr)									
Baseline - 1,460 (3.4)	1,580	1,580	125 (138)	1,970	1,970	251 (276)	2,370	2,370	376 (414)
Level 1 - 516 (1.2)	1,640	1,590	56.6 (62.4)	2,060	2,010	113 (125)	2,470	2,420	170 (187)
Level 2 - 258 (0.6)	1,840	1,740	31.3 (34.5)	2,260	2,160	62.6 (69.0)	2,690	2,590	93.9 (103)
22.0 MW (75 million Btu/hr)									
Baseline - 1,460 (3.4)	2,100	2,100	188 (207)	2,600	2,600	376 (414)	3,100	3,100	563 (621)
Level 1 - 516 (1.2)	2,180	2,130	84.9 (93.6)	2,710	2,660	170 (187)	3,230	3,180	255 (281)
Level 2 - 258 (0.6)	2,410	2,310	46.9 (51.7)	2,950	2,850	93.9 (103)	3,490	3,390	141 (155)
29.3 MW (100 million Btu/hr)									
Baseline - 1,460 (3.4)	2,610	2,610	251 (276)	3,220	3,220	502 (552)	3,830	3,830	751 (828)
Level 1 - 516 (1.2)	2,700	2,650	113 (125)	3,340	3,290	227 (250)	3,990	3,940	340 (374)
Level 2 - 258 (0.6)	2,950	2,850	62.6 (69.0)	3,620	3,520	125 (138)	4,290	4,190	188 (207)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Emissions based on actual fuel sulfur contents.

[c]Unless otherwise indicated, annualized costs and annual emissions are based on the following:
Baseline - Type E-Sub coal 903 nanograms per joule (ng/J) (2.1 lb $SO_2/10^6$ Btu)
Level 1 - Type B-Sub coal 409 ng/J (0.95 lb $SO_2/10^6$ Btu)
Level 2 - 75% SO_2 removal using FGD on Type E-Sub coal 930 ng/J (2.2 lb $SO_2/10^6$ Btu)

boiler, fuel, and add-on NO_x control equipment. Nitrogen oxide control cost algorithms for low excess air (LEA) were used to estimate the capital, O & M, and annualized costs for the model small boilers.[18]

In order to examine the overall costs of NO_x control on natural gas-, oil-, and coal-fired small boilers, it was necessary to investigate the compliance costs associated with meeting each alternative emission level. Therefore, the costs associated with a stack gas NO_x monitor and a CO_2/O_2 diluent monitor have been considered for each alternative emission level. The additional costs for the CEM's are $66,000 for capital costs, $44,000/year for O & M costs, and $53,000/year for annualized costs.[19,20] These additional costs have been added to the NO_x control costs for Level 1 to obtain the cost of NO_x controls with monitors. The baseline control level does not include monitors since they are not commonly required on new small boilers.

5.2.3.1 <u>Natural Gas-Fired Boilers</u>. Table 5-33 presents the costs of NO_x controls for natural gas-fired boilers without monitors. This table presents the capital, O & M, and annualized costs for each of the model boilers using ~~either~~ LEA~~, EGR, or LNB~~ without monitors. All costs are based on a capacity factor of 0.3.

For the 7.3 MW (25 million Btu/hour) heat input firetube boiler, capital cost for LEA control increased by 1.8 percent over the baseline. Baseline costs are the boiler costs without any NO_x controls. Annualized costs for LEA are 0.6 percent lower than baseline boiler costs. The decrease in annualized cost for LEA is due to fuel savings associated with a baseline excess air level of 38 percent and a controlled excess air level of 9 percent.

For the 29.3 MW (100 million Btu/hour) heat input watertube boiler, LEA control increases the baseline boiler capital costs by 0.44 percent. By operating this boiler with LEA, annualized costs are reduced by 1.1 percent due to fuel savings as discussed above.

Detailed costs of NO_x controls for natural gas-fired boilers operating at capacity factors of 0.6 and 0.9 are shown in Tables 5-34 to 5-35. These tables present costs on each capacity factor without CEM's.

TABLE 5-33. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR NATURAL GAS-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M Costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	1.67 (1.84)	430	203	169	372	441
2.9 (10)	FT	LEA	1.07 (1.18)	442	199	170	369	440
2.9 (10)[b]	WT	UNC	1.67 (1.84)	580	203	250	453	546
2.9 (10)[b]	WT	LEA	1.07 (1.18)	592	199	251	450	545
7.3 (25)	FT	UNC	4.17 (4.60)	716	507	224	731	846
7.3 (25)	FT	LEA	3.28 (3.61)	729	498	226	724	841
7.3 (25)[b]	WT	UNC	4.17 (4.60)	966	507	266	773	930
7.3 (25)[b]	WT	LEA	3.28 (3.61)	979	498	268	766	925
14.7 (50)	WT	UNC	8.94 (9.85)	1,460	1,010	268	1,281	1,520
14.7 (50)	WT	LEA	7.45 (8.21)	1,480	997	269	1,270	1,510
29.3 (100)	WT	UNC	19.7 (21.7)	2,280	2,030	353	2,380	2,750
29.3 (100)	WT	LEA	16.7 (18.4)	2,290	1,990	354	2,340	2,720

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; and LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel Direct O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

TABLE 5-34. BOILER AND NO_X CONTROL WITHOUT MONITORS FOR NATURAL GAS-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	3.34 (3.68)	461	405	249	654	726
2.9 (10)	FT	LEA	2.15 (2.37)	473	399	250	649	723
2.9 (10)[b]	WT	UNC	3.34 (3.68)	620	405	371	776	874
2.9 (10)[b]	WT	LEA	2.15 (2.37)	631	399	372	771	870
7.3 (25)	FT	UNC	8.34 (9.20)	778	1,010	330	1,340	1,460
7.3 (25)	FT	LEA	6.56 (7.23)	790	997	333	1,330	1,450
7.3 (25)[b]	WT	UNC	8.34 (9.20)	1,030	1,010	387	1,400	1,560
7.3 (25)[b]	WT	LEA	6.56 (7.23)	1,040	997	393	1,390	1,550
14.7 (50)	WT	UNC	17.9 (19.7)	1,570	2,030	380	2,410	2,660
14.7 (50)	WT	LEA	14.9 (16.4)	1,580	1,990	390	2,380	2,630
29.3 (100)	WT	UNC	39.3 (43.4)	2,470	4,050	510	4,560	4,950
29.3 (100)	WT	LEA	33.4 (36.8)	2,490	3,990	510	4,500	4,890

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; and LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel Direct O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

TABLE 5-35. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR NATURAL GAS-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	5.01 (5.52)	492	608	329	937	1,010
2.9 (10)	FT	LEA	3.22 (3.55)	504	598	330	928	1,010
2.9 (10)[b]	WT	UNC	5.01 (5.52)	659	608	492	1,100	1,200
2.9 (10)[b]	WT	LEA	3.22 (3.55)	671	598	595	1,090	1,190
7.3 (25)	FT	UNC	12.5 (13.8)	839	1,520	430	1,950	2,080
7.3 (25)	FT	LEA	9.83 (10.8)	851	1,500	430	1,930	2,060
7.3 (25)[b]	WT	UNC	12.5 (13.8)	1,100	1,520	510	2,030	2,200
7.3 (25)[b]	WT	LEA	9.83 (10.8)	1,110	1,500	510	2,010	2,180
14.7 (50)	WT	UNC	26.8 (29.6)	1,670	3,040	500	3,540	3,800
14.7 (50)	WT	LEA	22.4 (24.6)	1,690	2,990	510	3,500	3,760
29.3 (100)	WT	UNC	59.0 (65.0)	2,670	6,080	660	6,740	7,150
29.3 (100)	WT	LEA	50.1 (55.2)	2,680	5,980	660	6,640	7,050

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel Direct O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

Table 5-36 summarizes the annualized costs and emissions for natural gas-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Shown in the table are the NO_x control costs including and excluding the costs for monitors.

For all the costs shown, as the boiler capacity factor increases, the annualized cost increases. The costs increase because certain operating costs (e.g., fuel, water, electricity, water disposal) are directly related to capacity factor. Capital costs are not affected by differences in capacity factor.

