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Summary of NOx Control Technologies and their Availability and Extent of Application

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Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
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1.0 INTRODUCTION

Section 185B of the new Subpart 2 of the Clean Air Act Amendments of 1990 directs the Environmental Protection Agency, in conjunction with the National Academy of Sciences, to conduct a study on the role of ozone precursors in tropospheric ozone formation. The study is to include an examination of the availability and extent of controls for sources of oxides of nitrogen (NO_x), which include nitric oxide (NO) and nitrogen dioxide (NO_2). As required by Section 185B, this report has been prepared to summarize the extent and availability of NO_x controls for stationary air pollution sources.

Chapter 2 provides an overview of the types of NO_x controls that can be used to control NO_x emissions from combustion and noncombustion sources. Brief descriptions of each generic technology alternative are presented to acquaint the reader with the fundamental principles of NO_x control and with the terminology used in Chapter 3.

Chapter 3 identifies the major categories of stationary NO_x sources and provides information on the applicability of control alternatives for each type of source. For each source category, information is provided on the current availability of control alternatives and on the extent of its development and use. Additionally, information is provided where available on the performance of each control technology alternative in controlling NO_x emissions.

2.0 DESCRIPTION OF NO_x CONTROL TECHNOLOGIES

This section describes the major technologies that can be used to control NO_x emissions from stationary sources. The descriptions presented below are generic in that they are intended to provide a broad perspective on the concepts of NO_x controls. For combustion sources, these concepts involve controls that address the combustion process and those that involve flue gas treatment. For noncombustion sources, control concepts involve process modifications alone or in combination with tail gas cleanup.

2.1 CONTROL TECHNOLOGIES FOR COMBUSTION SOURCES

In general, there are four approaches to controlling NO_x emissions from combustion sources:

- Control of NO_x formation by modification of combustion operating conditions;
- Control of NO_x formation by modification of combustion equipment;
- Control of NO_x formation by fuel switching; and
- Postcombustion control of NO_x by flue gas treatment.

Because the first three approaches involve reducing formation of NO_x, it is important to understand the basic mechanisms by which NO_x is formed during combustion. Descriptions of these mechanisms are presented in Section 2.1.1. The control approaches for reducing NO_x emissions are described in Sections 2.1.2 through 2.1.5.

2.1.1 Theory of NO_x Formation

During combustion, NO_x formation occurs by three fundamentally different mechanisms: thermal NO_x, fuel NO_x, and prompt NO_x. Each of these mechanisms is described below.

2.1.1.1 Thermal NO_x. Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air. Its rate of formation is extremely sensitive to local flame temperature and, to a lesser extent, to local oxygen concentrations. Virtually all thermal NO_x is formed in the region of the flame at the highest temperature. Maximum thermal NO_x production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction within the hot flame zone. Control of local flame fuel-to-air ratio is critical in achieving reductions in thermal NO_x.

In general, the control mechanisms available for reducing the formation of thermal NO_x are:

- Reduction of local nitrogen concentrations at peak temperature;
- Reduction of local oxygen concentrations at peak temperature;
- Reduction of the residence time at peak temperature; and
- Reduction of peak temperature.

Because it is quite difficult to reduce nitrogen levels, most control techniques have focused on the remaining three mechanisms[1].

2.1.1.2 Fuel NO_x. Fuel NO_x derives from the oxidation of organically bound nitrogen in fuels such as coal and heavy oil. Its formation rate is strongly affected by the rate of mixing of the fuel and air in general and by the local oxygen concentration in particular. Typically, the flue gas NO_x concentration resulting from the oxidation of fuel nitrogen is a fraction of the level that would result from complete oxidation of all nitrogen in the fuel. Although fuel NO_x emissions tend to increase with increasing fuel nitrogen content, the emissions increase is not proportional. Thus, fuel NO_x formation, like thermal NO_x formation, is dominated by the local combustion conditions[1].

Although fuel-bound nitrogen occurs in coal and petroleum fuels, the nitrogen-containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation. Therefore, fuel NO_x formation is of importance primarily in residual oil and coal firing. Little or no fuel NO_x formation is observed when burning natural gas and distillate oil[1]. In general, the control strategy for reducing fuel NO_x

formation for high nitrogen fuels involves introducing the fuel with a sub-stoichiometric amount of air (i.e, a "rich" fuel-to-air ratio). In this situation, fuel-bound nitrogen is released in a reducing atmosphere as molecular nitrogen (N_2) rather than being oxidized to NO_x. The balance of the combustion air enters above or around the rich flame in order to complete combustion. Here, as with thermal NO_x, controlling excess oxygen is an important part of controlling NO_x formation[1].

2.1.1.3 Prompt NO_x. Prompt NO_x is produced by the formation first of intermediate hydrogen cyanide (HCN) via the reaction of nitrogen radicals and hydrocarbons in the fuel, followed by the oxidation of the HCN to NO. The formation of prompt NO_x has a weak temperature dependence and a short lifetime of several microseconds. It is only significant in very fuel-rich flames, which are inherently low-NO_x emitters[2].

2.1.2 Control of NO_x by Modification of Combustion Operating Conditions

As discussed above, the rates of formation of both thermal and fuel NO_x are dominated by combustion conditions. Therefore, modifications of combustion operating conditions can have a substantial impact on the formation of NO_x.

Retrofit of NO_x controls implemented by combustion modification usually proceeds in several stages, depending on the emission limits to be reached. These modifications can involve one or more of the control strategies described below. First, fine tuning of combustion conditions by lowering excess air and adjusting the burner settings and air distribution may be employed. If NO_x emission levels are still too high, minor modifications, such as employing biased burner firing or burners out of service, may be implemented. If further reductions of NO_x are necessary, these modifications may be followed by other retrofits, including installation of overfire air ports, flue gas recirculation systems, and/or low-NO_x burners.

2.1.2.1 Low Excess Air (LEA)[2]. For all conventional combustion processes, some excess air is required in order to ensure that all fuel molecules are oxidized. In the LEA approach to NO_x control, less excess air (oxygen) is supplied to the combustor than normal. The lower oxygen concentration in the burner zone reduces the fuel nitrogen conversion to NO_x. Additionally, in the flame zone, fuel-bound nitrogen is converted to N_2, thus reducing formation of fuel NO_x. The limiting criteria which define minimum acceptable excess air conditions are increased emissions of carbon monoxide and smoke, and a reduction in flame stability.

Adjustments of air registers, fuel injector positions, and overfire air dampers are operational controls which can reduce the minimum excess air level possible while maintaining adequate air/fuel distribution. However, LEA controls require closer operator attention to ensure safe operation. Continuous LEA operations require the use of continuous oxygen (and preferably carbon monoxide) monitoring, accurate and sensitive air and fuel flow controls, and instrumentation for adjusting air flow at various loads.

LEA operation has an economic incentive since it results in increased fuel efficiency. It may be used with all fossil fuels. LEA operations may be used as the primary NO_x control method or in combination with other NO_x controls discussed below, such as low-NO_x burners, overfire air, or flue gas recirculation.

2.1.2.2 <u>Off-Stoichiometric (OSC) or Staged Combustion</u>[1]. With off-stoichiometric or staged combustion methods, initial combustion is conducted in a primary, fuel-rich combustion zone. Combustion is then completed at lower temperatures in a second, fuel lean zone. The sub-stoichiometric oxygen introduced with the primary combustion air into the high temperature, fuel-rich zone reduces fuel and thermal NO_x formation. Combustion in the secondary zone is conducted at lower temperature, thus reducing thermal NO_x formation. This approach can be used for combustion of all fossil fuels. Operational modifications incorporating the staged combustion concept include biased burner firing (BBF), burners out of service (BOOS), and overfire air (OFA), discussed below. In addition, low-NO_x burners, discussed in Section 2.1.3.1, incorporate the staged combustion concept.

Biased Burner Firing consists of firing the low rows of burners more fuel-rich than the upper rows of burners. This modification may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that a greater amount of fuel enters the furnace through the lower rows of burners than through the upper row. Additional air required for complete combustion enters through the upper rows of burners, which are fired fuel-lean.

Burners Out of Service combustion operations involve using individual burners or rows of burners to admit air only (see Figure 2-1). Correspondingly, the total fuel demand is supplied through the remaining fuel-admitting or active burners. Therefore, the active burners are firing more fuel-rich than normal, with the remaining air required for combustion being admitted through the inactive burners.

Overfire Air combustion involves firing the burners more fuel rich than normal while admitting the remaining combustion air through overfire air ports or an idle top row of burners. This modification is more attractive in original designs than in retrofit applications because of cost considerations, including costs of additional duct work, furnace penetrations, extra fan capacity, and physical obstructions making retrofit difficult in some installations. Also, OFA is usually more easily implemented on large units than on small ones, because larger proportional increases in furnace size and cost may be required to assure complete fuel combustion. Overfire air is integral to retrofit low-NOx combustion control technology for tangentially fired boilers-all commercially available systems include some OFA with redesigned low-NO_x coal and air nozzles[3,4].

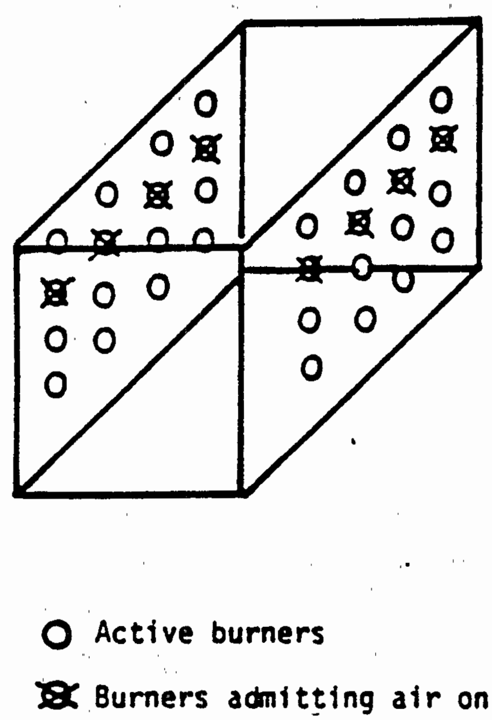

Figure 2-1. Typical boos arrangement for opposed fire unit.

2.1.2.3 Flue Gas Recirculation (FGR) or Exhaust Gas Recirculation (EGR)[2]. The FGR approach to NO_x control is based on recycling a portion of flue gas back to the primary combustion zone. This system reduces NO_x formation by two mechanisms. First, heating in the primary combustion zone of the inert combustion products contained in the recycled flue gas lowers the peak flame temperature, thereby reducing thermal NO_x formation. Second, to a lesser extent FGR reduces thermal NO_x formation by lowering the oxygen concentration in the primary flame zone.

The recycled flue gas may be pre-mixed with the combustion air or injected directly into the flame zone. Direct injection allows more precise control of the amount and location of FGR. In order for FGR to reduce NO_x formation, recycled flue gas must enter the flame zone.

The use of FGR has several limitations. The decrease in flame temperature alters the distribution of heat and lowers fuel efficiency. Because FGR reduces only thermal NO_x, the technique is applied primarily to natural gas or distillate oil combustion. Additionally, FGR is more adaptable to new designs than as a retrofit application.

2.1.2.4 Reduced Air Preheat (RAP)[2]. Reduced air preheat is limited to equipment with combustion air preheaters, and can be implemented by bypassing all or a fraction of the flue gas around the preheater, thereby reducing the combustion air temperature. Reducing the amount of combustion air preheat lowers the primary combustion zone peak temperature, thereby reducing thermal NO_x formation. Because the beneficial effects are limited to the reduction of thermal NO_x, this approach is economically attractive for only natural gas and distillate fuel oil combustion. Although NO_x emissions decrease significantly with reduced combustion air temperature, significant loss in efficiency will occur if flue gas temperatures leaving the stack are increased as a consequence of bypassing the air preheaters. Enlarging the surface area of existing economizers or installation of an economizer in place of an air preheater can be used to partially recover the heat loss.

2.1.2.5 Reburn[2]. Reburn, also referred to as in-furnace NO_x reduction or staged fuel injection, is the only NO_x control approach that is implemented in the furnace zone (i.e, the post-combustion, preconvection section). Reburning involves passing the burner zone products through a secondary flame or fuel-rich combustion process (see Figure 2-2). This approach diverts a fraction of the fuel to create a secondary flame or fuel rich-zone downstream of the burner (primary combustion zone). Sufficient air is then supplied to complete the oxidation process.

Reburning can be implemented either by redistributing the fuel and air through the existing burner pattern or by installing additional fuel and air ports above the burner pattern, with the latter approach likely to yield the best results. The burner pattern plus overfire air ports provide an existing, potential capability to implement the reburn control approach. In fact, the BOOS approach implemented on some units to achieve fuel-rich primary combustion (see Section 2.1.2.2) may also result in partial reburning. The LEA (see Section 2.1.2.1) and FGR (see Section 2.1.2.3) controls are combustion modification techniques often combined with reburning.

2.1.2.6 Steam/Water Injection[1]. Injection of steam or water into the combustion zone can decrease flame temperature, thereby reducing the formation of thermal NO_x. Because steam and water injection reduce NO_x by acting as a thermal ballast, it is important that the ballast reach the primary flame zone. To accomplish this, the ballast may be injected into the fuel, combustion air, or directly into the combustion chamber.

Water injection may be preferred over steam in many cases, due not only to its availability and lower cost, but also to its potentially greater thermal effect. In gas- or coal-fired boilers that are equipped for standby oil firing with steam atomization, the atomizer offers a simple means for injection. Other installations may require a developmental program to determine the degree of atomization and mixing with the flame

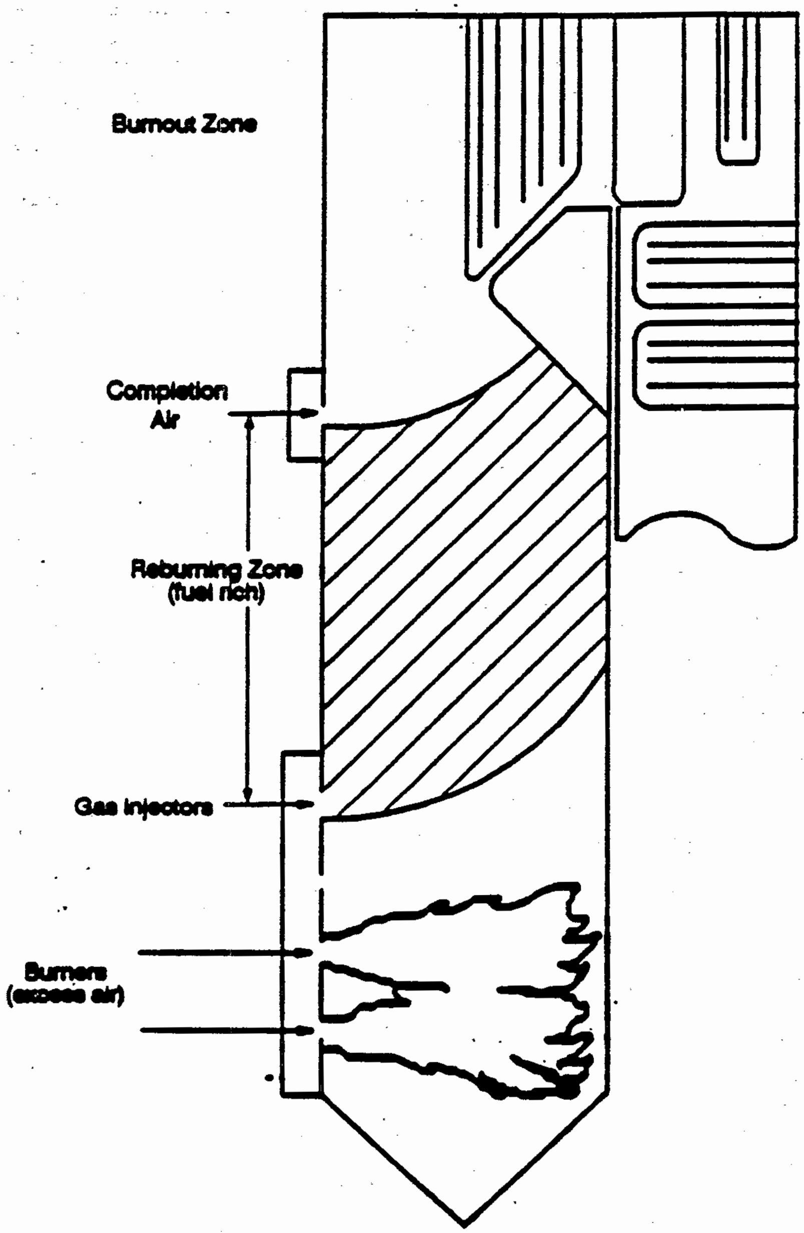

Figure 2-2. NO_x reburning with gas.

required, the optimum point of injection, and the quantities of water or steam necessary to achieve the desired effect.

The use of water injection may entail some undesirable operating conditions, such as decreased thermal efficiency and increased equipment corrosion. This technique has the greatest operating costs of all combustion modification schemes, with a fuel and efficiency penalty typically about ten percent for utility boilers and about one percent for gas turbines. Therefore, it has not gained much acceptance as a NO_x reduction technique for stationary combustion equipment except for gas turbines.

2.1.3 Control of NO_x by Modification of Combustion Equipment

The NO_x controls under this category include measures that may require significant changes in combustion equipment, either through substantial retrofitting or equipment replacement.

2.1.3.1 Low-NO_x Burners (LNB)[2]. The specific design and configuration of a burner has an important bearing on the amount of NO_x formed during the combustion process. Certain design types have been found to give greater emissions than others. Specific low-NO_x burner configurations that have been used or tested in a variety of boiler and process heater applications are described in Chapter 3. The most common approach, discussed below, is to control NO_x formation by carrying out the combustion in stages.

Staged air burners are two-stage combustion burners which are fired fuel-rich in the first stage (Figure 2-3). They are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The reduced availability of oxygen in the primary combustion zone inhibits fuel NO_x formation. Radiation of heat from the primary combustion zone results in reduced temperature. The longer, less intense flames resulting from the staged combustion lower flame temperatures and reduce thermal NO_x formation.

