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Nitrogen Oxide Control for Stationary Combustion Sources

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Nitrogen Oxide Control for Stationary Combustion Sources

Notice

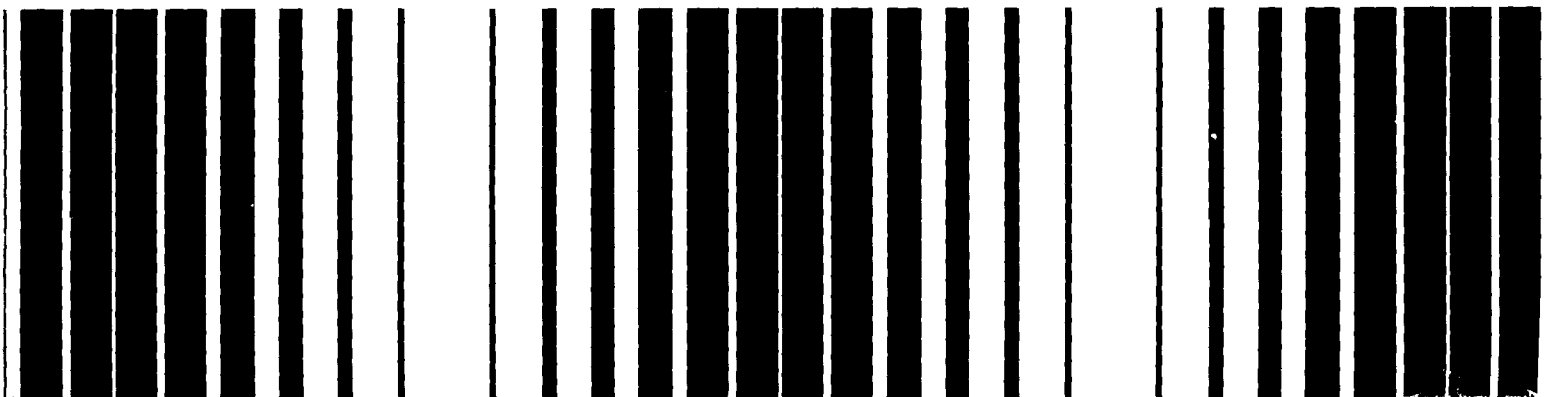This document has been reviewed in accordance with the U.S. Environmental Protection Agency's peer and administrative review policies and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

Contents

Figures

Figures (continued)

Tables

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Chapter 1

Introduction

1.1 Background

Nitrogen dioxide is a criteria pollutant under the Clean Air Act. Accordingly, nitrogen oxide emissions (notably nitrogen dioxide and nitric oxide, usually referred to as NO_x) are considered a major environmental concern. Most NO_x emissions result from fossil fuel combustion. *Mobile* sources of combustion, mainly motor vehicles and aircraft, contributed about 45 percent of total 1980 NO_x emissions nationwide.(1) *Stationary* sources, contributing about 55 percent, are covered in detail in this document.(1) Table 1-1 characterizes NO_x emissions from stationary sources.

Table 1-1. Stationary Sources of NO_x (1)

Source	Approximate No. of Sources	Appropriate Size Range MW	Total NO_x, %
Utility boilers	2,000	40-1,000	53
Industrial boilers	6,000	10-200	14
Gas turbines		10-1,000	2
Stationary engines		0-0.1	20
Miscellaneous			11
Total			100

This document covers the first four sources listed in Table 1-1, which together represent about 90 percent of all stationary source emissions of NO_x. This provides in one publication the basic information needed by managers and others who are involved with the major stationary sources of NO_x emissions to make prudent decisions for controlling these emissions to meet applicable regulations. The document provides a technology overview for managers of power plants and other stationary sources; state and local air pollution agency personnel charged with monitoring the compliance status of sources; and vendors and consultants actively engaged in developing equipment, systems, and approaches for reducing stationary source emissions of NO_x. The goal is not necessarily to provide all the information necessary to make a final decision on a means of NO_x control, but rather to present the available options with a brief assessment of the achievable results and, where it exists, the cost of the options.

1.2 NO_x Emission Regulations

The development of control technologies for stationary sources of NO_x has, in large measure, resulted in emis-

sion regulations for new sources that are based on the reduction achievable by these demonstrated technologies. In order to fully appreciate the later discussions of these technologies it is appropriate to review the regulations that must be met by the various source categories.

Utility boilers, which represent the largest stationary source sector, have been regulated at the Federal level since 1971. The New Source Performance Standards (NSPS) have since been revised as shown in Table 1-2, which lists the NO_x requirements of the 1978 NSPS. Note that the highest emission limits are for coal, reflecting the relative difficulty of NO_x removal from coal burning as discussed in detail later in this document. Note also that emission limitations for synthetic fuels are in general higher than for their fossil fuel counterparts due to the higher fuel nitrogen content.

Table 1-2. New Source Performance Standards for NO_x Emissions from Utility Boilers[a,b]

Fuel	Emission Limit, ng/J (lb/10⁶ Btu)
Bituminous and anthracite coal, certain lignites, and solid fuels not elsewhere classified[c,d]	260 (0.60)
Subbituminous coal and coal-derived fuel	210 (0.50)
Distillate and residual oil	130 (0.30)
Coal-derived oil and shale oil	210 (0.50)
Natural gas	86 (0.20)
Coal-derived gas	210 (0.50)

[a]Source: 40 CFR, Part 60, Subpart Da.
[b]Applies to units for which construction commenced after September 18, 1978, and which are capable of combusting more than 73 MW (250 x 10⁶ Btu/h).
[c]Lignites meeting certain conditions of source and type of combustion have an emission limit of 340 (0.80).
[d]Solid fuels containing more than 25 weight percent coal refuse are exempt from the NO_x standard.

The relative stringency of the 1978 NSPS is largely responsible for the recent efforts to develop so-called low NO_x burners, which constitute a major control technology, as discussed later, and which are designed to significantly reduce NO_x emissions. Also because of these requirements, most of the results presented in later sections are in terms of percent reduction of NO_x. An NSPS for particulate matter and NO_x was proposed for industrial boilers in June 1984 (Table 1-3).

1

Under a court order, EPA is required to promulgate regulations by November 1986. Industrial boilers that were placed in operation after June 1984 are subject to the standards. Again the limitations vary with fuel type and, in this case, within fuel type by method of combustion or fuel nitrogen content. The final regulation may differ from that summarized in Table 1-3 but is expected to be applied retroactively to June 1984.

Table 1-3.   Proposed New Source Performance Standards for NO_x Emissions from Industrial Boilers[a,b,c]

Fuel	Emission Limit, ng/J (lb/10⁶ Btu)
Coal, pulverized	301 (0.70)
Coal, mass-feed stoker	215 (0.50)
Coal, spreader stoker and fluidized bed and certain lignites[d]	258 (0.60)
Distillate oil	43 (0.10)
Residual oil > 0.35 weight percent nitrogen	172 (0.40)
Residual oil ≤ 0.35 weight percent nitrogen	129 (0.30)
Natural gas	43 (0.10)
Mixtures of natural gas or distillate oil with wood or solid waste	129 (0.30)

[a]Source: 40 CFR, Part 60, Subpart Db.
[b]Applies to units for which construction commenced after June 19, 1984, and which are capable of combusting more than 29 MW (100 x 10⁶ Btu/h).
[c]The standard includes a formula for the emission limit for mixtures of coal, oil, or natural gas with any other fuel except the special category of lignite.
[d]Lignites meeting certain conditions of source and type of combustion have an emission limit of 340 (0.80).

The NSPS for stationary gas turbines, as shown in Table 1-4, is more complicated than the new source standards for boilers. NO_x emission limitations under this standard are determined by one of two formulas depending on the size of the unit, with a stricter limit for larger turbines. Each formula includes an allowance for heat rate (the lower the heat rate, the greater the allowable emissions) and a term (F) for nitrogen content. Note that F applies for fuel nitrogen contents greater than 0.015 percent and varies as a gradually increasing function of nitrogen content (N) up to N = 0.25, above which F is constant at 0.005.

The control of NO_x emissions from stationary sources may also be regulated at the Federal level by the Prevention of Significant Deterioration (PSD) and Emission Offset (EO) programs. Under PSD, siting a new source may be contingent upon meeting specified air quality impact limits. Therefore, if the ambient NO_x concentration attributable to a source is limited, an effective limit is placed on the actual emissions from that source. Under EO, the NO_x emissions from a source may be voluntarily controlled to a stringent level in order to qualify for a less stringent emission limitation for another source in the same area. In either case, NO_x control technologies as efficient as those required by NSPS regulations will be required.

Furthermore, state and local air pollution control agencies may regulate NO_x emissions in areas which are in nonattainment of the National Ambient Air Quality Standard (NAAQS) or to assure that the standards are met in the future. For example, some of the air quality management districts in the State of California are currently enforcing utility and industrial boiler standards which are more stringent than the Federal NSPS. In addition, several states — including Texas, Florida, and New York — are employing an industrial boiler regulation for existing sources that is equivalent to the proposed industrial boiler NSPS.

Table 1-4.   New Source Performance Standards for Stationary Gas Turbines[a]

Type Turbine	Allowable Emissions Vol. % NO_x @ 15% O_2, Dry[b]		
Electric utility units with a heat input at peak load of > 107.2 GJ (100 x 10⁶ Btu) per hour	0.0075	$\dfrac{14.4 + F}{Y}$	(1)
Units with a heat input at peak load of > 10.7 GJ (10 x 10⁶ Btu) per hour but < 107.2 GJ (100 x 10⁶ Btu) per hour, and units with a base load at ISO conditions of 30 MW or less[c]	0.0150	$\dfrac{14.4 + F}{Y}$	(2)

[a]Source: 40 CFR, Part 60, Subpart GG. Refer to the source for several exceptions to the standard.
[b]Y = manufacturer's rated heat rate at manufacturer's rated load (equation 1) or rated peak load (equation 2) in KJ per watt hour, or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. Y must be no greater than 14.4. F varies with fuel nitrogen content (by weight) as follows: for $N \leq 0.015$, F = 0; $0.015 < N \leq 0.1$, F = 0.04 (N); $0.1 < N \leq 0.25$, F = 0.004 + 0.0067 (N −0.1); and N > 0.25, F = 0.005.
[c]ISO conditions: 288°K, 60% relative humidity, and 101.3 kPa pressure.

With this brief introduction as a background, the remainder of Chapter 1 presents several general topics designed to establish a background for later sections. First, the mechanisms of NO_x formation are briefly reviewed. Understanding these mechanisms is essential to gaining a full appreciation for the development of NO_x control technologies, most of which are aimed at preventing NO_x formation during combustion. Many of the technologies thus developed are designed to primarily reduce NO_x formation from the specific mechanism associated with a particular combination of fuel and combustion conditions.

Next, the general schemes for NO_x control are discussed. An overview is presented of the three classes of control; that is, control before, during, and after combustion. As explained later, control for major sources, such as coal-fired utility boilers, is limited by practical considerations and often confined to during-combustion technologies. This is because before-combustion techniques may be unavailable or limited, and after-combustion techniques may be cumbersome and cost-ineffective unless also required for control of other pollutants.

Finally, a subsection is devoted to describing the sources covered in this manual, namely, utility boilers, industrial boilers, gas turbines, and stationary engines. This information may be helpful to at least three groups of readers: (1) field personnel or managers interested in following NO_x control developments for other sources to ascertain if technologies can eventually be transferred to their source; (2) state and local agency personnel who may not be totally familiar with the sources that are being regulated; and (3) consultants and equipment vendors who supply engineering solutions to the problems of NO_x control. Therefore, the brief discussion of sources is provided for those readers who may feel that this background will be necessary to their understanding of control technology applications and results presented in later sections.

1.3 Mechanisms of NO_x Formation

In stationary source combustion approximately 95 percent of the NO_x formed is nitric oxide (NO), which can oxidize in the atmosphere to form nitrogen dioxide (NO_2), a criteria pollutant. The formation of NO_x during combustion of fossil fuels occurs by two mechanisms: oxidation of atmospheric nitrogen present in the combustion air at elevated temperatures (usually called thermal NO_x), and oxidation of a portion of the bound nitrogen in the fuel (fuel NO_x). The latter is less dependent on temperature than on fuel nitrogen content, fuel properties, and the stoichiometric conditions present at combustion. The two mechanisms are shown schematically in Figure 1-1. In general, fuel NO_x is responsible for the bulk of NO_x formation in the combustion of coal and certain fuel oils with high nitrogen content. For combustion of gas or low nitrogen fuel oils, thermal NO_x is the dominant mechanism.

Two important reactions in thermal NO_x formation are:

$$N_2 + O = NO + N \tag{1-1}$$

$$N + O_2 = NO + O \tag{1-2}$$

Note that Reaction 1-1, which is highly temperature dependent, provides the atomic nitrogen (N) necessary for Reaction 1-2. Both reactions, however, are equally important in terms of the amount of NO formed. Note further that the reverse reactions are not favored by the presence of molecular oxygen; therefore, in the oxidizing environment that normally prevails downstream from the actual combustion (due to excess air for combustion), the NO that has been formed is essentially fixed. Finally, it has been noted that in regions of the combustion chamber in which the temperature is less than 1,200C (2,200F), formation of NO is not significant.

The kinetics of fuel NO_x formation are not as well understood as thermal NO_x. The most significant factors in fuel NO_x formation are nitrogen content of the

Figure 1-1. Basic Mechanism of NO_x Formation.

High Temperature
Combustion
Process
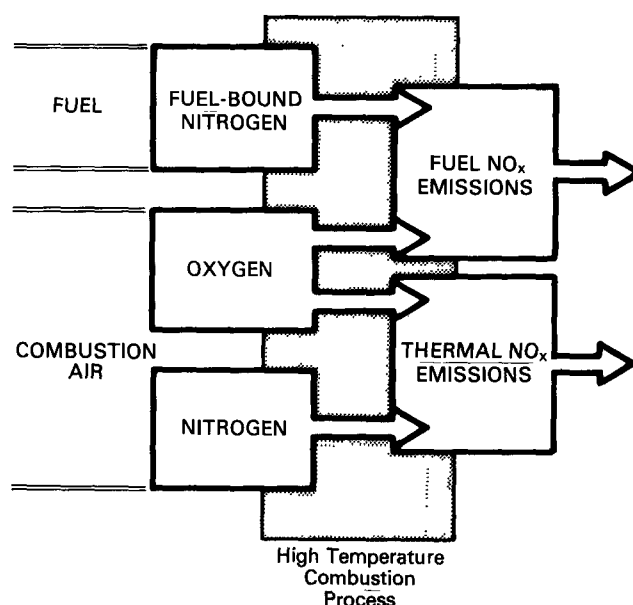
fuel and the degree to which the fuel is mixed with air during the early stages of combustion when bound nitrogen is liberated from the fuel. Table 1-5 shows the nitrogen content of selected fuels, including several nontraditional fuels, some of which exhibit relatively high nitrogen contents. The molecular nitrogen in natural gas responds in the same way as nitrogen in the combustion air. Because it is not bound it does not behave as fuel nitrogen.

Table 1-5. Typical Nitrogen Content of Selected Fuels

Fuel	Nitrogen Content, Weight %
Coal, anthracite, Pennsylvania	0.6-1.4
Coal, high-volatile "B," Ohio	1.4
Coal, subbituminous "B," Wyoming	1.0
Lignite, North Dakota	1.7
Fuel oil, No. 1	0.003
Fuel oil, No. 2	0.006
Fuel oil, No. 4	0.24
Fuel oil, No. 6, low sulfur	0.28-0.5
Tar sands oil	0.07
Shale oil	0.01
Coal-derived synthetic oil	
SRC-II heavy distillate	1.03
H-Coal	0.57
Natural gas, mid-continent	3.2*
Natural gas, Pennsylvania	1.1*
Coke oven gas	3.4
Crude oil	
Kern Co., California	0.5-0.83
Saudi Arabia, light	0.098

*Molecular nitrogen, N_2.

3

As the fuel enters the flame zone, it is pyrolyzed into small, reactive, nitrogen-containing molecules which react with oxygen to form NO. If little oxygen is present, as in the fuel-rich zone of staged combustion (a combustion modification NO_x reduction technology), the nitrogen-containing fuel fragments encounter and react with each other, and convert the nitrogen to molecular nitrogen (N_2).

This theory then serves as the basis for many of the combustion modification technologies for NO_x reduction that are discussed in this document.

1.4 General Schemes for NO_x Reduction

Because NO_x formation results primarily from combustion, three general schemes for NO_x reduction suggest themselves immediately:

- Reduction *before* combustion by reducing potential for formation
- Reduction *during* combustion by modification of the combustion process itself
- Reduction *after* combustion by some means of flue gas treatment.

These are shown schematically in Figure 1-2; the control technologies shown are described in detail later.

Precombustion schemes for reducing NO_x center on switching to fuels with a lower nitrogen content or a lower flame temperature. The choices are severely limited, however. The fuel choice is usually dictated by economic factors that transcend the economics of NO_x control. Furthermore, because nitrogen in solid and liquid fuels is chemically bound to organic chemical constituents, it is not efficiently removed. Therefore, no technology similar to physical cleaning of coal for sulfur removal is practical.

Emulsifying diesel oil with water is essentially a combustion modification technique in that the emulsification itself lowers the flame temperature and aids atomization. However, because it involves pretreatment of fuel, this technology is discussed further in Chapter 2 under precombustion control technologies.

NO_x reduction during combustion, usually referred to simply as combustion modification, has been employed since the early 1970s to effect moderate NO_x emission reductions. It is currently the principal NO_x reduction scheme for moderate control; a growing list of technologies in this category is being studied or applied. These technologies, discussed in detail in Chapter 2, suppress thermal or fuel NO_x by modifying the conditions for combustion, namely, stoichiometry, temperature, and residence time. These modifications can be achieved by modification of the burner itself or externally through modification of the air or fuel flow to the combustion chamber. Research, as well as pilot-scale and full-scale development of these technologies, is being carried out primarily by burner and boiler manu-

facturers, the Environmental Protection Agency (EPA), the Electric Power Research Institute (EPRI), and the Gas Research Institute (GRI).

Postcombustion schemes all involve some type of treatment of the flue gas and are normally classified as dry or wet processes. Some — mostly wet processes — are also designed for simultaneous removal of sulfur dioxide, primarily from coal-fired boilers. Many of the flue gas treatment processes have been developed in Japan, where NO_x emission limits are generally stricter than in the United States and where sulfur oxides (SO_x) removal processes have been widely applied.

Dry flue gas treatment processes usually consist of either reduction of NO_x to nitrogen by reducing agents or adsorption onto solids. The reduction processes may be catalytic or noncatalytic. Noncatalytic reduction is typified by the Exxon Thermal $DeNO_x$ process in which ammonia is used to selectively reduce NO_x at temperatures of 925 to 980C (1,700 to 1,800F) and by the EPRI urea injection process. These reduction processes may emit residual reducing agents (principally ammonia) and their by-products such as ammonium sulfate. Adsorption processes add expense due to the solid waste generated.

Wet flue gas treatment processes offer perhaps only one advantage over dry processes — simultaneous removal of sulfur oxides. These processes may be attractive for applications requiring stringent control of both pollutants. These processes are currently in the development stage and have not been commercially applied in the United States.

Figure 1-2.   General Schemes for NO_x Reduction.

PRECOMBUSTION TECHNIQUES

- Switch Fuel
- Emulsify Fuel with Water
- Fuel Denitrification

COMBUSTION MODIFICATION TECHNIQUES

- Stoichiometry
- Temperature
- Residence Time

POSTCOMBUSTION TECHNIQUES

- Flue Gas Treatment, NO_x Only
- Simultaneous SO_x/NO_x Treatment

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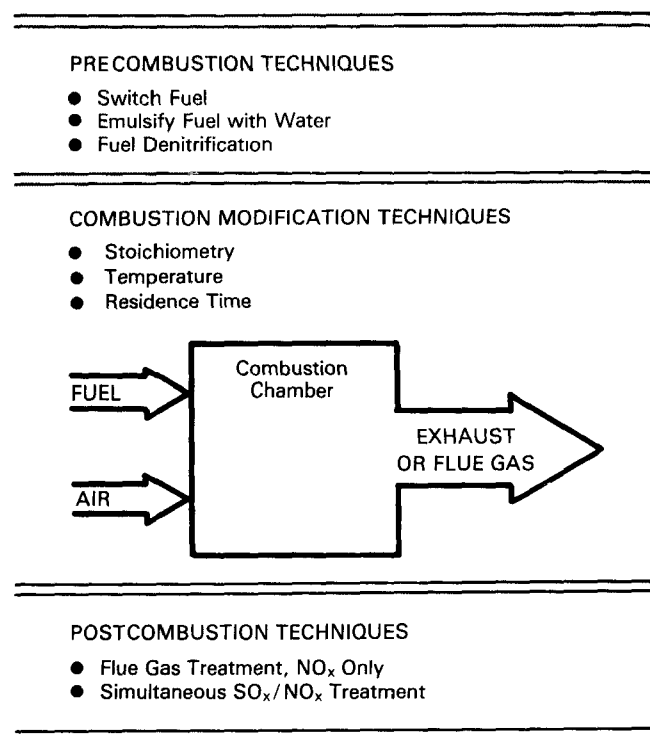
To summarize, although there are a myriad of theoretical options currently available for reducing NO$_x$ emissions from combustion sources, the actual selection for a specific case will come down to a few very practical choices. Until a few years ago nearly all NO$_x$ reduction for stationary sources was brought about by simple combustion modification. Recently, however, catalytic postcombustion technologies have been employed in increasing numbers, particularly for stationary engines.

The normal sequence has usually been to reduce NO$_x$ emissions from stationary sources with the simplest and most economical combustion modification that will achieve the necessary emission reduction. As further reduction is required, progressively more efficient (and more difficult to implement and hence more costly) combustion modifications are employed. In the case where the most efficient combustion modification still does not bring about the required reduction, postcombustion technologies are considered, often in addition to one or more combustion modifications.

1.5 NO$_x$ Emission Sources Considered in This Document

This document considers the following stationary sources of NO$_x$ emissions:

- Utility boilers, which account for approximately 53 percent of all stationary source emissions
- Industrial boilers, accounting for about 14 percent
- Gas turbines and stationary engines (gas and diesel), which together represent approximately 22 percent of stationary source emissions.

Therefore, this document covers technologies that apply to about 90 percent of the stationary sources of NO$_x$ emissions. Not covered in this document are commercial boilers, residential heaters, enhanced oil recovery steam generators, industrial process heaters, and miscellaneous combustion and noncombustion sources which account for most of the remaining 10 percent of emissions.

Each major source will now be described in detail sufficient to provide the necessary background for understanding the later discussions of control alternatives.

1.5.1 Utility Boilers

Approximately 80 percent of fossil fuel steam generation is from coal firing.(2) The remainder is nearly evenly divided between natural gas and oil (predominantly residual fuel oil such as No. 6). In addition, the uncontrolled NO$_x$ emission factors for coal-fired boilers are approximately twice those for natural gas-fired and oil-fired units (on a Btu basis).

All fossil fuel-fired utility boilers generate steam by transferring the heat from combustion of the fuel to water. The steam, in turn, produces electricity by expanding through a turbine. The steam generated may be saturated or superheated and is essentially always confined inside the tubes with the outside of the tubes exposed in part to combustion gases. This is the water-tube arrangement as opposed to the fire-tube arrangement found in low capacity industrial boilers.

Coal is fired either in a bed, or stoker, or in a state of suspension. Stoker-fired units are rarely found in large utility boilers and in terms of nationwide NO$_x$ emissions are of much less importance than suspension-fired boilers.

Suspension-fired boilers are categorized (Figure 1-3) as either cyclone-fired or pulverized coal- (PC) fired boilers. Cyclone boilers fire coal ground to about a 4-mesh size and carried into a cylindrical combustion chamber by primary air in a cyclonic flow pattern. Small particles burn in suspension while larger particles adhere to the molten slag on the furnace walls where they are burned with the addition of secondary combustion air.

In contrast, pulverized coal-fired boilers fire coal of particle sizes on the order of 70 percent passing 200-mesh. The coal particles burn in a state of suspension in the combustion chamber.

For our purposes, these boilers are categorized in accordance with the position of the burners in the combustion chamber (Figure 1-4). Wall-fired boilers have burners mounted horizontally either in a single wall (front or rear) or in two opposite walls horizontally opposed. Turbo-fired boilers also employ burners in horizontally opposed pairs but the burners are inclined downward to induce a turbulent flow. Tangential- or corner-fired boilers employ burners in groups of four, each firing horizontally from a corner of the furnace. At each elevation of four burners, each burner is aimed at the tangent to an imaginary circle in the center of the furnace, which sets up a vertically oriented vortex throughout the combustion zone. Arch- or vertical-fired boilers employ burners that fire vertically downward into the combustion chamber and may exhibit a turbulent flow pattern if the horizontally entering secondary air flows are so designed. This type of boiler is effectively obsolete but may find application again in the future for combustion of difficult-to-ignite fuels, such as chars from coal conversion processes, which are low in volatile matter.

The method of ash removal is also important to NO$_x$ emissions in suspension-fired boilers and is another way to classify such boilers. Dry-bottom boilers burn coal with a high ash fusion temperature and therefore are designed for a dry ash removal system. On the other hand, wet-bottom, or slag-tap, boilers remove molten ash (slag) resulting from combustion of coal with lower ash fusion temperatures. Wet-bottom boilers exhibit higher uncontrolled NO$_x$ emission rates than do dry-bottom boilers due to higher combustion temperatures. Combustion in these boilers is very intense; thermal NO$_x$ formation is increased by the higher temperature while fuel NO$_x$ formation is enhanced by the more turbulent mixing.

5

Figure 1-3.   Classification of Coal-Fired Boilers.