Annualized costs for Level 1 NO_x control based on LEA are lower than baseline annualized costs for all model boiler sizes operating at the three capacity factors without monitors. This is because LEA operation reduces fuel costs over baseline operation and this reduction in fuel costs is greater than additional annualized capital costs for level 1 control. It should be noted that Level 1 control costs for a 2.9 MW (10 million Btu/hour) heat input boiler operating at 0.9 capacity factor are the same as the baseline costs due to round-off.

When monitor costs are included in the Level 1 control costs, annualized costs for Level 1 control are higher than baseline costs for all model boiler sizes, except for the 29.3 MW (100 million Btu/hour) heat input boiler operating at 0.6 and 0.9 capacity factors. In these two cases, the fuel savings due to LEA are larger than the annualized cost of the monitors.

5.2.3.2 Distillate Oil-Fired Boilers. Table 5-37 presents the costs of NO_x controls for distillate oil-fired boilers without monitors. All costs are based on a capacity factor of 0.3. This table reports similar cost information as Tables 5-33 for the natural gas-fired boilers, except the fuel cost component of the O & M costs is higher for distillate oil than for natural gas. This is because distillate oil is projected to cost more than natural gas on a heat content basis (i.e., $7.60/kJ for distillate oil versus $7.31/kJ for natural gas in EPA Region V).

Since the NO_x control cost algorithms used for distillate oil-fired boilers are the same as those used for natural gas-fired boilers, the cost impacts of using these controls are the same. Control by LEA is the least

TABLE 5-36. VARIATION OF NO_x CONTROL COSTS ON NATURAL GAS-FIRED SMALL BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J ($lb/10^6$ Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)[b]									
Baseline - 60-2 (0.140)	441	441	1.67 (1.84)	726	726	3.34 (3.68)	1,010	1,010	5.01 (5.52)
Level 1 - 38.7 (0.090)	493	440	1.07 (1.18)	776	723	2.15 (2.37)	1,060	1,010	3.22 (3.55)
7.3 MW (25 million Btu/hr)[b]									
Baseline - 60.2 (0.140)	846	846	4.17 (4.60)	1,460	1,460	8.34 (9.20)	2,080	2,080	12.5 (13.8)
Level 1 - 47.3 (0.110)	894	841	3.28 (3.61)	1,500	1,450	6.56 (7.23)	2,110	2,060	9.83 (10.8)
14.7 MW (50 million Btu/hr)									
Baseline - 64.5 (0.150)	1,520	1,520	8.94 (9.85)	2,660	2,660	17.9 (19.7)	3,800	3,800	26.8 (29.6)
Level 1 - 53.8 (0.125)	1,560	1,510	7.45 (8.21)	2,680	2,630	14.9 (16.4)	3,810	3,760	22.4 (24.6)
29.3 MW (100 million Btu/hr)									
Baseline - 71.0 (0.165)	2,750	2,750	19.7 (21.7)	4,950	4,950	39.3 (43.4)	7,150	7,150	59.0 (65.0)
Level 1 - 60.2 (0.140)	2,770	2,720	16.7 (18.4)	4,940	4,890	33.4 (36.8)	7,100	7,050	50.1 (55.2)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Firetube boiler costs are presented only because this boiler size is outside the cost algorithm size range for watertube boilers.

TABLE 5-37. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR DISTILLATE OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	3.28 (3.61)	430	211	169	380	449
2.9 (10)	FT	LEA	2.38 (2.63)	442	207	169	377	448
2.9 (10)[b]	WT	UNC	3.28 (3.61)	581	211	250	461	555
2.9 (10)[b]	WT	LEA	2.38 (2.63)	593	207	251	458	553
7.3 (25)	FT	UNC	8.20 (9.03)	718	526	225	751	866
7.3 (25)	FT	LEA	5.96 (6.57)	731	517	226	743	860
7.3 (25)[b]	WT	UNC	8.20 (9.03)	967	526	267	793	950
7.3 (25)[b]	WT	LEA	5.96 (6.57)	980	517	268	785	944
14.7 (50)	WT	UNC	13.1 (14.5)	1,460	1,050	267	1,320	1,560
14.7 (50)	WT	LEA	9.24 (10.2)	1,480	1,040	268	1,310	1,540

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; and LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel Direct O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

expensive NO_x method used on distillate oil, ~~while FGR control is the most expensive.~~

The capital and annualized costs for NO_x controls without monitors on the largest size distillate oil-fired firetube model boiler (7.3 MW, 25 million Btu/hour, boiler) are essentially the same as the NO_x control costs for the same size natural gas-fired boiler as presented in Table 5-33. Control by LEA increases the uncontrolled boiler capital cost by 1.8 percent. Annualized costs are 0.7 percent less for LEA operation versus a baseline boiler due to fuel savings. Again, this cost savings assumes a baseline excess air level of 38 percent and a controlled excess air level of 9 percent.

The capital and annualized costs for NO_x controls without monitors on the largest size distillate oil-fired watertube boiler [14.7 MW (50 million Btu/hour) boiler] are summarized as follows. The increased capital cost for LEA, is 1.4 percent over that for the baseline. Annualized costs are 1.3 percent less for LEA operation compared to a baseline boiler. The same assumptions regarding excess air levels were used as stated previously.

Detailed costs of NO_x controls for distillate oil-fired boilers operating at capacity factors of 0.6 and 0.9 are shown in Tables 5-38 and 5-39, respectively. These tables present costs at each capacity factor without continuous emission monitors.

Table 5-40 summarizes the annualized costs for distillate oil-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Shown in the table are the NO_x control costs including and excluding the costs for monitors. Also included are the annual emissions which correspond to the given model boiler size and capacity factor. For all the costs shown, as the boiler capacity factor increases, the annualized cost increases due to the increase in O & M costs as discussed above.

The annualized costs for level 1 NO_x control based on LEA are lower than baseline annualized costs for all model boiler sizes operating at the three capacity factors without monitors due to fuel savings. When monitor costs are included in the Level 1 control costs, annualized costs for Level 1 control are higher than baseline costs for all model boiler sizes examined.

TABLE 5-38. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR DISTILLATE OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	6.56 (7.23)	462	421	249	670	742
2.9 (10)	FT	LEA	4.77 (5.26)	474	414	250	664	738
2.9 (10)[b]	WT	UNC	6.56 (7.23)	621	421	371	792	890
2.9 (10)[b]	WT	LEA	4.77 (5.26)	633	414	372	786	885
7.3 (25)	FT	UNC	16.4 (18.1)	781	1,050	330	1,380	1,500
7.3 (25)	FT	LEA	11.9 (13.1)	793	1,040	320	1,360	1,490
7.3 (25)[b]	WT	UNC	16.4 (18.1)	1,030	1,050	390	1,440	1,600
7.3 (25)[b]	WT	LEA	11.9 (13.1)	1,050	1,030	390	1,420	1,590
14.7 (50)	WT	UNC	26.2 (28.9)	1,570	2,100	390	2,490	2,740
14.7 (50)	WT	LEA	18.5 (20.4)	1,590	2,070	390	2,460	2,710

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; and LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel Direct O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

TABLE 5-39. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR DISTILLATE OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT 0.9 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	9.83 (10.8)	494	632	329	961	1,040
2.9 (10)	FT	LEA	7.15 (7.88)	506	621	330	951	1,030
2.9 (10)[b]	WT	UNC	9.83 (10.8)	661	632	488	1,120	1,230
2.9 (10)[b]	WT	LEA	7.15 (7.88)	674	621	489	1,110	1,220
7.3 (25)	FT	UNC	24.6 (27.1)	844	1,580	430	2,010	2,140
7.3 (25)	FT	LEA	17.9 (19.7)	856	1,550	430	1,980	2,110
7.3 (25)[b]	WT	UNC	24.6 (27.1)	1,100	1,580	510	2,090	2,260
7.3 (25)[b]	WT	LEA	17.9 (19.7)	1,110	1,550	510	2,060	2,240
14.7 (50)	WT	UNC	39.3 (43.4)	1,680	3,160	500	3,660	3,920
14.7 (50)	WT	LEA	27.7 (30.6)	1,700	3,110	500	3,610	3,870

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-40. VARIATION OF NO_x CONTROL COSTS ON DISTILLATE OIL-FIRED SMALL BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J ($lb/10^6$ Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)[b]									
Baseline - 118 (0.275)	449	449	3.28 (3.61)	742	742	6.56 (7.23)	1,040	1,040	9.83 (10.8)
Level 1 - 86.0 (0.200)	501	448	2.38 (2.63)	791	738	4.77 (5.20)	1,080	1,030	7.15 (7.88)
7.3 MW (25 million Btu/hr)[b]									
Baseline - 118 (0.275)	866	866	8.20 (9.03)	1,500	1,500	16.4 (18.1)	2,140	2,140	24.6 (27.1)
Level 1 - 86.0 (0.200)	913	860	5.96 (6.57)	1,540	1,490	11.9 (13.1)	2,160	2,110	17.9 (19.7)
14.7 MW (50 million Btu/hr)									
Baseline - 94.6 (0.220)	1,560	1,560	13.1 (14.5)	2,740	2,740	26.2 (28.9)	3,920	3,920	39.3 (43.4)
Level 1 - 66.7 (0.155)	1,600	1,540	9.24 (10.2)	2,760	2,710	18.5 (20.4)	3,920	3,870	27.7 (30.6)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Firetube boiler costs are only presented because this boiler size is outside the cost algorithm size range for watertube boilers.