Staged air burners generally lengthen the flame configuration so that their applicability is limited to installations large enough to avoid impingement. The

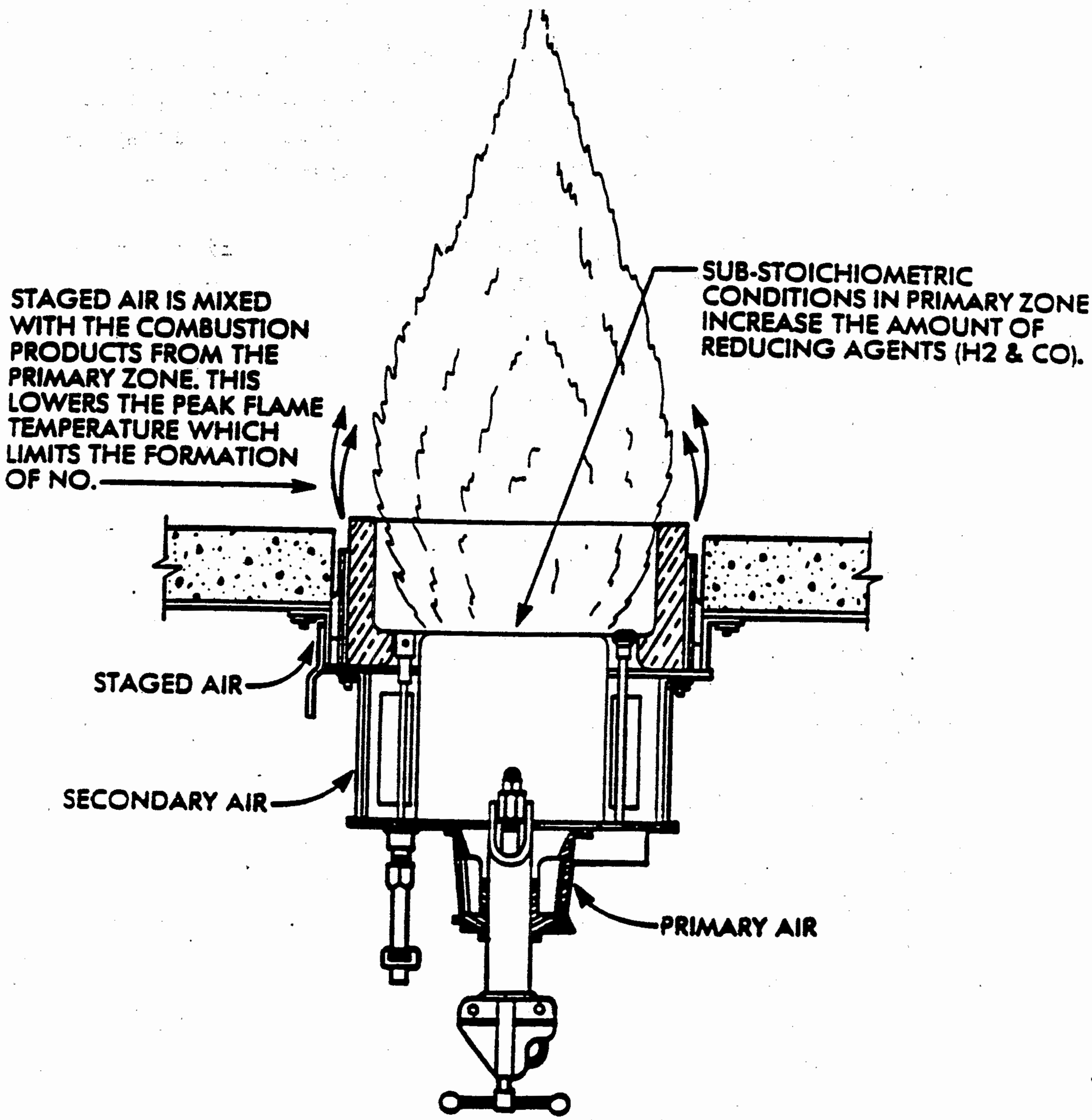

Figure 2-3. Staged air burner.

installation of replacement burners may require substantial changes in burner hardware, including air registers, air baffles and vanes, fuel injectors, and throat design. Existing burners can incorporate staged air burner features by modifying fuel injection patterns, installing air flow baffles, or reshaping the burner throat. Staged air burners can be used for all fuel types.

Staged fuel burners also use two-stage combustion, but mix a portion of the fuel and all of the air in the primary combustion zone (Figure 2-4). The high level of excess air greatly lowers the peak flame temperature achieved in the primary combustion zone, thereby reducing thermal NO_x formation. The secondary fuel is injected at high pressure into the combustion zone through a series of nozzles which are positioned around the perimeter of the burner. Because of its high velocity, the fuel gas entrains furnace gases and promotes rapid mixing with first stage combustion products. The entrained gases simulate flue gas recirculation. Heat is transferred from the first stage combustion products prior to the second stage combustion and, as a result, second stage combustion is achieved with lower partial pressures of oxygen and temperatures than would normally be encountered.

The staged fuel burner can be operated with lower excess air levels than the staged air burner due to the increased mixing capability resulting from the high pressure second stage fuel injection. An additional advantage of the staged fuel burner is a compact flame. Whereas in the first stage zone in the staged air burner cooling of the combustion products is accomplished primarily by radiation, in a staged fuel burner the entrained products give additional cooling to the flame. This particular characteristic permits more intense combustion with reduced NO_x

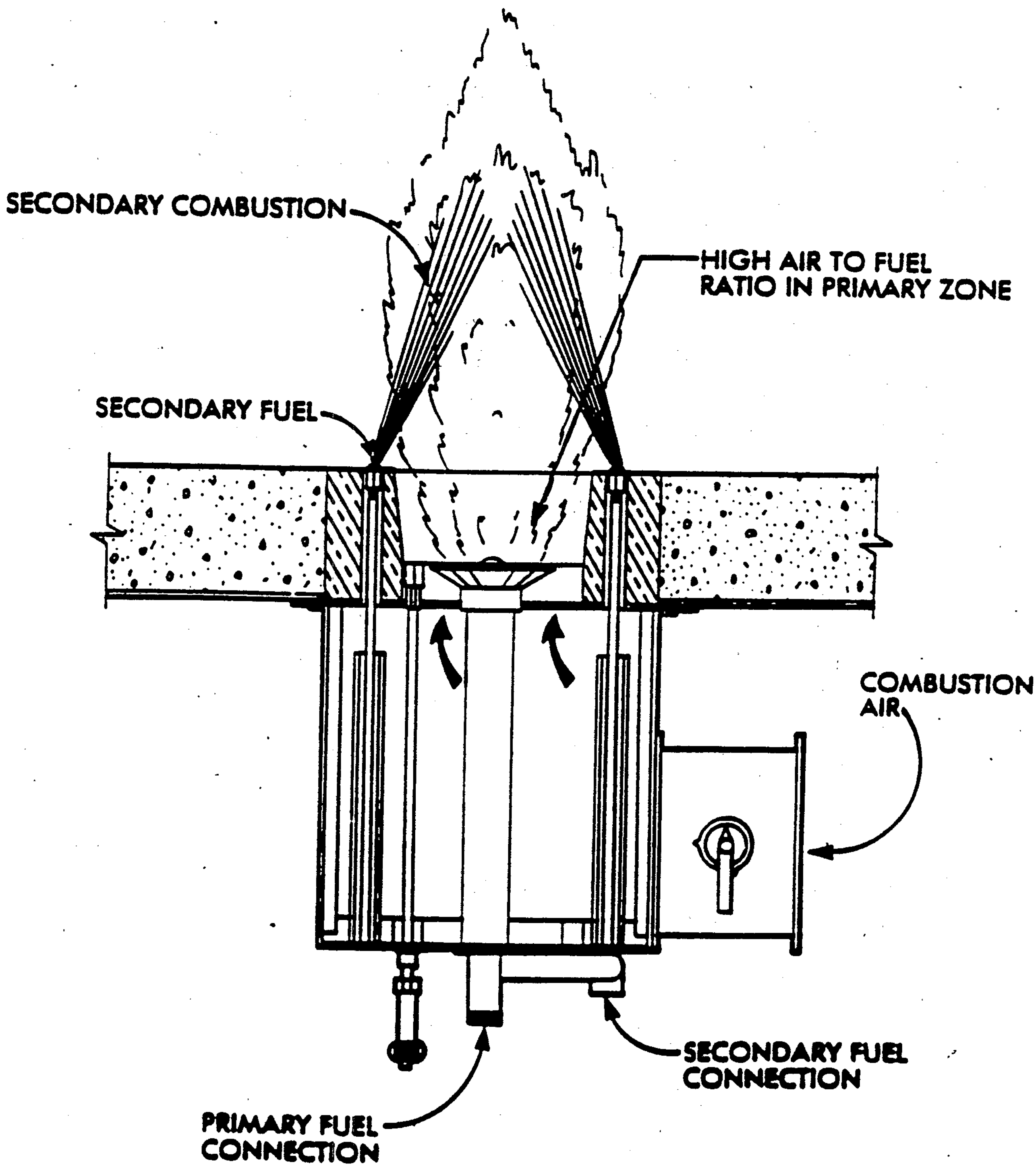

Figure 2-4. Staged fuel burner.

levels. Unlike staged air burners, staged fuel burners are only designed for gas firing.

2.1.3.2 Burner Spacing. The interaction between closely spaced burners, especially in the center of multiple-burner installations, increases flame temperature at these locations. Therefore, there is a tendency toward greater NO_x emissions with tighter spacing and a decreased ability to radiate to cooling surfaces. Therefore, in most new utility boiler designs, vertical and horizontal burner spacing has been widened to provide more cooling of the burner zone area. In addition, the furnace enclosures are built to allow sufficient time for complete combustion with slower and more complete heat release rates. Also, furnace plan areas have been increased to allow for larger heat transfer to the cooling walls[1].

Horizontal burner spacing is largest for tangentially fired boilers with the burners located at each corner of the furnace. Flames in these units interact only at the center of the furnace and, as a result, radiate widely to the surrounding cooling surfaces before interacting with each other. In addition, the tangential firing configuration results in slow mixing of fuel with the combustion air. For these reasons, tangentially-fired boilers generally may have baseline, uncontrolled NO_x emissions below those for other firing configurations. It is important to note, however, that other types of boilers installed since the new source performance standards were issued have uncontrolled NO_x emissions that compare favorably with tangentially-fired boilers[1,5].

2.1.3.3 Derating/Load Reduction[2]. Thermal NO_x formation generally increases as the heat release rate or combustion intensity increases. Reduced combustion intensity can be accomplished by load reduction, or derating, in existing units and by installation of enlarged fireboxes in new units. This NO_x control option is applicable to all fuel types.

Reduced firing rates can lead to several operational problems. The reduced mass flow can cause improper fuel-air mixing during combustion, creating carbon monoxide and soot emissions. This situation can be alleviated by operating at excess air levels higher than normally maintained at the original design load. This increase in oxygen levels reduces thermal operating efficiency and increases fuel NO_x generation. The net effect of decreasing thermal NO_x formation while increasing fuel NO_x is case specific.

When the combustion unit is designed for a reduced heat release rate, the problems associated with derating are largely avoided. An enlarged firebox produces NO_x reduction similar to load reduction on existing units, without necessitating an increase in excess air levels.

2.1.3.4 Catalytic Combustion. Catalytic combustion refers to combustion occurring in close proximity to a solid surface which has a special catalyst coating. A catalyst accelerates the rate of a chemical reaction, so that substantial rates of burning can be achieved at low temperatures, thereby reducing the formation of NO_x. Moreover, the catalyst itself serves to sustain the overall combustion process, minimizing stability problems. Catalytic combustion can be effective in reducing NO_x emissions, as well as emissions of carbon monoxide and unburned hydrocarbons. However, at present this control option has very limited applicability due to catalyst degradation at high temperatures (above 1000°C (1830°F)). While it may be applicable to gas turbines, its development for this purpose has been limited to prototype combustors[1,6].

2.1.3.5 Air-to-Fuel Adjustment[2]. In injection type engines used as prime movers, including all diesel and many dual-fuel and natural gas engines, the air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel or air that enters each cylinder. These engines are therefore operated lean, where combustion is most efficient and fuel consumption is optimum. Although the oxygen availability will increase, the capacity of the air and combustion products to absorb heat will also increase. Consequently, the peak temperature will fall, resulting in lower NO_x formation rates. The limiting factor for lean operation is the increased emissions of hydrocarbons at the lower temperatures.

2.1.3.6 Ignition Timing Retard[2]. Ignition timing retard is a NO_x control technique that is applicable to internal combustion (IC) engines. Ignition in a normally adjusted IC engine is set to occur shortly before the piston reaches its uppermost position (top dead center, or TDC). At TDC, the air or air-fuel mixture is at maximum compression and power output and fuel consumption are optimum. Retarding causes more of the combustion to occur during the expansion stroke, thus lowering peak temperature, pressure, and residence time. Typical retard values range from 2° to 6°, depending upon the engine. Beyond these levels, fuel consumption increases rapidly, power drops, and misfiring occurs.

2.1.4 Control of NO_x by Flue Gas Treatment

Flue gas treatment consists of technologies designed to reduce NO_x in the flue gas downstream of the combustion zone or by treatment in the boiler unit. These technologies can be used as the sole basis of control or in addition to the reductions achieved upstream by combustion operation or equipment modifications. Flue gas treatment systems are classified as "selective" or "non-selective" depending on whether they selectively reduce NO_x or simultaneously reduce NO_x, unburned hydrocarbons, and carbon monoxide.

2.1.4.1 Selective Catalytic Reduction (SCR)[2]. The SCR systems usually use ammonia to selectively reduce NO_x to N_2. Ammonia, usually diluted with air or steam, is injected through a grid system into the flue gas stream upstream of a catalyst bed (e.g., vanadium, titanium, or platinum-based) enclosed in a reactor. On the catalyst surface, the ammonia reacts with NO_x to form molecular nitrogen and water.

The reaction of ammonia and NO_x is favored by the presence of excess oxygen. The primary variable affecting NO_x reduction is temperature. A given catalyst exhibits optimum performance within a temperature range of plus or minus 28°C (50°F) for applications where flue gas oxygen concentrations are greater than one percent. Below this optimum range, the catalyst activity is greatly reduced, allowing unreacted ammonia to slip through. Above the range, ammonia begins to be oxidized to form additional NO_x. Further, excessive temperatures may damage the catalyst.

2.1.4.2 Non-Selective Catalytic Reduction (NSCR)[2]. In NSCR systems, NO_x is reduced in the presence of a catalyst by carbon monoxide in the flue gas, forming N_2 and carbon dioxide. The catalyst used to promote this reaction is usually a mixture of platinum and rhodium. Use of certain oil additives (e.g., phosphorus, zinc) may result in catalyst poisoning.

2.1.4.3 Selective Non-Catalytic Reduction (SNCR)[2]. The SNCR systems selectively reduce NO_x without employing catalysts. There are currently two commercially available SNCR systems. In the Thermal DeNO$_x$® system developed by Exxon, gaseous ammonia (NH_3) is injected into the air-rich flue gas to reduce NO_x to N_2. In the NO$_x$OUT® process, developed by the Electric Power Research Institute, a urea type (or amine salt) compound is injected into the oxygen-rich and/or high temperature convection section of a boiler to promote NO_x reduction. The exact chemical mechanism is not fully understood, but involves the decomposition of urea ($C(NH_2)_2O$) and the reduction of NO by reaction with NH_2. Temperature is the primary variable for controlling the selective reactions in both systems.

2.1.5 Control of NO_x by Fuel Modification

While not necessarily considered as a NO_x control technique, modification of fuels can in some cases provide reductions in NO_x formation. Fuel modification techniques that are currently available or potentially available are discussed below.

2.1.5.1 Fuel Switching[1]. Conversion to a fuel with a lower nitrogen content or one that burns at a lower temperature may result in a reduction of NO_x emissions. As discussed in Section 2.1.1.2, combustion of natural gas or distillate oils tends to result in lower NO_x emissions than is the case for coal or heavy fuel oils.

In addition to switching among conventional fossil fuels, emerging alternative fuels may offer viable longer term fuel switching options. A summary of the NO_x formation potential of some alternative fuels is provided in Table 2-1.

While fuel switching may be an attractive alternative from the standpoint of NO_x emission reductions, technical constraints and availability and costs of alternative fuels are major considerations in determining the viability of fuel switching.

2.1.5.2 Fuel Additives. The use of fuel additives has been considered for reducing the formation of NO_x when the fuel is burned. Tests were conducted in the early 1970's on 206 fuel additives burned in an oil-fired experimental furnace. None of the additives reduced NO_x emissions, and some additives containing nitrogen increased NO_x formation[7].

An investigation of fuel additives used in a high-pressure gas turbine cannular combustor indicated that transition metals added to Jet A Fuel as organometallic compounds could reduce No_x emissions by as much as 30 percent, with manganese, iron, cobalt, and copper being most effective. However, the investigator concluded that the resulting pollutants and operational problems would probably not warrant the additional fuel costs[8]. Investigations reported in the early 1970's indicated that 1.0 percent cobalt napthenate reduced NO_x emissions in a laboratory burner setup by 16 percent[9].

2.1.5.3 Fuel Denitrification. Fuel denitrification of coal or heavy oils could in principle be used to control fuel NO_x formation. The most likely use of this concept would be to supplement combustion modifications implemented for thermal NO_x control. Current technology for denitrification is limited to the side benefits of fuel pretreatment to remove other pollutants, such as oil desulfurization and chemical cleaning or solvent refining of coal for ash and sulfur removal. The low denitrification efficiency and high costs of these processes do not make them attractive solely on the basis of NO_x control, but they may prove cost effective on the basis of total environmental impact.

TABLE 2-1. NO_x FORMATION POTENTIAL OF SOME ALTERNATIVE FUELS

Fuel	Thermal NO_x	Fuel NO_x
Shale Oil	Moderate	High
Coal-Oil Mixture	Moderate	Moderate
Coal-Liquid Mixtures[a]	Low	Unchanged[b]
Methanol	Low	Low
Water-oil emulsion	Low	Unchanged
Hydrogen	High	Low

[a]Includes coal-water, coal-oil-water, and coal-alcohol.

[b]Fuel NO_x is probably unchanged unless a significant amount of low nitrogen oil or methanol replaces part of the coal on a heating basis.

Source: Reference 1

2.2 CONTROL TECHNOLOGIES FOR NONCOMBUSTION SOURCES

On a national basis, total emissions of NO_x from noncombustion stationary sources are small relative to those from manmade stationary combustion sources. Noncombustion industrial process sources accounted for about 8 percent of all stationary source emissions in the U.S. in 1985[10]. These sources include various chemical processes, such as nitric acid and explosives manufacturing. Since emissions from nitric acid manufacturing account for a significant amount of noncombustion stationary source emissions, control techniques for nitric acid plants are addressed in this report. Further, since techniques for controlling NO_x emissions from adipic acid manufacturing plants are similar to those from nitric acid plants, they are also included.

The absorption tower, common to all ammonia-oxidation nitric acid production facilities and to adipic acid plants using the cyclohexane-oxidation process, is the main source of atmospheric NO_x emissions at these plants. For new plants, NO_x emissions can be well controlled by increasing absorption column pressure, thereby increasing the efficiency of the absorber, or by employing processes for producing more highly concentrated acid, such as the Direct Nitric Acid process or SABAR (Strong Acid By Azeotropic Reactivation) process. However, these production alternatives are generally not feasible for existing plants. Hence, the focus of this report is on options for controlling tailgas from absorption towers. The following technologies are predominantly used.

2.2.1 Extended Absorption[11]

The final step for producing weak nitric acid involves the absorption of NO_2 and N_2O_4 to form nitric acid. As N_2O_4 is absorbed it releases gaseous NO_x. Extended absorption reduces NO_x emissions by increasing absorption efficiency (i.e., acid yield). This option can be implemented by installing a single large absorption tower, extending the height of an existing tower, or by adding a second tower in series with the existing tower. The increase in the volume and the number of trays in the absorber results in more NO_x recovered as nitric acid. This option can also be implemented at adipic acid plants.

2.2.2 Nonselective Catalytic Reduction (NSCR)[11]

In this process, absorber tailgas from nitric acid production is heated to ignition temperature using ammonia converter effluent gas in a heat exchanger, and fuel (usually natural gas) is added. The gas/fuel mixture then passes through the catalytic reduction unit where the fuel reacts in the presence of a catalyst with NO_x and oxygen to form elemental nitrogen, water, and carbon dioxide when hydrocarbon fuels are used. The process is called nonselective because the fuel first depletes all the oxygen present in the tailgas and then removes the NO_x. Catalyst metals predominantly used are platinum or mixtures of platinum and rhodium.

2.2.3 Selective Catalytic Reduction (SCR)[11]

The SCR technique has been described in Section 2.1.4.1. When applied to nitric acid plants, the process is typically applied downstream of the normal ammonia oxidation process. Absorber tailgas is passed through a heat exchanger to ensure that the temperature of the gas is within the operating temperature range of SCR unit. The gas enters the SCR unit, where it is mixed with ammonia and passed over a catalyst. Titanium/vanadium catalysts are most commonly used in nitric acid plants.