(Many types of stokers are used)
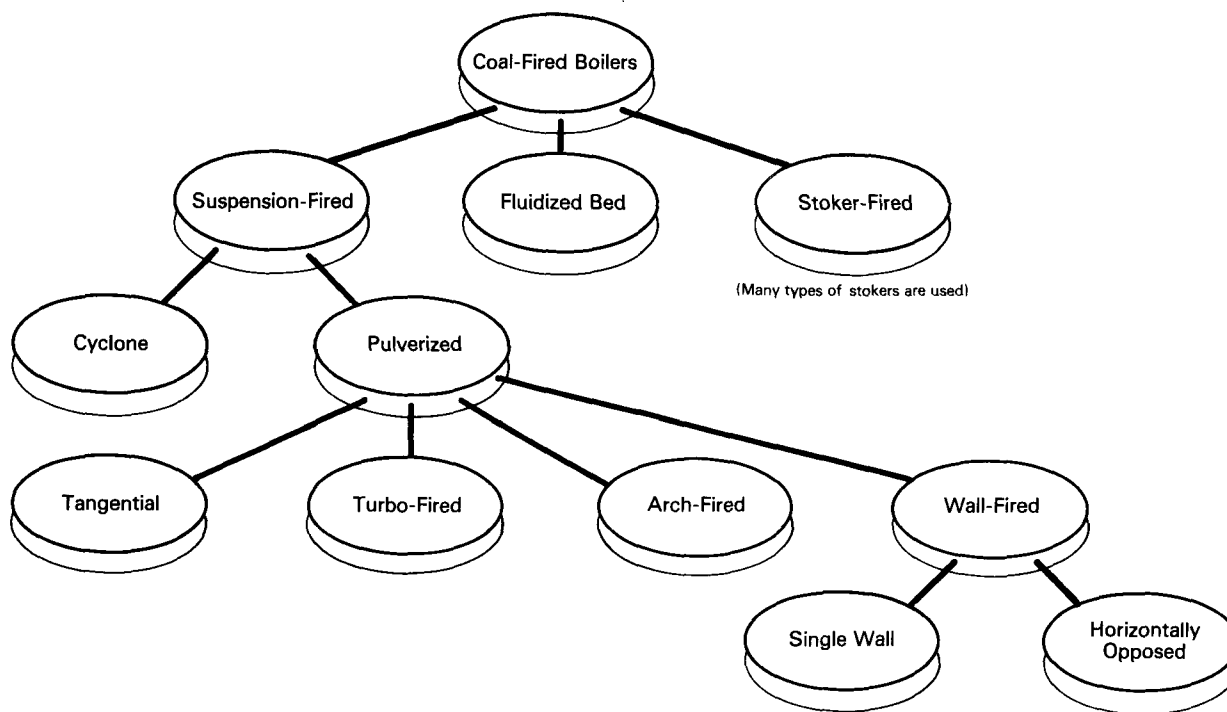
Figure 1-4.   Utility Boiler Firing Configurations for Pulverized Coal.

Wall-Fired,
Elevation View

Horizontally Opposed,
Wall-Fired, Elevation View

Turbo-Fired,
Elevation View

Arch-Fired,
Elevation View

Tangential Firing,
Plan View
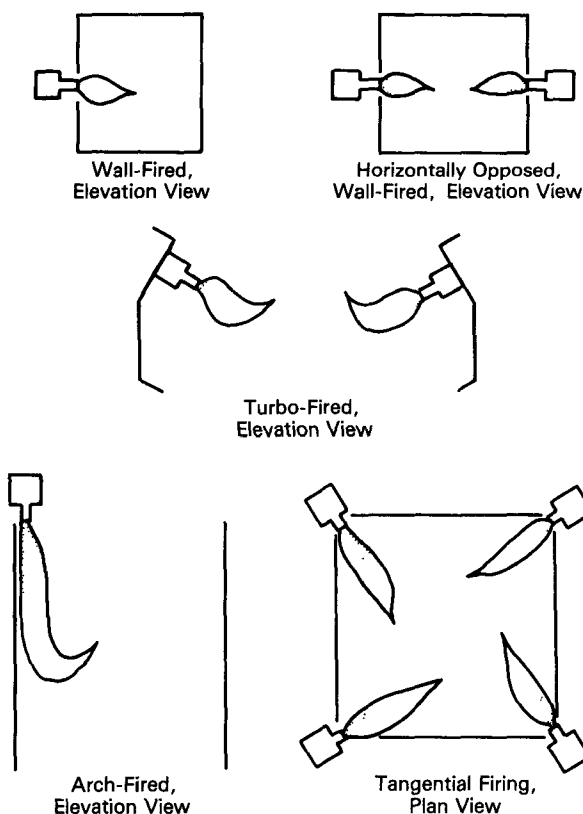
Stoker-type boilers are classified according to the method of feeding coal shown in Figure 1-5.

The four main burner configurations in coal firing — wall-fired (single), horizontally opposed-fired, turbo-fired, and tangential-fired — also predominate for oil- and gas-fired utility boilers, although the burners themselves are different.

The most frequently used burners for oil or gas combustion are the circular burner and the cell burner. These burners are also used for pulverized coal or for firing any of these fuels in combination. The maximum firing capacity of the individual circular burner is on the order of 165 million Btu/h; cell burners can fire up to about 495 million Btu/h.

The chief difference between the two types of burners is the fuel injection location. In the circular burner, fuel is introduced at one location — the center of the circle. In the cell burner, fuel is introduced through multiple spuds arranged annularly around the center of the burner. Each spud is a pipe with a pattern of holes at the end to discharge the fuel. Figure 1-6 depicts a circular burner and Figure 1-7 shows a cell burner.(4)

Figure 1-8 shows a "typical" utility boiler — in this case a pulverized coal-fired boiler employing horizontally opposed burners.

Figure 1-5. Main Types of Stokers Used in Industrial Boilers (3).

(a) Underfeed

(b) Crossfeed Spreader

(c) Overfeed Spreader

Figure 1-6. Front View of Circular Burner Used for Oil Combustion.

Impeller

Oil Atomizer
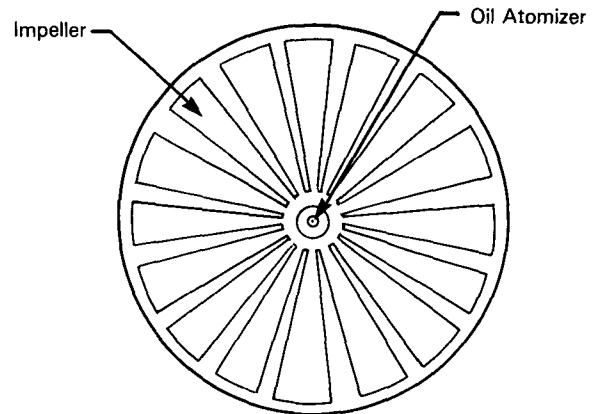
Figure 1-7. Front View of Cell Burner Used for Gas Combustion.

Gas Spud

Impeller

1.5.2 Industrial Boilers

Industrial boilers, used primarily to generate steam for heating or process uses, also fire coal, oil, gas, or waste fuels. Most coal-fired industrial boilers are water-tube boilers; fire-tube boilers are subject to ash plugs and other operational problems. Large coal-fired units (steam flow rate greater than 350,000 lb/h) generally fire pulverized coal and are very similar to comparably sized utility boilers. Smaller coal-fired industrial boilers (less than 100,000 lb/h of steam) are normally stoker fired, and a mixture is found in the middle size range. Because of the vast number of smaller boilers, stoker firing accounts for most of the coal consumption by industrial boilers.

The main stoker types in use are illustrated in Figure 1-5. Spreader stokers propel coal into the combustion chamber; a portion of the coal actually burns in suspension while the remainder burns on a grate. Grates may be of the stationary, dumping, or travelling variety.

Because they do not allow for continuous removal of ash, stationary grates must be zoned to allow for periodic removal. That is, not all zones are firing at any one time; this allows ash removal from one zone at a time. The underfeed stoker employs a ram to feed coal upward through the burning bed in the same direction as the flow of combustion air to the tuyeres. Multiple retort underfeed stokers are used for coking coals with high ash fusion temperatures. In contrast, the overfeed stoker supplies coal to the bed from above. The latter is normally used with travelling or pulsating grates and is amenable to burning nearly all types of coal.

Oil- and gas-fired industrial boilers are either water-tube or fire-tube boilers. The former employ burner flames on the outside of the tubes with boiler water flowing through the tubes, while the latter reverse this design. Fire-tube boilers tend most often to be small, packaged units, whereas water-tube boilers can be either packaged units or large, field-erected units. Packaged units are available up to a capacity of 350,000 lb/h of steam.

7

Figure 1-8.   Pulverized Coal-Fired Boiler Employing Horizontally Opposed Burners (5) .
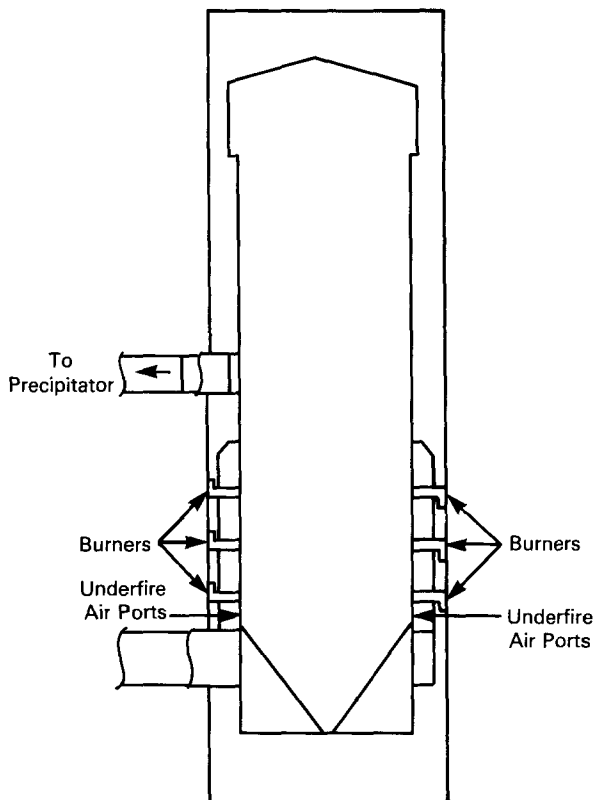
1.5.3   Gas Turbines

Gas turbines are used in industry for compressing gas or pumping liquids, and in utilities for generating electric power. Gas turbines fire natural gas or fuel oil; the oil is normally a distillate such as No. 2 fuel oil. The principle of operation is simply to expand the products of combustion through a turbine to generate power.

The combustion chamber of a gas turbine typically consists of two zones: the primary zone, where essentially all of the combustion takes place under low excess air conditions; and the secondary zone, where secondary air is introduced in quantity sufficient to cool the products of combustion to a temperature compatible with the turbine materials of construction.

There are basically three configurations for gas turbines. The so-called simple-cycle turbine is the basic type of gas turbine (Figure 1-9). Compressed air and fuel are directed to the combustion chamber, where combustion and dilution of exhaust gas take place. The exhaust gas is then expanded through the turbine which provides energy not only for the load (pump, generator, etc.) but also for the combustion air compressor.

The first refinement of the simple-cycle turbine is the regenerative-cycle turbine. This engine uses a simple-cycle turbine but also includes a recuperative heat exchanger to preheat combustion air with the turbine ex-

haust gas. This engine is more energy-efficient than the simple-cycle gas turbine.

The second refinement is the combined-cycle turbine. The heart of this type of turbine is a simple-cycle turbine, but it also includes a waste heat boiler to produce steam from heat exchange with the turbine exhaust gas.

1.5.4   Stationary Reciprocating Engines

This category of NO_x emission sources includes compression-ignition engines and spark-ignition engines (see Table 1-6). Compression-ignition engines are normally fired with diesel oil or with a combination of oil and natural gas (generally the oil is injected into the cylinder only to initiate combustion). The latter are referred to as dual-fuel engines. Spark-ignition engines are typically fired with natural gas. Stationary reciprocating engines have wide-ranging uses; perhaps their most important application, involving units of several thousand horsepower, is to drive large compressors in distribution of natural gas.

Compression-ignition engines are normally four-cycle engines of large bore that operate on this familiar cycle: admission of air and fuel; compression and ignition; expansion; and exhaust. Thermodynamically, compression-ignition engines follow a constant pressure, or diesel, cycle. Compression ratios are relatively high (on the order of 20 to 1) and compression pressures range up to several hundred psi. At such high pressures, combustion is spontaneous; therefore, no ignition sources (such as sparkplugs) are required.

Spark-ignition engines follow the spark-ignition, or Otto, cycle of constant volume combustion. These engines feature either four-cycle or two-cycle operation. In two-cycle operation, the air-fuel mixture is compressed outside the cylinder and expels the exhaust upon entering the cylinder. In two-cycle engines, a scavenging arrangement is normally used in order to hasten the exhaust of combustion products and minimize the escape of the air-fuel mixture with the exhaust. Immediately after the bulk of the exhaust gas leaves the cylinder, a jet of scavenger air enters the cylinder. The scavenger air is deflected usually into either a helical or cyclic pattern in order to force the remaining exhaust gas out the exhaust port. The cylinder is then relatively exhaust-free when the air-fuel mixture is introduced, which occurs nearly simultaneously with scavenging. The pressure for scavenging can be supplied by the crankcase (common in smaller engines) or by an external blower that is driven by the engine (common in larger engines).

1.6   Organization of This Document

The remaining chapters are devoted to a more in-depth examination of NO_x control technologies, specifically as they apply to, and have been refined for, the sources of NO_x discussed earlier in this chapter.

Figure 1-9.   Simple-Cycle Turbine.
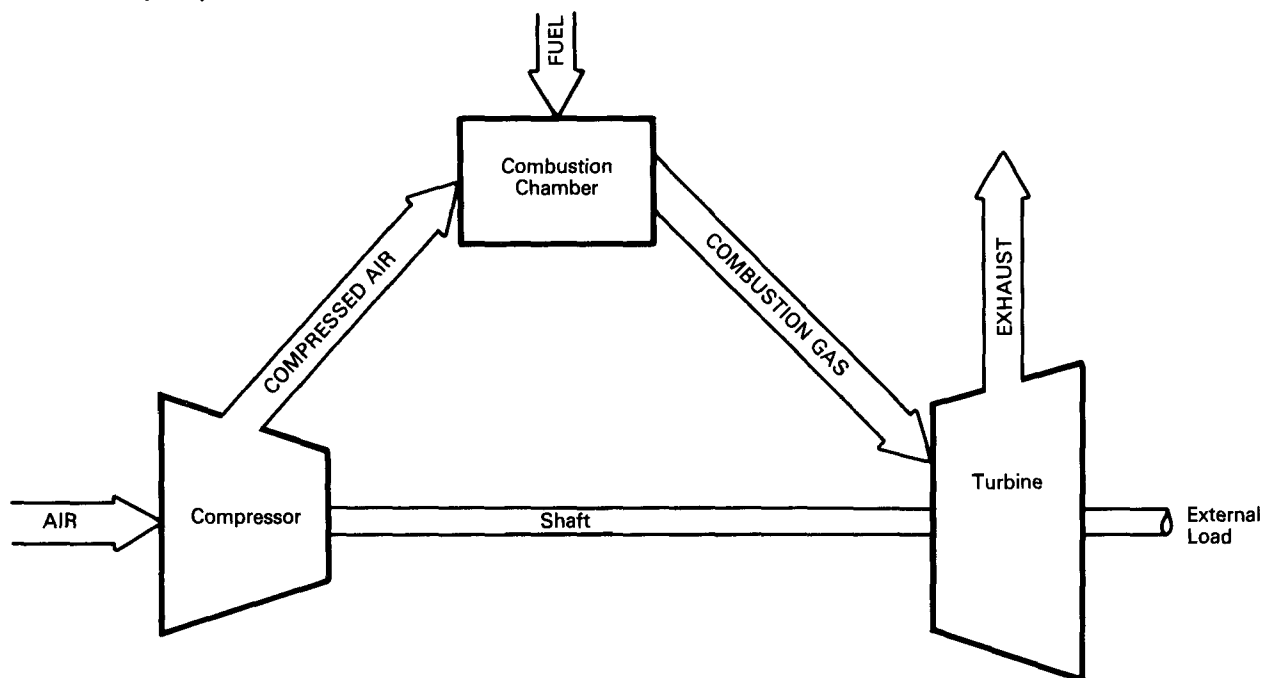
Table 1-6.   Characteristics of Stationary Reciprocating Engines

	Spark-Ignition	Compression-Ignition
Typical fuel	Natural gas	Diesel oil or dual fuel (oil and natural gas)
Thermodynamic cycle	Otto (constant volume)	Diesel (constant pressure)
Compression ratio	6:1 to 12:1	11.5:1 to 22:1
Maximum cylinder pressure	Over 2,000 kPa	Over 4,800 kPa
Operation	2-cycle or 4-cycle	Usually 4-cycle
Scavenging	Usually required for 2-cycle; crankcase pressure or external blower used	Not required for 4-cycle; 2-cycle engines often employ blower-scavenger

Chapter 2 presents a detailed discussion of all the NO$_x$ control alternatives that are generally commercially available and for which performance or cost data are available. Most pilot-plant technologies and untested conceptual designs are not included here; rather, those technologies offering a reasonable promise for success are presented. Chapters 3 through 5 present actual NO$_x$ reduction data and system cost data for application of these technologies to utility and large industrial boilers,

packaged boilers firing oil or gas, gas turbines, and stationary reciprocating engines. Both retrofit and new applications are considered where quality data on each are available. Note that no new cost data were developed for this document; rather, cost data appearing in the literature are merely reported as they were found in the references. Therefore, this report makes no representation as to the accuracy of such cost data.

2.1 Introduction

Three conceptual schemes for reducing NO$_x$ emissions from stationary sources of combustion were introduced earlier: precombustion, or the reduction of potential formation; combustion modification; and postcombustion removal of NO$_x$ from the flue gas. The numerous technologies that are commercially available for NO$_x$ reduction are now described in some detail, grouped into the above three categories. A more complete discussion of these technologies including results achievable, associated costs, and deleterious impacts, is presented in Chapters 3 through 5.

2.2 Precombustion Control Technologies

Switching to a lower nitrogen fuel is often economically unattractive, and removal of fuel nitrogen is usually not cost-effective solely for NO$_x$ control. Furthermore, with many fuels such as natural gas and low-nitrogen fuel oil, the majority of NO$_x$ emissions are from thermal NO$_x$ formation. Therefore, the choices in this category are quite limited. The process of removing sulfur from fuel oil by hydrodesulfurization has the side benefit of nitrogen removal but is very expensive in comparison with combustion modification techniques that produce a comparable NO$_x$ reduction.

2.2.1 Change of Fuel

Clearly, this is the trivial case. Where it is economically attractive to change to a lower nitrogen fuel, changes for economic reasons, not for NO$_x$ reduction incentives, have been or are made. Cost considerations are paramount and merely switching to a lower nitrogen fuel may not effect a large enough reduction to meet NO$_x$ emission regulations, which in any case are fuel-specific. Therefore, combustion or postcombustion NO$_x$ reduction techniques may be necessary.

2.2.2 Fuel Oil/Water Emulsions

This control technology could arguably be classified as a combustion modification technique because it alters the conditions for combustion; however, it is discussed here because it involves mixing of fuel prior to combustion. The technique has been tested on stationary engines firing diesel fuel. Tests of this technique have been typically performed on diesel engines in the 100 to 300 hp size range and have employed fuel mixtures from 7 to 45 percent water. Emulsions have been delivered to

the fuel injection system in a number of ways: a simple mixer and pump arrangement; a low-energy shear fluid mixer into which the oil-water mixture is pumped; or a high-energy emulsor in which the mixture is pumped through an orifice at a high (on the order of 2,000 psi) pressure drop.

The primary mechanism for NO$_x$ reduction provided by fuel oil/water emulsions is lowering of the flame temperature. Heat transfer from the flame to the flue gas is enhanced by the presence of water vapor which serves to increase the overall specific heat capacity of the products of combustion, thus lowering the flame temperature. Another probable mechanism taking place is the limiting of the NO formation reaction resulting from the water vapor's dilution of the oxygen in the flame zone. Finally, the rapid vaporization of water in an oil droplet is thought to increase the atomization of fuel, thus enhancing combustion efficiency.

2.3 Combustion Modification Technologies

The majority of NO$_x$ control technologies for combustion sources involve modifying the parameters of combustion. All of the techniques are aimed at achieving one or more of the following goals: reducing the available oxygen at critical stages of combustion; lowering the peak flame temperature; and reducing the residence time during which oxidation of nitrogen takes place. Table 2-1 summarizes the technologies covered in this subsection and the mechanisms these technologies rely on.

Where possible, the technologies to be considered under this heading have been grouped by similarity and ordered by degree of complexity. Retrofit technologies are presented first, in order of increasing complexity, followed by technologies for new combustion sources.

In terms of meeting compliance NO$_x$ emissions levels both on a source-by-source basis and in a general sense for fossil fuel-fired boilers as a whole, a logical progression of control technologies can be employed in order of increasing removal efficiency and cost. In this manner the appropriate and most cost-effective technology can be found most expediently. For example, low excess air would be the first technology employed; if the NO$_x$ emission reduction achieved at the limit of low excess air is not sufficient, any of various types of staged com-

Table 2-1.   Combustion Modification Technologies

Technology	Lowers Flame Temperature	Reduces Available Oxygen	Shortens Residence Time	Other
Low excess air	—	Yes	—	—
Staged combustion BOOS Biased firing Overfire air Arch firing	Yes	Yes	—	—
Reducing combustion air preheat	Yes	—	—	—
Water injection	Yes	—	—	—
Exhaust gas recirculation	Yes	—	—	—
Low NO_x burners Staged air Staged fuel Variations	Yes	Yes	—	—
In-furnace destruction (reburning)	—	Yes	—	Reduction of NO to N_2
Lean-burn, torch ignition	Yes	—	—	—
Turbocharging	Yes	—	—	—
Charge cooling (refrigeration)	Yes	—	—	—
Retardation (ignition or injection)	Yes	—	Yes	—

bustion typically would be applied. The logical progression would proceed in this manner until the desired reduction is achieved. As mentioned earlier, this progression applies for individual sources and also parallels the development of these technologies to meet ever-increasingly stringent NO_x emission levels. For retrofit applications, the feasibility and cost effectiveness are dependent on space requirements and operational side effects resulting from modified combustion conditions. Some control technologies may not be practiced because of cost or effect on boiler efficiency. In any event, the actual order in which technologies are implemented depends on the required emission reduction.

2.3.1 Low Excess Air

Operating burners with low excess air is perhaps the simplest NO_x reduction technology to implement on a retrofit basis; no capital equipment is required and combustion chamber modifications are normally unnecessary. However, the NO_x reductions achievable are modest and may not, in specific retrofit situations, be sufficient to comply with NO_x emission regulations. The degree of control is constrained by the onset of carbon monoxide (CO) emissions (generally held to 50 to 100 ppm) or plume opacity at low excess air. Other factors such as safety considerations (e.g., minimum air flow requirements) may also be considered. The technology is applicable to coal, oil, and gas firing in boilers of all sizes.

Most new coal-fired boilers are designed for low excess air firing. In order to meet New Source Performance Standards, however, they also usually are equipped

with low NO_x burners or other combustion modification NO_x reduction technique. Oil-fired and gas-fired boilers in many instances can be operated at excess air levels of 5 percent and lower. However, coal-fired boilers normally require a greater excess air level in order to ensure essentially complete carbon burnout and to minimize emissions of carbon monoxide.

The low excess air method accomplishes NO_x reduction of both thermal and fuel NO_x. Reduced availability of oxygen suppresses the formation of NO from nitrogen in the fuel and in the combustion air.

2.3.2 Staged Combustion

Staged combustion is actually a whole family of technologies. The most frequently employed for retrofit of large industrial and utility boilers are burners out of service (BOOS) and biased firing. For new units, overfire air is most frequently applied. Arch firing, a boiler configuration inherently low in NO_x formation, has also received attention lately as a form of staged combustion. Staged combustion can also be achieved internally by burner modification. A key characteristic of this technology is stretching of the combustion zone, which may cause flame impingement on side walls or superheater tubes and affect steam balance and consequently unit efficiency. When staging lowers stoichiometric air ratios below 1.0, there is the potential for increased tubewall corrosion rates.

2.3.2.1 Burners Out of Service (BOOS)

This technology is generally applicable to wall-fired utility and large industrial boilers. BOOS is normally im-

plemented on existing units by employing an upper row of burners — on one wall or on both walls of opposed-fired units — as sources of secondary combustion air only, without introduction of fuel through these burners. Also, selected burners can be removed from service other than the top row if the BOOS pattern is balanced. The effect is to provide so-called overfire air above the active burners which comprise the primary combustion zone. This zone is maintained under fuel-rich conditions by introducing air to these burners at lower than stoichiometric rates.

Operation of the lower furnace zone with a substoichiometric amount of air (fuel-rich conditions) lowers the conversion of fuel nitrogen to nitrogen oxide. Subsequent cooling and dilution of the combustion gas with the secondary air from the upper (out of service) burners reduces peak flame temperature and thus minimizes the formation of NO by thermal fixation.

BOOS could presumably be employed in new installations but finds the vast majority of its applications as a retrofit technology. It is applicable to suspension-fired coal boilers as well as boilers firing oil or gas.

2.3.2.2 Biased Firing
Biased firing is a retrofit technology generally only applicable to oil-fired and gas-fired utility and large industrial boilers. It is roughly equal to BOOS in ease of implementation; no new equipment is usually necessary, nor are any major boiler modifications.

In biased firing, the overall combustion chamber stoichiometry is preserved (which may in all probability involve low excess air) while air and fuel flows to individual burners are varied. There is no set or generally accepted pattern to variation of the burner conditions, as many combinations may yield the desired effect. The goal is to create fuel-rich and fuel-lean regions in the combustion chamber with an effect similar to that of overfire air or BOOS: The fuel-rich regions generate relatively low thermal and fuel NO_x. The best combination is usually found by experimenting with various patterns.

2.3.2.3 Overfire Air
The third widely used type of staged combustion is overfire air, which is applicable to coal-, oil-, and gas-fired utility boilers and large industrial boilers. Overfire air is usually used in new boiler designs. Unlike BOOS and biased firing, overfire air requires modification of the combustion chamber. Specifically, air ports above most or all of the rows of burners must be added to provide the secondary combustion air above the burners. The result is similar to BOOS operation: Fuel-rich burners reduce fuel and thermal NO_x formation, and interstage cooling by boiler tubes reduces peak flame temperatures which also suppresses thermal NO_x. Overfire air operation is shown in Figure 2-1.