5.2.3.3 <u>Residual Oil-Fired Boilers</u>. Table 5-41 presents the costs of NO_x controls for residual oil-fired boilers without monitors. This table presents the capital, O & M, and annualized costs for each of the model boilers using LEA.

The table shows that LEA control on residual oil-fired watertube boilers is less expensive than LNB control on a capital and annualized cost basis. The capital and annualized costs for NO_x controls without monitors on a 29.3 MW (100 million Btu/hr) heat input watertube boiler are summarized for LEA.

The increased capital costs over the uncontrolled boiler cost for LEA are 0.9 percent. Annualized costs are 0.8 percent less when operating the 29.3 MW (100 million Btu/hour) heat input boiler with LEA than at the baseline due to fuel savings. These fuel savings are based on a baseline excess air level of 38 percent and a controlled excess air level of 9 percent.

The capital costs for LEA without monitors on a 7.3 MW (25 million Btu/hour) heat input firetube boiler are 3.2 percent more than the boiler costs. However, the annualized costs for LEA are 0.4 percent lower. The lower annualized cost indicates a savings for this boiler using LEA rather than a cost.

Detailed costs of NO_x controls for residual oil-fired boilers operating at capacity factors of 0.6 and 0.9 are shown in Tables 5-42 and 5-43, respectively. These tables present costs at each capacity factor without CEM's.

Table 5-44 summarizes the annualized costs and emissions for residual oil-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Shown in the table are the NO_x control costs including and excluding the costs for monitors. For all the costs shown, as the boiler capacity factor increases, the annualized cost increases due to the increase in O&M costs as discussed above.

Annualized costs for Level 1 NO_x control based on LEA are lower than baseline annualized costs for all model boiler sizes operating at the three capacity factors without monitors due to fuel savings. When monitor costs

TABLE 5-41. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	5.48 (6.04)	439	166	169	335	406
2.9 (10)	FT	LEA	5.07 (5.58)	451	164	169	333	406
7.3 (25)	FT	UNC	13.7 (15.1)	729	416	225	641	758
7.3 (25)	FT	LEA	12.7 (14.0)	742	409	226	635	755
7.3 (25)[b]	WT	UNC	13.7 (15.1)	979	416	266	682	842
7.3 (25)[b]	WT	LEA	12.7 (14.0)	992	409	267	676	838
14.7 (50)[b]	FT	UNC	27.4 (30.2)	1,170	832	264	1,100	1,280
14.7 (50)[b]	FT	LEA	23.8 (26.3)	1,180	818	265	1,080	1,270
14.7 (50)	WT	UNC	27.4 (30.2)	1,470	832	267	1,100	1,340
14.7 (50)	WT	LEA	23.8 (26.3)	1,490	818	268	1,090	1,330
29.3 (100)	WT	UNC	54.8 (60.4)	2,280	1,660	352	2,010	2,390
29.3 (100)	WT	LEA	47.7 (52.6)	2,300	1,640	354	1,990	2,370

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel direct O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-42. BOILER AND NO_X CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr) Fuel	Nonfuel[f]	Total	Annualized costs[g] ($1,000/yr)
2.9 (10)	FT	UNC	11.0 (12.1)	467	333	249	582	655
2.9 (10)	FT	LEA	10.1 (11.2)	479	327	250	577	633
7.3 (25)	FT	UNC	27.4 (30.2)	783	832	328	1,160	1,280
7.3 (25)	FT	LEA	25.3 (27.9)	796	818	332	1,150	1,270
7.3 (25)[b]	WT	UNC	27.4 (30.2)	1,040	832	388	1,220	1,390
7.3 (25)[b]	WT	LEA	25.3 (27.9)	1,050	818	392	1,210	1,370
14.7 (50)[b]	FT	UNC	54.8 (60.4)	1,260	1,660	380	2,040	2,240
14.7 (50)[b]	FT	LEA	47.7 (52.6)	1,270	1,640	380	2,020	2,220
14.7 (50)	WT	UNC	54.8 (60.4)	1,570	1,660	390	2,050	2,300
14.7 (50)	WT	LEA	47.7 (52.6)	1,580	1,640	380	2,020	2,270
29.3 (100)	WT	UNC	110 (121)	2,450	3,330	500	3,830	4,220
29.3 (100)	WT	LEA	95.4 (105)	2,470	3,270	510	3,780	4,170

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-43. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR RESIDUAL OIL-FIRED MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	FT	UNC	496	16.5 (18.1)	499	329	828	905
2.9 (10)	FT	LEA	507	15.2 (16.8)	491	330	821	899
7.3 (25)	FT	UNC	837	41.1 (45.3)	1,250	430	1,680	1,810
7.3 (25)	FT	LEA	849	38.0 (41.9)	1,230	430	1,660	1,790
7.3 (25)[b]	WT	UNC	1,090	41.1 (45.3)	1,250	510	1,760	1,930
7.3 (25)[b]	WT	LEA	1,110	38.0 (41.9)	1,230	510	1,740	1,910
14.7 (50)[b]	FT	UNC	1,350	82.5 (90.7)	2,500	490	2,990	3,200
14.7 (50)[b]	FT	LEA	1,360	71.5 (78.8)	2,450	500	2,950	3,160
14.7 (50)	WT	UNC	1,660	82.3 (90.7)	2,500	500	3,000	3,260
14.7 (50)	WT	LEA	1,670	71.5 (78.8)	2,450	510	2,960	3,220
29.3 (100)	WT	UNC	2,620	165 (181)	4,990	660	5,650	6,060
29.3 (100)	WT	LEA	2,630	143 (158)	4,910	660	5,570	5,980

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]FT = firetube; WT = watertube.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M Costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized Costs = total O & M costs + capital charges.

TABLE 5-44. VARIATION OF NO_x CONTROL COSTS ON RESIDUAL OIL-FIRED SMALL BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb NO_x/10^6 Btu)	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
	Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)			Annualized costs ($1,000/yr)		
	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)	With monitors	Without monitors	Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)[b]									
Baseline - 198 (0.46)	406	406	5.48 (6.04)	655	655	11.1 (12.1)	905	905	16.5 (18.1)
Level 1 - 183 (0.425)	459	406	5.07 (5.58)	706	653	10.1 (11.2)	952	899	15.2 (16.8)
7.3 MW (25 million Btu/hr)[b]									
Baseline - 198 (0.46)	758	758	13.7 (15.1)	1,280	1,280	27.4 (30.2)	1,810	1,810	41.1 (45.3)
Level 1 - 183 (0.425)	808	755	12.7 (14.0)	1,320	1,270	25.3 (27.9)	1,840	1,790	38.0 (41.9)
14.7 MW (50 million Btu/hr)[c]									
Baseline - 198 (0.46)	1,340	1,340	27.4 (30.2)	2,300	2,300	54.8 (60.4)	3,260	3,260	82.3 (90.7)
Level 1 - 172 (0.40)	1,380	1,330	23.8 (26.3)	2,320	2,270	47.7 (52.6)	3,270	3,220	71.5 (78.8)
29.3 MW (100 million Btu/hr)									
Baseline - 198 (0.46)	2,390	2,390	54.8 (60.4)	4,220	4,220	110 (121)	6,060	6,060	165 (181)
Level 1 - 172 (0.40)	2,420	2,370	47.7 (52.6)	4,220	4,170	95.4 (105)	6,030	5,980	143 (158)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

[b]Firetube boiler costs are only presented because this boiler size is outside the cost algorithm size range for watertube boilers.