2.2.4 Thermal Reduction[11]

Thermal (or flame) reduction is used to control NO_x emissions from adipic acid manufacturing by reacting the NO_x in the absorber tailgas with excess fuel in a reducing atmosphere. In a typical thermal reduction unit, the NO_x-laden stream and excess fuel (usually natural gas) mixture passes through a burner where the mixture is heated above its ignition temperature. The hot gases then pass through one or more chambers to provide sufficient residence time to ensure complete combustion. For economic reasons, heat recovery is an integral part of thermal reduction unit operations.

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3.0 AVAILABILITY AND EXTENT OF APPLICATION OF NO_x CONTROL TECHNOLOGIES

This chapter provides a summary of the current state of development and use of the NO_x control technologies summarized in Chapter 2, including available information on the performance of each control alternative. The stationary air pollution sources addressed in this chapter include:

- Boilers, including electric utility and industrial/ commercial/institutional boilers;
- Commercial and residential space heaters;
- Prime movers, including stationary internal combustion engines and gas turbines;
- Municipal waste combustors;
- Industrial combustion sources (in addition to industrial boilers); and
- Noncombustion process sources.

The relative contribution of each of these source categories to nationwide NO_x emissions is discussed in Section 3.1. Controls for each category are then discussed in Sections 3.2 through 3.6.

3.1 SUMMARY OF NO_x EMISSIONS FROM STATIONARY SOURCES

The 1980 nationwide emissions of NO_x from all air pollution sources are summarized in Table 3-1. Stationary sources accounted for about 57 percent of total NO_x emissions in 1985. Of all stationary source categories, fuel combustion was by far the largest source of NO_x emissions, with about 90 percent of all stationary source emissions. Industrial process sources not involving fuel combustion accounted for about 8 percent of nationwide stationary source emissions in 1985, with the remaining 2 percent accounted for by municipal solid waste combustion and open fires[1].

3.2 CONTROL TECHNOLOGIES FOR BOILERS

As discussed in Section 3.1, in 1985 about 90 percent of all stationary source NO_x emissions, or 51 percent of NO_x emissions from all sources in the U.S., were from fuel combustion. Fossil

TABLE 3-1. NATIONAL ESTIMATES OF NITROGEN OXIDES EMISSIONS IN 1985

Source Category	Area Sources	Point Sources	Total Emissions (10^6 Tons)/Year	% of All Sources	% of Stationary Sources
Fuel Combustion	2,035	8,529	10,564	51	90.2
External Combustion	2,035	7,804	9,839	47.8	84.0
Residential	406	N/A	406	2.0	3.5
Anthracite Coal	1	N/A	1	0.0	0.0
Bituminous Coal	2	N/A	2	0.0	0.0
Distillate Oil	75	N/A	75	0.4	0.6
Residual Oil	0	N/A	0	0.0	0.0
Natural Gas	248	N/A	248	1.2	2.1
Wood	81	N/A	81	0.4	0.7
Electric Generation	N/A	6,614	6,614	32.0	56.5
Anthracite Coal	N/A	12	12	0.0	0.1
Bituminous Coal	N/A	5,604	5,604	27.2	47.9
Lignite	N/A	381	381	1.9	3.3
Residual Oil	N/A	169	169	.8	1.4
Distillate Oil	N/A	20	20	.1	.2
Natural Gas	N/A	419	419	2.0	3.6
Process Gas	N/A	4	4	0.0	0.0
Other	N/A	6	6	0.0	.1
Industrial	1,418	1,127	2,545	12.4	21.7
Anthracite Coal	0	6	6	0.0	.1
Bituminous Coal	131	434	565	3.2	5.0
Lignite	0	27	27	.1	.2
Residual Oil	50	136	186	.9	1.6
Distillate Oil	50	37	87	.4	.7
Natural Gas	1,187	274	1,461	7.1	12.5

TABLE 3-1. (continued)

Source Category	Area Sources	Point Sources	Total Emissions (10^6 Tons)/Year	% of All Sources	% of Stationary Sources
Process Gas	0	102	102	.5	.9
Coke	0	7	7	0.0	0.0
Wood	0	85	85	.4	.7
LPG	N/A	1	1	0.0	0.0
Bagesse	N/A	2	2	0.0	0.0
Other	0	18	18	.1	.2
Commercial/Institution	210	63	273	1.3	2.3
Anthracite Coal	6	1	7	0.0	0.0
Bituminous Coal	6	23	29	.1	.3
Lignite	N/A	0	0	0.0	0.0
Residual Oil	31	16	47	.2	.4
Distillate Oil	52	3	55	.2	.5
Natural Gas	115	15	130	.6	1.1
Wood	0	3	3	0.0	0.0
LPG	N/A	0	0	0.0	0.0
Other	N/A	2	2	0.0	0.0
Internal Combustion	N/A	725	725	3.5	6.2
Electric Generation	N/A	48	48	.2	.4
Distillate Oil	N/A	9	9	0.0	0.0
Natural Gas	N/A	38	38	.2	.3
Other	N/A	1	1	0.0	0.0
Industrial	N/A	654	654	3.2	5.6
Distillate Oil	N/A	5	5	0.0	0.0
Natural Gas	N/A	644	644	3.1	5.4
Gasoline	N/A	0	0	0.0	0.0
Diesel Fuel	N/A	2	2	0.0	0.0
Other	N/A	2	2	0.0	0.0

TABLE 3-1. (continued)

Source Category	Area Sources	Point Sources	Total Emissions (10^6 Tons)/Year	% of All Sources	% of Stationary Sources
Commercial/Institution	N/A	18	18	.1	0.2
Engine Testing	N/A	6	6	0.0	.1
Industrial Process	6	920	926	4.5	7.9
Chemical Manufacturing	N/A	171	171	.8	1.5
Food/Agriculture	N/A	5	5	0.0	0.0
Primary Metals	N/A	54	54	.3	.5
Secondary Metals	N/A	20	20	.1	.2
Mineral Products	N/A	240	240	1.2	2.0
Petroleum Industry	N/A	215	215	1.0	1.8
Wood Products	N/A	74	74	.4	.6
Organic Solvent Evap.	N/A	8	8	0.0	0.0
Petroleum Storage/Trans.	N/A	1	1	0.0	0.0
Metal/Fabrication	N/A	2	2	0.0	0.0
Textile Manufacture	N/A	0	0	0.0	0.0
Other/Not Classified	6	130	136	.7	1.2
Solid Waste Disposal	69	18	87	.4	.7
Government	N/A	8	8	0.0	0.0
Municipal Incineration	N/A	6	6	0.0	.1
Open Burning	N/A	0	0	0.0	0.0
Other Incineration	N/A	1	1	0.0	0.0
Residential	60	N/A	60	.3	.5
On-Site Incineration	3	N/A	3	0.0	0.0
Open Burning	57	N/A	57	.3	.5

TABLE 3-1. (continued)

Source Category	Area Sources	Point Sources	Total Emissions (10^6 Tons)/Year	% of All Sources	% of Stationary Sources
Commercial/Institution	7	5	12	.1	.1
On-Site Incineration	7	5	12	.1	.1
Open Burning	0	0	0	0.0	0.0
Other	0	0	0	0.0	0.0
Industrial	2	5	7	0.0	.1
On-Site Incineration	0	4	4	0.0	0.0
Open Burning	1	0	1	0.0	0.0
Other	0	1	1	0.0	0.0
Transportation	8,835	N/A	8,835	43.0	75.5
Lend Vehicles	8,549	N/A	8,549	41.6	73.0
Gasoline	5,139	N/A	5,139	25.0	43.9
Light Duty Vehicles	3,368	N/A	3,368	16.4	28.8
Light Duty Trucks	1,320	N/A	1,320	6.4	11.3
Heavy Duty Vehicles	297	N/A	297	1.5	2.5
Off-Highway	153	N/A	153	.7	1.3
Diesel Fuel	3,410	N/A	3,410	16.6	29.1
Heavy Duty Vehicles	1,825	N/A	1,825	8.9	15.6
Off-Highway	994	N/A	994	4.8	8.5
Rail	590	N/A	590	2.9	5.0
Aircraft	126	N/A	126	.6	1.1
Military	37	N/A	37	.2	.3
Civil	11	N/A	11	.1	.1
Commercial	78	N/A	78	.4	.7

TABLE 3-1. (continued)

Source Category	Area Sources	Point Sources	Total Emissions (10^6 Tons)/Year	% of All Sources	% of Stationary Sources
Vessels	160	N/A	160	.8	1.4
Bituminous Coal	0	N/A	0	0.0	0.0
Diesel	118	N/A	118	.6	1.0
Residual Oil	22	N/A	22	.1	.2
Gasoline	19	N/A	19	.1	.2
Miscellaneous	130	N/A	130	.6	1.1
Forest Fires	34	N/A	34	.2	.3
Forest Managed Fires	82	N/A	82	.4	.7
Agricultural Burning	8	N/A	8	0.0	.1
Structural Fires	6	N/A	6	0.0	.1
Grand Total	11,074	9,467	20,541		

N/A = Not Applicable
Source: Reference 1

fuel boilers used in the electric utility and industrial sectors comprise the majority of fuel combustion emissions. The applicability and extent of use of control technologies for utility boilers are discussed in Section 3.2.1. Control technologies for industrial, commercial, and institutional boilers are discussed in Section 3.2.2.

3.2.1 Utility Boilers.

In the U.S., the control of NO_x from utility coal-, oil-, and gas-fired boilers has focused on the use of combustion controls developed and implemented over the past two decades. However, in Germany and Japan recent regulations have necessitated the use of flue gas treatment processes in addition to combustion controls to achieve some of the lowest NO_x standards in the world[2]. The following information summarizes the experience of utilities in the U.S., Germany, and Japan with both combustion and post-combustion NO_x controls. The information was derived from Reference 3, unless otherwise indicated. Sections 3.2.1.1 and 3.2.1.2 address NO_x controls for coal-fired utility boilers using combustion modifications and flue gas treatment, respectively. For oil- and natural gas-fired utility boilers, combustion modifications and flue gas treatment techniques to control NO_x emissions are discussed in Sections 3.2.1.3 and 3.2.1.4, respectively.

3.2.1.1 Coal-Fired Boilers: NO_x Controls by Combustion Modifications. The major combustion controls applicable to coal-fired boilers include:

- Low excess air;
- Overfire air;
- Low-NO_x burners;
- Low-NO_x burners with overfire air and/or flue gas recirculation;
- Reburning; and
- Fuel switching.

Low excess air firing (LEA) is easy to install in most utility boilers, both for new and existing units. The LEA technique was initially implemented by the utility industry to increase thermal efficiency and to reduce stack gas opacity due to acid mist, and it is now often considered more of an energy conservation measure than a NO_x control technique. New designs and most existing combustion operations incorporate LEA firing as standard practice[2]. Because LEA is so predominantly and routinely used, the remainder of the combustion control alternatives discussed in this section can be considered to supplement NO_x reductions that are being achieved with LEA. A summary of these combustion control techniques for coal-fired utility boilers is provided in Table 3-2. The data on NO_x reduction performance and controlled emission levels are based on estimates developed for utilities in the Northeast States for Coordinated Air Use Management (NESCAUM) region, as reported in Reference 2. Due to limited data currently available, the actual percentage reduction of NO_x emissions for a given technology may vary for a specific site from that shown in the table.

Overfire air, where applicable, generally offers a low-cost approach to achieving NO_x reductions. For pulverized coal units, OFA is applicable to both corner-fired (tangential-fired) and wall-fired (front and opposed) boilers. Many U.S. tangential boilers put into service after the effective date of the federal new source performance standards (NSPS) come equipped with OFA ports. Newer designs that increase the penetration of air into the furnace for improved second stage performance under deeper staging have separate ports located above the main burner windbox (this design is often referred to as advanced overfire air, or AOFA). However, OFA is not applicable to cyclone boilers and other slagging furnaces because combustion staging will alter the heat release profile, significantly changing the slagging rates and properties of the slag[2].

There are two principal design requirements for the retrofit of OFA ports in existing coal-fired boiler furnaces. First, there must be sufficient furnace volume above the top row of burners to provide adequate residence time to achieve optimum NO_x reduction performance. Second, the high OFA velocity needed for good mixing requires installation of several ports, which can

TABLE 3-2. COMBUSTION CONTROLS FOR COAL-FIRED UTILITY BOILERS

Technology	Percent NO_x Reduction and Controlled NO_x Levels (lb/MM Btu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS Boilers	Post-NSPS Boilers[b]		
OFA or advanced overfire air (AOFA)	15-30 (0.40-0.50) T (0.55-0.65) W	15 (0.50) W	Older tangential units; most wall-fired units except slagging units	Installation of OFA ducting. Installation of OFA ports and water wall panel modification. Addition of airflow dampers for improved distribution. Installation of curtain air with some designs. Installation of emission monitoring system and control for air dampers.
Low-NO_x Burner control often applied with close-coupled OFA, especially for tangential units	30-55 (0.35-0.45) T (0.40-0.50) W	30-40 (0.35-0.40) T (0.35-0.40) W	Most tangential units; most wall-fired units except slagging units	Install new burners and scanners. Replace burner zone tubing panels. Burner/pulverizer control system replacement. Replace burner piping, hangers, valves. Replace igniters and viewports. Structure modifications and platforms. Installation of air ports for blanket air and CEM system.
AOFA + Low-NO_x Burners	50-65 (0.25-0.30) T (0.25-0.40) W	40-55 (0.25-0.30) T (0.25-0.30) W	Some older wall-fired boilers and most post-NSPS tangential	All those cited above, plus: replace tangential units or modify wall-fired units windbox. Replace combustion air control system. Partial replacement of coal piping. Fan and pulverizer modifications. Install separate OFA ports.
Reburning or fuel staging (requires OFA)	45-65 (0.40-0.70) C,S (0.25-0.35) T (0.30-0.45) W	40-65 (0.20-0.35) W (0.20-0.35) T	All boilers, but technology primarily targeted for cyclone and wet-bottom (slagging furnace) units	Install reburning burners and OFA ports. Replace tube wall panels. Piping ductwork to reburn burners and OFA ports. Burner/combustion control system. Gas fuel substation or oil and pump storage. FGR ducting and fan may be required (site dependent), and continuous emission monitoring system.

Source: Reference 2
T = Tangential or corner-fired W = Wall-fired (front or opposed) C = Cyclone S = Slagging furnace

[a]Controlled levels are based on estimated reduction performance and weighted average baseline emissions of utility plants in the Northeast States for Coordinated Air Use Management (NESCAUM) region.

[b]Only two boilers in the NESCAUM region are post-NSPS-design units. Controlled emission levels are from the current baseline of 0.60 lb/MM Btu for the tangential-fired unit and 0.58 lb/MM Btu for the wall-fired unit.

affect the structural integrity of the furnace. Also, penetration into the furnace with the installation of air ports may result in structural weakness of the boiler tube panels.

There are a number of constraints to retrofitting OFA to a number of existing utility boilers. At many existing units, sufficient distance between the top burner and the furnace exit is not available to achieve the optimum residence time. Further, the high overfire air velocity needed for good mixing requires installation of several ports, which can affect the structural integrity of the furnace.

In addition, because OFA uses a large portion of the entire firebox volume to obtain the needed separation between first and second stage combustion, unburned carbon in the fly ash as well as carbon monoxide emissions can be significant if excess OFA (greater than 25 percent) is used, especially when burning high-rank bituminous coals. Waterwall corrosion can also be a significant concern in retrofitting OFA to existing high-sulfur coal- and oil-fired boilers[2].

The NO_x control efficiency for OFA is estimated to range between 15 and 30 percent for boilers installed prior to the effective date of the NSPS. Post-retrofit NO_x levels from these boilers are anticipated to be in the range of 190 to 210 nanograms per Joule (ng/J), or 0.45 to 0.50 pounds per million Btu (lb/MMBtu) from an estimated baseline uncontrolled level of 250 ng/J (0.58 lb/MMBtu) for tangential or corner-fired units (14 to 22 percent reduction), and 230 to 280 ng/J (0.55 to 0.65 lb/MMBtu) from an uncontrolled level of 330 ng/J (0.77 lb/MMBtu) for wall/opposed-fired units[2] (16 to 29 percent reduction).

Because of recent advances in LNB technologies, all major utility boiler manufacturers, here and abroad, have developed low-NO_x burners that can be used in new and retrofit applications. Estimates by the Electric Power Research Institute (EPRI) indicate that the retrofit applicability for LNB is about 50 to 80 percent, depending on firing configuration and boiler manufacturer[2]. The performance of low-NO_x burners varies substantially from one boiler application to another, and from one LNB model to another[4]. Low-NO_x burner technology often includes OFA.

Combined with OFA, the use of low-NO_x burners can reduce NO_x emissions from coal-fired utility boilers to levels approaching 89 ng/J (0.21 lb/MMBtu), although full-scale experience at such low NO_x levels is limited. For example, at Allegheny Power Company's Pleasant Station Unit 2, NO_x emissions were reduced from uncontrolled levels of 410 to 510 ng/J (0.96 to 1.20 lb/MMBtu) to a controlled level of 170 ng/J (0.40 lb/MMBtu) without OFA, and to 140 ng/J (0.33 lb/MMBtu) with OFA, representing emission reductions of 58 to 67 percent without OFA and of 66 to 72 percent with OFA. Low-NO_x burner retrofits without OFA have shown NO_x reduction potential to levels as low as 150 to 210 ng/J (0.35 to 0.50 lb/MMBtu). Table 3-3 lists the known commercial coal-fired low-NO_x burners, including some recent domestic and foreign applications[2].

In the U.S., wall- and opposed-fired utility boilers retrofitted with a combination of low-NO_x burners and OFA or AOFA include[2]:

- Allegheny Power, Pleasant Station Unit No. 2: 650 Megawatt (MWe) unit burning eastern bituminous coal;
- San Juan Station Unit No. 1: 360 MWe unit burning sub-bituminous coal; and
- Campbell Station Unit No. 3: 778 MWe unit burning eastern subbituminous coal.

Domestic tangential boilers retrofitted with low-NO_x burners and OFA include[2]:

- Kansas Power and Light, Lawrence Station Unit No. 5: 400 MWe unit;
- Public Service of Colorado, Valmont Station Unit No. 5 (165 MWe) and Cherokee Unit No. 4 (350 MWe);
- Utah Power and Light, Hunter Unit No. 2; and
- Southern Company Services, Smith Unit No. 2 (180 Mwe).