Figure 2-1. Typical Staged Combustion: Overfire Air (6).
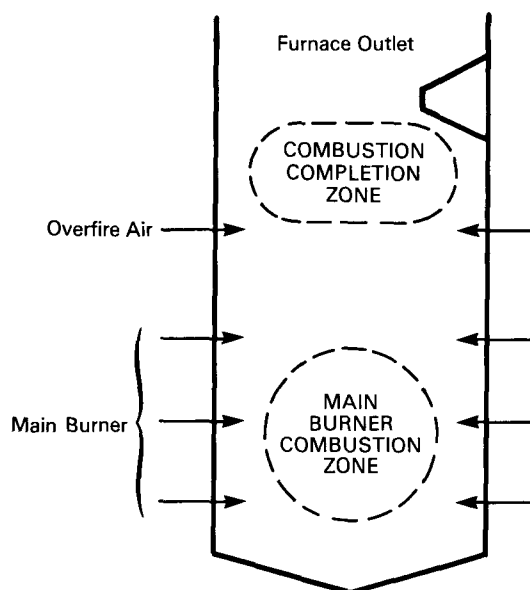
2.3.2.4 Arch Firing
This boiler configuration is one of the earliest designs for burning pulverized coal in utility boilers and is receiving some attention lately because it is an inherently low NO_x formation combustion technology. Burners are mounted such that they fire vertically downward in the combustion chamber; secondary air is injected farther down the vertical walls of the boiler. The result is a J-shaped flame in which the combustion is staged and therefore NO_x emissions are low. Figure 2-2 shows schematic views of three different arch-fired boilers.

Because this technology involves an entire combustion chamber configuration, its applicability on a retrofit basis is limited, especially when compared to the relative ease of retrofitting the furnace with low NO_x burners. Its best application may be for new units, although there are two basic drawbacks: The cost of an arch-fired boiler is generally significantly higher than a comparable wall-fired boiler; and the technology has not been applied to new boiler designs for years and there may be a natural reluctance on the part of utilities to employ it.

2.3.3 Temperature Reduction Technologies
Several NO_x reduction technologies employ some method of reducing peak flame temperature to reduce thermal NO_x formation. These include reducing the combustion air preheat, injecting water, and recirculating exhaust gas. These technologies are presented schematically in Figure 2-3. Temperature reduction technologies are generally applicable to oil- and gas-fired boilers and engines; they are not effective for sources firing coal or high nitrogen oil because thermal NO_x formation is usually the less important mechanism in such units.

13

Figure 2-2.   Arch-Fired Boilers (7).

80 MW   125 MW

275 MW
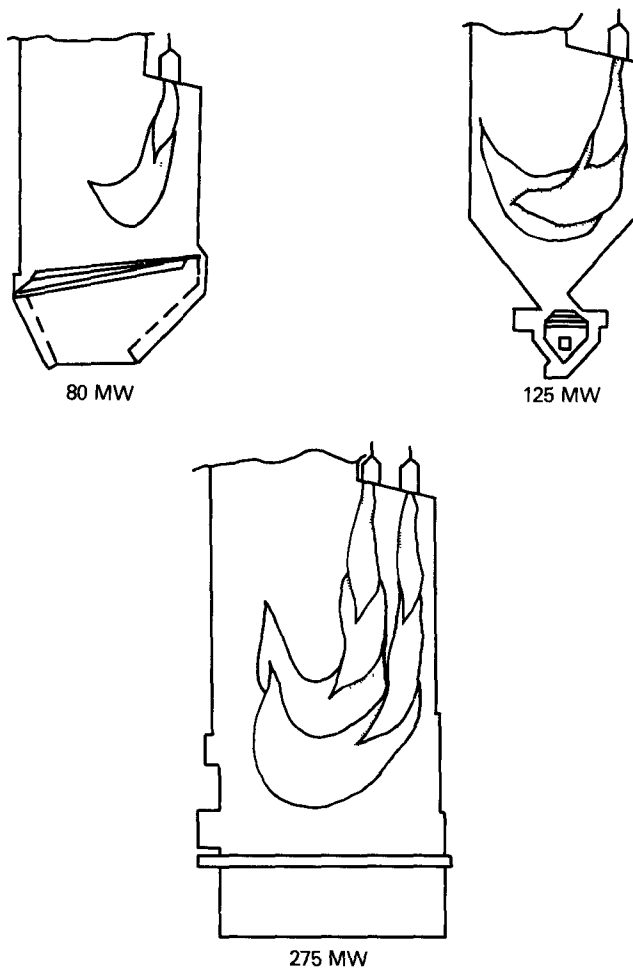
2.3.3.1 Reducing Combustion Air Preheat

This technology is applicable primarily to utility and industrial boilers burning oil or gas. The technique is merely to lower the temperature of the incoming combustion air, usually by providing a bypass around the air preheater for a portion of the combustion air. The result is that the peak flame temperature is correspondingly reduced, thus reducing thermal NO_x formation. In utility and some large industrial boilers, economizers can be used to recover some of the thermal efficiency that is sacrificed in reducing the combustion air preheat. However, the loss of thermal efficiency can represent a severe economic penalty. This technology, therefore, is often considered for interim control.

2.3.3.2 Water Injection

Water injection technology involves a modest modification to allow water to be injected into the combustion air stream. Normally, nozzles are mounted in the windbox in a manner that permits vaporization of the water before it enters the combustion chamber. The vaporization removes some of the heat from the combustion chamber, thus lowering peak flame temperature. It is important to design the system so that vaporization of the water occurs before the combustion air reaches the combustion chamber to avoid corrosion in this area. As it is a temperature reduction technology, water injection may also carry a significant energy penalty and thus should perhaps be viewed as an interim measure for utility boilers.

2.3.3.3 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR), or flue gas recirculation (FGR), is a technique similar to that used for

Figure 2-3.   Three Temperature Reduction Methods for Boilers
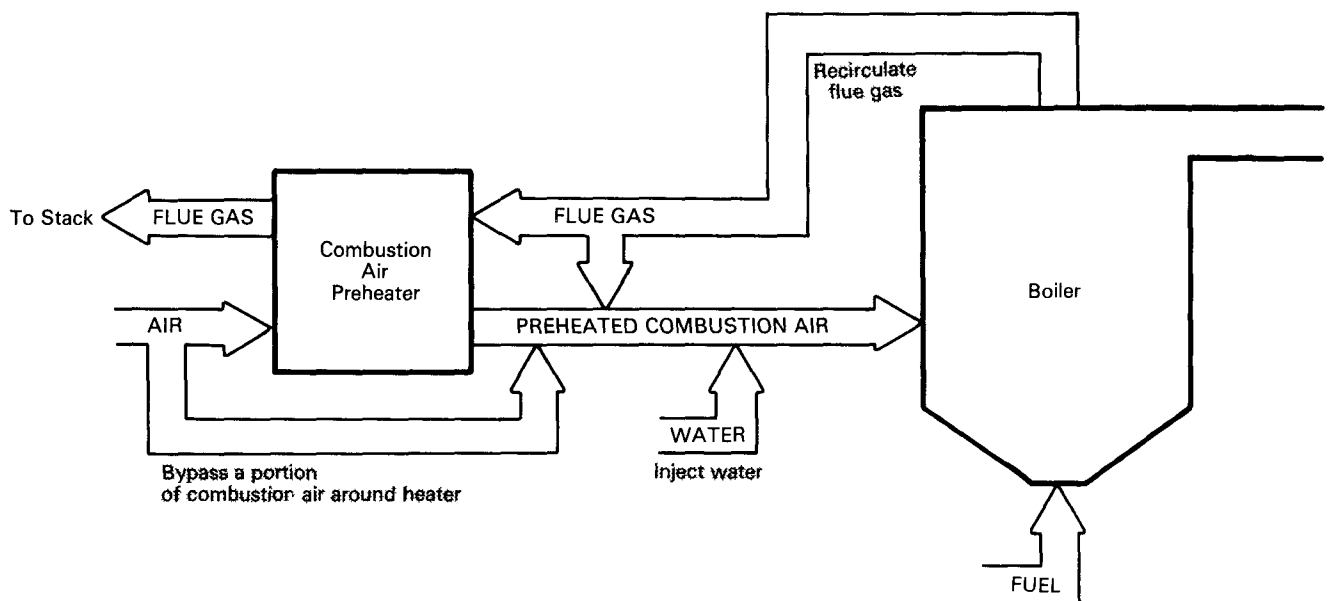
automobile engines. In fact its greatest applicability is with stationary engines and turbines. It is applicable on a new or retrofit basis for boilers, process heaters, and engines. A portion of exhaust gas or flue gas is recycled to a point where it joins, and therefore dilutes, the inlet combustion air flow. This dilution serves to lower peak flame temperature, thus reducing thermal NO_x formation. The local oxygen level in the flame is also reduced, which helps to suppress NO_x formation. This technique is normally not applicable for coal-fired boilers (where it is normally called "flue gas recirculation") because the greater portion of NO_x emissions are from fuel NO_x in coal combustion.

2.3.4 Low NO$_x$ Burners

Low NO_x burners have been and continue to be developed for coal-, oil-, and gas-fired boilers. These burners are applicable on a new or retrofit basis and can be used for utility boilers, large industrial boilers, or small packaged boilers. Low NO_x burners are normally developed by boiler and burner vendors and therefore exhibit a wide variety of designs. However, the principle for all NO_x burners is the same: They inherently generate lower NO_x emissions due to internal staging of fuel combustion.

For retrofit of low NO_x burners, the number, type and arrangement of original burners, the structural configuration of the firing walls, and the nature of the low NO_x burners to be retrofitted all need to be considered. Some retrofits are relatively straightforward; however, others are complex and may prove to be infeasible due to the complexity.

2.3.4.1 Staged-Air Burners

One of the first low NO_x burners to be developed employs staged air within the burner itself to effect NO_x reductions (Figure 2-4). The effect is similar to staged combustion except that the detailed design of the burner — as opposed to the arrangement of burners in the combustion chamber or the design of the combustion chamber itself — is responsible for the staged combustion. Low NO_x burners of this and other types are equally applicable in new or retrofitted boilers. With some designs, the firebox geometry may not permit a burner retrofit without derate or flame impingement.

The staged-air burner employs primary and secondary air for combustion in such a way that conditions in the primary flame zone are substoichiometric (fuel-rich). The remaining air (tertiary or staged air) is injected after a brief delay so that the flame experiences a predetermined residence time under reducing conditions. As with staged combustion, the peak flame temperature is thus lowered, resulting in lower rates of NO_x formation.

2.3.4.2 Staged-Fuel Burners

In staged-fuel burners, all of the air required for combustion is introduced into the primary combustion zone

Figure 2-4.   Low NO$_x$ Burner: Staged-Air Design (8).
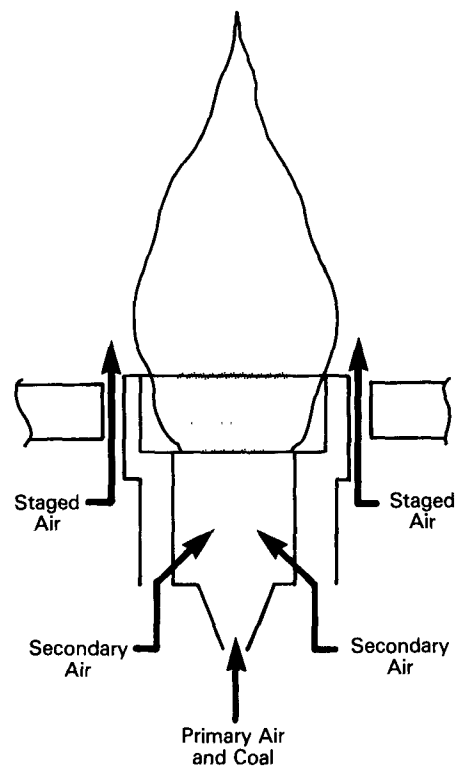
(Figure 2-5). The fuel is staged, however, so that the amount of fuel which the primary zone receives is less than stoichiometric. Primary combustion is under fuel-lean conditions and therefore NO_x formation is repressed by the lower flame temperature brought about by the excess air. The remaining fuel is injected into the flame through a peripheral pattern of high-velocity nozzles.

Figure 2-5.   Low NO$_x$ Burner: Staged-Fuel Design (9).

15
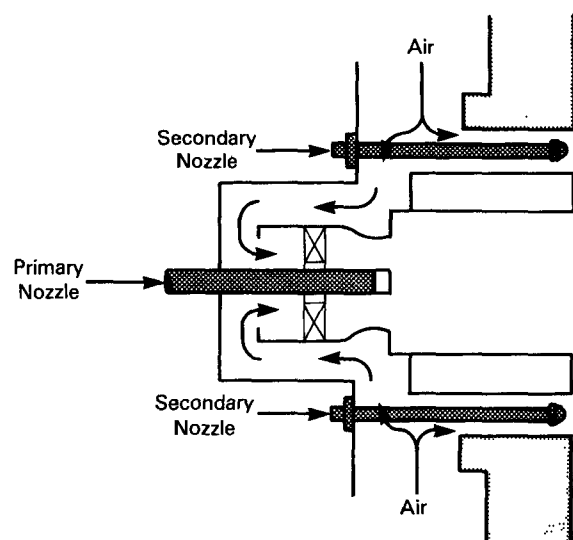
The design ensures rapid mixing by the entraining action of the injected fuel, which brings about results similar to exhaust gas recirculation: NO_x formation is reduced by a lower flame temperature in the secondary zone and by the decreased availability of oxygen in the staged zone.

2.3.4.3 Variations

A myriad of commercial variations of internally staged low NO_x burners are offered by vendors for both new and retrofit applications. For example, Foster Wheeler offers the controlled flow/split flame burner for coal-fired boilers (Figure 2-6). Adjustable inner and outer air registers provide staged air while a tapered annular split-coal nozzle separates the coal into several streams and thus generates several flames. The result is that primary combustion is at substoichiometric (fuel-rich) conditions and mixing is delayed until the secondary zone.

Babcock & Wilcox has offered for several years a dual-register burner, which is essentially a staged-air burner for coal-fired boilers (Figure 2-7). In fact this burner has been the standard for all new B&W units sold since 1972. Normally, a compartmented windbox is also employed. Therefore, the company refers to their low NO_x burner system as the dual-register burner/compartmented-windbox system.

Riley Stoker offers two major types of low NO_x burners for coal-fired boilers: the controlled combustion Venturi burner for wall-fired boilers, and the directional flame burner for turbo-fired boilers. The former (Figure 2-8) provides a fuel-rich zone along the burner axis surrounded by layers of progressively leaner mixtures. The

Figure 2-6. Low NO_x Burner: Foster Wheeler Controlled Flow/Split Flame Burner (10).

latter (Figure 2-9) is actually a burner arrangement wherein the combustion zone is designed to produce turbofiring and overfire air is used to produce a staged-combustion effect.

EPA has pioneered the development of the distributed mixing burner. It consists (Figure 2-10) of a circular burner that operates under reducing (fuel-rich) conditions in a recirculation zone where the inner secondary air combines with the primary air and fuel. Tertiary air is supplied through outer ports. This arrangement allows sufficient residence time in the burner zone to reduce bound nitrogen compounds to molecular nitrogen and also allows radiation heat transfer to reduce peak flame temperatures. The tertiary air provides an overall oxidizing atmosphere to efficiently complete the combustion. These burner concepts can also be applied with other commercial burners. The use of tertiary air ports, however, does complicate the retrofit application by requiring modifications to pressure parts.

A type of low NO_x burner — which is actually a burner arrangement — specifically designed for tangential-fired boilers is the low NO_x concentric firing system developed by Combustion Engineering in conjunction with EPA. In the conventional tangential-firing arrangement the primary air/fuel and secondary air streams are aimed at the same imaginary circle in the center of the combustion chamber. In the concentric firing system (Figure 2-11), the secondary air is directed at a larger concentric circle and therefore the initial combustion takes place in an atmosphere of reduced oxygen because the primary air/fuel stream does not entrain the secondary air stream as rapidly as in the conventional arrangement.
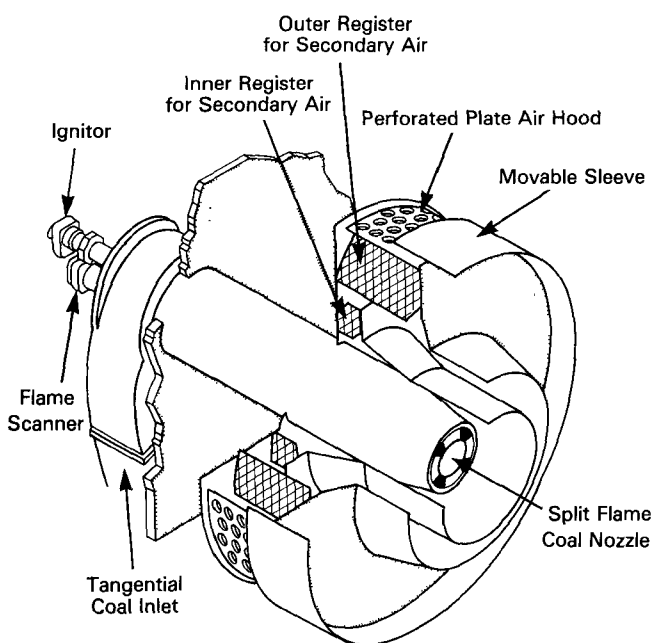
2.3.5 In-Furnace Destruction

This technology, which may be referred to as reburning or fuel staging, is here classified as a combustion modification technique, although it involves reduction of NO_x after it has been formed in the combustion zone. The technology is being investigated for both new and retrofit applications and for utility and large industrial boilers and for stationary engines, although it has not yet achieved full commercialization in the United States. The technology is applicable for pulverized coal, gas, or oil.

The principle of in-furnace NO_x destruction by reburning has been the subject of numerous investigations.(13,14,15,16) Although the basic reactions are similar to those that occur in staged combustion processes, the actual pathways are rearranged. The hydrocarbon fragments from the decomposing reburning fuel react directly with the nitrogen oxides from the primary zone to form fixed nitrogen intermediates (e.g., HCN), which can subsequently react under fuel-rich conditions to form molecular N_2. The actual extent of NO_x reduction depends on the time and temperature in the fuel-rich reburning zone. Above the reburning zone, overfire or burnout air is added to complete the com-

Figure 2-7.   Low NO$_x$ Burner: Babcock & Wilcox Dual Register Burner/Compartmented-Windbox System (11).
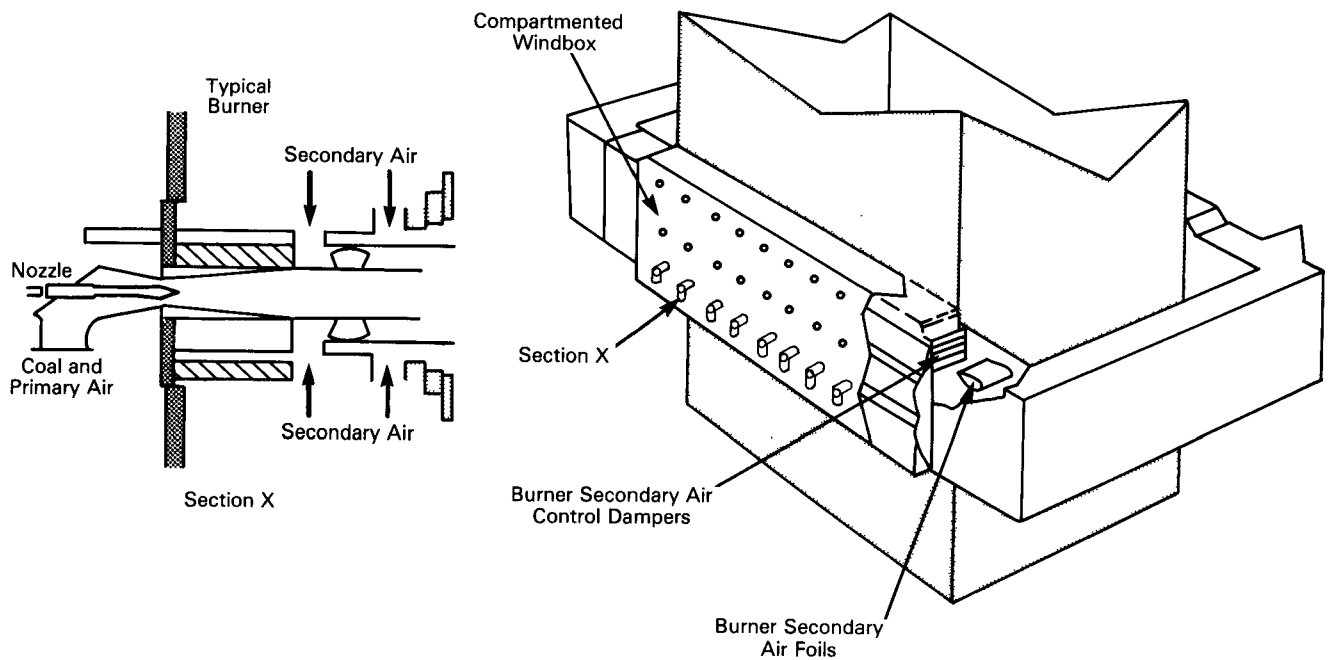
bustion of unburned material. In this zone, some of the nitrogen intermediaries can be reconverted to NO. Because of this reconversion there is an optimum fuel-rich stoichiometry that exists for the reburn zone.

Using the reburning concept originated by Wendt and Sternling, Mitsubishi Heavy Industries (Japan) developed the Mitsubishi Advanced Combustion Technology, or MACT, process (Figure 2-12). The process has been tested on various fuels and under conditions where the hydrocarbons for upper injection are the

Figure 2-8.   Low NO$_x$ Burner: Riley Stoker Controlled Combustion Venturi Burner (5).
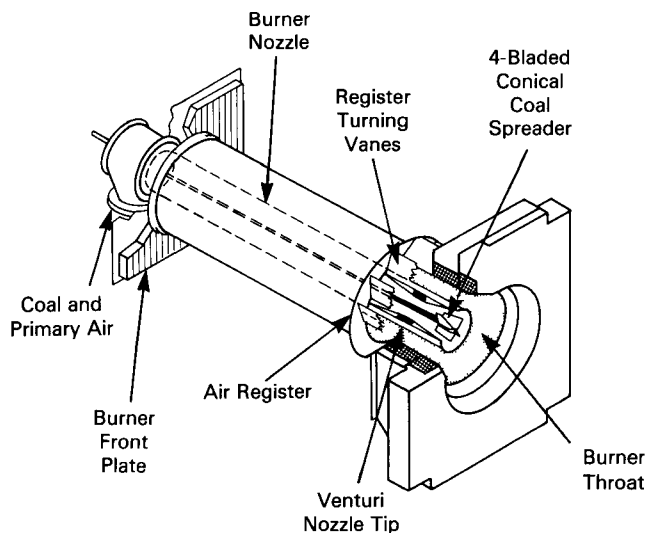
same as or different from the main boiler fuel. Since 1980 further advances have been made through EPA-funded extramural and in-house projects.(17,18,19,20) The process can be optimized by using low NO$_x$ burners in the primary combustion zone (e.g., the low NO$_x$ pollution minimum [PM] burners shown in Figure 2-12'

2.3.6   Other Types of Combustion Modifications
A significant number of additional combustion modifications are employed for reducing NO$_x$ emissions from specific sources. Most are employed for stationary engines or for turbines. Several of these are considered in this section and are shown schematically in Figure 2-13.

2.3.6.1   Lean Burning, Torch Ignition
This technology is applicable to stationary spark-ignition engines burning natural gas. In this technology, the air-to-fuel ratio is increased to a level not normally attainable by the use of spark ignition. An ignition chamber, rather than sparkplugs, is used in which a burning jet is created by igniting a fuel-rich mixture. This torch provides the ignition for the engine and extends the lean limit that otherwise would be limited by misfiring, incomplete combustion, or overworking the turbocharger. A possible drawback to this technology appears to be relatively high levels of hydrocarbon emissions; however, development work in this area is ongoing. The technology can be applied for new engines or on a retrofit basis; however, the latter could be quite involved and would also require extensive engineering to design and construct the most effective ignition chamber.

17

Figure 2-9.   Low NOx Burner: Riley Stoker Directional Flame Burner (5).

Section A-A'
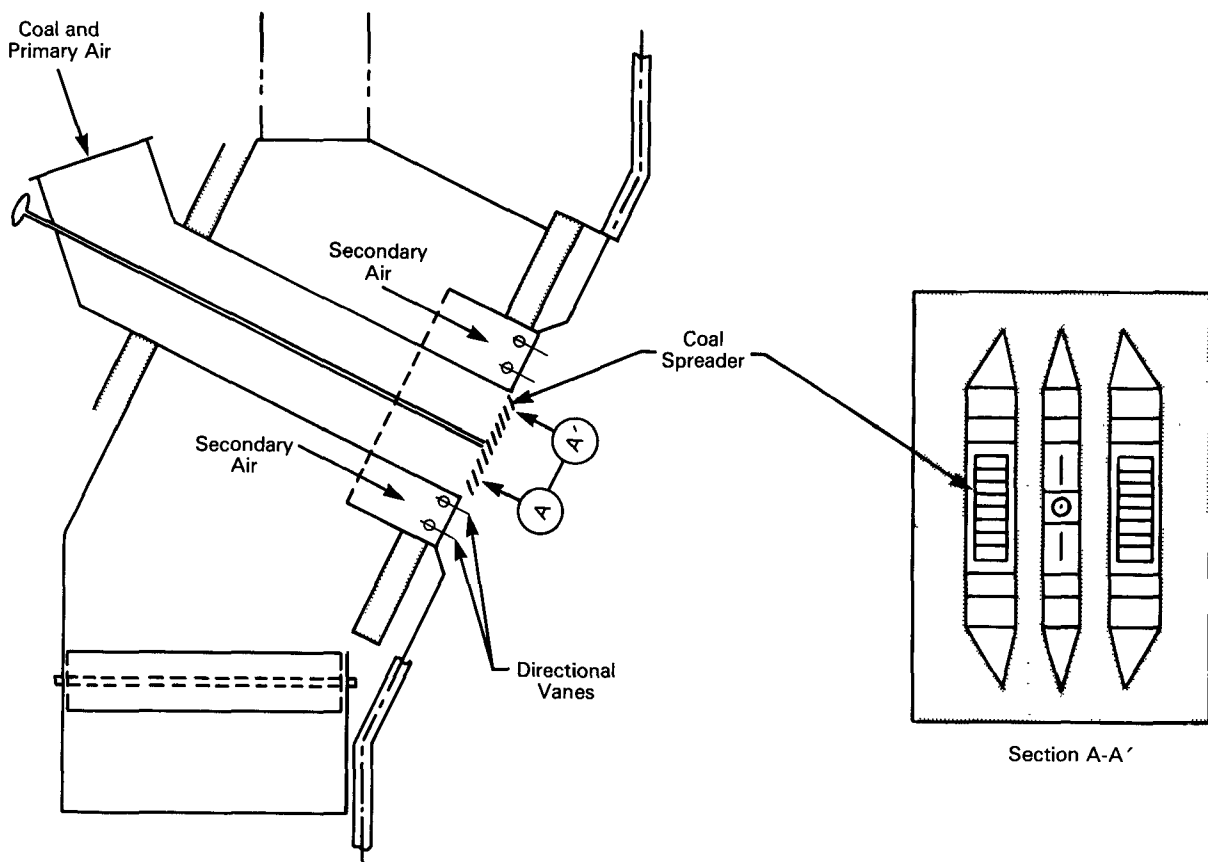
2.3.6.2 Turbocharging

Turbocharging, often employed primarily to increase an engine's available power, is a technology that also can be used to reduce NOx emissions by changing the fuel/air ratio to a leaner mixture for stationary engines. Turbocharging involves passing the engine exhaust through a turbine coupled to a compressor. The compressor provides higher pressure combustion air and therefore increases the mass of air in the cylinder per unit fuel.