[c]Watertube boiler costs are only presented because this boiler size is outside the cost algorithm size range for firetube boilers.

are included in the Level 1 control costs, annualized costs for Level 1 are higher than baseline costs for all model boiler sizes, except for the 29.3 MW (100 million Btu/hour) boiler operating at 0.9 capacity factor.

5.2.3.4 Coal-Fired Stoker Boilers. Table 5-45 presents the costs of LEA control for coal-fired stoker boilers without monitors. This table presents the capital, O & M, and annualized costs for each model boiler.

From Table 5-45, the increased capital cost for LEA control without monitors over the baseline boiler cost is 0.7 percent for a 2.9 MW (10 million Btu/hour) heat input stoker and 0.2 percent for a 29.3 MW (100 million Btu/hour) stoker. The increased annualized cost for LEA control is 0.5 percent for a 2.9 MW (10 million Btu/hour) stoker. For a 29.3 MW (100 million Btu/hour) heat input stoker using LEA, annualized costs are the same for LEA and baseline. Annualized costs correspond to baseline and controlled excess air levels are 60 and 35 percent, respectively.

The costs of NO_x controls for coal-fired boilers operating at capacity factors of 0.6 and 0.9 without the costs of continuous emission monitors are presented in Table 5-46 to 5-47, respectively. Table 5-48 summarizes the annualized costs and emissions for coal-fired boilers in Region V operating at capacity factors of 0.3, 0.6, and 0.9. Also shown in the table are the NO_x control costs including and excluding the costs for monitors. For all the costs shown, as the boiler capacity factor increases, the annualized cost increases due to the increase in O & M costs as discussed above.

5.3 OTHER COST CONSIDERATIONS

This section addresses additional costs that may be incurred by boiler operators and/or regulatory agencies, but that have not been addressed in Section 5.2. Additional cost impacts are possible in two areas:

- o boiler liquid and solid waste disposal, and
- o impact of compliance and reporting requirements.

TABLE 5-45. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED STOKER MODEL BOILERS IN EPA REGION V OPERATING AT A 0.3 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	UFS	UNC	4.77 (5.26)	1,470	79	262	341	583
2.9 (10)	UFS	LEA	3.81 (4.20)	1,480	78	263	341	586
7.3 (25)	UFS	UNC	11.9 (13.1)	2,630	197	365	562	998
7.3 (25)	UFS	LEA	9.54 (10.5)	2,650	195	366	561	1,000
14.7 (50)[b]	SS	UNC	23.8 (26.3)	4,690	394	552	946	1,720
14.7 (50)[b]	SS	LEA	19.1 (21.0)	4,710	391	553	944	1,730
22.0 (75)	SS	UNC	59.5 (65.5)	6,750	591	618	1,210	2,330
22.0 (75)	SS	LEA	42.5 (46.8)	6,770	586	619	1,210	2,330
29.3 (100)	SS	UNC	79.3 (87.4)	8,670	788	690	1,480	2,920
29.3 (100)	SS	LEA	56.6 (62.4)	8,690	781	692	1,470	2,920

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]UFS = underfeed stoker; SS = spreader stoker.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-46. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED STOKER MODEL BOILERS IN EPA REGION V OPERATING AT A 0.6 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	UFS	UNC	9.54 (10.5)	1,490	158	373	531	776
2.9 (10)	UFS	LEA	7.63 (8.41)	1,510	156	374	530	778
7.3 (25)	UFS	UNC	23.8 (26.3)	2,680	394	516	910	1,350
7.3 (25)	UFS	LEA	19.1 (21.0)	2,700	391	517	908	1,350
14.7 (50)[b]	SS	UNC	47.7 (52.6)	4,760	788	772	1,560	2,340
14.7 (50)[b]	SS	LEA	38.2 (42.1)	4,780	781	769	1,550	2,340
22.0 (75)	SS	UNC	119 (131)	6,840	1,180	860	2,040	3,170
22.0 (75)	SS	LEA	84.9 (93.6)	6,860	1,170	860	2,030	3,160
29.3 (100)	SS	UNC	159 (175)	8,780	1,580	950	2,530	3,980
29.3 (100)	SS	LEA	113 (125)	8,810	1,560	950	2,510	3,970

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]UFS = underfeed stoker; SS = spreader stoker.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-47. BOILER AND NO_x CONTROL COSTS WITHOUT MONITORS FOR COAL-FIRED STOKER MODEL BOILERS IN EPA REGION V OPERATING AT A 0.9 CAPACITY FACTOR[a]

Boiler size MW (10^6 Btu/hr) heat input	Boiler type[c]	NO_x Control[d]	Annualized emissions Mg/yr (tons/yr)	Capital costs[e] ($1,000)	O & M costs ($1,000/yr)			Annualized costs[g] ($1,000/yr)
					Fuel	Nonfuel[f]	Total	
2.9 (10)	UFS	UNC	14.3 (15.8)	1,520	237	484	721	968
2.9 (10)	UFS	LEA	11.4 (12.6)	1,540	234	485	719	970
7.3 (25)	UFS	UNC	35.8 (39.4)	2,720	591	669	1,260	1,710
7.3 (25)	UFS	LEA	28.6 (31.5)	2,740	586	664	1,250	1,700
14.7 (50)[b]	SS	UNC	71.5 (78.8)	4,830	1,180	990	2,170	2,960
14.7 (50)[b]	SS	LEA	57.2 (63.1)	4,850	1,170	990	2,160	2,960
22.0 (75)	SS	UNC	178 (197)	6,930	1,770	1,100	2,870	4,010
22.0 (75)	SS	LEA	127 (140)	6,960	1,760	1,090	2,850	4,000
29.3 (100)	SS	UNC	238 (262)	8,900	2,370	1,200	3,570	5,040
29.3 (100)	SS	LEA	170 (187)	8,920	2,340	1,210	3,550	5,020

[a]Costs are in 1983 dollars rounded to three significant figures.

[b]These cases were extrapolated outside the range of the industrial boiler cost algorithm.

[c]UFS = underfeed stoker; SS = spreader stoker.

[d]UNC = uncontrolled or baseline; LEA = low excess air.

[e]Capital cost = total turnkey + interest during construction + working capital + land.

[f]Nonfuel O & M costs = direct labor + supervision labor + maintenance labor + spare parts + electricity + water + overhead.

[g]Annualized costs = total O & M costs + capital charges.

TABLE 5-48. VARIATION OF NO_x CONTROL COSTS ON COAL-FIRED SMALL BOILERS WITH CAPACITY FACTOR[a]

Boiler size/ control level, ng/J (lb $NO_x/10^6$ Btu)	Capacity factor = 0.3: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.3: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.3: Annual emissions, Mg/yr (tons/yr)	Capacity factor = 0.6: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.6: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.6: Annual emissions, Mg/yr (tons/yr)	Capacity factor = 0.9: Annualized costs ($1,000/yr) With monitors	Capacity factor = 0.9: Annualized costs ($1,000/yr) Without monitors	Capacity factor = 0.9: Annual emissions, Mg/yr (tons/yr)
2.9 MW (10 million Btu/hr)									
Baseline - 172 (0.40)	583	583	4.77 (5.26)	776	776	9.54 (10.5)	968	968	14.3 (15.8)
Level 1 - 138 (0.32)	639	586	3.81 (4.20)	831	778	7.63 (8.41)	1,020	970	11.4 (12.6)
7.3 MW (25 million Btu/hr)									
Baseline - 172 (0.40)	998	998	11.9 (13.1)	1,350	1,350	23.8 (26.3)	1,710	1,710	35.8 (39.4)
Level 1 - 138 (0.32)	1,050	1,000	9.54 (10.5)	1,410	1,350	19.1 (21.0)	1,750	1,700	28.6 (31.5)
14.7 MW (50 million Btu/hr)									
Baseline - 172 (0.40)	1,720	1,720	23.8 (26.3)	2,340	2,340	47.7 (52.6)	2,960	2,960	71.5 (78.8)
Level 1 - 138 (0.32)	1,780	1,730	19.1 (21.0)	2,390	2,340	38.2 (42.1)	3,010	2,960	57.2 (63.1)
22.0 MW (75 million Btu/hr)									
Baseline - 286 (0.665)	2,330	2,330	59.5 (65.5)	3,170	3,170	119 (131)	4,010	4,010	178 (197)
Level 1 - 204 (0.475)	2,380	2,330	42.5 (46.8)	3,210	3,160	84.9 (93.6)	4,050	4,000	127 (140)
29.3 MW (100 million Btu/hr)									
Baseline - 286 (0.665)	2,920	2,920	79.3 (87.4)	3,980	3,980	159 (175)	5,040	5,040	238 (262)
Level 1 - 204 (0.475)	2,970	2,920	56.6 (62.4)	4,020	3,970	113 (125)	5,070	5,020	170 (187)

[a]All costs are 1995 "first year" costs presented in January 1983 dollars rounded to three significant figures.