Some low-NO_x burners, such as the Separate Gas Recirculation (SGR) and the Pollution Minimum (PM) burners developed by Mitsubishi Heavy Industries (see Table 3-3), incorporate FGR in

TABLE 3-3. PARTIAL LIST OF COAL-FIRED LOW NO_x BURNER APPLICATIONS

Burner Type	Manufacturer	Retrofit Applications	Reported Performance
LNCFS	ABB-CE	Corner-fired Boilers: U.S.: Utah P&L Hunter Unit 2, PSCC Valmont 165 MWe Unit 5 and Cherokee 350 MWe Unit 4 UK: Fiddler Ferry Unit 1 (Typically used with OFA)	25-32 percent NO_x reduction w/o OFA; 33-50 percent w/OFA to about 0.28 to 0.31 lb/MMBtu minimum
CCTFS	ABB-CE	ENEL: Fusina Unit 2 160 MWe	10-15 percent NO_x reduction without OFA and up to 49 percent reduction with 30 percent OFA to about 0.27 lb/MMBtu
SGR	MHI	Japan: EPDC Matsushima Thermal Power Station Unit 1 & 2 (500 MWe each)	30-50 percent NO_x reduction with OFA to 0.27 to 0.40 lb/MMBtu levels
PM	MHI-ABB-CE	US: DP&L Lawrence Unit 5 (recent demo) Japan: Several new and modified units Italy: Fiume Santo 320 MWe	30-50 percent NO_x reduction at KP&L (.25 to .45 lb/MMBtu). Capability for 0.2 to 0.25 lb/MMBtu reported for U.S. coals
CF/SF	FWEC	A total of 10 utility and large industrial units retrofitted to date with over 5000 MWe capacity in US. Installed with or without AOFA	50-60 percent reduction from pre-NSPS boilers to 0.4 lb/MMBtu; 70-80 percent reduction with AOFA to 0.2 lb/MMBtu
IFS	FWEC	Recently introduced as easy upgrade of CF/SF. Only pilot-scale data available to date	Reported 75 percent reduction from pre-NSPS boilers without AOFA to levels of 0.2 lb/MMBtu
CCV	Riley Stoker	Central Illinois P&L Duck Creek single wall 400 MWe and two Carolina P&L Roxboro units at 360 MWe each	50 percent NO_x reduction measured on U.S. retrofits with underfire air to levels of 0.43 to 0.53 lb/MMBtu
HT-NR	BHK	Wall-Fired Boilers: Japan: EPDC Matsuura 1000 MWe Unit 1 The Netherlands: Mass Unit 5, Njimegen Unit 13 Finland: 265 MWe Inkoo Unit 4	25-50 percent NO_x reduction to levels in the range of 0.32 to 0.40 lb/MMBtu with several coal types
BWE-Type 4AF	BWE	Wall-Fired Boilers: Denmark: Asnaes 270 MWe Unit 4, additional retrofit planned	50 percent NO_x reduction to about 400 ppm (0.53 lb/MMBtu)
XCL	B&W	U.S.: Ohio Edison Edgewater Italy: Brindisi Sud Unit 2	NO_x reduction capability to 0.5 to 0.55 lb/MMBtu
LNCB	B&W	Demonstration at DP&L Stuart 605 MWe Unit 4 and some applications in Italy	Anticipated 50 percent NO_x reduction to about 0.50 to 0.60 lb/MMBtu

(Note: This list includes full-scale as well as pilot-scale demonstrations under controlled combustion conditions in the U.S. and abroad. Data were obtained from a variety of coal ranks (i.e., low/high volatile coal)).

LNCFS: Low NO_x Concentric Firing System
SGR: Separated Gas Recirculation
PM: Pollution Minimum
CCV: Control Combustion Venturi
LNCB: Low NO_x Cell Burner
HT-NR: Hitachi NO_x Reduction
CF/SF: Controlled Flow/Split Flame
CCTFS: Concentric Clustered Tangential Firing System

ABB: Asea Brown Boveri
CE: Combustion Engineering
MHI: Mitsubishi Heavy Industries
B&W: Babcock & Wilcox
BHK: Babcock Hitachi K.K.
FWEC: Foster Wheeler Energy Corp.
BWE: Burmeister & Wain Energy
IFS: Internal Fuel Staging

Source: Reference 2

tangentially-fired boilers to provide a more distinct separation between the fuel-rich and fuel-lean zones of the burner, thereby enhancing the degree of NO_x control. However, low-NO_x burners designed for wall-fired boilers rarely use FGR[2].

Reburning is another technique that can be used for reducing NO_x emissions from coal-fired utility boilers. Although applicable to most boiler designs, reburning is expected to be primarily applied to cyclone and wet-bottom boilers, which are generally difficult to control by other combustion methods. The technology has been used in Japan on at least one large (600 MWe) boiler and several oil/gas-fired units in connection with LNB. Commercialization of this technology in the U.S. awaits the results of ongoing demonstration projects being conducted at five utility plants to evaluate the retrofit potential and control performance. These projects are[2]:

- Illinois Power, Hennepin Station Unit No. 1: 71 MWe unit employing tangential boiler;
- City Water, Light and Power, Lakeside Station Unit No. 7: 33 MWe unit employing cyclone boiler;
- Ohio Edison, Miles Unit No. 1: 108 Mwe unit employing cyclone boiler;
- Public Service of Colorado, Cherokee Station Unit No. 3: 158 MWe unit employing wall-fired boiler; and
- Wisconsin Power and Light, Nelson Dewey Station Unit No. 2: 100 MWe unit employing cyclone boiler.

The reburn technology used in the first two demonstrations is combined with dry sorbent injection for simultaneous NO_x/SO_x control. The first four demonstrations use natural gas for the reburning fuel, while the fifth uses pulverized coal. Because of its clean burning properties, natural gas holds better promise for a more efficient reburning fuel. One full-scale demonstration on a tangential boiler has shown NO_x reduction from an uncontrolled level of about 400 ppm to a range of 120 to 150 ppm with a reburn zone stoichiometry of 0.9, for emission reductions ranging from 62 to 70 percent. Thermal efficiency reduction for reburning is anticipated to be in the range of 0.1 percent[2].

In addition to the combustion modifications discussed above, fuel switching is another potential alternative for achieving NO_x emission reductions from coal-fired boilers. As discussed in Chapter 2, the combustion of oil and gas results in lower NO_x emissions than the combustion of coal. Therefore, for some coal-fired utility boilers, conversion to oil or gas may be a technically feasible means of reducing NO_x emissions[3].

3.2.1.2 <u>Coal-Fired Boilers: NO_x Controls by Flue Gas Treatment</u>. Postcombustion controls applicable to coal-fired utility boilers include the following flue gas treatment techniques:

- Selective catalytic reduction;
- Selective non-catalytic reduction; and
- Combined NO_x/SO_x controls.

Selective catalytic reduction systems have been widely used on utility boilers in Japan, and more recently in Germany and Austria. However, in the U.S. SCR application to power plants has been very limited. The first SCR units to be used on coal-fired boilers in the U.S. are under construction on two 140 MWe units at Carney's Point, New Jersey. These units, which will use low-NO_x burners combined with SCR, have permitted NO_x emission limits of 70 ng/J (0.17 lb/MMBtu)[5]. In addition, Southern Company Services, Inc. will soon undertake a test program where ten different SCR catalysts will be evaluated at a Florida utility plant[2]. The Electric Power Research Institute is sponsoring research at a level of about $15 million over a four-year period to assess SCR process design, catalyst life, instrumentation and controls, and plant design on boilers combusting medium and high sulfur coal at 14 specific locations[6].

Japan has about 20 years of full-scale utility experience with SCR, with recent experience reported to have significant success. Initially, there were concerns about ammonia slip (i.e., unreacted ammonia leaving the catalyst body), the formation of ammonia sulfate and bisulfate, and catalyst poisoning and subsequent deactivation. However, recent reports indicate that ammonia slip control to levels below 5 ppm of ammonia are routine. Ammonium sulfates have been reduced with the use of different catalyst formulations that minimize the amount of SO_2 to SO_3 conversion in the reactor[2]. It is reported that SCR systems are still operating without any catalyst replacement for four to five years for coal-fired boilers in Japan[7].

Today, SCR is used on more than 100 utility boilers in Japan, of which 40 burn coal[2]. Through 1990, total SCR-controlled coal-fired capacity in Japan is 10,900 MWe[7]. While most of these plants burn low sulfur coal, some SCR systems are operated on high sulfur (2.5 percent) coal. For example, the 250 MWe Takehara plant is burning 2.3 to 2.5 percent sulfur coal, and the SCR system is achieving a NO_x removal efficiency of more than 80 percent[7]. In Germany, 129 SCR systems have been installed on over 30,000 megawatts of utility service. Most utility applications have been retrofits on coal-burning plants. The sulfur content of coal burned in these plants generally ranges from 0.7 to 1.2 percent. Some wet bottom boilers in Germany have been retrofitted with SCR, but significant catalyst degradation due to arsenic oxide poisoning has been reported[2].

Reductions of NO_x emissions of 70 to 90 percent have been reported in applications of SCR to utility boilers in Germany and Japan. Slightly lower NO_x reduction efficiencies are generally found when the initial concentration of NO_x entering the reactor is low because of combustion controls. In applying these foreign SCR technologies to U.S. utilities, it is likely that application can be more easily accomplished when the coal burned has low-sulfur and low-ash[2].

The retrofit of SCR on existing power plants can be costly and complex since, for example, modifications to the boiler convective ducts are necessary. The SCR reactor must be placed in the existing flue gas path where the temperature is sufficiently high for efficient NO_x control. Modifications of the building structure and sootblower relocations are often necessary to accommodate the equipment installation. Further, regardless of the configuration and reactor location, the retrofit of SCR requires boiler modifications and control system upgrade. Upgrade of the combustion air fans is always necessary to accommodate the increase in pressure drop, and an ammonia monitoring and feedrate control system is necessary to maintain consistently high NO_x reductions and low ammonia slip at varying boiler loads[2].

Compared to SCR, there is very little experience with application of SNCR to coal-fired utility boilers. The State of New Jersey has recently approved an air quality permit for the 225 MWe Keystone plant. The plant, which will use low-NO_x burners combined with SNCR, has a permitted emission limit of 70 ng/J (0.17 lb/MMBtu)[5]. In the only coal-fired utility demonstration of urea injection in the United States, the NO_xOUT® process was tested on a tangentially-fired boiler. The NO_x emissions were reduced from 225 ppm to 155 ppm, a reduction of 31 percent, after application of combustion modifications[2]. In Sweden, the NO_xOUT® process applied to a 50 MWe front wall-fired boiler has achieved NO_x emission reductions of 65 to 75 percent, with ammonia slip less than or equal to 5 ppm[8]. A 75 MWe tangentially fired boiler in Germany has achieved NO_x reductions of 35 percent, from 150 ppm to less than 100 ppm[9].

One limitation of SNCR is that it has limited ability to follow load changes while maintaining minimal ammonia slip. Therefore, its application is generally limited to base loaded boilers. Another limitation of this technology is the formation of ammonium sulfate and bisulfate when applied to boilers burning high-sulfur fuels. Therefore, the technology is currently limited to utility plants fired with low-sulfur fuels. For coal-fired plants, ammonia contamination of the flyash can be a significant concern because of landfill restrictions and loss of revenue from the sale of flyash to cement manufacturers[2].

Recent regulatory and technological developments have resulted in an increased interest in the demonstration of low cost combined NO_x/SO_x control technologies as alternatives to separate SCR or SNCR and flue gas desulfurization systems. The Clean Air Act Amendments of 1990, with mandates for acid rain control and attainment of ozone standards, will require many coal-fired power plants to control both NO_x and SO_x.

In general, combined NO_x/SO_x control technologies are not commercially available. However, many are undergoing demonstration programs in the U.S., Canada, and Europe. Table 3-4 lists combined NO_x/SO_x control technologies that are currently being demonstrated under the Clean Coal Technology program sponsored by the U.S. Department of Energy. In addition to these technologies, a number of existing NO_x controls such as low-NO_x burners and urea injection are also being introduced with other SO_x reduction processes and marketed as combined NO_x/SO_x controls[2].

3.2.1.3 Oil- and Gas-Fired Boilers: NO_x Controls by Combustion Modifications. Combustion modification controls for reducing NO_x emissions from oil- and gas-fired utility boilers have been implemented in the U.S. since the early 1970's, especially in California. As is the case for coal-fired utility boilers, the use of LEA is standard practice for oil- and gas-fired boilers. This section provides a summary of experience with NO_x controls that are used in conjunction with LEA, which are:

- Off-stoichiometric combustion, including biased burner firing and burners-out-of-service;
- Flue gas recirculation;
- Overfire air;
- Low-NO_x burners; and
- Reburning.

A summary of these controls is provided in Table 3-5.

The off-stoichiometric NO_x control methods of biased burner firing (BBF) and burners-out-of-service (BOOS) are a common low-cost operational modification applied to oil- and gas-fired boilers. These techniques are attractive first level NO_x controls for existing boilers because few, if any, equipment modifications are required. The NO_x reductions using BOOS on oil-fired boilers have been reported in the range of 35 to 45 percent. For gas-fired boilers, the reported range is 35 to 55 percent. A reasonable average for this technique is

TABLE 3-4. COMBINED NO_x/SO_x CONTROL TECHNOLOGIES BEING EVALUATED UNDER THE CLEAN COAL TECHNOLOGY PROGRAM

Technology	Vendor	Retrofit Experience	Reported Performance
LIMB	Babcock and Wilcox Company	Ohio Edison Edgewater Plant, 104 MWe	50 to 60 percent NO_x/SO_x reduction
LNS	TransAlta Resources Investment Group	Southern Illinois Power Cooperative Marion Plant, 33 MWe	Expected to reduce SO_2 by 90 percent and NO_x to 0.2 lb/MMBtu
SNRB	Babcock and Wilcox Company	Ohio Edison Company R.E. Burger Station, 5-MWe slipstream	Expected to reduce SO_x by 70 percent and NO_x by 90 percent
WAS-SNO_x	ABB-Combustion Engineering, Haldor Topsoe	Ohio Edison Niles Station 35 MWe slipstream	Expected to reduce NO_x by 90 percent and SO_2 by 95 percent
GR-SI	Energy and Environmental Research Corporation and Gas Research Institute	Illinois Power Hennepin Plant and City Water, Light and Power Lakeside Station	Expected 70 percent NO_x reduction and SO_2 reduction of 75 percent or more
NOXSO	NOXSO Corporation	Ohio Edison Toronto Station 5 MWe	70 to 90 percent NO_x and 90 percent SO_x reduction

Source: Reference 10

TABLE 3-5. COMBUSTION CONTROLS FOR OIL AND GAS-FIRED UTILITY BOILERS

Technology	Percent NO_x Reduction and Controlled NO_x Levels (lb/MM Btu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS Boilers	Post-NSPS Boilers		
BOOS or BBF	15-50 (0.20-0.35) W	15-50 (0.20-0.30) W	Primarily wall-fired boilers	Windbox upgrade for effective air management. Fuel control system upgrade. Install 0_2/CO trim system. Possible modification to superheater tubes and attemperation.
OFA	15-50 (0.20-0.25) T (0.20-0.30) W	15-50 (0.15-0.30) T (0.20-0.30) W	Pre-NSPS tangential and some wall-fired units, primarily post-NSPS and fuel conversion boilers	Modification of existing windbox and installation of OFA ducting and dampers. Replacement of waterwall panels. Modification to burner registers. Installation of O_2/CO trim systems.
Windbox FGR	30-55 (0.15-0.20) T (0.20-0.30) W	30-55 (0.15-0.20) T (0.20-0.30) W	Mostly utility boilers	Installation of FGR fan and related ducting and dampers. Windbox modifications. Replacement of flame scanners. Installation of oxygen monitoring for windbox. FGR control system and O_2/CO trim systems. Boiler control system modification.
Low-NO_x Burners	25-50 (0.15-0.20) T (0.20-0.30) W	25-50 (0.15-0.20) T (0.20-0.30) W	Most utility boilers	Modification of windbox for compartmentalized combustion air distribution. Burner replacement and possible additional burner parts. Installation of O_2/CO trim systems. Modified fuel supply and valving. Boiler/burner control system modification.
OFA or BOOS or Low-NO_x Burners + FGR	30-80 (0.10-0.20) T,W	30-60 (0.10-0.20) T,W	Most utility boilers	Combination of the above.
Reburning	30-60 (0.20-0.30) T,W (0.30-0.55) C	30-50 (0.20-0.25) T,W	Best retrofits are fuel conversion units; some post-NSPS and >30 years old units	Possible extension of furnace height, especially for units 21 to 30 years of age with associated panel replacement and modification to water circuiting. Replacement of furnace water wall panels. Upgrade structural support. Install compartmentalized windbox. Installation of O_2/CO trim system. Upgrade boiler control system.

Source: Reference 2
T = Tangential or corner-fired W = Wall-fired (front or opposed) C = Cyclone and wet-bottom boilers

[a]Controlled levels are based on estimated reduction performance and weighted average baseline emissions of utility plants in the Northeast States for Coordinated Air Use Management (NESCAUM) region.

40 percent from uncontrolled levels for gas- and oil-fired boilers[2].

Although large NO_x reductions can be achieved with BOOS, the operational performance of the boiler is somewhat degraded because of the need to increase excess air to keep carbon monoxide, hydrocarbons, and smoke emissions in check. Some limitations in the degree of staging may also result from difficulty in steam temperature control. Because a flame stability problem can also result, care must be taken in selecting the appropriate burners to take out of service and the degree of staging at each of the remaining burners in service[2].

Flue gas recirculation is being used at a number of U.S. utility plants to control NO_x emissions. The FGR is an effective NO_x reduction technique for natural gas- and distillate oil-fired units but is less effective when the nitrogen content of the fuel is high, as is the case for residual oil. In California, FGR has been used effectively on utility oil- and gas-fired boilers to achieve reductions in NO_x on the order of 40 to 65 percent, with the highest reductions achieved on the gas-fired boilers. The NO_x reduction levels at individual units are dependent upon the amount of flue gas that is recirculated (typically 20 percent or less of the total flue gas) and the initial NO_x levels. In New York, the Niagara Mohawk Oswego Unit 6 and the Orange and Rockland Utilities, Inc., Bowline Unit 2 are equipped with FGR, with levels of controlled NO_x emissions reported as 128 and 115 ng/J (0.3 and 0.27 lb/MMBtu), respectively[2].

Overfire air is another potential control alternative. While OFA has been used to a limited extent in the U.S., it is generally not a preferred retrofit control for existing oil- and gas-fired boilers because BOOS can provide similar NO_x reduction efficiency at a fraction of the cost and with similar operational performance losses. Also, high heat release furnaces, built from the late 1950s to the early 1970s, are generally not suitable for retrofit of OFA ports because the furnaces are small and there is insufficient volume above the top burner zone to complete combustion. However, some units in California have been retrofitted with OFA ports, with NO_x reduction efficiencies reported to average 24 percent for oil and nearly 60 percent for gas. Generally, OFA is used in conjunction with other controls such as FGR and BOOS[2].

Low-NO_x burners are another NO_x control alternative for oil- and gas-fired boilers. Low-NO_x burners are often evaluated not as a replacement for the other controls but as additional combustion modifications needed to stabilize combustion, minimize furnace vibration, and reduce particulate matter emissions when higher FGR and OFA rates or additional BOOS are implemented to attain NO_x reductions[2]. Table 3-6 provides a partial list of low-NO_x burners for oil- and gas-fired applications and their reported performance.

Reburning is another commercially available NO_x control alternative. However, reburning for NO_x control of oil- and gas-fired boilers has received little attention in the U.S., and no retrofitting has been performed. A 1991 study investigated the performance and retrofit potential for the In-Furnace NO_x Reduction® (IFNR) reburn process, offered by Babcock & Wilcox and Babcock Hitachi K.K., along with other combustion and flue gas treatment controls for five utility boilers in California. In that study, NO_x reduction potential was reported in the range of 47 to 75 percent when IFNR was combined with derating (derating was considered necessary to provide adequate gas residence time in the furnace to complete combustion of the staged fuel). In Japan, the application of the Mitsubishi Advanced Combustion Technology process combined with low-NO_x burners has been reported as achieving NO_x levels of less than 64 ng/J (0.15 lb/MMBtu)[2].