Turbocharging is normally employed on a retrofit basis. In cases where air temperature rises significantly due to

Figure 2-10.   Low NOx Burner: EPA Distributed Mixing Burner (12).
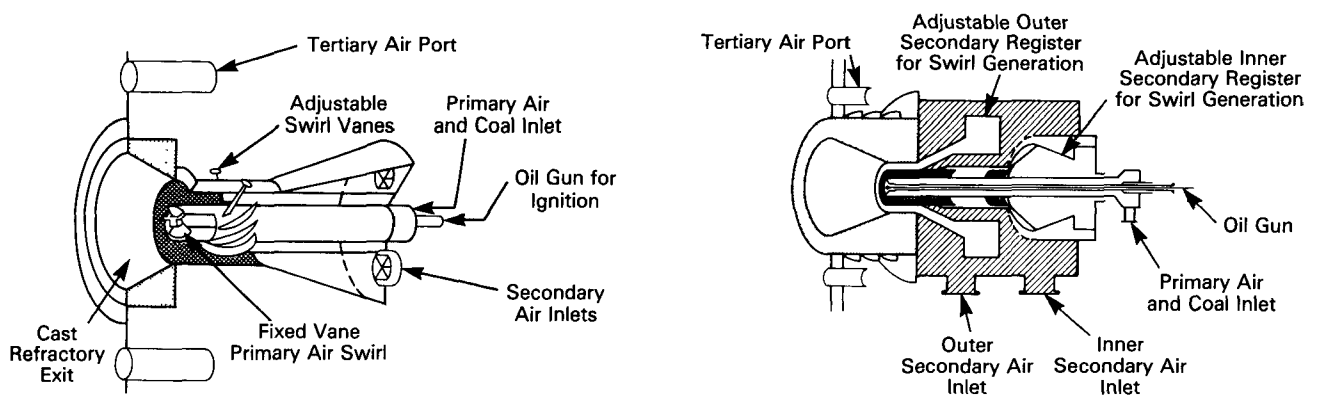
A. Development Distributed Mixing Burners (12.5, 50 and 100 x 10^6 Btu/h)

B. Full Scale Distributed Mixing Burner (12.5 x 10^6 Btu/h capacity)

18

Figure 2-11. Low NOx Burner: Combustion Engineering Low NOx Concentric Firing System (6).
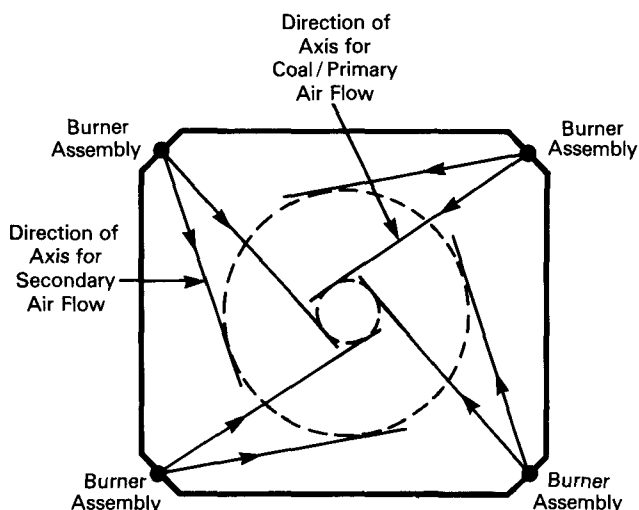
compression, an intercooler is also required. Turbocharging is applicable to compression-ignition (diesel) and spark-ignition (gas) stationary engines.

2.3.6.3 Charge Cooling

This technology, often referred to as charge refrigeration, is employed in diesel as well as spark-ignition stationary engines. Charge cooling can be applied on a new or retrofit basis. The NOx reduction principle is simply to decrease the peak flame temperature by cooling the air/fuel mixture prior to combustion. Normally, a refrigeration system is arranged as a heat exchanger upstream of the intake manifold to cool the combustion air. The air temperature reduction is usually on the order of 50 to 75F.

Charge cooling is often employed in conjunction with other NOx reduction techniques, particularly multiple

Figure 2-12. In-Furnace Destruction by Mitsubishi Advanced Combustion Technology (MACT) Process (21).
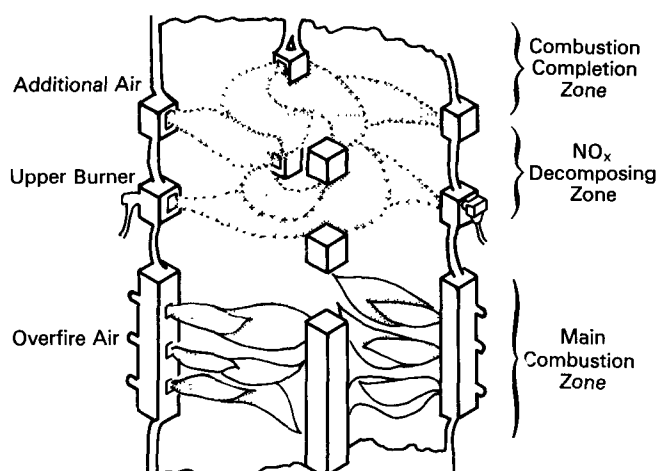
Figure 2-13. NOx Reduction Options for Stationary Engines.
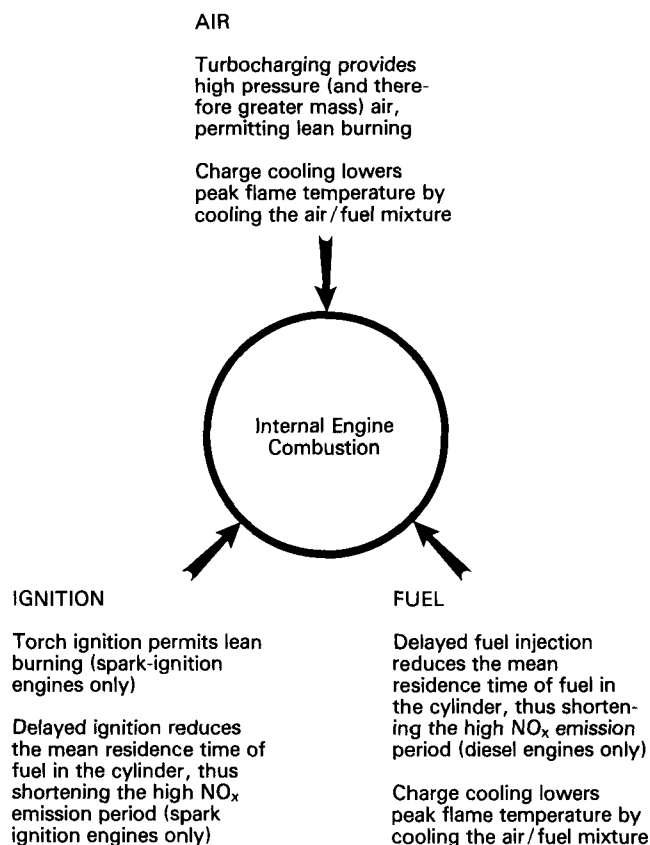
sparkplug firing, in order to rectify the problem of misfiring that is often experienced when combustion air is cooled to low temperatures.

2.3.6.4 Retardation

NOx emissions from all types of stationary engines can be reduced by adjustments that retard either the ignition timing (spark-ignition engines) or the fuel injection (diesel engines). This is strictly a retrofit technology and is normally applied with greater frequency on high-compression (diesel) engines and engines that run lean (such as turbocharged engines). Retarding both ignition and injection delay combustion for an instant. The theory is that the first portion of fuel that burns produces an inordinate amount of NOx because it is exposed to high temperatures the longest, and because it is heated by compression, while the balance of the fuel is burned. Therefore, this technology brings about a reduction in NOx formation by reducing the dwell time of the fuel in the cylinder.

An added benefit of NOx reduction by ignition or injection retard is an apparent reduction in emission of unburned hydrocarbons. However, there is often an increase in smoke emissions in diesel engines. Furthermore, cylinder exhaust valves are exposed to higher temperatures with this technology and may experience reduced life.

19

2.4 Postcombustion Technologies

There are many technologies for reducing NO_x once it has been formed by the combustion process. These do not compete directly with combustion modifications but rather are considered only after the easier to implement and less costly technologies have been exhausted and even more stringent control is required. Usually referred to as flue gas treatment (FGT) processes, these technologies are seldom cost-effective for moderate NO_x reduction when compared to combustion modifications for several reasons: relatively high initial cost, high operating cost, and possible waste disposal costs. Accordingly, these technologies are used when stringent regulations require high NO_x reductions. In the future, flue gas treatment may be the best approach for removal of NO_x and sulfur oxides, and a number of pro-cesses are under development to achieve these goals simultaneously.

FGT processes can be categorized as either dry or wet and can be further divided by the chemical reaction principles involved in the conversion. Figure 2-14 shows these processes, organized by type.

2.4.1 Dry Processes

A wide variety of dry processes are either commercially available or well along in research and development. They range from catalytic and noncatalytic reduction to adsorption processes and irradiation with electron beams. Dry processes usually involve less equipment and therefore are less costly than wet processes, and generally also produce less waste to dispose of.

2.4.1.1 Selective Reduction

Selective reduction technologies are either catalytic or noncatalytic. In the United States, both methods have been employed for oil-fired and gas-fired utility and in-dustrial boilers and process heaters and are being researched for use in coal-fired utility boilers. In addi-tion, catalytic processes have been used for spark-ignition stationary engines and for gas turbines.

In selective catalytic reduction (SCR), which is the most popular FGT process in international utility use today, ammonia is employed as the reducing agent. In the SCR process, NO_x is reduced to N_2 and H_2O by ammonia (NH_3) at 300-450 °C in the presence of a catalyst. NH_3 is an acceptable reducing agent for NO_x in combustion gases because it selectively reacts with NO_x while other reducing agents, such as H_2, CO, and CH_4, readily react with O_2 in the gases. Figure 2-15 shows a typical flowsheet for a selective catalytic process with am-monia. Flue gas from the boiler is passed through a reactor column which contains the catalyst bed. So-called parallel flow catalyst beds may be used in which the gas flows through channels rather than pores to minimize blinding of the catalyst by particulates. Am-monia vapor is injected into the flue gas upstream of the reactor. The treated flue gas then passes through the combustion air preheater and then to particulate and perhaps sulfur dioxide removal equipment before ex-iting up the stack. The major items of process equip-ment are the reactor and the equipment to store, vaporize, and inject ammonia.

In the early stages of its development, SCR had the following problems: catalyst poisoning by SO_x in the gas; plugging of the catalyst by dust; ammonium bisulfate deposition on the catalyst below about 300 °C; ammonium bisulfate deposition in the air preheater below about 250 °C; catalytic promotion of oxidation of SO_2 to SO_3; and erosion of the catalyst by fly ash from coal.(22)

Those problems have been addressed by the following countermeasures:

- Use of base metal catalysts with TiO_2 instead of Al_2O_3 or Fe_2O_3 substrates
- Use of parallel-flow type catalysts such as honeycomb, plate, and tube catalysts
- Maintaining the gas temperature above 330 °C by us-ing an economizer by-pass system

Figure 2-14. Classification of NO_x Flue Gas Treatment Processes.
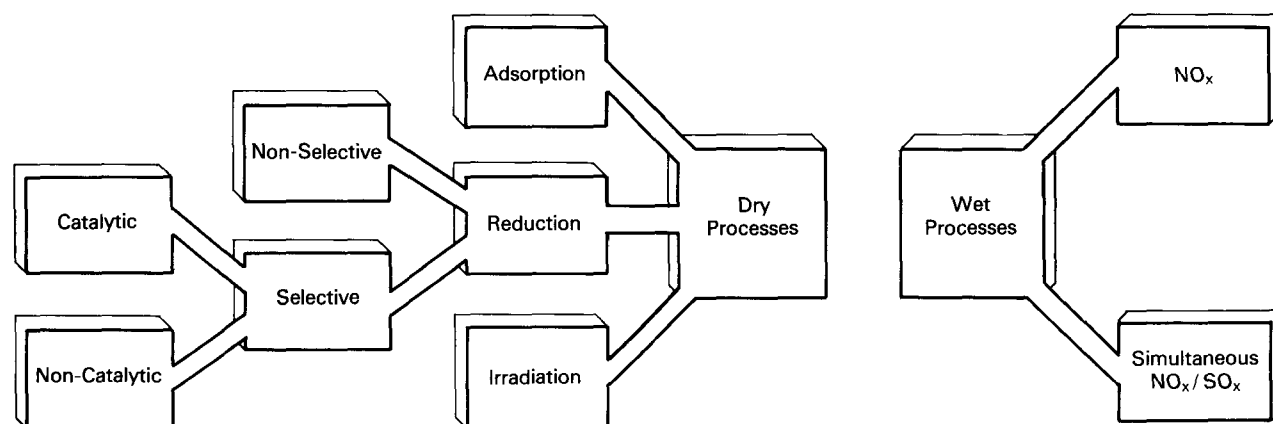
Blocks may represent several available processes, and many processes simultaneously remove SO_x.

Figure 2-15. Typical Flow Diagram for Selective (Ammonia) Catalytic Reduction Process (8).

Figure 2-16. Thermal DeNO$_x$ System — Process Flow Diagram (8).
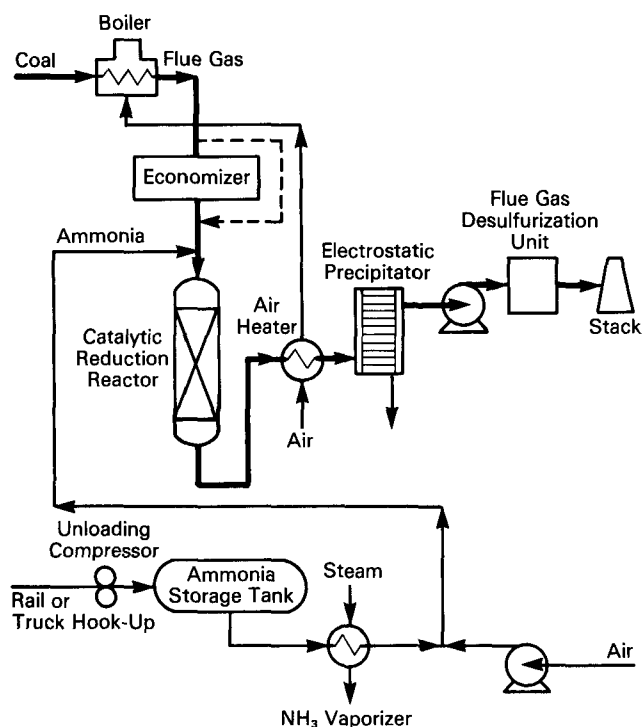
- Keeping unreacted NH$_3$ (NH$_3$ at the reactor outlet) below about 3 ppm
- Using a low-oxidation catalyst
- Using a moderate gas velocity, a hard catalyst, and a device for erosion prevention such as dummy spacer.

There are two noncatalytic selective reduction processes. The Thermal DeNO$_x$ process was developed by Exxon and is shown schematically in Figure 2-16. It employs ammonia as the reductant but the reaction is carried out at high temperature rather than under the influence of a catalyst. A similar process using urea as the reducing agent was developed by EPRI.(23) Both processes require that the reducing agent be injected directly into the superheater section of the boiler; it is therefore less complicated and expensive to retrofit than the catalytic process. However, temperature control is critical to avoid producing more NO or releasing unreacted reductant to the stack; therefore, ensuring that the injection is at the right place even though temperature patterns fluctuate is difficult and may limit the reduction efficiency. This process is being used for several boiler heaters, primarily on the West Coast.

2.4.1.2 Nonselective Reduction
This technology encompasses catalytic reduction without a reductant that is selective to NO. This

technology involves application, on a new or retrofit basis, of a catalytic converter of the type employed in most newer automobiles in the United States. The technology in terms of stationary sources is limited to stationary reciprocating engines, particularly rich-burn, spark-ignition engines.

This technology is applied by installing the catalytic converter in the exhaust line from the engine. The converter consists of a catalyst bed supported within a pressure-tight housing. Exhaust gas passes straight through with a large percentage of the NO reduced to molecular nitrogen. Catalysts employed are normally noble metals such as platinum.

2.4.1.3 Simultaneous NO$_x$/SO$_x$ Removal
Dry processes for simultaneous NO$_x$/SO$_x$ removal that are under development include reaction of sulfur dioxide (SO$_2$) with copper oxide simultaneous with selective catalytic reduction of NO$_x$ with ammonia; adsorption onto alkalized alumina; and irradiation with electron beams. Although many process concepts are promising, they have not been demonstrated commercially in the United States.

2.4.2 Wet Processes
Most wet flue gas treatment processes for NO$_x$ removal represent natural extensions of processes originally developed for SO$_x$ removal only. To date, wet processes are still in the developmental stage. Thus they cannot be considered as alternatives until they experience technical breakthroughs.

21

Chapter 3

Performance and Cost Data:
Utility and Large Industrial Boilers

3.1 Introduction

In this chapter data on NO$_x$ removal efficiency and associated cost are presented for actual operating technologies employed for utility and large industrial boilers. Systems are described in detail, including requirements for retrofitting the technologies to existing boilers. In general, performance and costs are more favorable for new unit installation since space and operational requirements can be designed into the unit. Retrofit costs and performance are usually quite site-specific due both to unique boiler characteristics and space constraints.

3.2 Coal-Fired Boilers

Coal-fired boilers are either pulverized coal-fired or stoker-fired, the latter usually involving small units. Most of the NO$_x$ control technologies developed for coal-fired boilers — and for boilers in general — have been developed for pulverized coal units. Data for these technologies are presented below, followed by discussions of technologies developed for stokers.

3.2.1 Pulverized Coal Boilers

The primary NO$_x$ reduction technologies for pulverized coal boilers have been low NO$_x$ burners, various types of staged combustion, and selective reduction techniques. Low excess air is easy to implement but may not bring about the required reductions. These technologies are presented below.

3.2.1.1 Low Excess Air

The effectiveness of low excess air firing for coal-fired utility boilers has been summarized for tests on boilers of the three most prevalent configurations.(14,24) The data are shown here in Table 3-1.

Note from Table 3-1 that for relatively modest reductions in excess air (for example, from 24 percent to 16 percent excess air, or a reduction of 8 percent for tangential firing), significant reductions in NO$_x$ emissions can be achieved. In most cases higher NO$_x$ reductions are precluded by operational problems that arise at lower levels of excess air. At very low excess air rates smoke and excessive carbon monoxide emissions result from incomplete combustion. Furthermore, depending on the type of coal fired, slagging and/or corrosion may increase to unacceptable levels and boiler tubes may suffer premature failure. Although it is currently a complex matter to predict the minimum level of excess air that will permit safe operation, further research in this area may both define the lower limit and perhaps extend it further with newer combustion chamber designs.

There is no significant additional cost to implement low excess air firing in new boilers.(3) In fact, decreasing excess air can in many cases actually reduce the cost of operating a boiler by increasing boiler efficiency as much as 5 percent. The estimated capital cost to retrofit a boiler for low excess air firing would be about $400 per

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Table 3-1.   Average Reported NO$_x$ Reduction with Low Excess Air Firing in Coal-Fired Utility Boilers (14).

| Equipment Type | Number of Tests | Baseline | | Low Excess Air (LEA) | | Average NO$_x$ Reduction, % | Maximum NO$_x$ Reduction Reported, % |
		Stoichiometry to Active Burners, %	NO$_x$ Emissions ppm dry @ 3% O$_2$	Stoichiometry to Active Burners, %	NO$_x$ Emissions ppm dry @ 3% O$_2$		
Tangential[a]	21	124	459	116	373	19	42
Opposed wall[b]	11	126	746	118	660	12	23
Single wall[c]	23	123	624	114	525	16	25
						(1)[d]	(3)[d]
Average (mean)	55	124	609	116	522	16	30

[a]Burners firing from the furnace corners on a tangent to an imaginary circle in the center of the boiler.
[b]Burners firing from two opposed walls in the furnace.
[c]Burners firing from only one wall in the furnace.
[d]Numbers in parentheses refer to boilers originally designed for coal firing with wet-bottom furnaces.
Note: To convert values in ppm (3% O$_2$) to lb/10^6 Btu, multiply by 0.0014 for coal and oil, 0.0012 for natural gas. (These factors are approximate and highly dependent on fuel characteristics.)

MW (1984 dollars), which is mostly for modifications to the combustion air handling system and windboxes.(25) A range of $640 to $740 per MW (1983 dollars) for capital cost, with a negligible annual cost, has also been reported.(7) Many operators require an oxygen trim system for low excess air firing to closely control the excess air rate; this will entail additional cost.

3.2.1.2 Burners Out of Service

One method of staging combustion in existing boilers is to employ burners out of service (BOOS). Figure 3-1 presents results for BOOS operation for several single wall-fired boilers in terms of NO_x reduction versus percent BOOS. For these tests the total number of burners ranges from 15 to 24, with those out of service from 2 to 8. For example, 2 of 16 burners out of service means 12.5 percent BOOS. The percentage reductions in Figure 3-1 represent between 100 and 600 ppm (dry, 3 percent oxygen basis), from baseline NO_x emissions of 400 to 700 ppm.

Figure 3-2 shows results for BOOS operation of horizontally opposed wall-fired boilers. Note that with two exceptions BOOS operation resulted in NO_x emission reductions of 15 to 30 percent from the baseline level. The Gaston Unit 1 boiler was equipped with specially designed (low NO_x) burners and therefore did not experience a dramatic NO_x reduction from BOOS operation.

Substantial NO_x reduction by BOOS operation has also been shown for tangential-fired boilers, as apparent from Figure 3-3. Again, there is a reasonably good correlation between degree of BOOS (percentage of

Figure 3-1. NO_x Reduction by BOOS for Single Wall-Fired Boilers Burning Coal at 120 Percent Excess Air (15,16).
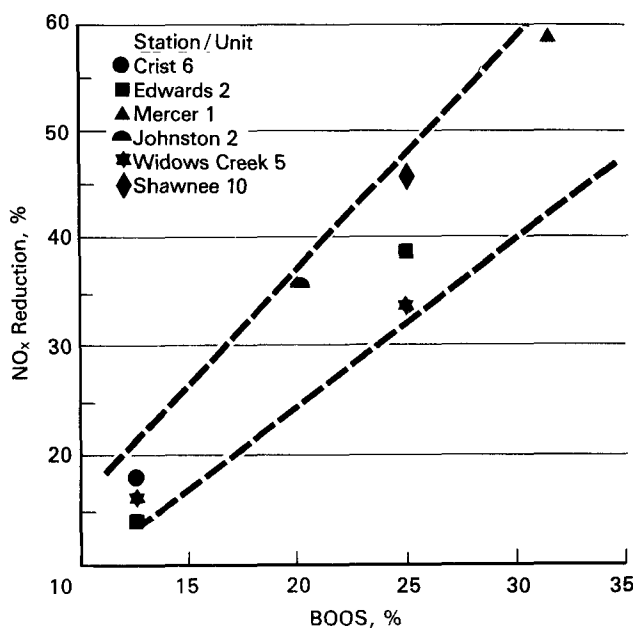
Figure 3-2. NO_x Reduction by BOOS for Horizontally Opposed Wall-Fired Boilers Burning Coal (15,16).
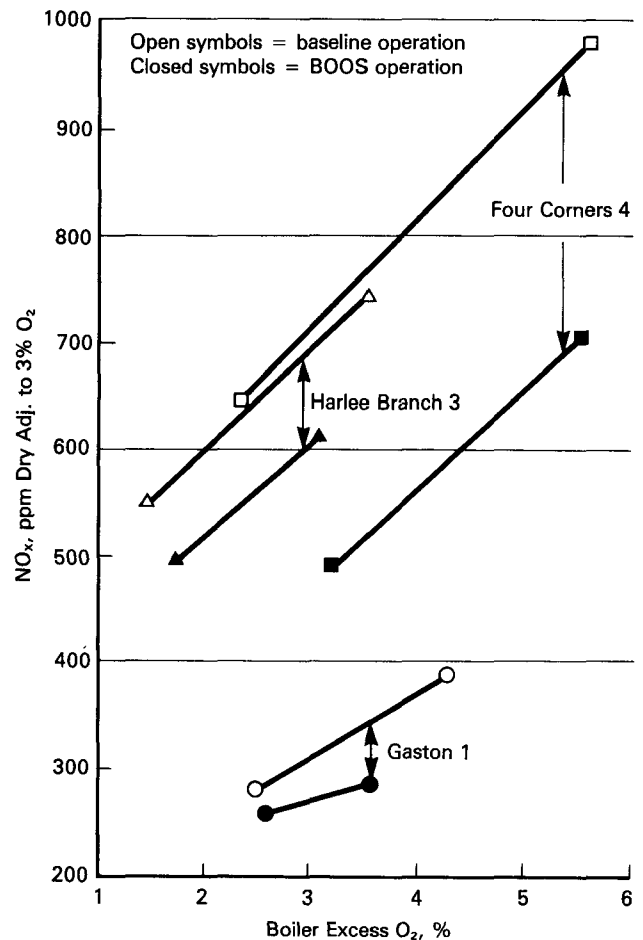
burners out of service) and NO_x reduction achieved. The units tested range in size from 16 burners (95 MW) to 56 burners (800 MW). For this boiler configuration the most effective BOOS pattern was observed to be operation with the top row of burners out of service, a pattern that simulates overfire air.