The major liquid and solid waste streams from an uncontrolled boiler are: water-softening sludge, condensate blowdown, bottom ash disposal, and coal pile runoff. Bottom ash collection, handling, and disposal costs have been incorporated into the uncontrolled boiler cost estimates. Bottom ash disposal costs were estimated based on a non-hazardous waste classification and RCRA regulations. If boiler wastes are classified as hazardous material in the future, then the disposal costs and overall boiler control costs could increase significantly.

Costs for treating the other three waste streams were not quantitatively evaluated in this study. The costs associated with the disposal problems are highly site-specific, with the following parameters being important:

- Water-softening sludge - raw water quality, steam quality, water makeup rate,
- Condensate blowdown - effluent discharge quality requirements, raw water quality, condensate blowdown quantity, and
- Coal pile runoff - coal quality, meterological conditions, effluent discharge quality requirements.

However, these costs would be associated with the boiler itself and would not affect the analysis of incremental cost impacts of air pollution control techniques.

Impacts of compliance and reporting for industrial boilers have been addressed in a separate study.[21]

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18. Reference 1, p. A-1 to A-34.

19. Reference 14.

20. Reference 15.

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6.0 MODEL BOILER EMISSION IMPACTS

This section presents estimates of the potential emission impacts associated with alternative emission levels for small model steam generators (i.e., boilers). The particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) emission impacts result from the control of emissions from new small boilers with heat inputs of 29.3 MW (100 million Btu/hour) or less to levels below baseline emissions. The emission impacts for the model boilers are presented in terms of total emissions and emission reductions from the baseline for the various types of fuel and boiler size categories.

Section 6.1 discusses the approach used to estimate the potential emission impacts for the model boilers. Section 6.2 presents and discusses the PM, SO_2, and NO_x emission impacts. Emission impacts for PM are presented for natural gas-, oil-, coal-, wood-, and municipal solid waste (MSW)-fired model boilers, while emission impacts for SO_2 and NO_x are presented for natural gas-, oil-, and coal-fired model boilers.

6.1 APPROACH

Emissions of PM and SO_2 associated with each model boiler were calculated for the baseline and two alternative control levels (Level 1 and Level 2). The baseline PM and SO_2 emission rates reflect the level of control typically required by State Implementation Plan (SIP) regulations. Emissions of NO_x associated with each model boiler were calculated for a baseline and one alternative control level (Level 1). Under SIP regulations, NO_x emissions are essentially uncontrolled. Thus, the baseline emission level for NO_x is the uncontrolled level. Detailed discussions of baseline emission levels are contained in Sections 2.2 and 2.3.

Emissions of PM, SO_2, and NO_x for the model boilers can be reduced below baseline levels using various emission control techniques. Level 1 and Level 2 emission levels have been established based on the available test data for these various emission control techniques. Section 4.3 discusses the applicable control techniques for PM, SO_2, and NO_x associated with both levels of control.

6.2 ANALYSIS OF EMISSION IMPACTS

6.2.1 Particulate Matter Control Emission Impacts

Table 6-1 presents the PM emission control levels in ng/J, and percent emission reductions from baseline, for Levels 1 and 2 for the model boilers. The emission levels presented in this table are the same as those presented in Tables 4-2 and 4-3. No PM emission levels are assigned to the natural gas- and distillate oil-fired boilers since these boilers emit negligible quantities of PM. For all the residual oil-fired model boilers, the percent PM emission reductions from baseline for Levels 1 and 2 associated with the assigned PM emission level for each control in Table 6-1 are 55.6 and 77.8 percent, respectively.

The percent PM emission reductions from baseline for each control level varies with boiler size for the coal-fired model boilers. For the two model coal-fired boilers rated at 2.9 and 7.3 MW (10 and 25 million Btu/hour) heat input, the percent PM emission reductions from baseline for Levels 1 and 2 are 44.4 and 88.9 percent, respectively. For the model coal-fired boilers rated above 7.3 MW (25 million Btu/hour) heat input, the percent PM emission reduction from baseline for Levels 1 and 2 are 58.3 and 91.7 percent, respectively. The greater percent PM emission reductions for boilers above 7.3 MW (25 million Btu/hour) heat input are attributed to a higher baseline PM emission level than for boilers less than 7.3 MW (25 million Btu/hour) heat input.

For the wood-fired model boilers, PM emission reductions for Level 1 are 50 percent for the 7.3 MW (25 million Btu/hour) heat input boiler size and 46 percent for the 22 MW (75 million Btu/hour) boiler size. Emission reductions in PM for Level 2 for the wood-fired boilers are 75.0 percent for the 7.3 MW boiler size and 73 percent for the 22 MW (25 million Btu/hour) heat input boiler size. The slightly lower percent emission reductions for the larger wood-fired boilers are attributed to a slightly lower baseline PM emission level for the larger size boiler than for the smaller size boiler.

Emission reductions for PM from MSW-fired boilers using Level 1 control are 66.7 percent for the 7.3 MW (25 million Btu/hour) heat input boiler size

TABLE 6-1. PM EMISSIONS AND CONTROLS FOR BASELINE, LEVEL 1, AND LEVEL 2 FOR SMALL MODEL BOILERS

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Boiler type[e]	Emission levels, ng/J (lb/10^6 Btu) Baseline	Level 1	Level 2	Percent reduction from baseline Level 1	Level 2
Natural Gas/ Distillate Oil	All Sizes	FT, WT	Negligible	Negligible	Negligible	-[f]	-[f]
Residual Oil[a]	All Sizes	FT, WT	77 (0.18)	34 (0.08)	17 (0.04)	55.6	77.8
Coal[b]	2.9 (10)	UFT	194 (0.45)	108 (0.25)	22 (0.05)	44.4	88.9
	7.3 (25)	UFT, UFS, FBC	194 (0.45)	108 (0.25)	22 (0.05)	44.4	88.9
	14.7 (50)	MFS, SS, FBC	258 (0.60)	108 (0.25)	22 (0.05)	58.3	91.7
	22.0 (75)	MFS, SS	258 (0.60)	108 (0.25)	22 (0.05)	58.3	91.7
	29.3 (100)	MFS, SS, FBC	258 (0.60)	108 (0.25)	22 (0.05)	58.3	91.7
Wood[c]	7.3 (25)	OFS	172 (0.40)	86 (0.20)	43 (0.10)	50.0	75.0
	22.0 (75)	SS	159 (0.37)	86 (0.20)	43 (0.10)	46.0	73.0
MSW[d]	7.3 (25)	SMI	129 (0.30)	43 (0.10)	22 (0.50)	66.7	83.3
	22.0 (75)	SS	73 (0.17)	43 (0.10)	22 (0.50)	41.2	70.6

[a]Baseline, Level 1, and Level 2 PM emissions from residual oil reflect the uncontrolled PM emissions predicted by AP-42 correlation for oil sulfur contents corresponding to SO_2 emissions in Table 6-4.

[b]Baseline PM emissions from coal reflect the performance of mechanical collectors applied to spreader stokers (258 ng/J) and underfeed stokers (194 ng/J). Levels 1 and 2 represent the use of side stream separators and fabric filters, respectively.

[c]Baseline PM emissions from wood reflect the average SIP levels in the nonfossil fuel-fired boiler BID.[1] Levels 1 and 2 represent the performance of a low ΔP scrubber and high ΔP scrubber or ESP, respectively.

[d]Baseline PM emissions reflect the uncontrolled PM emissions from small modular incinerators and the performance of an electrostatic precipitator (ESP) with an SCA of 160 $ft^2/10^3$ acfm applied to spreader stokers. Levels 1 and 2 represent the use of an ESP with SCA's of 250 and 370 $ft^2/10^3$ acfm, respectively.