Combinations of control techniques using combustion modifications can be used to achieve higher levels of NO_x control than can be achieved with a single technique. For example, 24 units in Southern California Edison's system are currently controlled with a combination of BOOS, OFA, and FGR. Southern California Edison's Scattergood Station Unit 3, a gas-fired unit, has achieved a NO_x emission level of 42 ppm from an uncontrolled level of 1000 ppm, using a combination of FGR and derating, for a NO_x emission reduction of 95 percent. Flue gas recirculation is

TABLE 3-6. PARTIAL LIST OF GAS AND OIL-FIRED NO_x BURNER APPLICATIONS

Burner Type	Manufacturer	Retrofit Applications	Reported Performance
STS[a]	Riley and Deutsche Babcock	Wall-fired boilers; Arzberg Power Station 220 MWe Unit 6 in Germany; Vartan Power Station 250 MWe in Sweden; more than 520 MWe retrofitted in Europe	0.06 lb/MMBtu for gas O.2 lb/MMBtu for heavy oil
LNCFS	ABB-CE	Corner-fired boilers; ENEL Fusina 160 MWe Unit 2 in Italy	50 to 60 percent NO_x reduction with OFA; controlled levels reported were 0.14 lb/MMBTu for oil and 0.06 lb/MMBtu for gas
PG-DRB[b]	B&W and BKH	Hawaiian Electric Co. Kabe 146 MWe; evaluation for retrofit on LADQWP boilers	NO_x reduced to below 0.23 lb/MMBtu with OFA and FGR
ROPM	ABB-CE and MHI	No installation in U.S. for wall-fired boilers	25 to 50 percent NO_x reduction projected from controlled levels to 0.06 to 0.08 lb/MMBtu natural gas and 0.12 to 0.17 lb/MMBtu for oil
PMFS[c]	ABB-CE and MHI	No installation in U.S., several in Japan for tangential boilers	40 to 50 percent NO_x reduction. Controlled NO_x levels same as ROP<
Dynaswiri	Todd	SCE Osmond Beach Unit 2 and Alamitos	Up to 93 percent NO_x reduction when combined with BOOS and FGR to 0.03 to 0.04 lb/MMBTU at partial load and 0.04 to 0.08 lb/MMBtu at full load
XCL	B&W	Italy: ENEL Brinidisisud Unit 2; no U.S. known retrofits to date; recently introduced	NA[d]

[a]STS: Swirl Tertiary Separation
[b]PG-DRG: Primary Gas-Dual Register Burner
[c]PM: Pollution Minimum
[d]NA: Not Available

Source Reference 2

used in combination with many low-NO_x burner designs to achieve NO_x reductions of 60 to 70 percent. For example, the Mitsubishi Heavy Industries PMFS® burner uses FGR to achieve a separation between the fuel jets and the secondary air, ensuring sufficient time for NO_x reduction during staging. Other tests with a combination of FGR and OFA at reduced boiler load have shown NO_x reductions in the range of 60 to 85 percent[2].

3.2.1.4 Oil- and Gas-Fired Boilers: NO_x Controls by Flue Gas Treatment. As is the case for coal-fired utility boilers, experience with flue gas treatment technologies for NO_x controls of oil- and gas-fired utility boilers is extremely limited in the U.S. Therefore, much of the information on the applicability and performance of these systems is based on the experience of use of these systems in Europe and Japan, as described in Section 3.2.1.2. The flue gas treatment systems applicable or potentially applicable to oil- and gas-fired utility boilers are:

- Selective catalytic reduction; and
- Selective non-catalytic reduction.

In spite of its relatively easier application on oil- and gas-fired utility boilers as compared to coal-fired applications, SCR has not been retrofitted on U.S. utility boilers except for a few demonstration projects. However, interest in using SCR has recently increased as NO_x emission limits have become more stringent. This is illustrated by the fact that gas-fired utilities in Southern California plan to retrofit several thousand megawatts of capacity with SCR systems by the mid-1990's to comply with stringent new air pollution requirements[7].

The Southern California Edison Company is currently conducting a demonstration project with an SCR system supplied by KAH of Germany. In this demonstration, one half of the rotating air heater serving 107 megawatts of the oil- and gas-fired boiler has been replaced with a catalytic ceramic surface that will perform as an SCR reactor while retaining the heat transfer properties of the air heater. This arrangement is attractive because it minimizes the space and boiler modification requirements. A similar arrangement can also be used with the

SNCR process, where any unreacted ammonia or urea below the reducing temperature range will reduce NO_x further when passing through the air heater. However, performance and reliance of this system remain to be demonstrated[2].

Most of the comments regarding the applicability and experience of SCR systems in Japan and Germany, discussed in Section 3.2.1.2 for coal-fired utility boilers, are also relevant to use of this technology for oil- and gas-fired boilers. Data supplied by Mitsubishi Heavy Industries indicates that oil-fired utility boilers retrofitted with SCR during the 1980's have achieved NO_x control efficiencies in the range of 75 to 80 percent. In Japan, SCR systems are operating that have not had any catalyst additions or replacements for seven to ten years for oil-fired boilers, and for more than ten years for gas-fired boilers[7].

As with SCR, there has been only limited experience with SNCR systems on U.S. oil- and gas-fired utility boilers. In an early 1980's demonstration of Exxon's Thermal $DeNo_x$® process, a SNCR system installed on the Los Angeles Department of Water and Power Haynes Unit 4 achieved only 35 to 45 percent NO_x reduction efficiency due to the inability of the process to follow boiler load, difficulty in controlling the amount of ammonia injected as the load changed, and inefficient mixing of the ammonia in the gas stream. Since that time, significant improvements have been made to the Thermal $DeNO_x$® process such that process guarantees are currently in the range of 40 to 60 percent NO_x reduction. However, no utility boiler retrofit has taken place in the U.S. since this demonstration[2].

Urea injection, using the NO_xOUT® process, has recently been installed on three California oil- and gas-fired boilers. On two of these boilers, NO_x reductions attributed to urea injection were approximately 30 percent with ammonia slip of 20 ppm. On the third boiler, NO_x reductions were limited to about 20 to 25 percent to minimize ammonia slip. The process was found to be very sensitive to temperature fluctuations that result from routine load changes. In New York, the Long Island Lighting Company is evaluating urea injection in a gas/oil-fired utility boiler, although as of late summer 1991 no performance information was available[2].

Oil- and gas-fired boilers with flue gas NO_x concentrations of 100 ppm or less attained via combustion controls will likely be limited to a maximum of 40 percent reduction using SNCR. For boilers with uncontrolled NO_x emissions, the performance of the urea-based SNCR is estimated to range between 40 and 50 percent, with less than 5 ppm ammonia slip[2].

The same concerns mentioned in Section 3.2.1.2 for coal-fired boilers regarding the difficulty of maintaining NO_x reduction performance of SNCR systems over a wide range of boiler loads, and problems associated with the formation of ammonium sulfate and bisulfate when the technology is applied to boilers burning high sulfur fuels, are also applicable to the use of SNCR for oil- and gas-fired boilers. Because of these concerns, SNCR applicability is principally limited to base-loaded plants burning natural gas or low-sulfur oil[2].

3.2.2 Industrial, Commercial, and Institutional Boilers

Industrial boilers are used in the manufacturing, processing, mining, and refining industries to provide process steam and/or hot water for space heating, process needs, and other uses. Steam may also be produced to generate electricity (cogeneration). Most industrial boilers range in size from 8.7 to 44 MW (30 to 150 MMBtu/hr), although they are as large as 250 MW (850 MMBtu/hr). Commercial and institutional boilers are also used for space heating, hot water generation and electricity generation. They are generally substantially smaller than industrial boilers, ranging in size from 0.1 MW to 3.6 MW (0.4 to 12.5 MMBtu/hr), but may range up to 29 MW (100 MMBtu/hr)[11].

Fuels burned by these boilers are primarily natural gas, distillate oil, residual oil, and coal. The fuel feed mechanism is an important characteristic affecting coal-fired boiler NO_x emissions. Coal-fired boilers can be either pulverized coal, stoker, or cyclone units. With pulverized coal units, coal pulverized to the consistency of powder is pneumatically injected into the furnace. Combustion begins at the burners and continues into the furnace volume. The stoker is a conveying system that feeds coal into the furnace while providing a grate upon which the coal is burned. The cyclone boiler uses a slagging precombustor to produce highly turbulent combustion. The population of cyclone burners is small, and their production has been terminated because of their high NO_x forming potential[11].

Nonfossil fuels, such as wood, bark, agricultural wastes, and industrial wastes, are also used to a much lesser extent. Nonfossil fuel-fired boilers generally exhibit low NO_x emissions relative to fossil fuel-fired boilers[11].

Tables 3-7 through 3-10 summarize the NO_x reductions for boilers burning coal, distillate oil, residual oil, and natural gas, respectively, that have been reported for NO_x controls based on combustion modification and on flue gas treatment. Controls using combustion modification are discussed in Section 3.2.2.1. Flue gas treatment controls are discussed in Section 3.2.1.2.

3.2.2.1 Combustion Controls. The combustion modification techniques summarized in Tables 3-7 through 3-10 are not universally applicable to all boiler types. The following discussion describes the applicability of each technique and limitations associated with their retrofit to existing units. These techniques are:

- Low excess air;
- Off-stoichiometric combustion, including overfire air, burners-out-of-service, and biased burner firing;
- Flue gas recirculation; and
- Low-NO_x burners.

None of these techniques are applicable to cyclone coal-fired boilers. The design limitations of cyclone boilers required to yield a melted slag are not compatible with the requirements of the control of NO_x emissions by combustion modification.

Because LEA firing primarily reduces thermal NO_x, it is most effectively used with units burning natural gas and distillates. While it can be used for stoker coal-fired boilers, its use presents potential problems with clinker formation. Low excess air controls can be applied to all small boilers equipped with

TABLE 3-7. NO_x RETROFIT CONTROLS APPLICABLE TO INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS FIRED WITH COAL

NOx Control Technique	Boiler Type	NOx Emissions lb NOx / 1,000,000 Btu uncontrolled	NOx Emissions lb NOx / 1,000,000 Btu controlled	% NOx Reduction	Reference	Page #
LEA	WT/PC	a		15	3	4-80
	WT/S	0.635	0.452	29	12	33
	WT/S	0.634	0.491	23	12	33
	WT/S	0.540	0.412	24	12	33
	WT/S	0.572	0.401	30	12	33
	WT/S	0.468	0.443	5	12	33
	WT/S	0.454	0.312	31	12	33
	WT/S	0.506	0.405	20	12	33
	WT/S	0.483	0.418	13	12	33
	WT/S	0.400	0.283	29	12	33
	WT/S	0.229	0.211	8	12	33
	WT/S	0.353	0.316	10	12	33
	WT/S	0.324	0.310	4	12	33
	WT/S	0.277	0.209	25	12	33
	WT/S	a		15	3	4-80
	WT/S	a		10 - 20	13	2-3
OFA	WT/S	a		5 - 10	13	2-3
FGR	WT/S	a		40 - 45	13	2-3
	WT/S	a		20 - 30	14	S.4
SCR	WT/PC	a		80 - 90	13	2-11
	WT/C	a		60 - 70	13	2-9
SNCR (ammonia)	WT/C	a		60 - 70	13	2-9
	WT/PC	a		60 - 70	13	2-11
	N/A	a		60 - 70	13	2-11
SNCR (urea)	WT/C	a		80 - 90	13	2-9
	WT/PC	a		50 - 85	15	5

PC: Pulverized Coal
S: Stoker
C: Cyclone
WT: Watertube
a: Supporting emissions test data not provided

TABLE 3-8. NO_x RETROFIT CONTROLS APPLICABLE TO INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS FIRED WITH DISTILLATE OIL

NOx Control Technique	Boiler Type	NOx Emissions lb NOx / 1,000,000 Btu uncontrolled	controlled	% NOx Reduction	Rererence	Page #
LEA	FT	0.221	0.197	11	12	15
	FT	0.224	0.186	17	12	15
	FT	a		10 - 25	16	50
	WT/Pkg	0.136	0.118	13	12	15
	WT/Pkg	0.098	0.088	10	12	15
	WT/Pkg	0.134	0.125	7	12	15
	WT/Pkg	0.107	0.105	2	12	15
	WT/Pkg	0.154	0.125	19	12	15
	WT/Pkg	0.158	0.134	15	12	15
OFA	N/A	a		15 - 30	14	S.4
	WT/PC	0.154	0.125	19	12	21
BOOS	N/A	a		50	14	S.3
BBF	N/A	a		20	14	S.4
FGR	FT	158	123	22	17	A.12
(ppm)	FT	138	109	21	17	A.12
(ppm)	WT/Pkg	136	115	15	17	A.16
(ppm)	WT/Pkg	136	104	24	17	A.16
(ppm)	WT/Pkg	144	118	18	17	A.16
	WT/Pkg	0.185	0.152	18	12	19
	WT/Pkg	0.154	0.041	73	12	19
Low NOx, LEA	FT	a		10 - 25	16	50
	FT	a		10	3	4-80
	WT	a		10	3	4-80
Low NOx, Staged Air	WT	a		30 - 65	16	53
Low NOx, Staged Fuel	N/A	a		50 - 70	16	58
Low NOx, FGR	FT	a		60+	18	M3
	FT	a		60 - 70	19	2
	WT/Pkg	a		60+	18	M3
	WT/Pkg	a		60 - 70	19	2
Low NOx & FGR	FT	a		20 - 25	20	1
SCR	FT/WT	a		To 90%	16	73
SNCR (ammonia)		None Found				
SNCR (urea)		None Found				

FT: Fire Tube
WT: Water Tube
Pkg Package
N/A Not Applicable
a: Supporting emissions data not provided

TABLE 3-9. NO_x RETROFIT CONTROLS APPLICABLE TO INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS FIRED WITH RESIDUAL OIL

NOx Control Technique	Boiler Type	Emissions lb NOx / 1,000,000 Btu uncontrolled	controlled	% NOx Reduction	Reference	Page #
LEA	FT	0.389	0.328	16	12	25
	FT	0.239	0.227	5	12	25
	FT	0.213	0.201	6	12	25
	WT/Pkg	0.256	0.236	8	12	25
	WT/Pkg	0.278	0.193	31	12	25
	WT/Pkg	0.459	0.438	5	12	25
	WT/Pkg	0.436	0.368	16	12	25
	WT/Pkg	0.217	0.159	27	12	25
	WT/Pkg	0.398	0.356	11	12	25
	WT/Pkg	0.2	0.145	28	12	25
	WT/Pkg	0.263	0.231	12	12	25
	WT/Pkg	0.251	0.23	8	12	25
	WT/Pkg	0.386	0.305	21	12	25
	WT/Pkg	0.419	0.312	26	12	25
	WT/FE	0.641	0.572	11	12	25
OFA	WT/Pkg	0.217	0.166	24	12	31
	WT/Pkg	0.217	0.141	35	12	31
	WT/Pkg	0.278	0.194	30	12	31
	WT/Pkg	0.419	0.222	47	12	31
	WT/Pkg	0.386	0.245	37	12	31
FGR	WT/Pkg	0.161	0.157	2	12	29
	WT/Pkg	0.161	0.112	30	12	29
	WT/Pkg	0.278	0.193	31	12	29
Low NOx, LEA	FT	a		15	3	4-80
	WT/Pkg	a		20	3	4-80
	WT/Pkg	a		5 - 10	13	2-16
Low NOx & FGR	FT	a		15	20	1
SCR	WT/Pkg	a		70 - 80	13	2-16
SNCR(ammonia)	WT/Pkg	a		50	13	2-16
SNCR(urea)	WT/Pkg	a		35 - 70	15	7
	WT/Pkg	a		50	13	2-16

FT: Fire Tube
WT Water Tube
Pkg Package
FE: Field Erected
a: Supporting emissions data not provided

TABLE 3-10. NO_x RETROFIT CONTROLS APPLICABLE TO INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS FIRED WITH NATURAL GAS

NOx Control Technique	Boiler Type	NOx Emissions lb NOx / 1,000,000 Btu uncontrolled	NOx Emissions lb NOx / 1,000,000 Btu controlled	% NOx Reduction	Reference	Page #
LEA	FT	0.122	0.080	34	12	4
	FT	0.132	0.111	16	12	4
	FT	0.076	0.072	5	12	4
	FT	0.071	0.093	-31	12	4
	FT	0.105	0.072	31	12	4
	WT/Pkg	0.101	0.079	22	12	4
	WT/Pkg	0.101	0.095	6	12	4
	WT/Pkg	0.117	0.094	20	12	4
	WT/Pkg	0.097	0.079	19	12	4
	WT/Pkg	0.127	0.132	-4	12	4
	WT/Pkg	0.075	0.066	12	12	4
	WT/Pkg	0.307	0.294	4	12	4
	WT/Pkg	0.257	0.202	21	12	4
	WT/Pkg	0.268	0.222	17	12	4
OFA	N/A	a		15 - 30	14	S.4
	WT/Pkg	0.084	0.073	13	12	11
	WT/Pkg	0.268	0.073	73	12	11
BOOS	N/A	a		50	14	S.3
BBF	N/A	a		20	14	S.4
FGR	FT	64.4	29.7	54	17	A-16
(ppm)	FT	64.4	22.0	66	17	A-16
(ppm)	FT	81.7	33.9	59	17	A-16
	WT/Pkg	0.102	0.036	65	12	15
	WT/Pkg	0.078	0.027	65	12	15
	WT/Pkg	0.079	0.040	49	12	15
	WT/Pkg	0.079	0.03	62	12	15
(ppm)	WT/Pkg	74	24	68	17	21
(ppm)	WT/Pkg	80	33	59	17	21
Low NOx, LEA	FT	a		10 - 25	16.	50
	FT	a		5	3	4-80
	WT	a		5	3	4-80
Low NOx, Staged Air	WT	a		30-65	16	53
Low NOx, Staged Fuel	WT	a		50 - 70	16	58
Low NOx, FGR	FT/WT	a		60-70	19	2
	FT/WT	a		60+	18	M3
Low NOx and FGR	FT	a		75	20	1
(ppm)	FT	85	30	65	21,22	
SCR	FT/WT	a		80 - 90	13	2-13
	FT/WT	a		To 90	16	1
SNCR(ammonia)	FT/WT	a		50 - 60	13	2-13
	FT/WT	a		70 - 80	23	129
	FT/WT	a		70-75	24	2
SNCR(urea)	FT/WT	a		50-60	13	2-13
	FT/WT	a		35 - 70	23	129

FT: Fire Tube
WT Watertube
Pkg Package
a: Supporting emissions test data not provided

forced-air burners. For boilers equipped with natural draft burners, LEA cannot be used since excess air levels cannot be controlled. However, some larger cast-iron boilers currently equipped with natural draft burners can be equipped with forced draft burners, thereby allowing the use of the LEA control technique[11,12].

Emission test data reported by EPA for 14 small natural gas-fired boilers, ranging in size from 2.3 to 26 MW (8 to 88 MMBtu/hr) that controlled NO_x emissions in the range of 28.4 to 126 ng/J (0.066 to 0.294 lb/MMBtu) were achieved using LEA from uncontrolled emissions in the range of 30 to 130 ng/J (0.071 to 0.307 lb/MMBtu) for reductions ranging from 4 to 34 percent. In two boilers, NO_x emissions were found to increase after application of LEA, by 4 and 31 percent, respectively. Test data for six small distillate oil-fired boilers, ranging in size from 3.8 to 11 MW (13 to 38 MMBtu/hr), indicated LEA control levels ranging from 37.8 to 84.7 ng/J (0.088 to 0.197 lb/MMBtu) from uncontrolled levels of 41.6 to 95.2 ng/J (0.098 to 0.224 lb/MMBtu), with NO_x emission reductions ranging from 2 to 19 percent. Test data for 14 boilers fired with residual oil, ranging in size from 2.7 to 30 MW (9 to 100 MMBtu/hr), showed control levels in the range of 62.4 to 246 ng/J (0.145 to 0.572 lb/MMBtu) from uncontrolled levels ranging from 85 to 272 ng/J (0.200 to 0.641 lb/MMBtu), with NO_x emission reductions in the 5 to 31 percent range. Finally, test data was collected for 11 coal-fired boilers ranging in size from 16 to 29 MW (56 to 100 MMBtu/hr). A variety of boilers, including spreader, underfeed, overfeed, and vibrating grate stokers are included in the database. The data indicated that LEA resulted in controlled NO_x emissions ranging from 90 to 211 ng/J (0.209 to 0.491 lb/MMBtu) from uncontrolled levels of 97.3 to 270 ng/J (0.229 to 0.635 lb/MMBtu), with emission reductions ranging from 4 to 30 percent. In all of these sets of data, wide variability from unit to unit was observed in both controlled and uncontrolled emissions levels[12].