Retrofitting a coal-fired boiler for BOOS operation normally does not involve a significant capital expense. However, there are subtle costs involved in such a retrofit that are difficult to predict. Considerable experimentation may be required to find the optimum number and arrangement of burners to be taken out of service, although most BOOS patterns consist of taking burners out of service in the upper regions of the boiler. In any case, a BOOS design creates fuel-rich and oxygen pockets that essentially stage the combustion. This not only takes operator and management time but also requires testing the flue gas for NO_x as well as for smoke and carbon monoxide. Tests are necessary to verify the arrangement that will minimize NO_x while holding smoke and carbon monoxide emissions to acceptable levels. Each case will be different in that there are no "normal" or "average" combinations of coal pro-

perties, boiler layouts, and combustion conditions. BOOS may also require a boiler derating if the pulverizer mills cannot supply the additional fuel to the lower (in-service) burners. If so, there may be a substantial additional cost for replacement power.

3.2.1.3 Biased Firing

Little performance or cost information is available for biased firing in coal-fired boilers. The meager data that are available indicate that NO_x reductions on the order of 7 to 8 percent were found in limited testing.

3.2.1.4 Overfire Air

Overfire air is a new and retrofit technology for staging combustion in coal-fired boilers (including stoker-fired boilers). It has been used extensively, especially for tangential-fired boilers where it is offered for new boilers. A typical overfire air retrofit is shown schematically in Figure 3-4.

Limited data are available on the effectiveness of overfire air for single and horizontally opposed wall-fired boilers. A 22 percent NO_x reduction was achieved in a test of simulated overfire air in which the top row of burners in a single wall unit was taken out of service. This mode of operation provided about 16 percent of the total air as overfire air to the boiler. Tests of a horizontally opposed 350 MW unit showed NO_x reductions of 50 percent and higher (from a baseline of 650 ppm) with a significant (greater than 50 percent) amount of air delivered as overfire air. Although impressive, this testing was limited and further verification in the field is required.
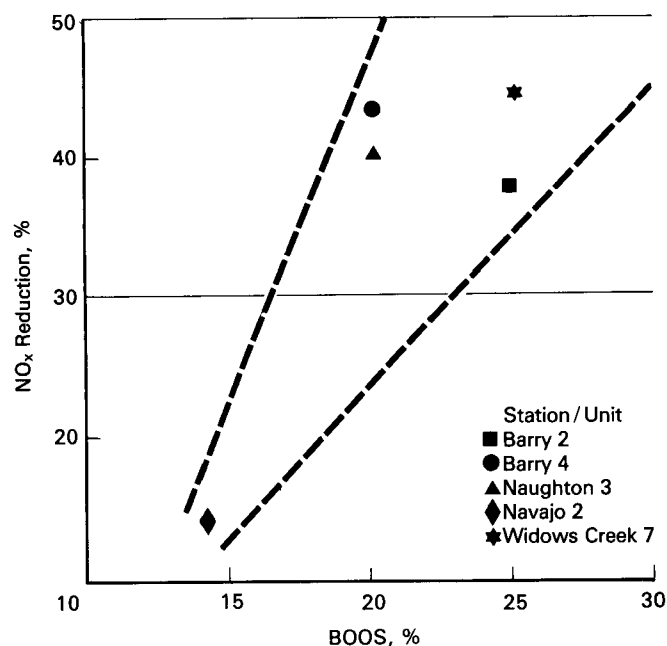
Figure 3-4. Typical Retrofit Arrangement for Overfire Air (26).

F - Fuel and air
A - Air
O - Overfire air
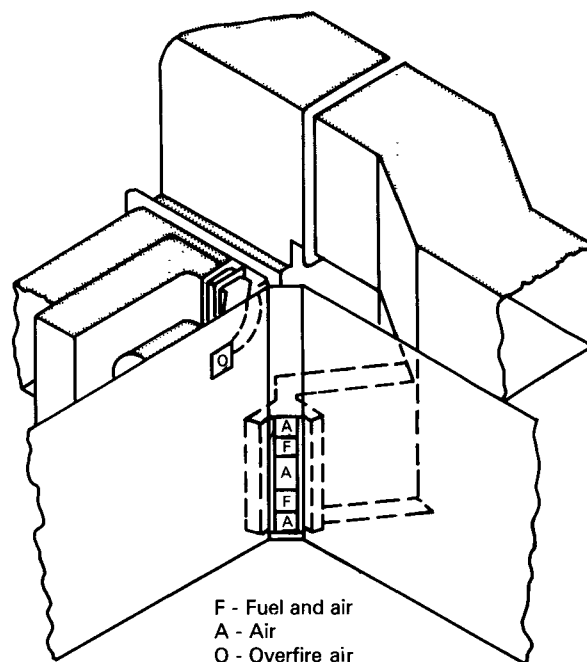
Substantial data showing the effectiveness of overfire air for NO_x control are available for tangential-fired boilers. Figure 3-5 shows the reductions achieved in tests at three boilers ranging in capacity from 130 to 800 MW, each operating at 120 percent excess air. Note that significant (10 to 30 percent) reductions were achieved at relatively high overfire air rates. A 1980 Acurex Corporation study reported on 46 tests of tangential-fired boilers wherein NO_x emissions were measured for the baseline condition and the condition of overfire air. The results are shown in Table 3-2. Note from Table 3-2 that diverting about 20 percent of the total combustion air to the overfire air ports resulted in an average reduction of 31 percent in NO_x emissions.

Considerable cost data are available for retrofitting overfire air to existing boilers. Figure 3-6 presents capital cost in terms of dollars per kilowatt versus boiler size in megawatts. Note that data are from three different sources and that the actual boiler modifications were likely to be different for each. Therefore a cost range has been designated, as the shaded area indicates. Note also that the cost data plotted are from three different time periods.

Table 3-3 summarizes capital and annualized costs (1983 dollars) for retrofitting three model-sized boilers with overfire air. For retrofits, overfire air is in general relatively inexpensive; it mainly involves the installation of several ports above the burner rows and the associated air piping. Low excess air is the least costly option and in larger sizes may actually provide a net credit due to increasing the efficiency of the boiler.

Figure 3-3. NO_x Reduction by BOOS for Tangential-Fired Boilers Burning Coal (15,16).

Station / Unit
■ Barry 2
● Barry 4
▲ Naughton 3
◆ Navajo 2
★ Widows Creek 7

Figure 3-5. NOx Reduction by Overfire Air For Tangential-
Fired Boilers Burning Coal (7).

Figure 3-6. Costs of Retrofitting Coal-Fired Boilers for
Overfire Air (7).
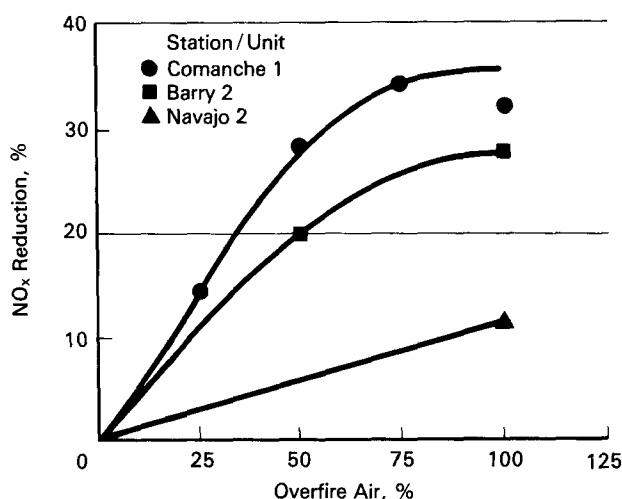
3.2.1.5 Arch Firing

Because this technology involves elemental changes in the design of a boiler, it cannot be conceived of as a retrofit technology but rather must be viewed as a potential "new" technology. Arch firing is a technology primarily limited to boilers firing difficult-to-burn anthracite coal and coke and a small number of bituminous coal-fired units of Wisconsin Electric Power Co.(27) There are few studies comparing the effectiveness of arch firing and wall firing from which a meaningful estimate of NOx reduction could be calculated. Tests of existing arch-fired boilers (27) have shown that NOx emissions are on the order of 200 to 350 ppm NOx (at 3 percent oxygen), which is relatively low for "uncontrolled" NOx emissions. However, the units tested were relatively small, ranging in capacity from 80 to 265 MW; most of the units constructed in the future would be expected to be in a larger size range.

Available data (27) indicate that the total installed cost for a base arch-fired boiler (500 MW) is estimated to be 5.4 percent greater than the cost of a comparable wall-fired unit; an alternate arch-fired boiler was estimated to cost 26 percent more than the base wall-fired unit. The alternate unit selected corresponded to a larger boiler due to different geometry, although it too was rated at 500 MW.

3.2.1.6 Low NOx Burners

Burners have been designed, primarily by equipment and boiler vendors, that are inherently low in NOx pro-

duction, usually because of internal combustion staging. Many of these burners have been tested at laboratory, demonstration, and full scale, with corresponding data for NOx reductions achieved and cost. The data available on cost are usually for retrofitting an existing boiler. The reader is cautioned, however, that the performance and cost data presented below are for specific applications and are given as examples of achievable results. Particularly for retrofits, every case will be different and more than one NOx reduction technology may be required in some retrofit applications.

Riley Stoker Corporation has developed and tested the Controlled Combustion Venturi (CCV) burner for retrofitted wall-fired boilers. Figure 3-7 shows results of pilot-scale tests for the traditional Riley flare burner and the CCV burner. The tests were conducted at the EER Corporation test facility at firing rates up to 50×10^6 Btu/h. The NOx reductions achieved by the CCV burner were about 55 percent compared to the baseline of the flare burner.

The effectiveness of the CCV burner as a retrofit to replace the traditional flare burner was also tested for full-scale operating units. A single-wall boiler rated at 400 MW was tested before and after replacing the 24 flare burners with CCV burners.(5) The NOx emission

Table 3-2. Average Reported NOx Reduction with Overfire Air Firing in Tangential Coal-Fired Utility Boilers (14).

| Number of Tests | Baseline | | Overfire Air (OFA) | | | | |
	Stoichiometry to Active Burners, %	NOx Emissions ppm dry @ 3% O2	Stoichiometry to Active Burners, %	Furnace Stoichiometry, %	NOx Emissions ppm dry @ 3% O2	Average NOx Reduction, %	Maximum NOx Reduction Reported, %
46	129	454	105	122	311	31	41

Table 3-3.   Cost of Retrofitting Coal-Fired Boilers for Overfire Air (7)
(1983 dollars)

Overfire Air	MW	Capital Invest. $/kW	Annual Capital $/kW	Oper. $/kW	Fuel $/kW	Annual Total $/kW	Electrical mills/kWh
New	250	0.30	0.054	0.005	—	0.059	0.011
	500	0.20	0.036	0.003	—	0.039	0.007
	750	0.15	0.027	0.003	—	0.030	0.005
Retro	250	1.17	0.21	0.02	—	0.23	0.043
	500	0.75	0.14	0.01	—	0.15	0.027
	750	0.60	0.11	0.01	—	0.12	0.022

rate was reduced approximately 50 percent to levels of 320 to 440 ppm (3 percent oxygen) while burning a high volatile "C" bituminous coal at 22 percent excess air. Loss on ignition tests of combustible materials in the ash established a decrease in boiler efficiency of only 0.25 percent.

Also tested was a 360-MW, horizontally opposed boiler with a total of 24 burners.(5) After retrofitting with CCV burners the NO_x emission level fell from 810 ppm to between 353 and 397 ppm (all on 3 percent oxygen basis). Again, no significant adverse effects on boiler performance were noted.

The Controlled Flow/Split-Flame (CF/SF) burner has been developed by Foster Wheeler Energy Corporation and has been tested on a variety of pilot and full-scale

units. Figure 3-8 presents idealized NO_x emissions versus burner stoichiometry for the CF/SF burner as compared to the intervane burner which represents the baseline case for retrofitting a Foster Wheeler boiler. Foster Wheeler has also tested NO_x emissions for a 360-MW front wall-fired boiler and a 525-MW opposed-fired boiler as well as for a 50×10^6 Btu/h test burner, all equipped with CF/SF burners.(10) Although none was tested before retrofit, the company claims NO_x reductions of about 60 percent by retrofitting with CF/SF burners. Currently, two domestic utility boilers are operating with retrofitted CF/SF burners: a 350-MW

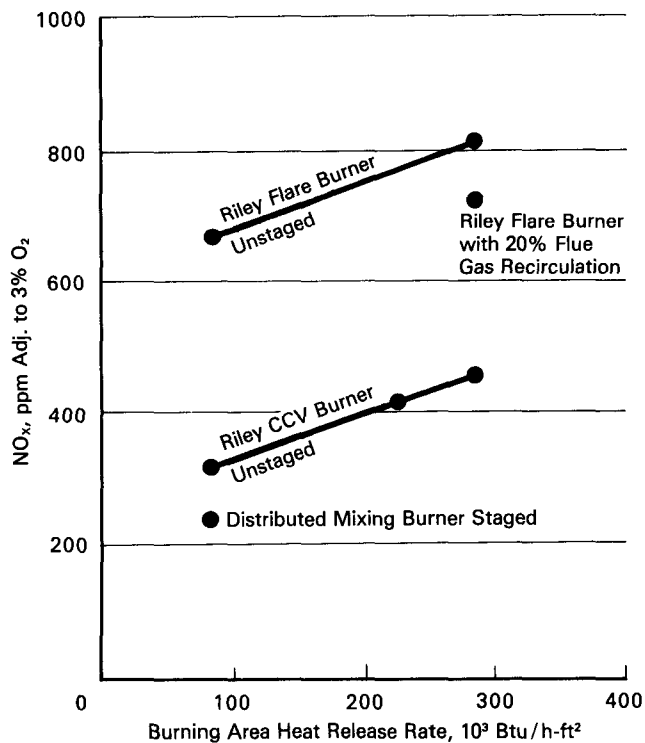Figure 3-7.   Pilot-Scale Test Results for the CCV Burner (5).

Figure 3-8.   Theoretical NO_x Emissions Versus Burner Stoichiometry for the Controlled Flow/Split Flame Burner (10).
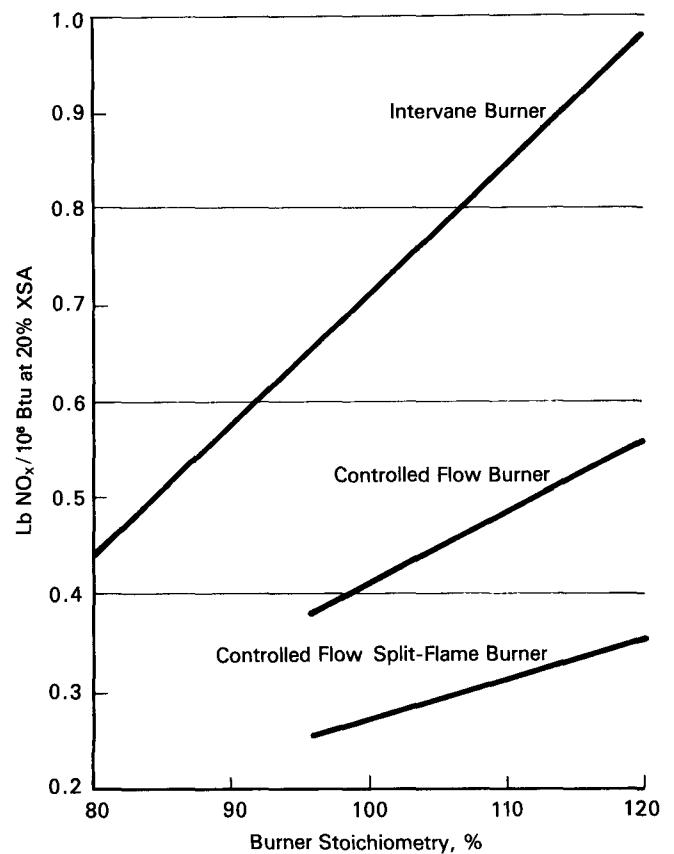
single-wall-fired unit and a 525-MW opposed-fired unit. Tests indicate that both units operate at well below the NSPS limit of 0.5 lb/10⁶ Btu for subbituminous coal.(10)

Foster Wheeler, in conjunction with EER Corporation and EPA, has also developed the Distributed Mixing Burner (DMB). Full-scale test results may be available presently but to date the bulk of data available are for research burners and in some cases for research furnaces.

Babcock & Wilcox Company developed the Dual Register burner early in the history of low NO_x burners and as a result, several thousand of these burners have been sold domestically, mostly for new wall-fired boilers. This burner has also been retrofitted and in fact, the company's NO_x emission guarantees are based on extensive testing in a retrofitted boiler. Considerable data are available on the emissions and emission reductions achievable with this burner simply because there are so many currently in use. Figure 3-9 shows the performance of the dual register burner compared to the B&W circular burner it has replaced. Note that the reductions achieved are on the order of 50 to 60 percent throughout the range of boiler sizes and are nearly all comfortably below the NSPS level of 0.5 lb/10⁶ Btu for subbituminous coal.

Babcock & Wilcox is also, in conjunction with EPRI, developing a retrofit low NO_x burner to replace B&W cell burners.(28) Cell burners, inherently high in NO_x emissions, represent a significant segment of the pre-NSPS pulverized coal-fired boiler population. Each cell consists of two circular burners mounted together to produce a high-velocity turbulent flame in horizontally opposed wall-fired boilers.

The company has developed two low NO_x replacement burners, able to be retrofitted into the existing cell. One is a cell in which the upper burner supplies overfire air only; the other is a pair of distributed mixing burners. In pilot-scale testing the former arrangement provided 65 percent NO_x reduction (Figure 3-10). In addition to reducing NO_x emissions to below the NSPS level, the pilot tests of the ash revealed that for both coals tested, operation with low NO_x burners resulted in slightly lower levels of unburned hydrocarbons, suggesting that thermal efficiency is preserved after retrofit.(28) This burner arrangement is currently being evaluated in an actual operating boiler of 610 MW capacity, and will undergo further subscale tests in an EPA test facility.

Low NO_x burners for tangential-fired boilers have been developed primarily by Combustion Engineering, Inc., and their licensee, Mitsubishi Heavy Industries. The Low NO_x Concentric Firing System (LNCFS) was developed by C-E primarily as a retrofit technology for existing coal-fired boilers.

In conventional tangential firing, the burners are corner mounted with their axes tangent to an imaginary circle in the center of the boiler. In LNCFS, the auxiliary air is directed at a larger concentric circle so that the flame front is stabilized and the devolatilization of the coal occurs in a fuel-rich atmosphere. The retrofitting involves modifications to the boiler windboxes alone; therefore, strictly speaking the LNCFS is not really a low NO_x burner. However, modifications of this type are often classified as low NO_x burners.

Results of full-scale (400 MW) tests of the LNCFS versus the conventional burner arrangement are shown in Figure 3-11. Note that NO_x reductions on the order of 20 to 30 percent from baseline levels of 460 to 480 ppm are

Figure 3-9. NOx Emissions for Dual Register Versus Circular Burners in Coal-Fired Boilers (14).
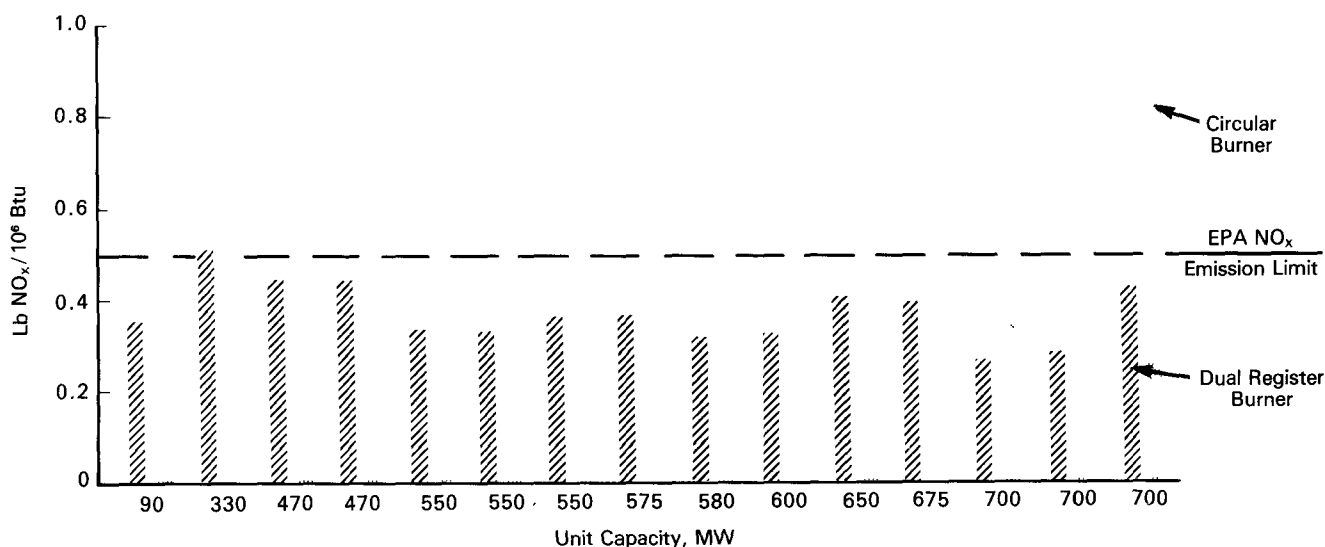
Figure 3-10.   Pilot-Scale Results for NOx Reduction by Low NOx Cell Retrofit Burners (28).

□ Standard cell burner with Ohio No. 6
■ Standard cell burner with lower Kittaning
△ Low NOₓ cell burner with Ohio No. 6
▲ Low NOₓ cell burner with lower Kittaning
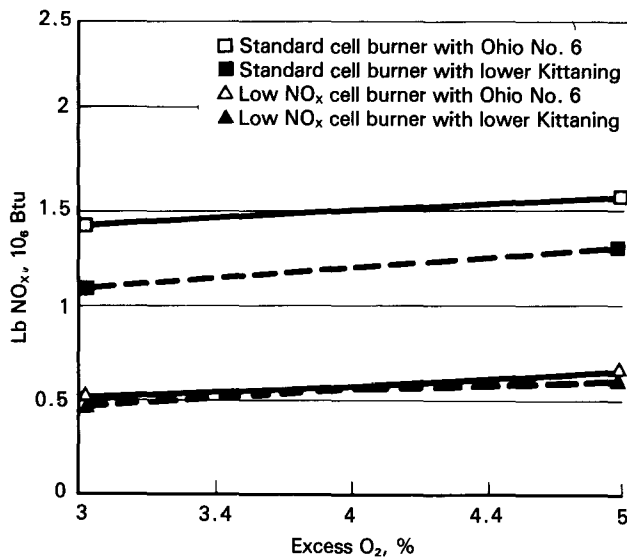
possible. Even greater reductions can be achieved where overfire air is employed in addition to retrofitting with LNCFS (Figure 3-12). In these tests, potential impacts on boiler efficiency were gauged by unburned carbon in flyash. Levels of unburned carbon in flyash were actually lower after retrofit (on an equivalent NOₓ emission basis), indicating no adverse impact of the LNCFS on efficiency.(6)

MHI has also developed the Low NOₓ Pollution Minimum (PM) Burner System to meet stringent NOₓ

Figure 3-11.   NOx Emissions for the Low NOx Concentric Firing System in Coal-Fired Tangential Boilers: No Overfire Air (6).

Full load (390-420 MW)
No overfire air
● Baseline
■ Postmodification
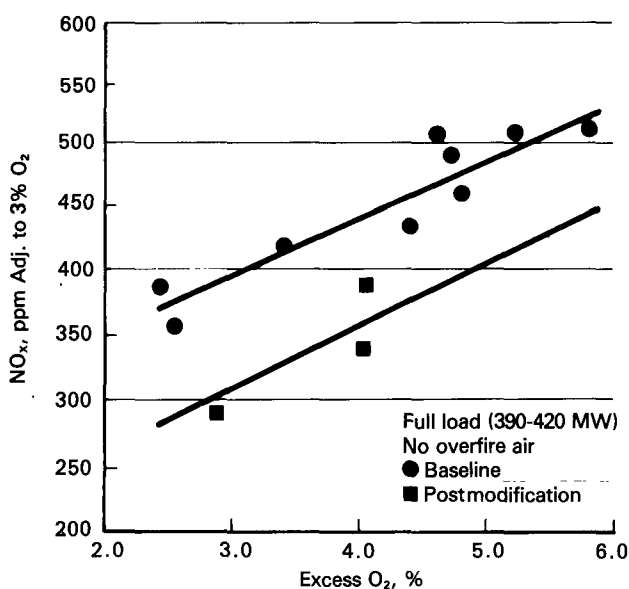
regulations in Japan. The PM burner basically divides the coal/air mixture into fuel-rich and fuel-lean streams and supplies auxiliary air in an intricately designed windbox. The design is a refinement of the SGR burner that itself was a wall-fired version of the LNCFS concept.

Projections of NOₓ reductions for a 600-MW boiler and a 575-MW divided boiler are shown in Table 3-4. Note the significant NOₓ reductions estimated over conventional tangential firing. Case I refers to a retrofit designed for minimum boiler modifications, while Case II refers to a retrofit where maximum NOₓ reduction was the goal. The "new unit" was actually Plant A retrofitted in such a manner as to reflect how the boiler would be constructed if new.

The cost of retrofitting with the PM burner system is given later in this chapter.

Figure 3-12.   NOx Emissions for the Low NOx Concentric Firing System in Coal-Fired Tangential Boilers: Full Overfire Air (6).

Full load (390-420 MW)
Full overfire air
● Baseline
■ Postmodification
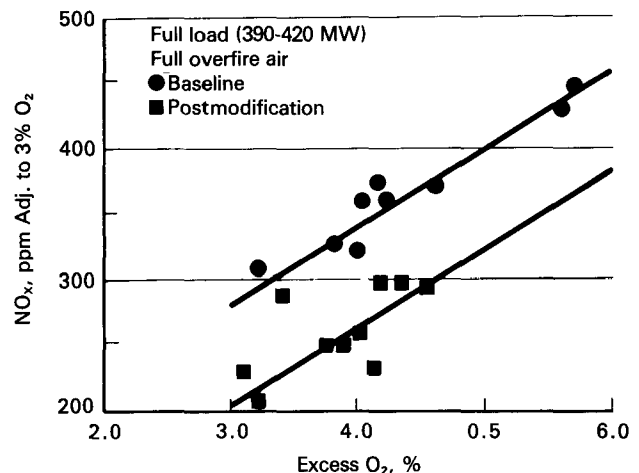
3.2.1.6.1 Side Effects of Low NOₓ Burner and Staged Combustion

Commercial methods of reducing NOₓ in coal-fired boilers are often characterized by two conditions potentially detrimental to the longevity of boiler tubes: a reducing atmosphere that may promote slagging and remove the oxidized coating of tubes and expose them to accelerated corrosion; and flame impingement resulting from longer flames which can overheat tubes and cause premature failure by thermal stress.