[e]FT = firetube; WT = watertube; UFT = underfeed firetube; UFS = underfeed stoker, FBC = fluidized bed combustor; MFS = massfeed stoker; OFS = overfeed stokers; SS = spreader stokers; and SMI = small modular incinerator.

[f]Percent reductions for natural gas- and distillate oil-fired boilers are not applicable.

and 41.2 percent for the 22 MW (75 million Btu/hour) boiler size. For Level 2, PM emission reductions from baseline are 83.3 percent for the 7.3 MW (25 million Btu/hour) heat input boiler size and 70.6 percent for the 22 MW (75 million Btu/hour) boiler size. As discussed above for wood-fired boilers, the larger MSW-fired boiler showed a slightly lower reduction due to lower baseline emissions.

Table 6-2 presents annual PM emissions for baseline, Level 1 and Level 2 controls on a megagram per year basis for the model boilers operating at capacity factors of 0.3, 0.6, and 0.9. Excluding the natural gas- and distillate oil-fired PM emissions, this table shows that PM emissions at each control level increase as the capacity factor increases. Within a fuel type category, PM emissions for each control level also increase as the boiler size increases. Table 6-3 presents the PM emission reductions from baseline for Levels 1 and 2 in terms of megagrams per year. The PM emission reductions presented in Table 6-3 follow the same trends as discussed above for the annual PM emissions.

6.2.2 Sulfur Dioxide Control Emission Impacts

Table 6-4 presents the SO_2 emission control levels in ng/J, and the percent emission reductions from baseline, for Levels 1 and 2 for the model boilers. The emission levels presented in this table are the same as those presented in Table 4-4. It should be noted that these SO_2 emission levels are based on the average sulfur contents of classes of coals which can be used to meet specified emission limits. A range of sulfur contents is associated with each coal class.

For the natural gas- and distillate oil-fired boilers, no SO_2 levels are assigned because these boilers emit negligible amounts of SO_2. Based on SO_2 emission levels characteristic of residual oil-fired boilers, SO_2 emission reductions from baseline for Levels 1 and 2 are 66 and 87.2 percent, respectively. Emission reductions from baseline for Levels 1 and 2 for coal are 66.7 and 80.7 percent, respectively.

TABLE 6-2. ANNUAL PM EMISSIONS FOR BASELINE, LEVEL 1, AND LEVEL 2 CONTROLS FOR MODEL BOILERS IN MEGAGRAMS PER YEAR (TONS PER YEAR)

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
		Baseline	Level 1	Level 2	Baseline	Level 1	Level 2	Baseline	Level 1	Level 2
Natural gas/ Distillate oil	All Sizes	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Residual oil	2.9 (10)	2.1 (2.4)	1.0 (1.1)	0.45 (0.50)	4.3 (4.7)	1.9 (2.1)	1.0 (1.1)	6.4 (7.1)	2.9 (3.2)	1.4 (1.6)
	7.3 (25)	5.4 (5.9)	2.4 (2.6)	1.2 (1.3)	10.7 (11.8)	4.8 (5.3)	2.4 (2.6)	16.1 (17.7)	7.2 (7.9)	3.6 (3.9)
	14.7 (50)	10.7 (11.8)	4.8 (5.3)	2.4 (2.6)	21.5 (23.7)	9.5 (10.5)	4.8 (5.3)	32.2 (35.5)	14.3 (15.8)	7.2 (7.9)
	22.0 (75)	16.1 (17.7)	7.2 (7.9)	3.6 (3.9)	32.2 (35.5)	14.3 (15.8)	7.2 (7.9)	48.3 (53.2)	21.5 (23.7)	10.7 (11.8)
	29.3 (100)	21.5 (23.7)	9.5 (10.5)	4.8 (5.3)	42.9 (47.3)	19.1 (21.0)	9.5 (10.5)	64.4 (71.0)	28.6 (31.5)	14.3 (15.8)
Coal	2.9 (10)	5.4 (5.9)	3.0 (3.3)	0.6 (0.7)	10.7 (11.8)	6.0 (6.6)	1.2 (1.3)	16.1 (17.7)	8.9 (9.9)	1.8 (2.0)
	7.3 (25)	13.4 (14.8)	7.5 (8.2)	1.5 (1.6)	26.8 (29.6)	14.9 (16.4)	3.0 (3.3)	40.2 (44.3)	22.4 (24.6)	4.5 (4.9)
	14.7 (50)	35.8 (39.4)	14.9 (16.4)	3.0 (3.3)	71.5 (78.7)	29.8 (32.9)	6.0 (6.6)	107 (118)	44.7 (49.3)	8.9 (9.9)
	22.0 (75)	53.6 (59.1)	22.4 (24.6)	4.5 (4.9)	107 (118)	44.7 (49.3)	8.9 (9.9)	161 (177)	67.1 (73.9)	13.4 (14.8)
	29.3 (100)	71.5 (78.8)	29.8 (32.9)	6.0 (6.6)	143 (158)	59.6 (65.7)	11.9 (13.1)	215 (236)	89.4 (98.6)	17.9 (19.7)
Wood	7.3 (25)	11.9 (13.1)	6.0 (6.6)	3.0 (3.3)	23.8 (26.2)	12.0 (13.2)	6.0 (6.6)	35.7 (39.3)	18.0 (19.8)	9.0 (9.9)
	22.0 (75)	33.1 (36.5)	17.9 (19.7)	9.0 (9.9)	66.4 (73.0)	35.8 (39.4)	18.0 (19.8)	99.1 (109)	53.7 (59.1)	27.0 (29.7)
MSW	7.3 (25)	8.9 (9.9)	3.0 (3.3)	1.5 (1.6)	17.9 (19.7)	6.0 (6.6)	3.0 (3.3)	26.8 (29.6)	8.9 (9.9)	4.5 (4.9)
	22.0 (75)	15.2 (16.8)	8.9 (9.9)	4.5 (4.9)	30.4 (33.5)	17.9 (19.7)	8.9 (9.9)	45.6 (50.3)	26.8 (29.6)	13.4 (14.8)

TABLE 6-3. LEVELS 1 AND 2 PM EMISSION REDUCTIONS FOR SELECTED MODEL BOILERS

IN MEGAGRAMS PER YEAR (TONS PER YEAR)[a]

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3		Capacity factor = 0.6		Capacity factor = 0.9	
		Level 1	Level 2	Level 1	Level 2	Level 1	Level 2
Natural gas/ Distillate oil	All Sizes	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Residual oil	2.9 (10)	1.2 (1.3)	1.7 (1.8)	2.4 (2.6)	3.3 (3.7)	3.6 (3.9)	5.0 (5.5)
	7.3 (25)	3.0 (3.3)	4.2 (4.6)	6.0 (6.6)	8.3 (9.2)	8.9 (9.9)	12.5 (13.8)
	14.7 (50)	6.0 (6.6)	8.3 (9.2)	11.9 (13.1)	16.7 (18.4)	17.9 (19.7)	25.0 (27.6)
	22.0 (75)	8.9 (9.9)	12.5 (13.8)	17.9 (19.7)	25.0 (27.6)	26.8 (29.6)	37.5 (41.4)
	29.3 (100)	11.9 (13.1)	16.7 (18.4)	23.8 (26.3)	33.4 (36.8)	35.8 (39.4)	50.1 (55.2)
Coal	2.9 (10)	2.4 (2.6)	4.8 (5.3)	4.8 (5.3)	9.5 (10.5)	7.2 (7.9)	14.3 (15.8)
	7.3 (25)	6.0 (6.6)	11.9 (13.1)	11.9 (13.1)	23.8 (26.3)	17.9 (19.7)	35.8 (39.4)
	14.7 (50)	20.9 (23.0)	32.8 (36.1)	41.7 (46.0)	65.6 (72.2)	62.6 (69.0)	98.3 (108)
	22.0 (75)	31.3 (34.5)	49.2 (54.2)	62.6 (69.0)	98.3 (108)	93.9 (104)	148 (163)
	29.3 (100)	41.7 (46.0)	65.6 (72.3)	83.4 (92.0)	131 (145)	125 (138)	197 (210)
Wood	7.3 (25)	5.9 (6.5)	8.9 (9.8)	11.8 (13.0)	17.8 (19.6)	17.7 (19.5)	26.7 (29.4)
	22.0 (75)	15.2 (16.8)	24.1 (26.6)	30.6 (33.6)	48.4 (53.2)	45.4 (49.9)	72.1 (79.3)
MSW	7.3 (25)	5.9 (6.6)	7.4 (8.3)	11.9 (13.1)	14.9 (16.4)	17.9 (19.7)	22.3 (24.7)
	22.0 (75)	6.3 (6.9)	10.7 (11.9)	12.5 (13.8)	21.5 (23.6)	18.8 (20.7)	32.2 (35.5)

[a]Because of roundoff errors, percent emission reductions from baseline which can be calculated from this table and Table 6-2 do not exactly agree with the percent reductions reported in Table 6-1.