The OFA technique is another control alternative for many boilers, but its applicability is limited. In general, the OFA technique is applicable only to boilers with burners (i.e., gas-, oil-, and pulverized coal-fired boilers), although OFA ports can be used in new stoker coal-fired boilers. It is not commercially available for all boiler design types, particularly firetube boilers, and retrofit may not be feasible for most units, especially package boilers. Further, the technique is generally not available for boilers with capacities less than 7.5 MW (25 MMBtu/hr)[11].

In regard to the NO_x removal efficiency of OFA, performance test data reported by EPA for three small gas-fired boilers, ranging in size from 6.5 to 16 MW (22 to 56 MMBtu/hr), showed that controlled levels in the range of 31 to 61 ng/J (0.073 to 0.142 lb/MMBtu) were achieved, with emission reductions of 13 to 73 percent reported. Data for a 6.5 MW (22 MMBtu/hr) boiler burning distillate oil showed that emissions were reduced from an uncontrolled level of 66.2 ng/J (0.154 lb/MMBtu) to a controlled level of 53.8 ng/J (0.125 lb/MMBtu), an emission reduction of 19 percent. Test data for four small residual oil-fired boilers, with capacities ranging from 6.5 to 16 MW (22 to 56 MMBtu/hr), showed that controlled NO_x levels in the range of 60.6 to 105 ng/J (0.141 to 0.254 lb/MMBtu) were achieved, with NO_x reductions ranging from 24 to 47 percent[12].

Performance data on NO_x emissions from small coal-fired boilers using OFA are limited. Overfire air applied to a coal-fired fluidized-bed combustion boiler rated at 26.4 MW (90 MMBtu/hr) resulted in an average NO_x emission level of 258 ng/J (0.6 lb/MMBtu) achieved over a two-day period. Compared with a two-day average of 378 ng/J (0.88 lb/MMBtu) without OFA, a NO_x emission reduction of 32 percent was achieved[12].

In addition to OFA, BOOS and BBF are two other off-stoichiometric techniques potentially available for NO_x control. However, these techniques are applicable only to boilers that are fired with gas or oil and have multiple burners. Further, in some cases, BOOS and BBF may require derating of the boiler if the extra firing capacity of the remaining active burners is very limited[11].

Flue gas recirculation systems are commercially available for small boilers with capacities as low as 1.5 MW (5 MMBtu/hr), although no FGR systems have been installed to date on cast-iron boilers[12]. Although FGR systems have been retrofitted on gas-, oil-, and stoker coal-fired boilers, the technique is not as effective for reducing NO_x emissions from residual oil- and coal-fired boilers as it is for gas- and distillate oil-fired units[11].

The EPA has conducted emission tests on oil- and gas-fired boilers using FGR. Tests were conducted over a variety of loads, excess oxygen levels, and FGR levels. Test results for five natural gas-fired boilers using FGR, with boiler sizes ranging from 6.5 to 16 MW (22 to 56 MMBtu/hr), indicated attainment of FGR-controlled levels ranging from 6.8 to 17 ng/J (0.016 to 0.040 lb/MMBtu), for a NO_x removal efficiency range of 49 to 75 percent. Test data for two distillate oil-fired boilers with capacities of 6.6 and 17 MW (22 and 56 MMBtu/hr) indicated that FGR-controlled NO_x levels of 17.6 and 65.4 ng/J (0.041 and 0.152 lb/MMBtu), respectively, were achieved, corresponding to removal efficiencies of 73 and 18 percent. Test data for two residual oil-fired boilers with capacities of 6.5 and 9.1 MW (22 and 31 MMBtu/hr) showed FGR-controlled emissions ranging from 47.6 to 82.0 ng/J (0.112 to 0.193 lb/MMBtu), with a range of NO_x removal efficiencies of 3 to 31 percent[12].

Low-NO_x burners can be installed in many industrial, commercial, and institutional boilers. Tangential- or wall-fired pulverized coal boilers can use LNB technology with controlled and uncontrolled fuel-air mixing. It should be noted, however, that the majority of coal-fired boilers used in the industrial and commercial sectors are stoker fed. The LNB system in combination with LEA is also applicable for retrofit on boilers fired with oil or gas, primarily on boilers with single burners[11]. Not all boilers can be retrofitted with LNB. For example, staged air and staged fuel LNB are applicable only to watertube boilers, and are generally not available for boilers with capacities less than 7.5 MW (25 MMBtu/hr). It should be noted that one type of LNB, called the radiant or ceramic fiber burner, is available for natural gas-fired boilers. Burners of fiber matrix design are available for single burners from less than 5 MW (16 MMBtu/hr) and for multiple burners up to 60 MW (200 MMBtu/hr)[25]. Retrofit of LNB systems may require derating of equipment because of the potential for increased flame lengths, which may result in flame impingement on the furnace walls[11,12].

Test data for three natural gas-fired boilers using low-NO_x burners, with sizes ranging from 18 to 31 MW (63 to 106 MMBtu/hr), indicated attainment of controlled NO_x levels of 30 to 39 ng/J (0.07 to 0.09 lb/MMBtu). Test data for a distillate oil-fired boiler, rated at 22 MW (75 MMBtu/hr) and using a low-NO_x burner, indicated a controlled NO_x emission level of 47.3 ng/J (0.110 lb/MMBtu). Since test data for uncontrolled NO_x emissions were not available for either set of tests, the reductions in NO_x emissions could not be determined[12].

3.2.2.2. Post-Combustion Controls. Flue gas treatment applicable or potentially applicable to industrial, commercial, or institutional boilers include:

- Selective catalytic reduction; and
- Selective non-catalytic reduction.

Experience with selective catalytic reduction on industrial, commercial, and institutional boilers is extremely limited in the U.S. However, in Japan, SCR has been applied to over 50 industrial boilers firing gas, oil, and coal. Sixty percent of these boilers fire oil, followed by gas firing (25 percent) and coal firing (15 percent). The boiler sizes range from 15 to 450 MW (50 to 1,500 MMBtu/hr), with start-up dates from 1977 to 1989. Typical oil-fired boiler NO_x reductions range from 80 to 90 percent, with controlled emission levels of 25 to 50 ppm NO_x. In the coal-fired boiler applications, emission reductions range from 40 to 80 percent, with controlled emissions of 60 to 250 ppm NO_x. For the gas-fired boiler applications, typical NO_x reductions are 90 percent, with controlled emission levels of 15 to 30 ppm NO_x[26].

Selective non-catalytic reduction technology has been applied to fluidized-bed combustion boilers and wood-fired boilers. Over 20 sites have been permitted based on the application of SNCR. Almost all of the sites are coal or wood-biomass-fired fluidized bed boilers and conventional wood-biomass-fired boilers. For the wood and coal-fired SNCR applications, about 70 percent have NO_x permit levels of 0.1 lb/MMBtu (about 25 ppm at 15 percent O_2)[26].

3.3 CONTROL TECHNOLOGIES FOR COMMERCIAL AND RESIDENTIAL SPACE HEATERS

Commercial heating systems can be divided into three general categories: space heaters, warm air furnaces, and hot water or steam systems. Residential heating units are characterized by thermostatically controlled heating cycles. Natural gas-fired residential space heating units generally employ single port upshot or tubular multiport burners. Oil-fired units usually use high pressure atomizing gun-type burners. Natural gas and distillate oil are the primary fuels used for commercial and residential space heating[3].

Space heating equipment tuning has been considered as a potential means of reducing NO_x emissions. Tuning involves normal equipment cleanup, nozzle replacement as required, and simple scaling and adjustment with the use of field instruments. However, while tuning can have significant beneficial affects on reducing emissions of smoke, carbon monoxide, hydrocarbons, and filterable particulate matter it has been shown to have little effect on NO_x emissions[3].

Replacement of heating equipment with equipment designed to produce lower emissions of NO_x is the most viable approach for achieving significant reductions in NO_x emissions from space heaters. A summary of the major types of residential space heating equipment alternatives for gas-fired units is provided in Table 3-11, including NO_x, carbon monoxide, and unburned hydrocarbon emissions, and steady state and cycle efficiencies for each alternative. As indicated, use of equipment that is currently commercially available can reduce NO_x emissions by up to 70 to 80 percent over conventional units. Further, equipment presently under research may have the capability of achieving

TABLE 3-11. PERFORMANCE SUMMARY OF LOW-NO_x CONTROL EQUIPMENT FOR NATURAL GAS-FIRED RESIDENTIAL HEATERS

Control	Average Operating Excess Air (percent)	Cyclic Pollutant Emissions, ng/J Heat Input			Steady State Efficiency (percent)	Cycle Efficiency (percent)	Comments
		NO_x[a]	CO	UHC[b]			
Conventional Units	40-120	28-45	8.6-25	3.3-33	70	60-65	
Radiant Screens	40-120	15-18	6.4	NA	75	70	Emissions of CO and HC can increase significantly if screen is not placed properly or deforms.
Secondary Air Baffles	60-80	22	14	NA	NA	NA	Requires careful installation. Suited for single port upshot burners.
Surface Combustion Burner	10	7.5	5.5-9.6	NA	NA	NA	Not commercially available. Still under development.
Perforated Burner	NA	7.7	26	NA	85	80	Commercially available design.
Modulating Furnace	NA	25	NA	NA	75	70	Furnace is essentially derated. It requires longer operation to deliver a given heat load.
Pulse Combustor	NA	10-20	NA	NA	95	95	Currently being investigated by AGAL.
Catalytic Combustor	NA	<5	NA	NA	90	85	Still at the R&D stage.

[a] Sum of NO + NO_2 reported as NO_2.
[b] Unburned hydrocarbons calculated as methane (CH_4).
NA = Not Available.

Source: Reference 3

even greater reductions. The same types of information are presented for oil-fired residential space heaters in Table 3-12.

Application of the control technologies shown in Tables 3-11 and 3-2 to commercial space heating uses has been very limited, although the potential exists for applying some of them to commercial units. Compared to residential gas-fired equipment, a greater percentage of commercial warm air heaters or duct heaters use power burners instead of naturally aspirated burners. Power burners generally have more flexibility for excess air control while maintaining low carbon monoxide and volatile hydrocarbon emissions. Furthermore, theoretical considerations indicate that the flame quenching and surface combustor concepts shown in Table 3-11 could be implemented for commercial systems. Application of control techniques similar to those for residential oil burners may also be possible[3].

3.4 CONTROL TECHNOLOGIES FOR PRIME MOVERS

Prime movers include stationary internal combustion (IC) engines and gas turbines used for a wide variety of industrial, commercial, and municipal uses. Control techniques for IC engines and gas turbines are presented in Section 3.4.1 and 3.4.2, respectively.

3.4.1 Internal Combustion Engines

Stationary IC engines are widely used to generate electric power, to pump gas and liquids, to compress air for pneumatic machinery, and for other commercial/industrial uses. The majority of IC engines burn natural gas, oil, or are dual fuel compatible, with about two-thirds using natural gas as the primary fuel.

Two methods of igniting the fuel-air mixture are used in IC engines: compression ignition (CI) and spark ignition (SI). All diesel-fueled engines are CI engines, while all natural gas engines are SI engines. From a NO_x control viewpoint, the most important distinction between different engine models and types is whether they burn as fuel-rich or fuel-lean. Rich-burn engines operate with an air-to-fuel ratio close to stoichiometric levels, resulting in low excess oxygen levels and therefore low exhaust oxygen concentrations. Conversely, lean-burn engines

TABLE 3-12. PERFORMANCE SUMMARY OF LOW-NO_x CONTROL EQUIPMENT FOR DISTILLATE OIL-FIRED RESIDENTIAL HEATERS

Control	Average Operating Excess Air (percent)	Cyclic Pollutant Emissions, ng/J Heat Input					Steady State Efficiency (percent)	Cycle Efficiency (percent)	Comments
		NO_x[a]	CO	UHC[b]	Smoke Number	Particulate			
Conventional Units	50-85	37-85	15-30	3.0-9.0	3.2	7.6-30	75	65-70	Range in NO_x emissions is for residential systems not equipped with flame retention burners. Emissions for other pollutants are averages.
Flame Retention Burner Head	20-40	26-88	11-22	0.2-1.8	2.0	NA	80-83 (also depends on heat exchanger)	NA	
Controlled Mixing Burner Head	10-50	34	13	0.7-1.0	<1.0	NA	80 (also depends on heat exchanger)	NA	Combustible emissions are relatively low because hot firebox was used.
Integrated Furnace System	20-30	19	20	1.2	<1.0	NA	84	74	Uses optimized burner head. For new furnace only. Combustible emissions are higher than with burner head because of quenching in air cooled firebox.
"Blue Flame" Burner/Furnace System	20	10	4.5-7.5	1.5-2.5	zero	NA	84	74	New installation only. Furnace is commercially available.
Internal Recirculation	10-15	10-25	<30	NA	<1.0	NA	85	NA	Both for retrofit or new installations. Not yet commercially available in U.S.

[a] Sum of NO and NO_2 reported as NO_2.
[b] Unburned hydrocarbons calculated as methane.
NA = Not Available.

Source: Reference 3

operate with significant excess oxygen, resulting in excess oxygen levels in the exhaust gas stream. All naturally aspirated, SI four-cycle engines and some turbocharged SI four-cycle engines burn fuel-rich. All other engines, including all two-cycle engines and all CI engines burn fuel-lean[26,27].

3.4.1.1 Combustion Controls. The major types of combustion controls currently or potentially applicable to IC engines are:

- Pre-ignition chamber combustion, or "clean burn" engines;
- Ignition timing retardation;
- Air-to-fuel adjustment (includes turbocharging);
- Prestratified charge (PSC);
- Exhaust gas recirculation;
- Water or steam injection; and
- Derating.

For natural gas-fired engines, engine design modifications in general and clean burn or pre-ignition chamber combustion in particular have been the most commonly applied NO_x control technologies in the past decade. For oil-fired engines, the most common technique is injection timing retardation and clean burn[26].

In the pre-ignition chamber combustion NO_x control approach, cylinder heads are structured with small, separately fed, combustion chambers where a rich mixture is ignited by a spark plug, combusted, and then expanded into a very lean mixture in the main combustion chamber. Some engine manufacturers have developed retrofit kits using this approach. Systems employing the pre-ignition chamber combustion approach are also referred to as "clean burn" systems[28].

Pre-ignition combustion chamber systems have been shown to achieve NO_x reductions in excess of 80 percent for natural gas-fired lean-burn engines. Levels of NO_x emissions have been reported in the range of 1.3 to 3.0 grams per horsepower-hour (g/hp-hr)[28].

Applicability of pre-ignition combustion is currently limited to constant load uses and to natural gas-fired IC engines. Conversion of direct injection diesel engines to pre-ignition chamber combustion can increase fuel consumption by 10 percent or more. Precombustion chambers were implemented in the 1980's by one diesel engine manufacturer, but have been discontinued due to marginal NO_x reductions compared to fuel efficiency losses. Currently no manufacturers have off-the-shelf prechamber cylinder heads for diesel engines[27,29].

Ignition timing retardation can reduce NO_x emissions from all types of diesel and dual-fuel engines and, in fact, is used to some extent by virtually all manufacturers of these engines. While this technique reduces NO_x emissions, it also increases fuel consumption. In general, a 4^0 timing retard can result in NO_x reduction of 20 to 34 percent in diesel or dual-fuel engines with a corresponding 1 to 4 percent fuel consumption penalty. The amount of NO_x reduction per degree of retard decreases with increasing levels of retard[29].

The control effectiveness of ignition timing retardation varies considerably between direct and indirect injection diesel engines. Application of this technique to direct injection engines generally results in a significant reduction in NO_x emission and a slight increase in fuel consumption. Conversely, application to indirect diesel engines has less effect on NO_x emission rates and a greater effect on fuel consumption[29].

Adjusting the air-to-fuel mixture ratio is another technique for reducing NO_x emissions from IC engines. By increasing the airflow, rich-burn IC engines can effectively be converted to lean-burn operation. Engine manufacturers now offer lean-burn conversion kits for some engines. These kits include a turbocharger and intercooler for naturally-aspirated engines or increased capacity turbocharger and intercooler for turbocooler engines, along with engine components (i.e., new carburetor and intake manifolds, cylinder heads, pistons, and ignition system). The level of NO_x emissions can be reduced to between 1.5 and 2.0 g/hp-hr. from pre-retrofit emission levels in the range of roughly 9 to 20 g/hp-hr using these kits[30]. The applicability of air-to-fuel adjustment to existing engines is limited to those engine models for which conversion packages are available from the manufacturer[27].

Existing lean-burn SI engines can, in some cases, reduce NO_x emissions by increasing the air-to-fuel ratio. The additional air required is accomplished by installing a turbocharger on naturally aspirated engines, or by replacing an existing turbocharger with a larger one. The NO_x emissions can be further reduced by adding an aftercooler (or intercooler) to cool the air downstream of the turbocharger. For diesel engines, the use of turbocharging as a NO_x control measure is very limited because most engines already use turbochargers. Further, turbocharging alone will not reduce NO_x emissions, but rather it allows reoptimization of other parameters, such as ignition timing, which will reduce NO_x emissions[27,29].

The results of emissions tests conducted on engines retrofitted with PSC systems indicate that NO_x emission levels in the range of 1.5 to 2.5 g/hp-hr. are commonly achieved for all gaseous fuels. The NO_x reduction efficiency for natural gas ranges from approximately 80 to 90 percent. The NO_x reduction efficiency for low Btu fuels may be lower, corresponding to the lower uncontrolled NO_x emissions levels for these fuels, but the 1.5 to 2.5 g/hp-hr. achieved using natural gas is also achieved using low Btu fuels[27]. The PSC systems have been successfully applied to natural gas-fueled engines as well as engines fueled by digester and landfill gas. The technology can also be used with sulfur-bearing fuels. However, engines that operate in cyclic or fluctuating load applications may not be candidates for PSC technology. There currently is no proven control system that can operate PSC on a cyclically loaded engine and achieve NO_x reduction levels above 50 percent without a significant increase in hydrocarbon emissions or serious degradation to the performance of the engine[28].

Prestratified charge systems are applicable to naturally aspirated and turbocharged four-stroke engines. The technology cannot be applied to fuel injected and blower-scavenged engines. Retrofit kits are currently available for virtually all candidate engines with a rated power output of 100 horsepower or more. These engines represent more than 90 percent of the existing candidate population, including engines built in the 1940's. In addition, retrofit kits can be developed for any candidate engine, and the development of tailored retrofit kits is economically practical for engine populations as low as five or six units[27].

In addition to the combustion controls to reduce NO_x emissions just discussed, others have been considered for IC engines. For example, exhaust gas recirculation (EGR) systems may be applicable to rich-burn engines. However, data are currently very limited and the available data indicate that NO_x reductions are very marginal. Manufacturers are currently not offering EGR for production SI and CI engines[27].

Water or steam injection is another NO_x emission control technique that has been considered for IC engines. However, this technique does not appear to be a viable control alternative. Unlike gas-fired turbines, where water/steam injection can be an effective NO_x control technique (see Section 3.4.2.1), IC engines have a lubricating oil film on the walls of the cylinders which minimizes mechanical wearing of reciprocating parts. Water injection adversely affects this oil film, accelerating engine wear. This control technique is not available from any engine manufacturer[27].

Although engine derating (or reducing the power output) does not appear to be a promising method to reduce NO_x emission rates from diesel engines, it may be effective for dual-fueled engines. When NO_x emissions are expressed on a grams/hp-hr basis, they appear to be fairly insensitive to load. Consequently, for a given amount of work, engine derating is unlikely to reduce NO_x emissions from diesel engines. Derating also has minimal NO_x reduction potential for natural gas-fueled engines for this same reason[29].