Air staging (BOOS or overfire air) can potentially result in increased tube wall corrosion. Proper application and design can minimize or even eliminate corrosion.(17)

Extensive testing of the corrosion potential of low NOₓ operation has been conducted with major conclusions as follows:

• It is critical that the burner and boiler design and operating conditions avoid sulfidation of tubes by

Table 3-4. NOₓ Performance for PM Burner System in Tangential-Fired Boilers (6)

	NOₓ Guarantee[a] ppm	% NOₓ Reduction
Plant A[b]		
Case I	190	46[d]
Case II	150	57[d]
New Unit	150	57[d]
Plant B[c]	160	50[e]

[a]Corrected to 3% O_2.
[b]600 MW boiler.
[c]575 MW divided boiler.
[d]Based on Plant A emissions of 350 ppm corrected to 3% O_2.
[e]Based on Plant B emissions of 320 ppm corrected to 3% O_2.

flame impingement of unburned sulfur pyrites and corrosion by liquid pyrosulfate.

- Proper selection of materials of construction can minimize stress corrosion from alternating oxidizing and reducing environments.

- Corrosion can be minimized by selection of certain stainless steels and other alloys over carbon steel.

While corrosion is the side effect of most concern resulting from low NOₓ combustion, there are several others, which become constraints on how the unit is controlled:

- Increased carbon monoxide emissions which may be generated by incomplete combustion at very low excess air rates

- Smoke (carbon) emissions which may likewise increase as a result of low excess air

- Problems associated with flame instability

- Limits on flexibility of the combustion unit (changes in load)

- The presence of carbon in the fly ash.

These problems may impose limits on fuel switching or even require a derating of the unit.

3.2.1.6.2 Cost of Low NOₓ Burners

Data on the cost of retrofitting coal-fired burners are not plentiful and the data that are available are naturally highly site-specific. However, a few examples are presented here in order to show the magnitude of the cost of such retrofits. In terms of new boilers, the incremental cost of the low NOₓ burners themselves is impossible to separate out. Low NOₓ burners or controls such as low excess air, biased firing, and so on have become state-of-the-art and thus are offered as standard equipment for new boilers at relatively low investment cost.

Figure 3-13 shows the cost (1983 dollars) in terms of dollars per ton of NOₓ removed for retrofitting boilers of two different ages with the Foster Wheeler controlled flow/split flame burner. Note that because of increased capability to fire at low loads without significant auxiliary fuel, the costs are presented as a function of "oil reduction" in hours per year, which means the hours that the original Class 1 ignitors (which fire auxiliary oil

Figure 3-13. Offsetting Retrofit Costs of Controlled Flow/Split Flame Burners with Oil Savings*(10).

Reduction in Oil Usage by Auxiliary Oil Burners, h/yr
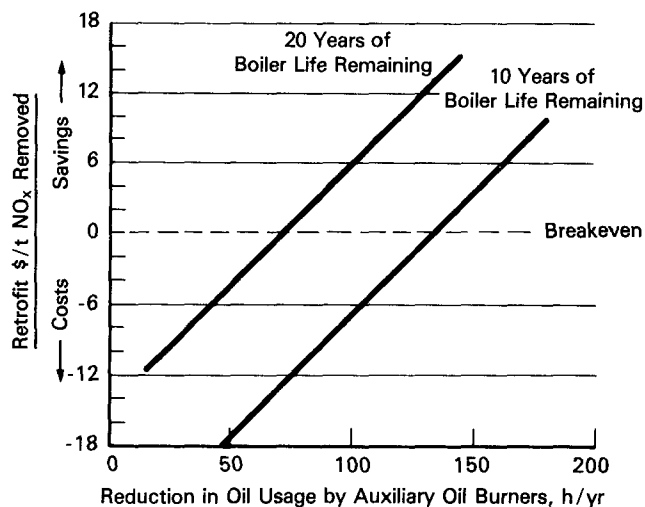
*This offset is a function of remaining boiler life, reductions in annual oil usage by auxiliary oil burners (expressed in hours per year), and the retrofit cost of the controlled flow/split flame burners (expressed as dollars per ton of NOₓ removed).

to sustain combustion at low boiler loads) are not fired. Further note that for the newer boiler, oil reduction in excess of about 70 hours per year will offset the cost of retrofitting and bring about a net savings at higher values.

Estimated capital and annual power costs for retrofitting with PM burners are shown in Table 3-5 in 1981 dollars. Note the high capital cost for the extensive modification (Plant A, Case II) and for the retrofit in a divided boiler (Plant B). These costs are from a feasibility study (29) and are only presented as an example. Every retrofit is a special case with a corresponding cost that may not apply to any other boiler.

Table 3-5. Cost of Retrofitting with PM Burners[a](20) (1981 dollars)

	Total Capital $/kW	Power Costs mills/kWh
Plant A		
Case I	7.91	0.22
Case II	15.90	0.45
New Unit	5.44	0.15
Plant B	14.29	0.40

[a]Confidence levels ±20%.

3.2.1.7 Reburning

There have been a number of development efforts, initially in Japan, to apply reburning for the control of NOₓ from large industrial and utility boilers. The activity in the United States has extended this technology to other combustion sources and to the consideration of simultaneous SO_2 control by dry sorbent injection.

These have been supported by EPA, Department of Energy (DOE), EPRI, and GRI. Several specific technologies have arisen such as MACT (for Mitsubishi Advanced Combustion Technology), an application to cyclone combustors (Japanese Ministry of International Trade and Industry) (30), an application to furnaces (Hitachi Zosen) (31), and the In-Furnace NOₓ Reduction (IFNR).(32)

The bench- and pilot-scale results have generally demonstrated greater than 50 percent reduction of NOₓ using between 10 and 20 percent of the fuel for reburning.(30,32,33,34) A relatively complete data base is available on the impact of the major process variables from these studies. The data indicate that less reduction can be achieved at lower initial NOₓ levels and that the parameters within the reburn zone control the achievable NOₓ reduction. In particular, the reburn fuel type can have a significant impact on the level of control. The nitrogen in the reburn fuel is an impediment to the process. Natural gas is an effective reburn fuel because it has no fuel nitrogen, reacts rapidly so that short reburn zones are achievable, does not slag or have burnout problems as with other fuels, can achieve more reduction in NOₓ especially at lower initial values, and finally, can work at lower temperatures. Pilot-scale tests with practical times, temperatures, and primary fuels have generally demonstrated over 60 percent reduction.(35,36) EPA in-house tests have shown that distillate oil is slightly more effective than natural gas as a reburn fuel.

Full-scale test results are available for a 600-MW tangentially fired boiler (37) firing coal and oil and using oil as the reburn fuel. There were five burner elevations for oil and two for coal. Figure 3-14 shows the results which are for a 90:10 ratio of oil to coal. Note that NOₓ reductions on the order of 40 to 50 percent were found in these tests. There are no known instances of full-scale testing of reburning for coal-fired boilers in the United States, although a number of studies are currently underway.

3.2.1.8 Slagging Combustors

Recently there has been a significant amount of research at the laboratory and pilot scale concerning slagging or external combustion. The technology has emerged out of the field of magnetohydrodynamic (MHD) power generation where such combustors are used to provide heat to ceramic heat exchangers.(38) In certain applications, especially in converting gas- or oil-fired boilers to coal firing, it is advantageous or necessary to initiate combustion external to the boiler and to remove slag from the combustion gas prior to entry into the boiler. For boilers designed for oil or gas firing the use of coal would result in fouling of heat transfer surfaces and plugging of the boiler gas passages, rendering the boiler inoperable in a short time period. The benefits which accrue from the retrofit of coal-fired boilers are greatly reduced boiler tube wastage, NOₓ and sulfur dioxide emission reduction,

Figure 3-14. NOₓ Reduction by MACT for a 600-MW Coal/Oil Boiler (37).
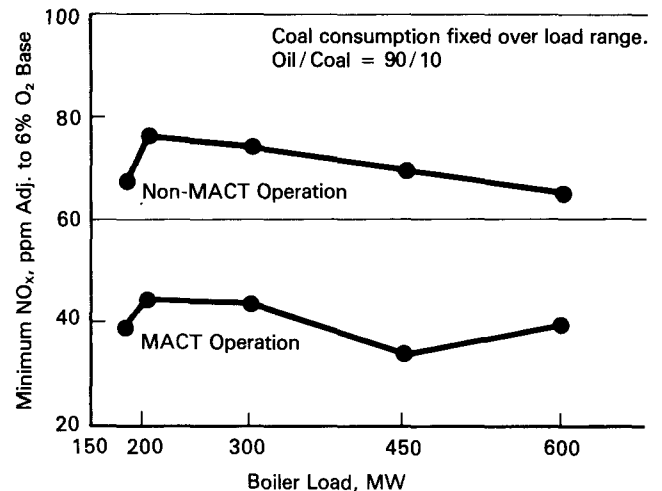
and greater efficiency that would result from reduced coal flyash deposits on boiler heat transfer surfaces.

In slagging combustion the initial combustion process is carried out quickly and under fuel-rich conditions so that formation of fuel NOₓ is minimized.

Sulfur oxides can be absorbed in this stage usually by addition of a calcium-based sorbent. The sorbent reacts with the SO_2 to form solids which are removed with slag or collected in the particulate emission control device. Provided a brief cooling period is allowed before the gas enters the boiler, overfire air can be added to complete combustion without significant formation of thermal NOₓ.

Several configurations of slagging combustors have been tested at a pilot scale where the radiant heat transfer of a boiler has been simulated. Results of some tests are shown in Figures 3-15 and 3-16 on different configurations. Note in Figure 3-15 that the low

Figure 3-15. NOₓ Emissions from a Slagging Combustion Pilot Plant Firing Coal (39).
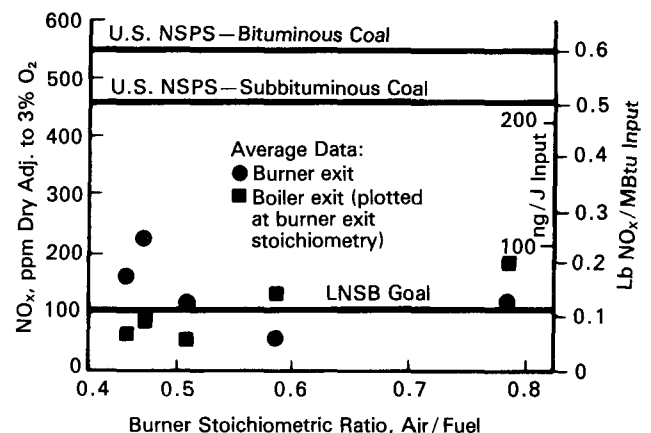
Figure 3-16. NOₓ Emissions from a Slagging Combustion Pilot Plant Firing Coal, Oil, and Mixtures (38).
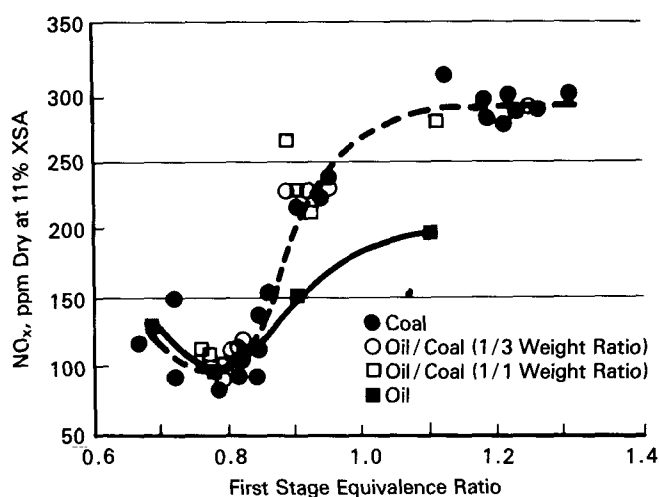
NOₓ/SOₓ Burner (LNSB) program goal of 100 ppm was not realized in all tests, but results were well below the NSPS levels. In Figure 3-16, the minimum NOₓ of about 100 ppm was realized at a stoichiometric ratio of about 0.8 for all fuels (in the primary combustion stage). Further pilot-scale research is underway to test the ability of slagging combustors to simultaneously reduce SO_2 emissions by sorbent injection. This technology is a long way from commercialization as full-scale tests will not be completed for several years. TRW is presently performing tests on an industrial boiler.

3.2.1.9 Dry Flue Gas Treatment Technologies
Two major dry FGT processes — the selective non-catalytic reduction process and the selective catalytic reduction process — are still in the development stage in terms of their application to coal-fired boilers in the United States. Selective catalytic reduction has been applied extensively in Japan and is being planned for several European facilities. Figure 3-17 shows results for a Japanese utility boiler (175 MW). NOₓ removal has been a steady 80 percent and higher. Note that maximum NOₓ reductions were found at an NH_3/NOₓ mole ratio of 1.0 with little ammonia slip. Also, NOₓ reductions averaging about 90 percent were found in EPA pilot-scale tests at a Georgia Power Company boiler.(40) The pilot plant treated a 1,500 scfm slipstream of flue gas from a 60-MW boiler. It was noted that when the NH_3/NOₓ ratio was below 1.0, the NOₓ reduction achieved dropped to well below 90 percent.

A number of major concerns need to be resolved before this process can be considered totally commercial for coal-fired boilers in the United States. These are:

- Ammonia slip
- Sulfate and bisulfate formation and deposition
- Catalyst durability, cost, and reliability
- Ammonia and NOₓ control systems.

Ammonia slip refers to that portion of the ammonia that passes through the boiler without reacting with nitrogen oxide. Once excess ammonia has "slipped" through the NOₓ control system, it can react with sulfur trioxide to form ammonium bisulfate. This compound is a particulate that can foul the combustion air preheater and could conceivably, in extreme cases, jeopardize particulate compliance. Therefore, ammonia slip must be controlled; accordingly, Japanese utilities employing SCR on their boilers usually specify strict limits for their vendors on the amount of ammonia permitted to slip. Some Japanese boilers continuously monitor for ammonia in the flue gas.(14)

There are cost data and calculations available for SCR as applied to coal-fired boilers. One example, shown in

Figure 3-17. Test Results for SCR on a Coal-Fired Boiler (2).

Unit load = full load
Flue gas temperature = 340C
3% O_2 concentrations assumed

Figure 3-18, is the projected cost of an SCR retrofit for a 300-MW tangential-fired boiler relative to other NO_x control technologies. Note the distinct cost disadvantage, but nevertheless, the NO_x removal efficiency advantage represented by SCR compares to other technologies employed more frequently for tangential-fired boilers.

Selective noncatalytic reduction, as represented by the Exxon Thermal $DeNO_x$ process, reportedly costs less than SCR but NO_x removal is significantly lower. Table 3-6 pre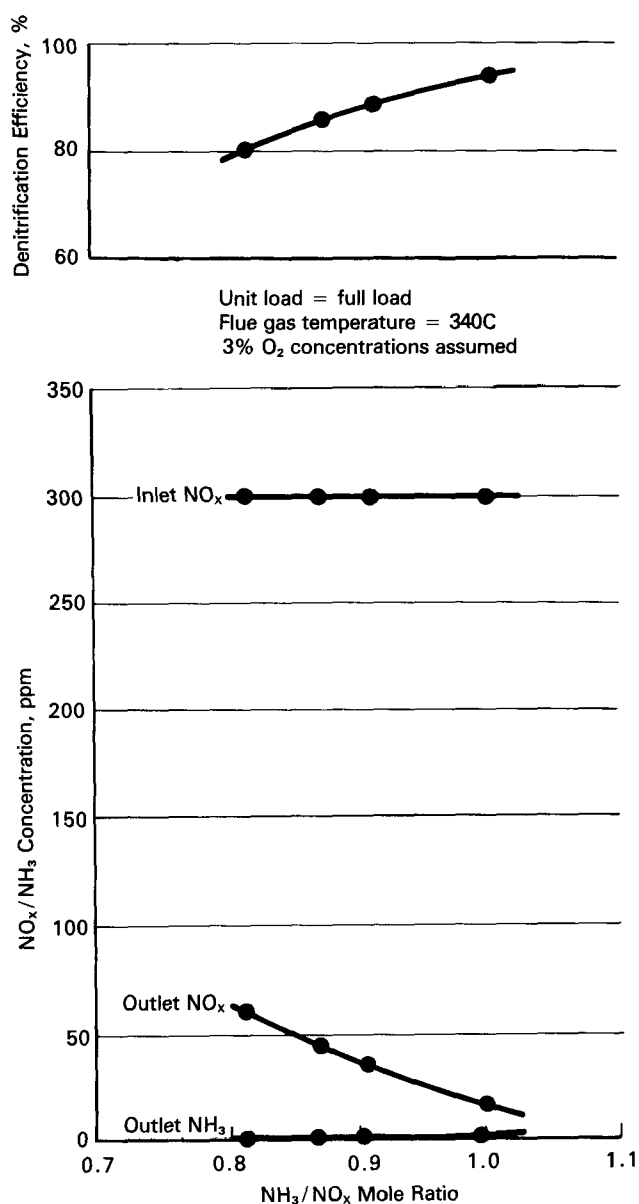sents vendor-supplied data on capital cost and cost-effectiveness for the Thermal $DeNO_x$ process. The costs, which are in 1983 dollars, were developed by the vendor for a hypothetical, 500-MW boiler. The design NH_3/NO_x mole ratio was 1.5.

Table 3-6. Capital Cost and Cost-Effectiveness of Thermal DeNox Process (48) (1983 dollars)

NO_x[a]	Investment $/kW	Cost Effectiveness mills/kWh	Cost Effectiveness $/lb NO_x Removed
300 ppm	19	2.03	0.57
600 ppm	25	2.94	0.41

[a]Initial (before SCR) NO_x concentration at 3% O_2.

An EPA-sponsored economic evaluation for coal-fired utility power plants included SCR for NO_x control.(42) The SCR systems consist of two trains of insulated reactors. An ammonia storage and handling system injects an ammonia/air mixture in the inlet duct. The catalyst life is assumed to be 1 year. Table 3-7 summarizes the capital investment and annual revenue requirements.

The most important capital and annual cost is for the catalyst. Other than the catalyst, the main factor affecting NO_x control costs is the flue gas volume which determines the fan and ductwork costs and the catalyst volume.

Table 3-7. Economic Evaluation of SCR for Coal-Fired Utility Power Plants: 80% NO_x Removal (42)

Coal	MW	SO2 Control	Capital Investment $/kW[a]	Annual Revenue[b] mills/kWh
East	200	Limestone FGD	103.1	8.8
East	500	Limestone FGD	83.7	8.0
West	200	Lime Spray Dryer	121.0	10.6
West	500	Lime Spray Dryer	100.2	9.6
West	200	Limestone FGD	121.6	10.1
West	500	Limestone FGD	96.1	9.0

[a]1982 dollars.
[b]1984 dollars.

3.2.1.10 Wet Flue Gas Treatment

Many processes have been proposed for simultaneous removal of SO_x and NO_x. However, there are no data on their effectiveness for full-scale coal firing. Limited testing by the Pittsburgh Energy Technology Center has shown that NO_x removals of 60 to 70 percent are achievable along with 90 percent removal of SO_x.(43)

No cost data on wet flue gas treatment processes for actual coal-firing installations are available. Model plant cost estimates are available for several processes.

3.2.2 Stoker-Fired Boilers

The primary NO_x reduction technologies that have been applied to stoker-fired boilers are overfire air control and flue gas recirculation. The former has traditionally been employed to reduce smoke emissions from stoker-fired boilers while the latter has recently been proposed for the same purpose but has the added benefit of reducing NO_x emissions. Exhaust gas recirculation reduces fuel NO_x by lowering oxygen concentrations in the bed where fuel nitrogen is evolved.

Figure 3-18. Incremental Capital Cost of SCR and Other NO_x Control Technologies for a New Tangential-Fired Boiler (26).
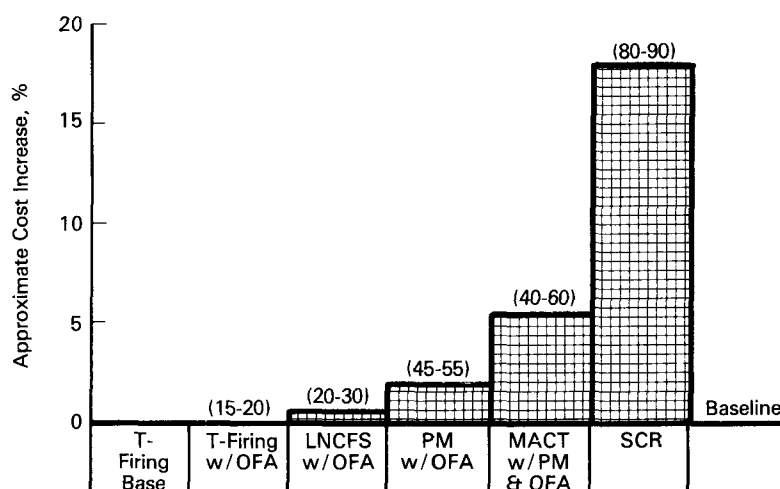
NO_y removal in parentheses.

T-Firing	Tangential firing
OFA	Overfire air
LNCFS	Low NO_x concentric firing system
*PM	Pollution minimum burner
*MACT	Mitsubishi advanced combustion technology
*SCR	Selective catalytic reduction system

*C-E/MHI licensed technology

Based on material and construction costs for a new 300 MW coal-fired unit.
SCR system costs are based on 80% NO_x removal.
SCR system costs do not include NH_3 tank farm equipment or external structural support steel.
These cost approximations may change depending on specific unit design requirements.

3.2.2.1 Overfire Air

NO_x reductions of between 10 and 25 percent have been reported for employing additional overfire air ports (44); existing overfire air ports are designed primarily for smoke control and may not be optimally located for control of NO_x emissions. This method is severely limited in that redirecting a large portion of air from the bed to the overfire ports reduces the cooling effect of the air on the grate and disturbs the natural staged combustion of the stoker.

3.2.2.2 Flue Gas Recirculation

Flue gas recirculation, also called stoker gas recirculation in this instance, has been suggested for application to stoker-fired boilers. Full-scale testing of stoker-fired boilers is reported (45) in which slight NO_x reductions were achieved for flue gas recirculation in spreader stokers. The boiler, rated at 100,000 lb/h of steam, fired Western Kentucky coal at excess oxygen levels of 8 to 10 percent. It was found that in addition to particulate emission reduction (about 40 percent) and efficiency increases (6 to 7 percent), a side benefit was reduction in NO_x emissions. Since the recirculated gas is injected along with the primary combustion air, the technique results in lower excess air which in turn reduces both fuel NO_x and thermal NO_x. Figure 3-19 shows test results indicating that NO_x emission levels approaching 100 ppm (3 percent oxygen basis) are achievable. Note that NO_x emissions for a stoker-fired boiler are relatively low to begin with; note further that the modified (flue gas recirculation) system results in lower excess oxygen rates and hence reduced NO_x emissions.

No cost data for either overfire air or flue gas recirculation for stoker-fired boilers are available.

3.3 Oil- and Gas-Fired Boilers

Many of the techniques discussed above for reducing NO_x emissions from coal-fired boilers are also applicable to oil-fired and gas-fired utility and industrial boilers of comparable size. Most of the techniques that have been used are those that reduce peak flame temperatures. A discussion of available data on the effectiveness and cost of these techniques follows.

3.3.1 Low Excess Air

Modest (average 11 percent) NO_x reductions can be achieved by lowering excess oxygen to the vicinity of 2.5 percent for combustion of residual and distillate oils.(44) A side benefit is an increase in boiler efficiency; however, a possible detriment is increased emission of carbon monoxide, hydrocarbons, particulates, and visible plume.

The reductions achievable for gas-fired, water-tube boilers are also modest, in the range of 3 to 15 percent.(44) However, the technology is desirable because it is easy to implement, can be combined with another technology, and again has the added benefit of increasing boiler efficiency. The excess oxygen can be safely reduced to about 2 percent in most boilers without jeopardizing carbon monoxide and particulate compliance. Figure 3-20 shows the results of tests of a 110-MW gas-fired utility boiler, where NO_x emissions were reduced by over 30 percent by lowering oxygen in

Figure 3-20. NO_x Reduction by Lowering Excess Air in a Gas-Fired Utility Boiler (46).

Figure 3-19. NO_x Reduction Due to Flue Gas Recirculation in a Stoker-Fired Boiler (45).

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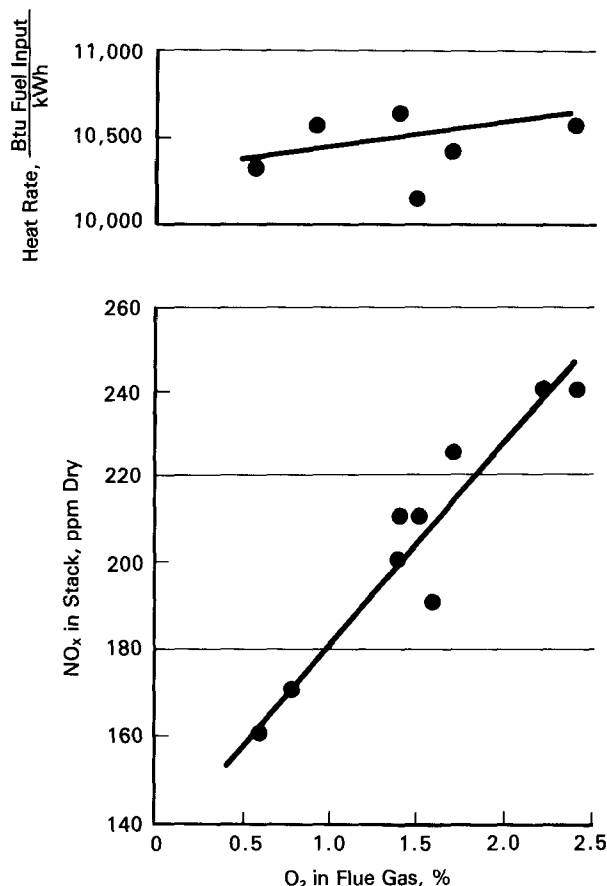
the flue gas from 2.2 to 0.6 percent (corresponding to about 2.8 percent excess air).(46) At oxygen levels in flue gas of about 0.6 percent and lower, flame instability and combustibles in the flue gas were found, making this a practical lower limit for reducing excess air on that boiler.(46) Any reduction in excess oxygen should be made only after evaluating a specific application and determining that a potential safety hazard will not arise at the lower oxygen level.