TABLE 6-4. SO_2 EMISSIONS AND CONTROLS FOR BASELINE, LEVEL 1, AND LEVEL 2 FOR SMALL MODEL BOILERS

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Boiler type[c]	Emission levels, ng/J (lb/10^6 Btu)			Percent reduction from baseline	
			Baseline	Level 1	Level 2	Level 1	Level 2
Natural gas/ distillate oil	All Sizes	FT, WT	Negligible	Negligible	Negligible	-	-
Residual oil[a]	All Sizes	FT, WT	1,011 (2.35)	344 (0.8)	129 (0.30)	66.0	87.2
Coal[b]	All Sizes	All Types	1,226 (2.85)	409 (0.95)	237 (0.55)	66.7	80.7

[a]Baseline SO_2 emissions from residual oil reflect the actual representative State fuel consumption weight-averaged SIP emission limit (fuel sulfur contents for a class of oil are less variable than for a class of coal). Levels 1 and 2 represent the use of low sulfur oil and FGD or very low sulfur oil, respectively.

[b]Baseline SO_2 emissions from coal reflect the average fuel sulfur content of a class of coal that would consistently meet a representative SIP emission level of 1,462 ng/J or 3.4 lb/10^6 Btu (determined by weight-averaging individual SIP levels with their respective State's commercial/industrial fuel consumption). Level 1 represents the use of low sulfur coal without including variability. Level 2 represents 90 percent SO_2 scrubbing using a high sulfur coal (5.54 lb SO_2/10^6 Btu).

[c]FT = firetube; WT = watertube.

Table 6-5 presents annual SO_2 emissions for baseline, Level 1, and Level 2 controls on a megagram per year basis for the model boilers operating at capacity factors of 0.3, 0.6, and 0.9. This table shows that SO_2 emissions for residual oil- and coal-fired boilers at each control level increase as the capacity factor increases. Within the same fuel type category, SO_2 emissions for each control level also increase as the boiler size increases. Table 6-6 presents the SO_2 emission reductions from baseline for Levels 1 and 2 in terms of megagrams per year. The SO_2 emission reductions in Table 6-6 follow the same trends as discussed above for the annual SO_2 emissions.

6.2.3 Nitrogen Oxides Control Emission Impacts

Table 6-7 presents NO_x emission control levels in ng/J, and the percent emission reductions from baseline, for Level 1 for the model boilers. The emission levels presented in this table are the same as those presented in Table 4-5. For the natural gas-fired boilers, NO_x emission reductions from baseline for Level 1 ranged from 15.2 percent for the 29.3 MW (100 million Btu/hour) heat input boiler to 35.7 percent for the 2.9 MW (10 million Btu/hour) boiler.

Level 1 NO_x emission reductions from baseline for the distillate oil-fired model boilers ranged from 27.3 percent for both the 2.9 MW (10 million Btu/hour) and 7.3 MW (25 million Btu/hour) heat input boilers to 29.3 percent for the 14.7 MW (50 million Btu/hour) boiler.

For the residual oil-fired boilers using Level 1 control, NO_x emission reductions ranged from 7.6 percent for the 2.9 MW (10 million Btu/hour) heat input boiler to 13.0 percent of for the 29.3 MW (100 million Btu/hour) boiler.

For the coal-fired boilers, the emission reductions from baseline for Level 1 control range from 20.0 percent for the 2.9 MW (10 million Btu/hour) heat input boiler to 28.6 percent for the 29.3 MW (100 million Btu/hour) boiler.

TABLE 6-5. ANNUAL SO_2 EMISSIONS FOR BASELINE, LEVEL 1, AND LEVEL 2 CONTROLS FOR MODEL BOILERS IN MEGAGRAMS PER YEAR (TONS PER YEAR)

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3			Capacity factor = 0.6			Capacity factor = 0.9		
		Baseline	Level 1	Level 2	Baseline	Level 1	Level 2	Baseline	Level 1	Level 2
Natural gas/ Distillate oil	All Sizes	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Residual oil	2.9 (10)	28.0 (30.9)	9.5 (10.5)	3.6 (3.9)	56.0 (61.8)	19.1 (21.0)	7.2 (7.9)	84.0 (92.6)	28.6 (31.5)	10.7 (11.8)
	7.3 (25)	70.0 (77.2)	23.8 (26.3)	8.9 (9.9)	140 (154)	47.7 (52.6)	17.9 (19.7)	210 (232)	71.5 (78.8)	26.8 (29.6)
	14.7 (50)	140 (154)	47.7 (52.6)	17.9 (19.7)	280 (309)	95.4 (105)	35.8 (39.4)	420 (463)	143 (158)	53.6 (59.1)
	29.3 (100)	280 (309)	95.4 (105)	35.8 (39.4)	560 (618)	191 (210)	71.5 (78.8)	840 (926)	286 (315)	107 (118)
Coal	2.9 (10)	34.0 (37.4)	11.3 (12.5)	6.6 (7.2)	67.9 (74.9)	22.6 (25.0)	13.1 (14.5)	102 (112)	34.0 (37.4)	19.7 (21.7)
	7.3 (25)	84.9 (93.6)	28.3 (31.2)	16.4 (18.1)	170 (187)	56.6 (62.4)	32.8 (36.1)	255 (281)	84.9 (93.6)	49.2 (54.2)
	14.7 (50)	169.9 (187.2)	56.6 (62.4)	32.8 (36.1)	340 (374)	113 (125)	65.6 (72.3)	510 (562)	170 (187)	98.3 (108)
	22.0 (75)	254.8 (280.9)	84.9 (93.6)	49.2 (54.2)	510 (562)	170 (187)	98.3 (108)	765 (843)	255 (281)	148 (163)
	29.3 (100)	339.7 (374.5)	113.2 (124.8)	65.6 (72.3)	680 (749)	227 (250)	131 (145)	1,019 (1,123)	340 (374)	197 (217)

TABLE 6-6. LEVELS 1 AND 2 SO_2 EMISSION REDUCTIONS FOR SELECTED MODEL BOILERS IN MEGAGRAMS PER YEAR (TONS PER YEAR)[a]

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3		Capacity factor = 0.6		Capacity factor = 0.9	
		Level 1	Level 2	Level 1	Level 2	Level 1	Level 2
Natural gas/ Distillate oil	All Sizes	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Residual oil	2.9 (10)	18.5 (20.4)	24.4 (26.9)	37.0 (40.7)	48.9 (53.9)	55.4 (61.1)	73.3 (80.8)
	7.3 (25)	46.2 (50.9)	61.1 (67.3)	92.4 (102)	122 (135)	139 (153)	183 (202)
	14.7 (50)	92.4 (102)	122 (135)	185 (204)	244 (269)	277 (305)	367 (404)
	29.3 (100)	185 (204)	244 (269)	370 (407)	489 (539)	554 (611)	733 (808)
Coal	2.9 (10)	22.6 (25.0)	27.4 (30.2)	45.3 (49.9)	54.8 (60.4)	67.9 (74.9)	82.3 (90.7)
	7.3 (25)	56.6 (62.4)	68.5 (75.6)	113 (125)	137 (151)	170 (187)	206 (227)
	14.7 (50)	113 (125)	137 (151)	226 (250)	274 (302)	340 (375)	411 (453)
	22.0 (75)	170 (187)	207 (227)	340 (374)	411 (453)	510 (562)	617 (680)
	29.3 (100)	227 (250)	274 (302)	453 (499)	548 (604)	680 (749)	823 (907)

[a]Because of roundoff errors, percent emission reductions from baseline which can be calculated from this table and Table 6-5 do not exactly agree with the percent reductions reported in Table 6-4.