Coal/water slurries and methanol have been fired in IC engines in limited testing to date. Test data for coal/water slurries indicate reduced NO_x emissions. Since methanol produces lower combustion temperatures than natural gas and diesel, methanol firing should theoretically produce lower NO_x emissions. However, data regarding the performance of methanol-fired IC engines are not currently available. Neither coal/water slurries nor methanol is currently being used in any identified commercial IC engine in the U.S[27].

3.4.1.2 Post-Combustion Controls. Post-combustion controls for IC engines include:

- Selective catalytic reduction (SCR); and
- Non-selective catalytic reduction (NSCR).

Since SCR reaction mechanisms require the presence of oxygen, SCR technology has been applied only to lean-burn reciprocating and diesel engines where the exhaust gas oxygen concentrations are high[26]. A further limit to applicability is that SCR has only been demonstrated as applicable to engines with non-cyclical loads[28].

In the U.S., applications have largely been limited to natural gas-fired engines in the past decade, with a recent application in Massachusetts to a dual fuel-fired diesel engine. This unit has been operating since September 1988 with apparently no major problems. The manufacturer claims that this unit will achieve a NO_x reduction of 90 percent and guarantees the catalyst for five years[26,29].

A demonstration program conducted by the South Coast Air Quality Management District in California on SCR applied to lean-burn natural gas-fired IC engines has shown the ability of SCR to achieve an 80 percent NO_x emission reduction level, while source tests conducted in Ventura County, California, on 19 SCR systems applied to these types of engines found an average NO_x reduction level of 87 percent[28].

There is very limited experience with this technology for diesel IC engines. In Japan, SCR has been applied to natural gas- and oil-fired engines. Two of these three units started operation in the 1978-80 period, with another unit coming on-line in 1989. Reported NO_x removals for two of the units have been 85 and 90 percent, although significant daily maintenance is required to keep the catalyst soot free. In West Germany, SCR has been applied to engines firing natural gas, dual fuel, oil, and landfill gas[26,29].

Non-selective catalytic reduction systems require fuel-rich engine operation or the addition of a reducing agent in the flue gas upstream of the catalyst. Therefore, application of this technology has been limited to rich-burn engines. These systems are applicable to all natural gas-fired engines with exhaust oxygen content below 4 percent, and, for engines with exhaust oxygen concentration of less than 1 percent, the systems can achieve reductions of at least 90 percent[26,28].

The NSCR systems are supplied by many manufacturers for non-cyclic gas-fired IC engines. A number of catalyst manufacturers guarantee their catalysts for two to three years. Tests of two 65 horsepower engines in Southern California equipped with NSCR showed NO_x reduction levels of 95 and 96 percent. Experience with engines rated at less than 0.04 MW (50 hp) is lacking due to the increasing costs on a per megawatt (horsepower) basis for smaller engines. About 250 source tests have been conducted on engines equipped with NSCR in Ventura County with only ten failing to comply with permitted emission levels of 0.8 g/hp.hr or 50 ppmv. Of those complying, the average reduction efficiency was about 97 percent[28].

The ability of NSCR to control NO_x emissions from cyclically loaded rich-burn engines has only been demonstrated on a limited basis. The major problem with the use of NSCR on cyclically loaded engines is with the varying temperature, oxygen content, and NO_x levels in the exhaust. There are, however, several approaches that can be taken to apply NSCR for gas-fired cycling engines. For example, one manufacturer makes a catalyst/muffler combination that includes an oversized catalyst and exhaust pipe. The manufacturer guarantees this system to achieve 90 percent NO_x reductions for three years[28].

3.4.2 Gas Turbines

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocal motion. Gas turbines employ three types of combustors: annular, can-annular, and silo. There are four basic types of cycles in which gas turbines are operated: simple, regenerative, cogeneration, and combined cycle operations.

3.4.2.1 Combustion Controls. The major types of combustion control alternatives applicable or potentially applicable to gas turbines include:

- Water or steam injection;
- Low-NO_x burners, including lean premixed and rich/lean combustors;
- Catalytic combustors; and
- Use of alternative fuels, such as coal-derived gas or methanol.

The injection of water or steam into the flame area of a turbine combustor provides a heat sink which lowers the flame temperature and thereby reduces thermal NO_x formation. Water or steam injection, also referred to as "wet controls", have been applied effectively to both aeroderivative and heavy duty gas turbines, and to all configurations except regenerative cycle applications. It is expected that wet controls can be used with regenerative cycle turbines, but no such installations have been identified by EPA. Water injection control systems are generally available from turbine manufacturers, and most also offer steam injection control systems[31].

Water or steam injection can be added as a retrofit to most gas turbine installations. One limitation with water or steam injection is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate an additional injection port required for water or steam. An additional limitation for steam injection is that it is not an available control option from some gas turbine manufacturers[31].

Reduction efficiencies of 70 to 85+ percent can be achieved with properly controlled water or steam injection, with NO_x emissions generally higher for oil-fired turbines than for natural gas-fired units. The most important factor affecting reduction efficiency is the water-to-fuel ratio. In general, NO_x

reduction increases as the water-to-fuel ratio increases; however, increasing the ratio increases carbon monoxide and, to a lesser extent, hydrocarbon emissions at water-to-fuel ratios less than one. Further, energy efficiency of the turbine decreases with increasing water-to-fuel ratio[31].

Several types of low-NO_x combustors are available for application to gas turbines. In a lean premixed combustor, the air and fuel are premixed prior to introduction into the combustion zone. This results in a mixture with a very lean and uniform air-to-fuel ratio for delivery to the combustion zone, and NO_x formation is minimal. To stabilize the flame and to assure complete combustion with minimum carbon monoxide emissions, a pilot flame is incorporated in the combustor or burner design.

Lean premixed combustors are applicable to can-annular, annular, and silo combustors. They are effective in reducing thermal NO_x for both natural gas and distillate oil, but since they are not effective on fuel NO_x they are not as effective in reducing NO_x levels if high nitrogen fuels are fired. Further, low NO_x emissions when burning oil can only be achieved with water or steam injection. Also, since low NO_x levels are achieved only at loads greater than approximately 40 to 75 percent, the use of lean premixed combustors is not an effective control technique at reduced load conditions[31].

Virtually all gas turbine manufacturers have initiated programs to develop lean premixed combustors on a commercial scale. At the present time, lean premixed combustors are available for limited turbine models from at least three manufacturers. Two additional manufacturers project an availability date of 1994 for some models. All of these manufacturers state that the lean premixed combustors will be available for retrofit applications[31].

The primary factors affecting the performance of lean premixed combustors are the type of fuel and the air-to-fuel ratio. Natural gas produces lower NO_x levels than oil fuels. In terms of the air-to-fuel ratio, it must be maintained in a narrow range near the lean flammability limit of the mixture to achieve low NO_x emission levels. Lean premixed combustors are designed to maintain this ratio at the rated load. At reduced load conditions the fuel requirement is decreased, the lean flammability limit of the mixture will be exceeded, and carbon monoxide emissions will rise dramatically. To avoid these conditions, all manufacturers' lean premixed combustors switch to a conventional combustion mode at reduced load conditions, resulting in higher NO_x emissions[31].

Controlled emissions levels for natural gas, without water/steam injection, range from 25 to 42 ppmv, referenced to 15 percent O_2. This range, from uncontrolled levels of 105 to 430 ppmv, is a 60 to 94 percent reduction in NO_x emissions. One manufacturer has achieved levels of 9 ppmv for natural gas fuel, a reduction of 98 percent. For operation on oil fuel, water/steam injection is required to achieve reduced NO_x emissions levels ranging from 42 to 60 ppmv, a reduction of 79 to 90 percent.[31]

Rich/lean combustors are another type of low-NO_x burner using the staged air combustion concept. These combustors are applicable to all types of gas turbines. They are particularly well-suited for controlling NO_x when burning fuels with high nitrogen content. Emission reductions of 40 to 50 percent were achieved in a test rig burning diesel fuel. Tests on other rich/lean combustors indicate that NO_x emission reductions of 50 to 80 percent can be achieved. At the present time, gas turbine manufacturers do not have this design available for their production models. This may be due to current lack of demand due to the limited use of high nitrogen fuels in gas turbines[31].

Catalytic combustors are another potential NO_x control technique for gas turbines. Catalytic combustors are applicable to all combustor types and are effective on both distillate oil and natural gas fired units. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines). Presently, the development of catalytic combustors has been limited to bench scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high temperature and pressure environment of gas turbine combustors. Additional issues to be resolved are combustor ignition and the need to design a catalyst to operate over a range of loads[31].

Another control method for gas turbines is fuel substitution. Use of fuels with flame temperatures lower than those of natural gas or oil, such as coal-derived gas or methanol, can result in lower thermal NO_x emissions. Turbine combustor rig tests have demonstrated that burning coal-derived gas produces approximately 30 percent of the NO_x emission levels obtained from burning natural gas. A demonstration facility, known as Cool Water, operated using coal gas for five years in Southern California in the early 1980's. The NO_x emissions were reported at 30 ng/J (0.07 lb/MMBtu)[31].

In regard to methanol, the NO_x emissions data for a full-scale turbine firing methanol without water injection ranged from 41 to 60 ppmv, and averaged 49 ppmv. Water injection provided additional reductions. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol ranged from 17 to 28 ppm, a reduction of 42 to 65 percent. The test also indicated that methanol increases turbine output due to the higher mass flows resulting from methanol firing. Methanol firing also increased carbon monoxide and hydrocarbon emissions slightly compared to the same turbine firing distillate oil with water injection. All other aspects of turbine performance were as good as when firing natural gas or distillate oil, and, in addition, turbine maintenance requirements were estimated to be lower and turbine life longer than with distillate oil due to fewer deposits in the combustor and power turbine[31].

In terms of retrofitting performance, a 1984 study sponsored by the California Energy Commission studied the performance of an existing 3.2 MW gas turbine modified to burn methanol. A new fuel delivery system was required, but the only major modifications required for the turbine were new fuel manifolds and nozzles. Tests showed emissions of NO_x in the range of 22 to 38 ppm compared to emissions of 62 to 100 ppm for natural gas, with NO_x emission reductions as high as 65 percent, while no visible smoke emissions occurred and only minor increases in carbon monoxide were experienced[31].

3.4.2.2 Post-Combustion Controls. The major types of postcombustion controls which are applicable or potentially applicable to gas turbines include:

- Selective catalytic reduction; and
- Selective non-catalytic reduction.

Selective catalytic reduction is used on a total of 72 gas turbine installations in the U.S. All of these applications use SCR to supplement reductions from steam or water injection or combustion modifications. Carefully designed SCR systems can achieve NO_x reduction efficiencies as high as 90 percent[31]. Ammonia slip levels as low as 3 to 5 ppm have been reported, with vendor guarantees of 10 ppm available[32].

Due to its limited temperature operating window, SCR is most applicable to new combined-cycle/cogeneration installations which have heat recovery equipment with no flue gas bypass provision. Some combined-cycle/cogeneration bypass some of the gas turbine exhaust to reduce steam flow during off-peak hours or route only a portion of the turbine exhaust through the heat recovery steam generator and use the remainder for direct heating. For these configurations, much of the exhaust will bypass the SCR reactor and the turbine exhaust that does enter may be below the minimum temperature[31].

For simple-cycle configurations, the exhaust gas must be lowered to the required SCR operating temperature, thereby making SCR expensive for these configurations. Retrofit applications of SCR involve high capital costs since retrofits require the addition of a heat exchanger for simple cycle installations, and replacement of the existing heat recovery steam generator in combined cycle applications.

The formation of ammonium sulfate and bisulfate is a concern when using SCR with sulfur-bearing fuels (i.e., distillate and residual oil and some low-Btu fuels). Formation of ammonia salts can be avoided only by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Limiting the ammonia slip to levels which inhibit the formation of ammonia salts is possible, but higher catalyst volume may be needed to achieve the required NO_x efficiency[32]. Another concern is that SCR may not be readily applicable to gas turbines firing fuels which produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, this may not be a significant impediment to SCR use with gas turbines since fuels with high levels of ash or contaminants are typically not used because of concern over damage to the turbines.

The SNCR system has not been applied to gas turbines to date. Its application is impeded by several technical issues. For one thing, the operating temperature window for SNCR (870° to 1200°C (1600° to 2200°F) without hydrogen injection; 700°C (1300°F) with hydrogen injection) is higher than gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the SNCR reaction is relative slow for gas turbine operating flow velocities. It may be feasible, however, to apply this technology within the gas turbine itself, where operating temperatures fall within the reaction window, if suitable turbine modifications and injection systems can be developed[31].

3.5 CONTROL TECHNOLOGIES FOR MUNICIPAL WASTE COMBUSTORS

In general, the three types of municipal waste combustors predominantly used in the U.S. are: mass burn units (waterwall or refractory), refuse-derived fuel (RDF) units, and modular units (excess-air or starved-air). The relative contribution of thermal NO_x and fuel NO_x to the total NO_x emitted from municipal waste incinerators is dependent upon the design and operation of the furnace and the nitrogen content of the refuse burned. Generally, 75 to 80 percent of the total NO_x may be fuel NO_x[26].

3.5.1 Combustion Controls[33]

The types of combustion control techniques that are applicable to municipal waste combustors are:

- Low excess air;
- Staged combustion;

- Flue gas recirculation; and
- Reburning.

Low excess air (LEA) and staged combustion can be used separately or together. With LEA, less air is supplied to the combustor than normal, lowering the supply of oxygen available in the flame zone. With staged combustion, the amount of underfire air is reduced to generate a starved-air condition. Secondary air to complete combustion is added as overfire air (OFA). The effects of LEA and overfire air rate were evaluated at a municipal waste combustor in Marion County, Oregon, a mass burn/ waterwall unit. Compared to normal operating conditions (75 percent excess air), LEA conditions (40 percent excess air) reduced NO_x emissions from an average baseline level of 286 ppm to 203 ppm, a reduction of 29 percent. Under low load conditions, NO_x emissions were reduced from 257 ppm (at 70 percent excess air) to 195 ppm (at 58 percent excess air), a reduction of 24 percent. During tests of this combustor with only underfire air (low OFA) but at normal excess air conditions, NO_x emissions decreased by 27 percent at low load (188 ppm versus 257 ppm) and by 23 percent at normal load (220 ppm versus 286 ppm).

Tests at another mass burn/waterwall combustor at Quebec City, Canada, indicated that use of low overfire air reduced NO_x emissions by about 24 percent compared to tests conducted at similar load and at higher overfire air rates. For two sets of test runs, average NO_x emissions were reduced from 259 ppmv to 196 ppmv at 7 percent oxygen. A Japanese mass burn/refractory combustor using automatic controls to obtain combined LEA and staged combustion conditions demonstrated up to 35 percent reduction in NO_x emissions from emission levels obtained when using manual controls. The average NO_x emission level for this combustor was 155.5 ppmv[34].

The reason that a low overfire air rate generates less NO_x is not certain, but it may be at least partially caused by high excess air at the grate reducing the peak flame temperature. At the Marion County combustor, NO_x measurements taken during testing with high overfire air and normal load (276 ppm) and low load (252 ppm) were roughly equal to NO_x measurements taken during tests conducted at similar load with normal air distribution (286 ppm and 257 ppm, respectively). These data suggest that use of high overfire air may be ineffective in reducing NO_x emissions from mass burn/waterwall combustors.

Flue gas recirculation (FGR) is another technique for reducing NO_x emissions from municipal waste combustors. At a mass burn/waterwall unit in Long Beach, California, where FGR is used to supply 10 percent of the underfire air, reductions in NO_x emissions have been observed, although no quantitative results are available. At a mass burn/refractory combustor in Tokyo, Japan, FGR is used to supply 20 percent of the combustion air, with reported NO_x emission reductions in the range of 10 to 25 percent. At higher FGR rates, little increase in NO_x reduction was observed. Two modular excess-air combustors in the U.S. are using combustion units that have FGR built into the system. In these units, FGR supplies approximately 35 percent of the combustion air. Emissions of NO_x from these units have been measured in the range of 100 to 140 ppm at 7 percent excess oxygen, although no data are available comparing NO_x emissions with and without FGR.

The METHANE DeNO_x (reburning) approach involves the injection of natural gas, together with recirculated flue gases (for mixing), above the grate to provide oxygen deficient combustion conditions that promote the destruction of NO_x, as well as NO_x precursors. A full scale METHANE DeNO_x system was designed and retrofitted to a 100-ton per day Riley/Takuma mass burn system at the Olmsted County, Minnesota, Waste-to-Energy facility for field evaluation. The results of the field evaluation demonstrated reductions of up to 60 percent in NOx emissions and up to 50 percent in CO emissions. The average NO_x level was about 80 ppmv at an average CO level of 35 ppmv. Further benefits included a reduction of up to 50 percent in excess air requirements and furnace efficiency improvement[35].

3.5.2 Post-Combustion Controls[33]

Post-combustion controls for municipal waste combustors include:

- Selective catalytic reduction; and
- Selective non-catalytic reduction.

Currently there are no applications of SCR to municipal waste combustors in the U.S. However, this technology has been applied to municipal waste combustors in Europe and Japan. In Japan, SCR has been applied to two mass burn municipal waste combustors using special low temperature catalysts (V_2O_5 or TiO_2). At one of these sites, a 65 tpd unit in Iwatsuki, Japan, an average NO_x reduction of 77 percent was demonstrated at an average stack temperature of 395°F. Average inlet NO_x concentrations for the two units at this site were 215 and 211 ppm, respectively, with outlet concentrations of 43 and 51 ppm, respectively. At the Tokyo-Hikarigaoka 150 tpd municipal waste combustor, the SCR system demonstrated an average NO_x reduction of 44 percent at a stack temperature of 475°F. The average inlet NO_x concentration was 156 ppm, and the average outlet concentration was 83 ppm. Ammonia slip averaged 8.5 ppm and ranged from 0.5 to 14 ppm.

There are several operating considerations regarding the applicability of SCR. First, the SCR operating temperatures at both of the Japanese municipal waste combustors exceed the fabric filter outlet temperature required to achieve maximum control of dioxin/furans and acid gases. As a result, flue gas reheat may be necessary to reach the desired catalyst operating temperature, depending on the location of the catalyst bed. Flue gas reheat can be a significant expense. Second, performance of SCR can be detrimentally affected by catalyst poisoning by either metals or acid gases. Third, ammonia slip can occur. In a properly operated system, ammonia emissions are typically less than 10 ppm.

In regard to SNCR, long-term performance and reliability data are limited. One municipal waste combustor, at Wilmington, North Carolina, is known to use the NO_xOut® process[1].

The Thermal $DeNO_x$® system is being used at several municipal write combustions in the U.S. At a 380 tpd mass burn/waterwall unit in Commerce, California, ten short-term optimization tests conducted in conjunction with alternative ammonia injection locations showed average NO_x reduction of 49 percent. Maximum one-hour NO_x emission measurements made in 1989 were less than 150 ppm at 7 percent oxygen on all but six days of a total of 110 days. All of the 24-hour averages were less than 120 ppm at 7 percent oxygen. The estimated average NO_x emission reduction was 44 percent.

A mass burn facility in Long Beach, California, has three waterwall combustors, each with a capacity of 460 tpd. Each combustor has a Thermal $DeNO_x$® system and FGR for NO_x control, with other pollutants controlled downstream by a spray dryer/fabric filter system. When neither the FGR or Thermal $DeNO_x$® are in operation, NO_x emissions are typically 190 to 230 ppm at 7 percent oxygen. With FGR only, NO_x emissions are typically 160 to 190 ppm. With both FGR and Thermal $DeNO_x$®, NO_x emissions are reported to be consistently less than 120 ppm, and frequently less than 50 ppm. These data indicate that the Thermal $DeNO_x$® system reduces NO_x emissions at this facility by 30 to 70 percent.