3.3.2 Burners Out of Service

This technology is only available as a retrofit and obviously only applies to boilers with more than one burner. Some utility and industrial boilers burning residual fuel oil or natural gas have used this technology. NO_x reductions range from 10 to over 40 percent (44) and of course are highly dependent on whether or not the BOOS pattern tested is the optimum pattern. Figure 3-21 shows results of testing for a 110-MW gas-fired utility boiler in which BOOS was tested in combination with opening of an overfire air port to further enhance the BOOS effect. A potential drawback to this technology is possible derating of the boiler unless modifications to the fuel piping are made so that the design heat input can be maintained after retrofit. Heat rate may also be increased with BOOS.

3.3.3 Reduced Combustion Air Preheat

This technique requires extensive modifications to the air and flue gas handling systems of a boiler and is obviously applicable as a retrofit only for boilers employing

Figure 3-21. NO_x Reduction by BOOS for a Gas-Fired Utility Boiler (46).

combustion air preheaters. The best application for this technology would probably be a new boiler where it is necessary to include heat recovery equipment to preserve the thermal efficiency of the boiler. The technology has been tested on a limited basis for oil-fired and gas-fired boilers.(44) The NO_x reductions demonstrated for firing residual oil ranged from 5 to 16 percent; results of only two tests for gas-fired boilers indicate NO_x reductions of perhaps 30 percent are possible with a combustion air temperature decrease of about 50C (90F). Unless alternate heat recovery equipment is used to minimize stack losses, this technique usually produces unacceptable efficiency penalties.

3.3.4 Flue Gas Recirculation

As with reduced combustion air preheat, flue gas recirculation is difficult to retrofit because of extensive modifications to air and flue gas handling systems. The amount of flue gas that is typically recycled is in the range of 15 to 20 percent, although levels as high as 45 percent have been used for gas firing.(44) The proportion is limited in oil-fired boilers by the onset of flame instability; this is less of a problem with gas-fired boilers if other than ring burners are employed.

Testing of this technology for oil-fired and gas-fired boilers has not been extensive. However, preliminary indications are that substantial NO_x reductions can be achieved. For example, tests for residual oil firing showed NO_x reductions of 15 to 30 percent while results for firing distillate oil (one boiler only) ranged from 58 to 73 percent. Tests of three gas-fired boilers showed NO_x reduction ranging from 48 to 86 percent.

3.3.5 Low NO_x Burners

Several burner manufacturers have for some time been engaged in developing and providing low NO_x burners for oil- and gas-fired boilers. In some instances the burners thus developed are modifications of pulverized coal burners in which the basic principles of air or fuel staging have been employed. Many of these low NO_x burner designs have been licensed for sale in Japan where operators of oil- and gas-fired utility and industrial boilers in general face more stringent NO_x emission regulations than their U.S. counterparts.

Babcock & Wilcox has developed the Primary Gas-Dual Register Burner (PG-DRB) for oil-fired and gas-fired boilers. In this burner—which is a modification of the coal-firing DRB—the primary air zone is surrounded by a primary gas recirculation zone. Here, recirculated flue gas shields the flame and reduces oxygen availability. The company claims NO_x emission reductions of 65 percent for oil and 75 percent for gas firing, as compared to conventional circular burners.(41) The field experience with this type of burner includes utility as well as industrial boilers, primarily in Japan. There are 114 PG-DRB's firing oil in four generating stations in Japan ranging in size from 175 to 600 MW; 176 PG-DRB's fire gas in six stations ranging in size from 175 to 1,000 MW. The total capacity covered by these burners is 4,700 MW.

35
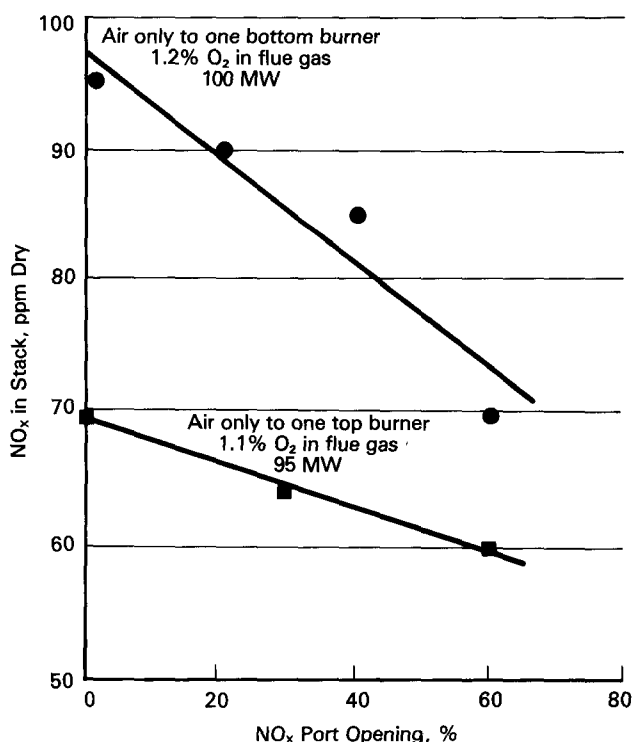
Coen Company, Inc. supplies low NO_x burners for oil or gas firing in industrial boilers.(47) Two basic types of staged air burners are offered: the front wall arrangement that is especially suited for residual oil (high fuel nitrogen); and the side wall arrangement that is well suited for gas firing. The company claims NO_x reductions of 25 to 30 percent for oil firing and 35 to 40 percent for gas firing, employing these burners. The company literature reveals a total of 11 installations ranging in size from one burner and 20,000 lb/h of steam to four burners and 400,000 lb/h of steam that employ this type of burner. The guaranteed or actual NO_x emissions for these units are 0.1 lb/10^6 Btu and less for natural gas, and 0.2 to 0.3 lb/10^6 Btu for oil.(47)

3.3.6 Dry Flue Gas Treatment

Figure 3-22 shows results of tests of the Exxon Thermal DeNO$_x$ process at full load on a 235-MW oil-fired utility boiler in California. The figure shows that $NO_x$ removals of over 50 percent were achieved at the full load condition. At partial load, the change in convective section temperature reduced the NO_x reduction efficiency to below 50 percent. There was also significant ammonia slip during these tests. Exxon reports that the ammonia compounds formed from slippage do not cause unacceptable corrosion or preheater fouling. Deposits formed can be removed from the system by periodic washing with water.(48) Exxon is continuing to develop the process to improve efficiency.

Catalytic technologies have been tested and used extensively in Japan for coal-, oil-, and gas-fired industrial

Figure 3-22. NO$_x$ Reduction by SNR for Oil-Fired Utility Boiler (48).
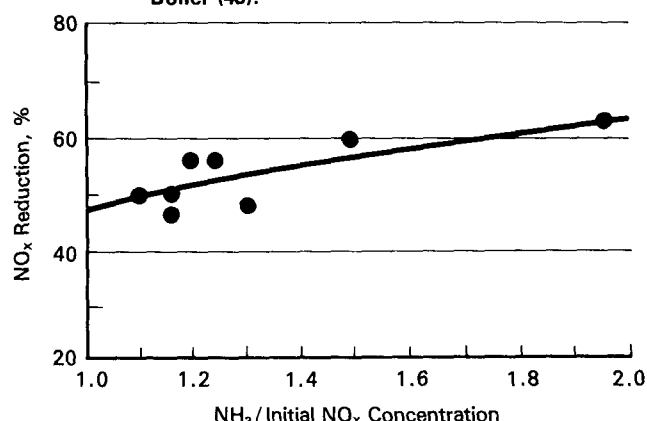
boilers. Processes with fixed beds and moving beds have been tested. Performance data for actual operating systems are available; some representative results for oil-fired boilers are shown in Table 3-8. Performance data for gas-fired boilers are also available in which NO_x removal efficiencies of 90 percent have been realized over operating periods of several thousand hours.(43)

An SCR system was tested that handles half of the flue gas from a 215-MW gas-fired utility boiler of Southern California Edison Company.(49) The system attained the design goal of 90 percent NO_x reduction in 18,000 hours of operation; however, it is not clear that the

Table 3-8. NO$_x$ Removal in Oil-Fired Industrial Boilers with Selective Catalytic Reduction (43)

Operation Parameters of Major Plants Constructed by Hitachi Zosen		Operation Data of a Commercial SCR Plant for Dirty Gas		SCR Plant by Mitsui Engineering and Shipbuilding Co.	
Completed	11/75	Gas for SCR (Nm³/hr)	300,000	Capacity (Nm³/hr)	220,000
Plant site	Yokkaichi	Fuel	Oil (S = 0.7%)	Gas composition	
Gas source	Oil-fired boiler	Load fluctuation (%)	60-100	NO$_x$ (ppm)	150
Capacity (Nm³/hr)	440,000	Stack height (m)	140	SO$_x$ (ppm)	300
Load factor (%)	50-100	Inlet gas composition		Dust (mg/Nm³)	100-150
Pretreatment of gas	EP[a], FGD, heating	O$_2$ (%)	6	Catalyst and reactor	
		SO$_x$ (ppm)	400	Catalyst carrier	TiO
Reactor inlet		NO$_x$ (ppm)	200	Catalyst shape	PP
NO$_x$ (ppm)	150	Particulates after EP		SV (hr⁻¹)	4,000
SO$_x$ (ppm)	80-130	(mg/Nm³)	10-20	Temperature (C)	350-400
Dust (mg/Nm³)	30-100	FGD unit	Scheduled	NH$_3$/NO$_x$ mol ratio	1.0
O$_2$ (%)	3.2	SV (h⁻¹)	5,000	NO$_x$ removal (%)	Above 90
Reactor type	Fixed bed	Temperature (C)	320	Total pressure drop	
Reaction temp.	420	NO$_x$ removal (%)	Over 90	(mm H$_2$O)	180
NO$_x$/NH$_3$ ratio	1.0	NH$_3$/NO$_x$ mol ratio	1.0	Leak NH$_3$ (ppm)	Below 10
Catalyst No.	304	Leak ammonia (ppm)	10-20	Operation start	7/77
SV (hr⁻¹)	10,000	Type of reactor	Moving bed	Plant cost (10⁶ yen)	260
NO$_x$ removal (%)	80[b]	Plant completed	10/76		
Pressure drop by SCR reactor (mm H$_2$O)	160				
Catalyst life	1 year				

[a]Electrostatic precipitator.
[b]Including leakage in heat exchanger.
Note: At 8/9/85 exchange rate of 237.70 yen per U.S. dollar.

36

system can achieve the design of 10 ppm maximum ammonia slip. During the test period the boiler was fired with oil for periods of time. During these periods, however, "heavy" deposits of ammonium bisulfate and iron sulfate were found in the air preheater. At its worst, this condition resulted in an increase in pressure drop through the air preheater of 50 percent.(49)

The estimated cost for a Thermal DeNO$_x$ process for a 200,000 lb/h oil- or gas-fired industrial boiler is available.(49) Table 3-9 shows the estimated annual operating costs for this application. The total investment cost is estimated to be $389,000. If the system is assumed to have a useful life of 20 years, the annual

Table 3-9. Annual Operating Cost Estimates for Thermal DeNO$_x$ on a 200,000 lb/h Oil-Fired Industrial Boiler (30) (1982 dollars)

Cost Item	Annual Consumption[a]	Unit Cost, $	Annual Cost, $
Ammonia[b]	164 t	220/t	36,080
Electric power[c]	55 MWh	50/MWh	2,750
Steam[d]	3,890 t	13.50/t	52,515
Maintenance (Material and Labor)[e]			7,560
Total			98,905

[a]Assumes 65% load factor.
[b]Includes ammonia for direct injection.
[c]Includes power requirement for ammonia vaporizer.
[d]Low pressure steam (0.1 MP ag minimum) for carrier.
[e]Assumed to be 7% of direct investment cost.

capital-related cost would be $45,690 at a 10 percent interest rate, and thus the total annualized cost of the DeNO$_x$ system would be about $160,000, including a small percentage of capital cost for insurance, taxes, and administration.

Table 3-10 shows Japanese data (43) on capital and operating cost of selective catalytic reduction systems for oil-fired and gas-fired boilers. The smaller flowrate would correspond to an industrial boiler while the large flowrate is more typical of a utility boiler. Note the economy of scale evident in the capital cost figures while the operating cost is much closer to linear with flowrate.

Cost data are also available (49) for an SCR system applied to gas firing. The data are in the form of 20-year levelized costs and are for combustion of oil. The cost is a strong function of the unit's capacity factor ranging from greater than $0.060/kWh at a capacity factor of 30 percent, down to $0.010/kWh at a capacity factor of 80 percent.(49)

Table 3-10. Capital and Operating Cost Data for Selective Catalytic Reduction Systems for Oil-Fired and Gas-Fired Boilers (43) (1981 dollars)

Gas Flow Rate, Nm^3/h	Capital Cost, $	Operating Cost, $
50,000	0.5 x 10^6	0.2 x 10^6
1,200,000	5.0 x 10^6	3.5 x 10^6

Chapter 4

Performance and Cost Data:
Packaged Boilers Firing Oil or Gas

4.1 Introduction

This chapter presents available data on the NO_x removal efficiency and associated cost of those technologies employed for smaller, packaged boilers that fire oil, gas, or both. Much of the material in the latter parts of Chapter 3 pertaining to large industrial oil-fired and gas-fired boilers also applies to packaged boilers. However, many of those technologies have limited application to smaller boilers. These limitations will be discussed in this chapter.

Packaged boilers are for the most part industrial rather than utility and are small. There has not been a great deal of research and development of NO_x control technologies for these boilers. NSPS were proposed in June 1984, but have not yet been promulgated. State and local regulations that may apply usually only limit emissions of particulates and sulfur dioxide.

Where low NO_x technology has been required for packaged boilers, the normal procedure has been to go directly to a low NO_x burner. On a new or retrofit basis, low NO_x burners are usually straightforward to implement (packaged boilers normally employ only one burner) and relatively cost-effective compared to more complicated technologies of lesser NO_x reduction efficiency. A few other technologies have received limited attention, however, and these are discussed first.

4.2 Reduced Combustion Air Preheat

This technology is available for use with packaged boilers of the water-tube design but, as with large boilers, requires a combustion air preheater. Fewer than 20 percent of packaged boilers have preheaters; most use economizers for heat recovery. Limited data show NO_x reductions in the range of 5 to 16 percent, which is the same for industrial boilers in general.(44) To recover lost thermal efficiency boilers equipped with this technology (new or retrofit) require heat recovery systems. Due to this severe energy penalty, this technology is not expected to proliferate, especially in view of the ease of implementing low NO_x burners and the much greater NO_x reduction achievable.

4.3 Flue Gas Recirculation

Flue gas recirculation is a technology available for both fire-tube and water-tube packaged boilers. It is a technology that is being increasingly implemented on packaged units. Tests have reflected a NO_x reduction ranging from 15 to 30 percent for residual oil, 58 to 73

percent for distillate oil, and 48 to 86 percent for gas-fired boilers.(44) For gas-fired units the technique is more effective with water-tube boilers than fire-tube boilers.

4.4 Low NO_x Burners

In Chapter 3 a discussion of low NO_x burners for oil and gas firing was presented as part of the material on utility and large industrial boilers. In large part, that discussion also applies here for packaged boilers.

Several burner manufacturers have designed low NO_x burners for oil and gas firing that may be used in packaged boilers. Particularly applicable are the data from Coen Company, Inc.(47) in which two basic types of staged air low NO_x burners are discussed. To reiterate, these burners are claimed to be capable of NO_x reductions of 25 to 30 percent (oil) and 35 to 40 percent (gas). Of the eleven installations mentioned, seven are relatively small, one-burner, packaged units. This information is summarized in Table 4-1.

As pointed out earlier there are a number of burner manufacturers offering low NO_x burners for small oil- and gas-fired boilers. Although performance data are scarce, many manufacturers are agreeing to guaranteed emission levels comparable to the rather stringent levels of the proposed industrial NSPS.

Table 4-1. NO_x Emission Performance for Low NO_x Burners in Single-Burner Oil- and Gas-Fired Boilers (47)

Boiler Capacity, lb/h	Fuel	Guaranteed or Actual NO_x Emission
20,000	Refinery or natural gas	70 ppm (@3% 02)
68,200	Natural gas or No. 2 fuel oil	75 ppm (@3% 02)
80,000	Refinery or natural gas	0.15 lb/10^6 Btu
55,000	Natural gas or No. 2 fuel oil	0.09 lb/10^6 Btu
30,000	Natural gas or No. 2 fuel oil	0.12 lb/10^6 Btu
100,000	Natural gas or No. 2 fuel oil	0.12 lb/10^6 Btu
50,800	Natural gas	0.08 lb/10^6 Btu

Note: To convert emissions in lb/10^6 Btu to ppm for firing natural gas, multiply by 833.

EPA has developed a low NO$_x$ heavy oil burner that generates no more than 75 ppm NO$_x$ regardless of the fuel nitrogen content. This precombustion type burner has been applied only to an enhanced oil recovery steam generator rated at 60 x 10^6 Btu/hr. The precombustor is operated fuel rich at very high temperatures to take advantage of very low NO$_x$ equilibrium levels. Burnout air is added at the precombustor outlet to complete the combustion process at lower temperatures.

In addition, Alzeta Corporation, under contract to EPA, has developed a "fiber" low NO$_x$ burner for gas-fired fire-tube boilers. Flame temperatures are kept low because a substantial portion of the heat is provided by radiant transfer.

The fiber burner has been demonstrated on gas-fired fire-tube boilers ranging in rating from 245 to 980 kW. Results are shown in Table 4-2. Note that substantial reductions in NO$_x$ emissions (on the order of 80 percent) are possible at varying boiler loads. Earlier tests (51) disclosed that 10 percent excess air was the optimum operating point. Below this level, carbon monoxide emissions were excessive and above this level, efficiency was compromised. The carbon monoxide emissions at 10 percent excess air were comparable to those for a conventional burner.

4.5 Other Technologies
Several other technologies are available for packaged boilers but have not been demonstrated. Reasons may include doubts about cost-effectiveness, lack of interest due to the availability of alternatives, or technical limitations. Low excess air is available and readily implemented. As with overfire air for stoker-fired boilers, however, low excess air for packaged boilers has traditionally been employed for a reason other than NO$_x$ control (in this case for fuel savings) with reduction of NO$_x$ emissions as a side benefit.

Typically, an oxygen trim system has been used to balance oxygen against carbon monoxide and smoke emissions. Either oxygen or carbon monoxide in the flue gas is monitored to approach the lowest practical excess air level while still complying with any applicable regulations on particulates (smoke) and carbon monoxide. At this low excess air level (generally about 2.5 percent), NO$_x$ emissions are reduced approximately 11 percent.(44)

Tests performed on a package boiler simulator and a commercial fire-tube boiler, both rated at 0.73 MW or 2.5 x 10^6 Btu/hr, have shown that reburning can effectively reduce NO$_x$ by 50 percent or greater with minimal facility modifications.(19) However, for very low primary flame NO$_x$ levels (less than 200 ppm), reburning fuel nitrogen content is a limiting factor. Reburning with a low nitrogen content fuel such as natural gas or distillate oil may be necessary. Selective noncatalytic reduction is offered commercially and has been applied to several packaged boilers and enhanced oil recovery steam generators in California.

Table 4-2. NO$_x$ Emission Reduction for Gas-Fired Fire-Tube Boiler with a "Fiber" Low NO$_x$ Burner[a] (50)

Site	Boiler Size kW	Burner Type	Excess Air %	CO ppm	NO ppm	HC ppm	Boiler Eff. %	Hours of Operation
Alzeta Lab	245	Conventional	16	11	57	0	82.8	NA
Santa Clara, CA		Fiber	10	10	10	10	82.3	500[b]
York-Shipley	588	Conventional	15	10	NT	NT	85.0	NA
Boiler Test Bay York, PA		Fiber	10	10	NT	NT	85.8	2,000
Vandenberg AFB	392	Conventional	55	240	NT	NT	81.0	NA
CA		Fiber	10	0	NT	NT	82.3	3,800
Peter Paul Cadbury	588	Conventional	20	400	NT	NT	83.2	NA
York, PA		Fiber	7	35	20	NT	84.0	3,450
								2,500
Hall Chemical Co.	980	Conventional	7	1,000	80	NT	82.7	NA
Wickliffe, OH		Fiber	13	35	18	NT	83.7	3,450[c]
								2,500[c]
								1,500[c]

[a]All results at high fire conditions, emissions corrected to 0% O$_2$.
[b]On segmented burner.
[c]Three different burners employed.
Note: NT = not tested
NA = not applicable.

Chapter 5

Performance and Cost Data:
Gas Turbines and Stationary Reciprocating Engines

5.1 Introduction

Available data on the effectiveness and cost of NO_x reduction technologies for turbines and engines are presented in this chapter. With the exception of selective catalytic reduction technologies, the techniques presented are unique to these sources and have not been discussed in Chapters 3 and 4.

5.2 Gas Turbines

The two primary methods of NO_x reduction that have been employed for gas turbines are water/steam injection and selective catalytic reduction. The former technology is the more advanced in the United States; the latter has been used extensively in Japan for several types of sources, including gas turbines, and it has been used or tested at a few U.S. installations.

5.2.1 Water/Steam Injection

Nearly 50 percent of the gas turbines in California employ water/steam injection for NO_x reduction.(52) A water injection system consists of nozzles mounted inside the combustor, a proportional controller to ensure the correct injection rate, a pump, and the associated piping. Typical water- or steam-to-fuel ratios are 0.21:1 to 1:1 for water and 1:1 to 2:1 for steam. Water for injection must meet the purity requirements of boiler feedwater in order to avoid corrosion in the turbine.(24) The reference also reports that for water-to-fuel ratios in the range of 1:1, NO_x reductions up to 75 percent are realized. This is basically confirmed by data shown in Figures 5-1 and 5-2.(53) Increased (less than 5 percent) fuel consumption is a drawback.

Water/steam injection is only effective in reducing thermal NO_x. Therefore, it is not recommended for turbines combusting fuels with significant fuel-bound nitrogen such as coal-derived liquid, shale oil, and high-nitrogen residual oil.

A by-product of water/steam injection is a modest (1 to 11 percent) increase in power output but a slight decrease in turbine efficiency.(53) It is difficult to generalize on turbine wear and maintenance problems because the studies (53) do not indicate any discernible trend. Suffice it to say that increased turbine wear and more frequently required maintenance may be consequences of water/steam injection in rare instances. The formation of ice fog could be a deterrent to the use of

this technology in populated areas located in cold climates, such as Alaska.(53)

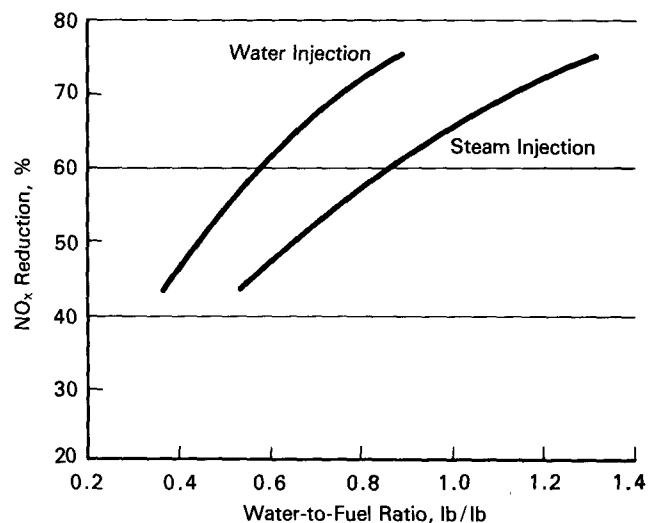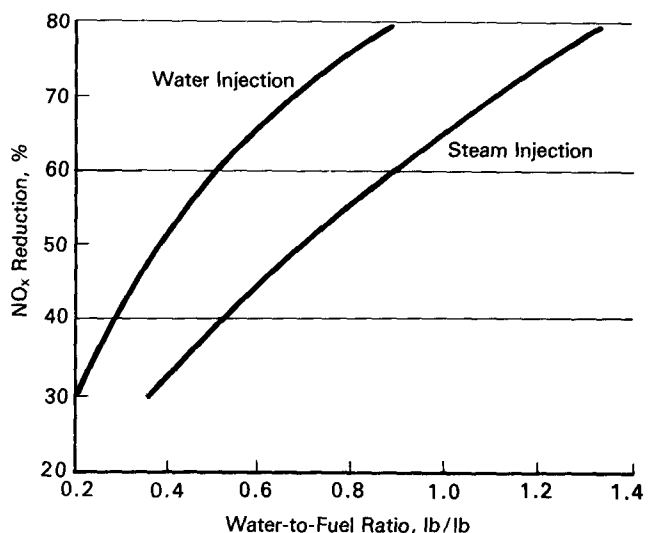Figure 5-1. NO_x Reduction by Water or Steam Injection: Gas Turbine Firing Natural Gas (53).

Figure 5-2. NO_x Reduction by Water or Steam Injection: Gas Turbine Firing Distillate Oil (53).


41

Another possible disadvantage is an increase in emission of carbon monoxide. For turbines operating at base load with water-to-fuel ratios of 1:1, CO emissions are approximately 300 ppm, which is about five times the baseline level.(52) However, for these units operating in California, the carbon monoxide emissions are well below the limit of 2,000 ppm. (These concentration levels assume a 3 percent oxygen basis.) In any case it is difficult to generalize on this point because tests are not consistent with turbine size and fuel type.(53)

5.2.2 Selective Catalytic Reduction

Extensive testing of selective catalytic reduction has been carried out in Japan for actual operating gas turbines. Figure 5-3 presents data for the Kawasaki Power Station Number 1 combined cycle turbine which is rated at a total of 141 MW (97 MW prime turbine plus 44 MW steam turbine). Note that at all turbine loads greater than 25 percent the NO_x reduction efficiency is well over 80 percent and ammonia emissions—a potential drawback to use of SCR—are low. At the time of the site visit, the SCR catalyst had performed through 11,000 hours of operation including daily start-ups.(54) Seven larger (370 MW to 1,000 MW) gas turbines that employ selective catalytic reduction for NO_x removal are currently in construction or start-up phase in Japan with no results available to date. Most, if not all, of these units are designed for an outlet NO_x concentration of 15 ppm at 15 percent oxygen.