TABLE 6-7. BASELINE AND LEVEL 1 NO_X EMISSIONS FOR SMALL MODEL BOILERS

Fuel	Model boiler size, MW (10^6 Btu/hr) heat input	Model boiler type[a]	NO_x Emissions, ng/J (lb/10^6 Btu)		Percent reduction from baseline
			Baseline[b]	Level 1[c]	Level 1
Natural gas	2.9 (10)	FT	60.2 (0.140)	38.7 (0.090)	35.7
	7.3 (25)	FT	60.2 (0.140)	47.3 (0.110)	21.4
	14.7 (50)	WT	64.5 (0.150)	53.8 (0.125)	16.7
	29.3 (100)	WT	71.0 (0.165)	60.2 (0.140)	15.2
Distillate oil	2.9 (10)	FT	118 (0.275)	86.0 (0.200)	27.3
	7.3 (25)	FT	118 (0.275)	86.0 (0.200)	27.3
	14.7 (50)	WT	94.6 (0.220)	66.7 (0.155)	29.5
Residual oil	2.9 (10)	FT	198 (0.460)	183 (0.425)	7.6
	7.3 (25)	FT/WT	198 (0.460)	183 (0.425)	7.6
	14.7 (50)	WT	198 (0.460)	172 (0.40)	13.0
	29.3 (100)	WT	198 (0.460)	172 (0.40)	13.0
Coal	2.9 (10)	UFS	172 (0.400)	138 (0.320)	20.0
	7.3 (25)	UFS	172 (0.400)	138 (0.320)	20.0
	14.7 (50)	OFS	172 (0.400)	138 (0.320)	20.0
	22.0 (75)	SS	286 (0.665)	204 (0.475)	28.6
	29.3 (100)	SS	286 (0.665)	204 (0.475)	28.6

[a] FT = Firetube; WT = Watertube; UFS = Underfeed Stoker; OFS = Overfeed Stoker; and SS = Spreader Stoker.

[b] Baseline NO_x emissions of natural gas- and oil-fired boilers were determined from analysis of small boiler NO_x datasets at 6 percent O_2. For coal-fired small boilers, baseline NO_x emissions were determined at 60 percent excess air (7.8 percent O_2).

[c] Level 1 NO_x emissions of natural gas- and oil-fired boilers are based on LEA control at 2 percent O_2 from NO_x emissions datasets on small boilers. For coal-fired small boilers, Level 1 NO_x emissions are based on NO_x emission data at 35 percent excess air (5.4 percent O_2).

Table 6-8 presents annual NO_x emissions for baseline and Level 1 control on megagrams per year basis for the model boilers operating at capacity factors of 0.3, 0.6, and 0.9. This table shows that NO_x emissions at each control level increase as the capacity factor increases. Within the same fuel type category, NO_x emissions for each control level also increase as the boiler size increases. Table 6-9 presents the NO_x emission reductions from baseline for Level 1 in terms of megagrams per year. The NO_x emission reductions in Table 6-9 follow the same trends as discussed above for the annual NO_x emissions.

TABLE 6-8. ANNUAL NO_X EMISSIONS FOR BASELINE AND LEVEL 1 CONTROL FOR MODEL BOILERS IN MEGAGRAMS PER YEAR (TONS PER YEAR)

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3		Capacity factor = 0.6		Capacity factor = 0.9	
		Baseline	Level 1	Baseline	Level 1	Baseline	Level 1
Natural gas	2.9 (10)	1.67 (1.84)	1.07 (1.18)	3.34 (3.68)	2.15 (2.37)	5.01 (5.52)	3.22 (3.55)
	7.3 (25)	4.17 (4.60)	3.28 (3.61)	8.34 (9.20)	6.56 (7.23)	12.5 (13.8)	9.83 (10.8)
	14.7 (50)	8.94 (9.85)	7.45 (8.21)	17.9 (19.7)	14.9 (16.4)	26.8 (29.6)	22.4 (24.6)
	29.3 (100)	19.7 (21.7)	16.7 (18.4)	39.3 (43.4)	33.4 (36.8)	59.0 (65.0)	50.1 (55.2)
Distillate oil	2.9 (10)	3.28 (3.61)	2.38 (2.63)	6.56 (7.23)	4.77 (5.26)	9.83 (10.8)	7.15 (7.88)
	7.3 (25)	8.20 (9.03)	5.96 (6.57)	16.4 (18.1)	11.9 (13.1)	24.6 (27.1)	17.9 (19.7)
	14.7 (50)	13.11 (14.45)	9.24 (10.2)	26.2 (28.9)	18.5 (20.4)	39.3 (43.4)	27.7 (30.6)
Residual oil	2.9 (10)	5.48 (6.04)	5.07 (5.58)	11.0 (12.1)	10.1 (11.2)	16.5 (18.1)	15.2 (16.8)
	7.3 (25)	13.7 (15.1)	12.7 (14.0)	27.4 (30.2)	25.3 (27.9)	41.1 (45.3)	38.0 (41.9)
	14.7 (50)	27.4 (30.2)	23.8 (26.3)	54.8 (60.4)	47.7 (52.6)	82.3 (90.7)	71.5 (78.8)
	29.3 (100)	54.8 (60.4)	47.7 (52.6)	110 (121)	95.4 (105)	165 (181)	143 (158)
Coal	2.9 (10)	4.77 (5.26)	3.81 (4.20)	9.54 (10.5)	7.63 (8.41)	14.3 (15.8)	11.4 (12.6)
	7.3 (25)	11.9 (13.1)	9.54 (10.5)	23.8 (26.3)	19.1 (21.0)	35.8 (39.4)	28.6 (31.5)
	14.7 (50)	23.8 (26.3)	19.1 (21.0)	47.7 (52.6)	38.2 (42.1)	71.5 (78.8)	57.2 (63.0)
	22.0 (75)	59.5 (65.5)	42.5 (46.8)	119 (131)	84.9 (93.6)	178 (197)	127 (140)
	29.3 (100)	79.3 (87.4)	56.6 (62.4)	159 (175)	113 (125)	238 (262)	170 (187)

TABLE 6-9. LEVEL 1 NO_x EMISSION REDUCTIONS FOR SELECTED MODEL BOILERS IN MEGAGRAMS PER YEAR (TONS PER YEAR)[a]

Fuel	Boiler size, MW (10^6 Btu/hr) heat input	Capacity factor = 0.3	Capacity factor = 0.6	Capacity factor = 0.9
Natural gas	2.9 (10)	0.60 (0.66)	1.19 (1.31)	1.79 (1.97)
	7.3 (25)	0.89 (0.99)	1.79 (1.97)	2.68 (2.96)
	14.7 (50)	1.49 (1.64)	2.98 (3.28)	4.47 (4.93)
	29.3 (100)	2.98 (3.29)	5.96 (6.57)	8.94 (9.85)
Distillate oil	2.9 (10)	0.89 (0.99)	1.79 (1.97)	2.68 (2.96)
	7.3 (25)	2.24 (2.46)	4.47 (4.93)	6.71 (7.39)
	14.7 (50)	3.87 (4.27)	7.75 (8.54)	11.6 (12.8)
Residual oil	2.9 (10)	0.42 (0.46)	0.83 (0.92)	1.25 (1.38)
	7.3 (25)	1.04 (1.15)	2.09 (2.30)	3.13 (3.45)
	14.7 (50)	3.58 (3.94)	7.15 (7.88)	10.7 (11.8)
	29.3 (100)	7.15 (7.88)	14.3 (15.8)	21.5 (23.7)
Coal	2.9 (10)	0.95 (1.05)	1.91 (2.10)	2.86 (3.15)
	7.3 (25)	2.38 (2.63)	4.77 (5.26)	7.15 (7.88)
	14.7 (50)	4.77 (5.26)	9.54 (10.5)	14.3 (15.8)
	22.0 (75)	17.0 (18.7)	34.0 (37.5)	51.0 (56.2)
	29.3 (100)	22.7 (25.0)	45.3 (49.9)	68.0 (74.9)

[a]Because of roundoff errors, percent emission reductions from baseline which can be calculated from this table and Table 6-8 do not exactly agree with the percent reductions reported in Table 6-7.

6.3 REFERENCES

1. U.S. Environmental Protection Agency. Nonfossil Fuel-Fired Industrial Boilers - Background Information. Research Triangle Park, N.C. Publication No. EPA 450/3-82-007. March 1982. p. 3-73 and 3-74.