Figure 5-3. Performance of Selective Catalytic Reduction on a Gas Turbine (54).

*Actual O_2

NH_3/NO_x = 1.03
Ambient temp = 15C
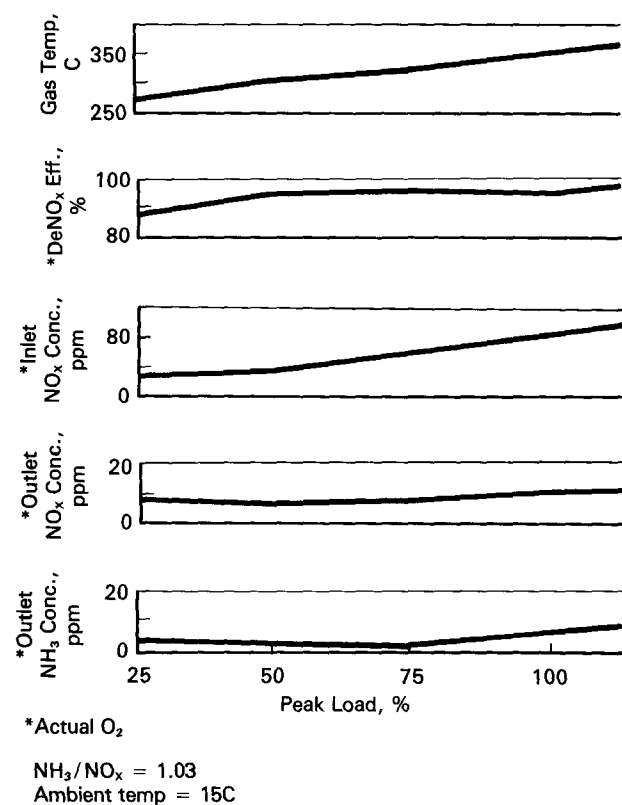
Data are also available on the variation of NO_x reduction with space velocity, gas temperature, and NH_3/NO_3 mole ratios. These data are also for Japanese installations.

Cost data are available (54) for selective catalytic reduction units serving four large (General Electric "Frame 6") gas turbines (total rating approximately 300 MW). In 1982 dollars the total capital cost would be about $2,650,000. The operating cost, including all direct and indirect costs as well as the incremental fuel cost, is estimated to be a maximum of $0.00125 per kWh. In order to employ SCR, a means of cooling the exhaust gas must be provided. The temperature range required is from 300 to 400C (570 to 750F), depending on catalyst.(53)

Efforts are underway in Japan and the United States to develop new combustor designs for turbines that will reduce NO_x emissions without water/steam injection or use of SCR. Both catalytic combustion and staged combustion techniques have been developed. EPA has developed the rich-burn quick quench (RBQQ) concept combustor system that uses staging to reduce both thermal and fuel-bound NO_x emissions.(55) Testing so far has been limited and performance data for actual operating units are not available.

5.3 Stationary Engines

Several methods for reducing NO_x emissions from stationary engines have been employed or at least tested. They include: water/fuel emulsions (diesel engines primarily), exhaust gas recirculation (diesel), lean burning-torch ignition (spark-ignition engines only), turbocharging, charge cooling (spark), ignition retard (spark), injection retard (diesel), selective catalytic reduction (spark), and nonselective catalytic reduction (spark).

5.3.1 Water/Fuel Emulsion

EPA has conducted demonstration tests on the use of water/fuel emulsions to reduce NO_x emissions from diesel engines. Results for a four-stroke, six-cylinder turbocharged diesel engine with a generator output rated at 165 kW are shown in Figure 5-4.(56) NO_x reductions of about 60 percent were consistently achieved over a wide range of loads. The load range also represents a range of water-to-fuel ratios of 0.27 to 0.60.

An important part of emulsion research involves investigation of the side effects of NO_x reduction through use of water/fuel emulsions. Of concern in this research were emissions of carbon monoxide, hydrocarbons, particulates, and sulfur oxides. Carbon monoxide emissions were found to increase dramatically at low- to mid-range loads and then to decrease to a level of about 20 percent above baseline at full load.(56) A similar effect was noticed for hydrocarbons except that at about 85 percent of load the hydrocarbon emissions dropped below the baseline to a value of about 60 percent of the baseline at full load. Particulate emissions were also higher with NO_x control dropping rapidly from over 2.5

Figure 5-4. NOₓ Reduction by Water/Fuel Emulsion for Diesel Engine.

Figure 5-4 chart: NO/NO_Base versus Load, kW. Legend:
— Baseline
— — Control effect
● Catalyst
■ Emulsion
▲ Combined

recirculation. Tests reported for the same engine described above were carried out by water scrubbing the exhaust gas from the turbocharger (to remove particulates) and returning a portion to mix with the incoming combustion air.(57) The optimum value was found to be about 15 percent exhaust gas by volume in the inlet air, at which NOₓ reductions were approximately 50 percent. Higher reductions were obtained but the fuel penalty was excessive and smoke emissions also became a problem at higher proportions of exhaust gas. Fuel penalty was reported in BSFC, or brake-specific fuel consumption, which has units of Btu per brake horsepower-hour. Test results are shown in Figure 5-6.

Data have also been collected for exhaust gas recirculation for large-bore spark engines firing natural gas.(58) Table 5-1 shows data correlating NOₓ emission reduction with the amount of exhaust gas recirculated. The BSFC penalty in these tests ranged from 1 to 3 percent.

5.3.3 Lean-Burning Torch Ignition

Another technique that has been used to reduce NOₓ emissions from spark-ignition engines is lean-burning torch ignition. Use of torch ignition extends the lean-burning limit of the engine. Figure 5-7 shows test results (57) for a single-cylinder, two-stroke, gas-fired engine rated at 681 hp at 330 rpm. Note that the use of torch ignition extended the lean-burn limit to a fuel/air equivalence ratio of 0.55 to 0.60. (This ratio is the percentage of stoichiometric.) As a result, NOₓ emissions can be reduced by 50 percent or more by this

times the baseline at zero load to less than baseline at about 25 percent of load. At higher loads particulate emissions stayed below the baseline level. Sulfur dioxide emissions were found to be essentially constant in that they are fixed by the sulfur content of the fuel (0.24 percent in this case). Conversion of sulfur dioxide to sulfate is consistently low except at zero load.

Performance data for water/fuel emulsions with diesel engines are also available.(57) The test engine was a single-cylinder, four-stroke turbocharged diesel engine, rated at 350 hp at 1,000 rpm. Water content in fuel ranged from 7 to 45 percent by volume. Both high energy and low energy emulsifiers were tested with similar results. Figure 5-5 shows test results which indicate NOₓ reductions of about 35 to 40 percent from a baseline emission level of approximately 10.4 g/bhp-h (Btu per brake horsepower-hour, units used for state and local regulations for engines). Losses in efficiency were 4 percent or less in these tests and increased with water/fuel ratio.

5.3.2 Exhaust Gas Recirculation

Another method for NOₓ reduction that has been tested primarily for large-bore diesel engines is exhaust gas

Figure 5-5. NOₓ Reduction by Water/Fuel Emulsion for Diesel Engine (57).

Figure 5-5 chart: Relative NOₓ Level versus Water/Fuel Ratio by Volume, with the following data key:

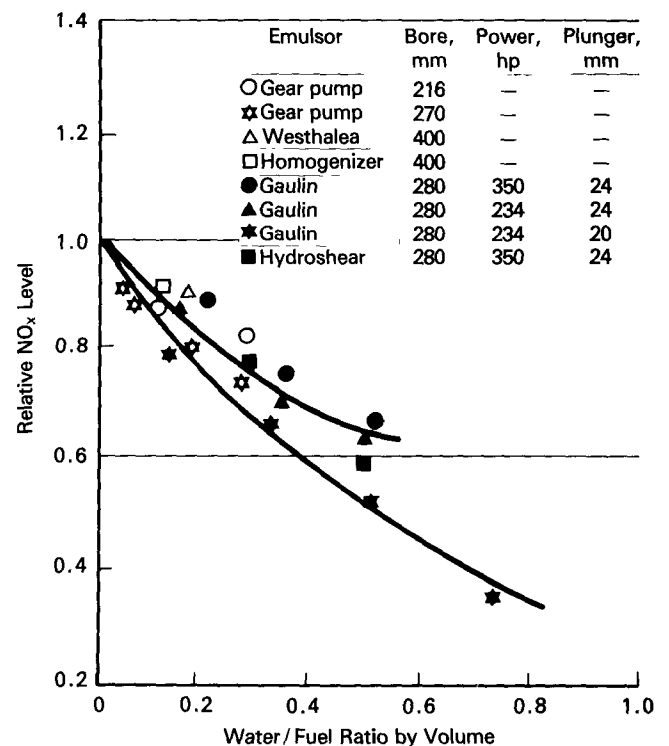| Emulsor	Bore, mm	Power, hp	Plunger, mm
O Gear pump	216	—	—
✪ Gear pump	270	—	—
△ Westhalea	400	—	—
□ Homogenizer	400	—	—
● Gaulin	280	350	24
▲ Gaulin	280	234	24
✱ Gaulin	280	234	20
■ Hydroshear	280	350	24

Table 5-1. NOₓ Reduction by Exhaust Gas Recirculation: Natural Gas, Spark Ignition Engines (58)

	% NO$_x$ Reduction	
Approximate % EGR	Pump-Scavenged Engines	Blower-Scavenged Engines
12	20	20
17	35	30
20	40	40

Figure 5-7. Effect of Lean-Burning Torch Ignition on Spark-Ignition Gas-Fired Engine (57).

method. Note in Figure 5-7 that slight increases in hydrocarbon emission also result from this modification. Factory test data are available that show an NO$_x$ reduction of 80 percent and higher for new engines modified to use lean-burning torch ignition in the form of "jet-cell igniters."(59) Operation at fuel/air equivalence ratios of less than 0.6 may affect turbocharger performance somewhat because the exhaust gas now has comparatively less energy content; however, reducing emissions to 2 g/hp-h only involves a fuel penalty of approximately 2 percent.(58) Note in

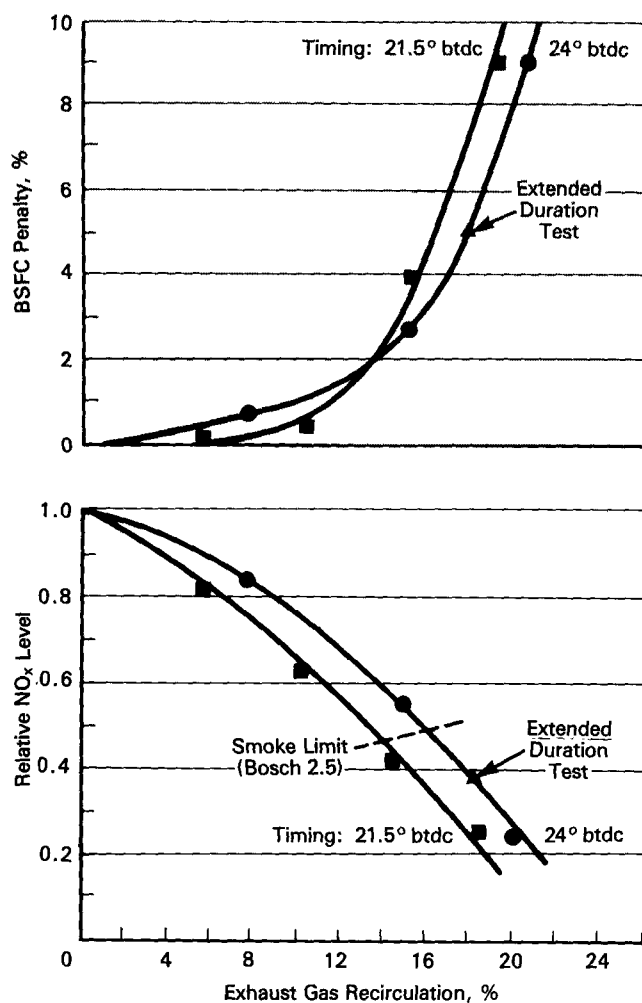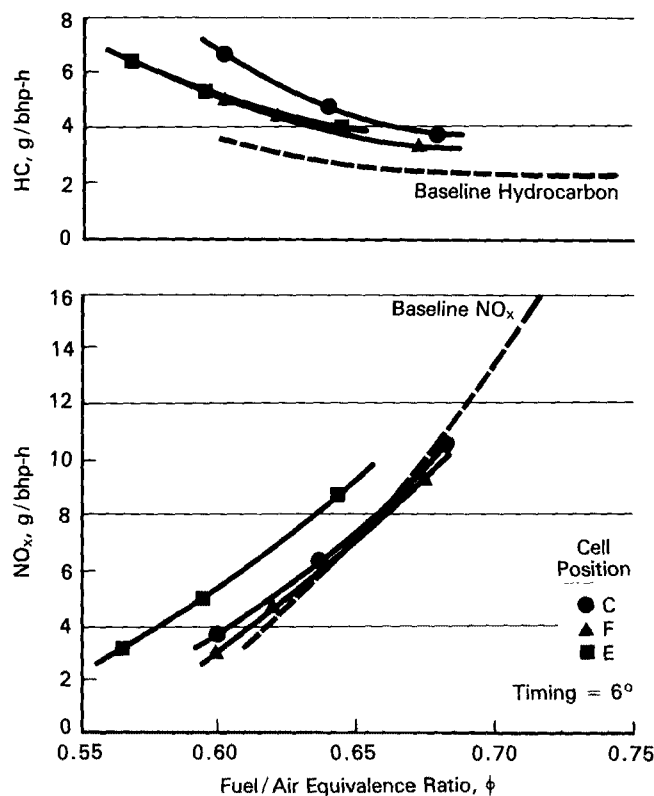**Figure 5-6.** NO$_x$ Reduction by Exhaust Gas Recirculation for Diesel Engine (57).

Figure 5-7 that NO$_x$ emissions are given in grams per brake horsepower-hour.

5.3.4 Charge Cooling

Charge cooling, sometimes referred to as charge refrigeration, is another technique that has been applied to spark-ignition engines, usually on a retrofit basis. Test results are available for this technique as applied to the earlier described engine.(57) Again, the NO$_x$ emissions were measured at various fuel/air equivalence ratios but also at incoming fuel/air temperatures ranging from a baseline of 43C (110F) down to 2C (35F). Figure 5-8 shows the results. Note that for a given fuel/air ratio, NO$_x$ reductions of about 40 percent were observed for charge cooling to 2C (35F). The side effects of charge cooling are the same as those for operation at leaner fuel mixtures, namely, the ignition is further delayed and the duration of combustion is extended. In order to combat these conditions which could lead to misfiring, it may be advisable to combine charge cooling with torch ignition or use of high energy sparking. Temperature drops to less than 5.5C (10F) above ambient would require extensive and expensive retrofitting including refrigeration.(60) Thus, if such a close temperature approach is required to meet a NO$_x$ emission level, this technology would not be cost-effective.

44

Figure 5-8. NO$_x$ Reduction by Charge Cooling for a Spark-Ignition Gas-Fired Engine (57).
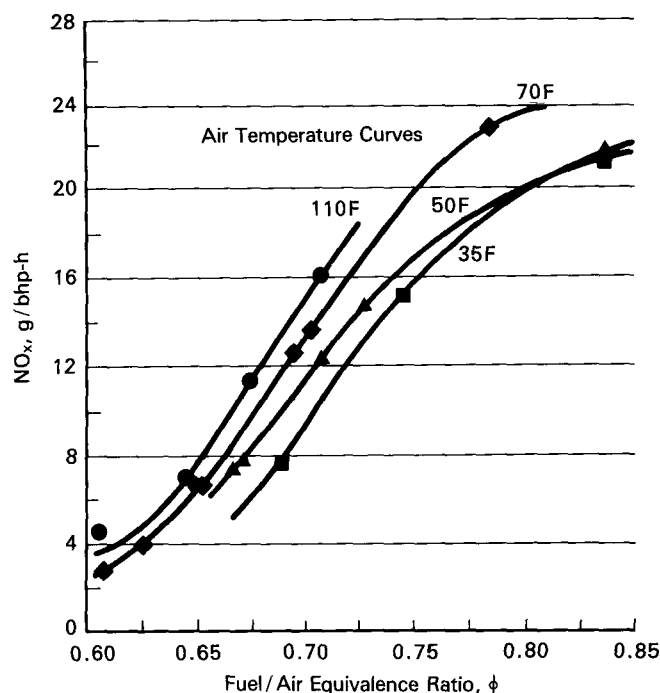
5.3.5 Ignition Retard

Data are available on NO$_x$ reductions in spark-ignition engines resulting from retarding ignition timing, which is used almost exclusively on a retrofit basis. Table 5-2 summarizes results for several types of natural gas-fired engines.(58) Typical NO$_x$ reductions achievable range from 15 to 30 percent. However, the fuel consumption penalty is not negligible (up to 3 percent).

5.3.6 Turbocharging

Limited data are available on the NO$_x$ reduction effect of turbocharging a natural gas-fired engine.(58) For turbocharging to 15 in Hg, NO$_x$ reductions were 55 percent for pump-scavenged engines and 45 percent for blower-scavenged engines, each with aftercooling to 38C (100F). Also, fuel consumption decreases between 10 and 13 percent were reported with a corresponding power increase of between 25 and 33 percent.

Table 5-2. NO$_x$ Reduction by Ignition Retard: Natural Gas-Fired Engines (58)

Type of Engine	Retard,°	NO$_x$ Reduction, %
Pump-scavenged, atmospheric*	4	15
Blower-scavenged, atmospheric*	4	25
2-stroke, turbocharged	4	30
4-stroke, turbocharged, medium pressure	5	17
4-stroke, turbocharged, high pressure	5	25

*Not turbocharged.

5.3.7 Postcombustion Controls

In addition to during-combustion technologies for controlling NO$_x$ emissions, both selective and nonselective catalytic reduction technologies have been employed for stationary engines. Most of the applications of these after-combustion technologies have been in Japan and in California.
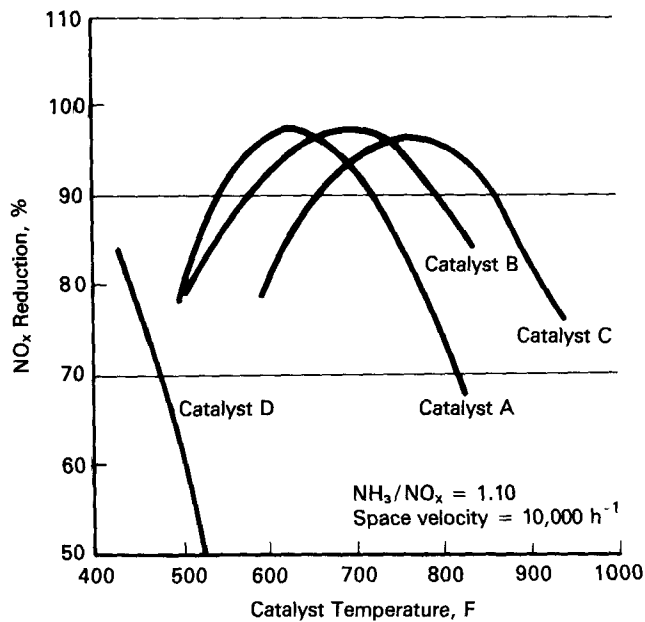
Long-term (2,300 h) testing of SCR on a diesel engine has been accomplished. The engine tested was rated at 165 kW with a displacement of 10.5 l (638 in³) and fired No. 2 diesel fuel. The results, shown in Table 5-3, are for extensive testing at an 80 kW load and at various NH$_3$/NO injection rates. Note that 90 percent reduction (from a baseline of about 400 ppm) was achievable at reasonable NH$_3$ injection rates until sometime before 2,000 hours of operation by which time catalyst performance had declined significantly. There was, however, significantly improved NO$_x$ reduction after catalyst cleaning.(61) Fouling of catalyst by diesel particulate was indicated as one possible factor in catalyst deactivation.

SCR has also been tested for spark-ignition engines.(57) The engine was a six-cylinder model rated at 1,350 hp at 330 rpm and burning natural gas. Results are shown in Figure 5-9. Note that reductions of 95 percent were found over a temperature range 38C (100F) wide. With the proper choice of catalyst, 95 percent reduction

Table 5-3. NO$_x$ Reduction by Selective Catalytic Reduction for Diesel Engine (61)

Cat. Hours	NO/NO Base	NH$_3$/NO Base	NO, ppm
10-500	1.0	0	433
	0.582	0.41	252
	0.213	0.81	92
	0.089	1.04	38
	0.043	1.09	18.5
	0.0173	1.37	7.5
	0.0173	1.65	7.5
	0.0173	1.98	7.5
1,000	1.0	0	350
	0.586	0.45	205
	0.471	0.60	165
	0.371	0.73	130
	0.214	0.81	75
	0.143	0.99	50
	0.077	1.18	27
2,000	1.0	0	370
	0.635	0.432	235
	0.541	0.570	200
	0.486	0.708	180
	0.446	0.778	165
	0.378	0.949	140
	0.292	1.114	108
	0.243	1.592	90
2,300	1.0	0	384
	0.372	0.70	143
	0.268	0.88	103
	0.216	1.05	83
	0.169	1.22	65
	0.138	1.40	53
	0.117	1.57	45
	0.099	1.75	38

45

Figure 5-9.

Figure 5-9. NOₓ Reduction by Selective Catalytic Reduction for Spark-Ignition Engine (57).

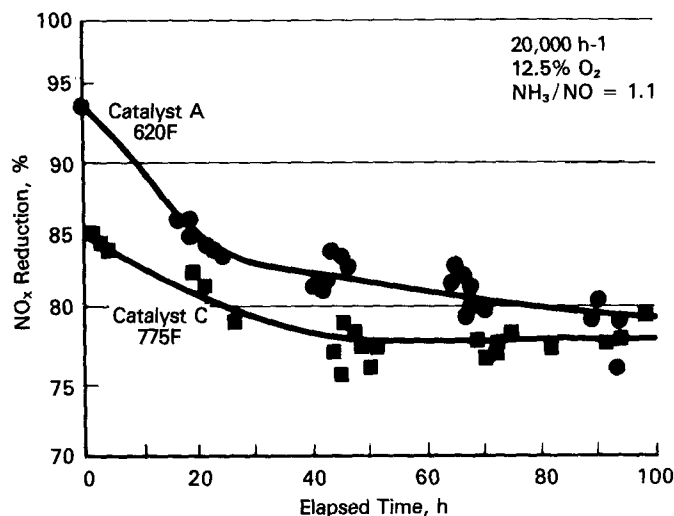$NH_3/NO_x = 1.10$
Space velocity = 10,000 h^{-1}

Table 5-4. Capital Costs for SCR Systems for Lean-Burn Spark-Ignition Engines[a] (24) (1984 dollars)

Engine Size, bhp	SCR Catalyst Cost, $	Cost, $ NH₃ Addition Controls Manual	Automated
460	29,000	6,500	50,000
820	47,000	7,000	51,000
1,280[b]	71,000[b]	7,500	52,000
2,500[b]	130,000[b]	8,500	54,000
5,150[b]	263,000[b]	11,000	59,000

[a]Engelhard 2-stroke engines.
[b]For 4-stroke engines, use 65% of this cost.

could probably be achieved at any gas temperature from 288C (550F) to 425C (800F). Figure 5-10 shows results of extended tests for two catalyst-temperature combinations. Note that if greater than 80 percent reduction is required, catalyst life may be quite limited.

The California Air Resources Board has investigated the cost of SCR for spark ignition (primarily lean-burn) engines.(42) Table 5-4 shows some relatively recent capital costs for several engines ranging in size from 660 to 4,000 hp. For units with manual controls for ammonia rejection, the major cost item is catalyst; where automatic ammonia controls are used, the control cost may outweigh the catalyst cost, especially for engines of less than 1,000 hp.

Spark-ignition engines are also controlled by nonselective catalytic reduction (NCR) units, especially rich-burning engines in California which are required to reduce NOₓ emissions by 90 percent. Table 5-5 shows data for NCR units applied to 13 rich-burn engines ranging from 50 to 1,100 hp and firing natural gas or, in two cases, digester gas.(62) NOₓ reduction efficiency after 4,000 h of operation was still in excess of 80 percent on average.

Costs for NCR (in 1984 dollars), including catalyst and air/fuel controls (manual or automatic), are shown in Table 5-6.(24)

Table 5-5. NOₓ Reduction by NCR: Results for Tests of 13 Rich-Burn Spark-Ignition Engines (62)

No. of Units	Engine Manufacturer	Engine Characteristics Rating, bhp	Loading
3	Waukesha	83	Cyclic
1	Waukesha	71	Steady
1	Waukesha	51	Steady
2	Waukesha	818	Variable
1	IHC	50	Cyclic
1	Climax	500	Variable
1	Climax	300	Variable
1	Caterpillar	130	Steady
1	Superior	500	Steady
1[a]	Ingersoll-Rand	1,100	Steady

Uncontrolled NOₓ, ppm[b] Mean	Std. Dev.	Controlled NOₓ, ppm[b] Mean	Std. Dev.	Average NOₓ Reduction, %
404	221	36.4	33.0	91

[a]Fueled by digester gas; all others by natural gas.
[b]Corrected to 15% O_2.

Figure 5-10. NOₓ Reduction by Selective Catalytic Reduction: Long-Term Test for Spark-Ignition Engine (57).

20,000 h-1
12.5% O_2
$NH_3/NO = 1.1$

Catalyst A 620F
Catalyst C 775F

Table 5-6. Cost of NCR Systems for Rich-Burn, Spark-Ignition Engines[a] (62) (1984 dollars)

Engine Size bhp	NSCR Catalyst Cost, $	Air/Fuel Controls Cost, $ Manual	Automatic	Dual or Single
70	2,000	1,300	7,900	Single
280	6,200	1,300	7,900	Single
585	11,400	2,000	10,900	Dual
1,170	19,700	2,000	10,900	Dual

[a]Engelhard Systems.

Chapter 6
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