At a mass burn facility in Crows Landing, California, two 400 tpd waterwall combustors are equipped with Thermal $DeNO_x$® systems. Tests performed on these units indicated NO_x emissions without ammonia injection of 297 ppm and 304 ppm, respectively, with emissions using ammonia injection of 93 ppm and 113 ppm, respectively, at 12 percent carbon dioxide. This corresponds to emission reductions of 69 and 63 percent, respectively.

There are several potential concerns associated with applying the Thermal $DeNO_x$® system to municipal waste combustors. First, ammonia or ammonium chloride emissions may result when the ammonia is injected outside the desired temperature window, at a higher than normal rate, or when residual acid gas levels in the stack exceed roughly 5 ppm. At the three facilities discussed above, ammonium chloride plumes have been observed. Second, corrosion of the boiler tubes by ammonia salts has been hypothesized as a potential problem. However, no boiler corrosion problems attributed to ammonia salts have been observed with the U.S. systems during their limited operating time. Third, increased carbon monoxide emissions have been suggested as a potential problem. However, at the Commerce, California, facility, measurements of carbon monoxide emissions taken with and without operation of the Thermal $DeNo_x$® system were essentially the same.

A recently identified concern with Thermal $DeNo_x$® is that the ammonia injected into the flue gas may reduce control of mercury emissions by a spray dryer/fabric filter. Compliance tests at three municipal waste combustor facilities in California with Thermal $DeNO_x$® have shown relatively high mercury emissions (180 to 900 μg/dscm at 7 percent oxygen) compared to four other facilities without SNCR.

There are several theories to explain these observed differences in mercury emissions. One possible explanation is that mercury is normally in a combined ionic form (principally $HgCl_2$) that can absorb or condense onto particulate matter at the low operating temperatures of fabric filters (300°F). By injecting ammonia into the flue gas, pockets of reducing atmosphere may form which reduce mercury to an elemental form which is more volatile and difficult to collect. However, data collected in 1988 at the Commerce, California facility demonstrated mercury removals while the ammonia injection system was operating of 91 percent while firing a mixture of 60 percent commercial refuse and 40 percent residential refuse, and 74 percent while firing a mixture of 95 percent commercial and 5 percent residential refuse. These test results indicate that ammonia injection may not be the reason for the observed low mercury removals.

Another theory gaining acceptance is that carbon in the flue gas enhances adsorption of mercury and that Thermal $DeNO_x$® has no effect. This theory suggests that the poor removals of mercury at the units with Thermal $DeNO_x$® are the result of good combustion leaving little carbon in the fly ash onto which the mercury could adsorb. Little direct data are available on the carbon content of the fly ash at the seven MWC facilities where mercury emissions have been evaluated. However, it is expected that CDD/CDF concentrations at the combustor exit are indicative of good combustion, and thus provide a surrogate measure for the carbon content of the fly ash. Data on mercury removal efficiency and outlet concentrations versus CDD/CDF concentrations at the combustor exits for these facilities support the theory that reduced carbon content in the fly ash increases mercury emissions.

Because of the limited amount of mercury emissions data from municipal waste combustors with Thermal $DeNO_x$® and the apparent strong relationship between fly ash carbon content and mercury control, the hypothesized detrimental effect of Thermal $DeNO_x$® on mercury control by spray dryer/fabric filters cannot be proven with certainty.

3.6 CONTROL TECHNOLOGIES FOR INDUSTRIAL PROCESSES INVOLVING COMBUSTION

Fossil fuel derived heat for industrial processes is supplied in two ways: (1) by heat transfer media, such as steam or hot water, generated from boilers or IC engines, or (2) by direct contact of the raw process material to flames or combustion products in furnaces or specially-designed vessels. The first type of equipment has been discussed in the preceding sections. In this section process heating involving direct contact is discussed.

3.6.1 Petroleum Refining and Chemical Manufacturing Process Heaters and Boilers[36]

Process heaters are used extensively at petroleum refineries in a range of refining processes, including distillation, thermal cracking, coking, thermal cracking, hydroprocessing, and hydroconversion. Large integrated refineries can have as many as 100 heaters, while small, topping refineries can have as few as 4. The total number of process heaters in the petroleum refining industry was estimated by the American Petroleum Institute in 1980 to be about 3,200 of which 89.6 percent were natural draft heaters, 8.0 percent were mechanical draft without preheat, and 2.4 percent were mechanical draft with preheat.

Process heaters are also used in a wide variety of applications in the chemical manufacturing industry. Uses include fired reactors, feed preheaters for non-fired reactors, reboilers for distillation, and heating for heat transfer oils. More than 30 organic chemical and 7 inorganic chemical manufacturing operations are reported to require process heaters.

3.6.1.1 Combustion Controls. Combustion controls to reduce NO_x emissions from process heaters include:

- Low excess air;
- Low-NO_x burners;
- Staged combustion air (air lances); and
- Flue gas recirculation.

Low excess air using automatic controls has been applied to more than 50 process heaters in the U.S. Available information suggests that automatic LEA controls based on flue gas monitoring are applicable to all new process heaters. Manual and automatic damper control systems designed to reduce excess air can be used with natural or mechanical draft heaters fired with oil, gas, or oil/gas combinations. An assessment of the NO_x removal efficiencies of 12 process heaters, consisting of 11 natural draft heaters and 1 mechanical draft heater, indicates that an average 9 percent reduction in NO_x accompanies each 1 percent reduction in excess oxygen level.

Commercially packaged automatic damper control systems may not be directly applicable to some specific heater applications. For example, it may be difficult to equip multicell heaters with common convection zones and one or more stacks when the cells are not well balanced with respect to variations in product charge and fuel firing rates. In these cases, the basic package may require modification or compromise in achieving minimum low excess air.

Low-NO_x burners are another NO_x emission control alternative for process heaters. Many types of LNB are commercially available, with most employing staged air, staged fuel, or FGR.

Staged air, low-NO_x burners are most commonly used with existing process heaters.

In new heaters, low-NO_x burners may be used instead of conventional burners regardless of draft, fuel, or flame type. Special low-NO_x burner designs are available for firing low-Btu fuels (high intensity low-NO_x burners) and for providing uniform radiant heat transfer from the furnace walls (radiant wall low-NO_x burners). Burners of fiber matrix design are available for simple burners from 5 MW (16 MMBtu/hr) and for multiple burners up to 60 MW (200 MMBtu/hr)[25]. The use of low-NO_x burners for a specific heater application may be limited if the application has unusual process requirements. Also, in some retrofitted heaters the longer burner flame associated with staged air, low-NO_x burners may cause flame impingement problems.

Table 3-13 lists the petroleum refinery process heater applications known to be using low-NO_x burners. The table is not intended to be a comprehensive list of all refinery heater low-NO_x burner applications, but is representative of the heater types that are compatible with the use of low-NO_x burners. These applications account for approximately 86 percent of the fired heater energy used in typical refineries. Table 3-14 lists the chemical industry process heater applications that are currently using low-NO_x burners, as reported by members of the Chemical Manufacturers Association.

Tests using a test furnace burning natural gas at 10 percent excess air showed that at 200°F, NO_x emissions were roughly 65 ppm compared to about 98 ppm for conventional burners, a reduction of 34 percent. At 500°F, emissions were about 83 ppm compared to roughly 153 ppm for conventional burners, for a NO_x reduction of 46 percent. For staged fuel low-NO_x burners, the tests found that at 200°F NO_x emissions were about 30 ppm, a reduction of 69 percent compared to the emissions from conventional burners (98 ppm). At 500°F NO_x emissions were about 42 ppm, as compared to the emissions of 153 ppm for conventional burners at this temperature, a reduction of 72 percent. The tests also found that the effect of fuel type on NO_x emissions is roughly the same for both low-NO_x burners and conventional

TABLE 3-13. PETROLEUM REFINERY PROCESSES FOR WHICH LOW-NO_x BURNER DATA ARE APPLICABLE

Heater	Estimated percent of total fired heater capacity at typical petroleum refinery (energy basis)
Crude heater	26
Naptha reformer	20
Vacuum column heater	15
Debutanizer bottoms reboiler	2
Hydrodesulfurization preheater	10
Coke heater	13
TOTAL	86

Source: Reference 36

TABLE 3-14. CHEMICAL INDUSTRY PROCESSES FOR WHICH LOW-NO_X BURNERS ARE REPORTED TO BE IN USE

Agricultural chemical
Ammonia (steam hydrocarbon reformers)
Biphenyl
Butadiene
Chlorinated organics/oxides
Cumene
Ethylbenzene/styrene
Isocyanate
Olefins (ethylene pyrolysis furnaces)
PVC and polymers
PVC film
Silicones
Xylene

Source Reference 36

burners. Emissions of NO_x from burners firing oil with 0.3 percent by weight nitrogen were consistently twice as high as those from comparable burners firing gas.

Staged combustion air, also referred to as air lances, is an off-stoichiometric combustion control technique that can be applied alone or concurrently with LEA and/or low-NO_x burners. To date, it has been used only in retrofit applications, but it could also be used on new heaters. The applicability of this technique to existing process heaters has been demonstrated in a long term EPA test and on a commercial basis by at least one refiner in California. The refinery has been successfully operating three low temperature heaters retrofitted with natural draft lances since 1983 with no problems.

Tests performed by EPA on a retrofitted full-scale, natural gas-fired, vertical, crude heater have shown that natural draft air lances reduce NO_x emissions by 10 to 20 percent relative to emissions without lances. Uncontrolled NO_x emission levels at 5.5 and 3.0 percent oxygen were 67.1 and 54.0 ng/J (0.158 and 0.127 lb/MMBtu), respectively, compared to emissions controlled by natural draft air lances of 54.0 and 46.3 ng/J (0.127 and 0.109 lb/MMBtu), respectively. For forced draft air lances, NO_x reductions of 50 to 60 percent were found relative to emissions without lances. Controlled emissions were found to be 34.0 and 34.0 ng/J (0.080 and 0.080 lb/MMBtu) at 5.5 and 3.0 percent oxygen, respectively.

The applicability of staged combustion air has several limitations. First, in heaters where the process fluid flow may be seriously affected by variations from the design heat flux distribution, as is often the case with reforming heaters and vacuum heaters, staged air lances may not be applicable. Another limitation is that in some cases the use of staged combustion air can lead to a corrosive environment, requiring frequent replacement of air lances. Finally, the larger flame associated with staged combustion air may require a larger flame zone in some heaters.

Flue gas recirculation has been used on only a few process heaters, and several inherent drawbacks will limit its use in the future. The most important of these is that the technology is usually not cost effective because of the increased energy costs associated with transporting and reheating the recirculated flue gas. Another drawback is that FGR requires a relatively large capital investment because of the need for high temperature fans and ductwork. In addition, FGR may not be applicable to all types of heaters. Its low flame temperature and susceptibility to flame instability limits the use of FGR in high temperature applications. Furthermore, FGR can only be used on forced draft process heaters because of the need to recirculate the flue gas.

3.6.1.2 Post-Combustion Controls. Post-combustion NO_x controls for process heaters include:

- Selective catalytic reduction; and
- Selective non-catalytic reduction.

Selective catalytic reduction has been installed on at least nine refinery process heaters in California. The refinery systems were permitted in the early 1980s, with permit emission levels for all of the units established in the range of 0.03 to 0.05 lb/B\MMBtu at about 10 to 15 percent oxygen. One of the units has been reported as achieving a NO_x emissions reduction of 90 percent, with minimal operator attention required[26,36].

Selective catalytic reduction systems are applicable to most new mechanical draft process heaters, and it has wide applicability to a variety of processes. For existing heaters, retrofitting generally requires installation of a fan or additional fan capacity and extensive ductwork. One potential disadvantage of SCR systems is that they may not be applicable to oil-fired heaters due to problems with residual oil mist carryover and catalyst plugging. Selective noncatalytic reduction has been installed on several refinery process heaters in California. While the NO_x reduction efficiency of individual units depends on a number of factors, NO_x emission reductions have generally ranged from 35 to 70 percent.

Selective noncatalytic reduction is applicable to most new process heaters and can be used in conjunction with combustion modifications. However, since SNCR systems are very sensitive to low load and variable load conditions, their applicability to many processes is limited. Since SNCR performance is sensitive to the residence time during reaction, significant load changes can decrease NO_x reduction capabilities considerably. Furthermore, the ability of SNCR to reduce NO_x emissions becomes almost negligible when the heater load drops below 50 percent, because the temperature window required for efficient operation is not reached.

3.6.2 Petroleum Refining Catalytic Crackers and Carbon Monoxide Boilers

Catalytic cracking regenerators and carbon monoxide boilers can be large NO_x emission sources at petroleum refineries. Testing conducted on one carbon monoxide boiler in 1977 showed that adjustment of staged air ports and use of BOOS had negligible effects on NO_x emissions, although carbon monoxide increased rapidly below about two percent excess oxygen. The lack of response of NO_x formation to combustion modifications was attributed to NO_x that is formed from ammonia in the carbon monoxide gas feed[3].

3.6.3 Metallurgical Processes

The iron and steel industry is the predominant source of NO_x emissions from metallurgical processes. Other industries, such as aluminum processing, extensively use electric melting furnaces or operate process equipment at temperatures below the minimum required for substantial NO_x formation. The processes with the largest potential NO_x emissions at iron and steel plants include: pelletizing, sintering, coke ovens, blast furnace stoves, open hearth furnaces, soaking pits and reheat furnaces, and heat treating and finishing[3].

Tests conducted at iron and steel plants in the late 1970's yielded the following information about the performance of NO_x controls for some of these processes[3]:

- An open hearth furnace was found to have wide variations in NO_x emissions, from 100 to 3500 ppm, due to large changes in excess air as operators opened the hearth doors. Following baseline tests, the furnace was overhauled to repair refractory and to fix leaks.

- A second test cycle showed that a NO_x emission reduction of about 40 percent was achieved after the overhaul.
- One steel billet reheat furnace was tested while firing natural gas. Lowering the excess air resulted in a decrease in NO_x emissions of 24 percent, and employing BOOS produced a 43 percent NO_x reduction.
- One steel ingot soaking pit was tested while firing natural gas through a single burner. Reduction of excess air reduced NO_x by 69 percent with no adverse effect on the steel.

3.6.4 Glass Manufacturing

The flue gas from glass-melting furnaces is the major source of NO_x emissions in the glass industry. Certain process modifications can reduce NO_x emissions from these furnaces. For example, preheating and agglomeration of raw batch materials could reduce NO_x emissions by 25 to 50 percent at some plants. Augmentation of heat transfer in glass-melting furnaces (e.g., by burner repositioning) could reduce NO_x in proportion to the energy saved, with potential NO_x reductions in the range of 10 to 20 percent. Finally, development of a submerged combustion process could substantially reduce NO_x emissions[3].

3.6.5 Cement Manufacturing

Combustion modifications to cement kilns can reduce NO_x emissions to some extent. Emission tests conducted in the late 1970's on a wet process cement kiln showed that reduction of excess oxygen at the baseline air temperature reduced NO_x by 36 percent. In addition, NO_x emissions were found to be highly dependent upon kiln temperature. Increasing the temperature from 700°F to 770°F increased NO_x emissions by 15 percent. The independent reductions of either excess air or air temperature caused unacceptable reduction of kiln temperature that could lead to process upset. It was found that simultaneous reduction of excess air and an increase in air temperature could result in a reduction in NO_x emissions of about 14 percent while maintaining the required kiln temperature[3]. Another means of emission control in cement kiln operation is the choice of kiln type. Some NO_x reduction is achieved by using a vertical instead of a rotary kiln. The mechanism of operation in vertical kilns is such that heat transfer to the load is very high, and peak temperatures in the kiln are lower[3].

Cement kilns have lower NO_x emissions when using solid and liquid fuels than when using gas, due to the highly adiabatic nature of the process. An emissions test conducted on a dry process kiln in the late 1970's showed that operation on oil resulted in 60 percent less NO_x emissions than operation on natural gas. Operation on combined coke and natural gas produced 50 percent less emissions compared to use of natural gas alone[3].

3.7 CONTROL TECHNOLOGIES FOR NONCOMBUSTION INDUSTRIAL PROCESSES

The NO_x control technologies discussed in the preceding sections involved controls for sources where NO_x formation takes place during combustion. This section addresses the control of NO_x from industrial process sources where NO_x formation results from noncombustion chemical processes. For these sources, NO_x control techniques involve flue gas treatment.

3.7.1 Nitric Acid Plants[37]

For new nitric acid plants, NO_x emissions can be well controlled by using advanced processes, such as high inlet pressure absorption columns or strong acid processes. However, NO_x emission controls at existing plants must rely on flue gas treatment techniques, including:

- Extended absorption;
- Selective catalytic reduction; and
- Nonselective catalytic reduction.

Other techniques have been developed or demonstrated, including wet chemical scrubbing, chilled absorption, and molecular sieve absorption. However, poor NO_x control performance or other disadvantages have excluded these controls for common use.

Extended absorption is typically used in retrofit applications by adding a second absorption tower in series with the existing tower. Compliance tests for seven new (post-1979) nitric acid plants using extended absorption showed NO_x control efficiencies to range from 93.5 to 97 percent. Emission factors for these plants range from 0.59 to 1.28 kilograms (Kg) of NO_x per metric ton of acid (1.3 to 2.81 lb/ton). Maximum NO_x control efficiencies of extended absorption systems is achieved by operating at low temperature, high pressure, low throughput, low acid strength, and long residence time.

Selective catalytic reduction is used in many nitric acid plants in Europe and Japan. However, only three U.S. plants are currently using this technology. Reported NO_x control efficiencies for the European plants using Rhone-Poulenc SCR technology range from 83.4 to 86.7 percent. Inlet NO_x concentrations range from 1,200 to 1,500 ppm, with outlet concentrations at about 200 ppm. The European plants using BASF SCR technology have NO_x control efficiencies ranging from 41 to 83 percent. Inlet NO_x concentrations range from as low as 200 ppm to as high as 3,000 ppm, and outlet concentrations range from less than 110 ppm up to about 500 ppm. The SCR system on one of the U.S. facilities, which is a new plant, is estimated to have a NO_x control efficiency of 97.2 percent, based on an uncontrolled emission factor of 10 Kg per metric ton (20 lb/ton) and a controlled emission factor of 0.29 Kg per metric ton (0.57 lb/ton). It should be noted that less stringent standards apply to the European plants as compared to U.S. standards. The SCR technique is used on the European plants to bring NO_x emissions down to required levels only.

Several advantages of SCR make it an attractive control technique. Since the SCR process can operate at any pressure, it is a viable retrofit control alternative for existing low-pressure acid plants as well as for new plants. Another technical advantage is that because the temperature rise through the SCR reactor bed is small, energy recovery equipment (e.g., waste-heat boilers and high-temperature turboexpanders) is not required, as is the case with the NSCR system, discussed below.

Nonselective catalytic reduction was widely used on new nitric acid plants between 1971 and 1977. However, rapid fuel cost escalation caused a decline in use of NSCR systems for new plants, and many opted instead for extended absorption.

Despite the associated fuel costs, NSCR offers advantages that continue to make it a viable option for new and retrofit applications. Flexibility is one advantage, especially for retrofit considerations. An NSCR unit generally can be used in conjunction with other NO_x control techniques. Furthermore, NSCR can be operated at any pressure. Additionally, heat generated by operating an NSCR unit can be recovered in a waste heat boiler and a tailgas expander to supply the energy for process compression with additional steam for export.

Test data for five nitric acid plants using NSCR shows that controlled NO_x emission factors ranged from 0.4 to 2.3 lb/ton of nitric acid produced. No trends were apparent relating the type of NSCR unit (i.e., the number of stages, fuel type, and catalyst support) to the observed emission factors. The NO_x control efficiencies were found to range from 94.7 to 99.1 percent.

3.7.2 Adipic Acid Plants[37]

Adipic acid is produced at four plants in the U.S. The following types of NO_x control techniques are used at three of these plants:

- Extended absorption; and
- Thermal reduction.

Extended absorption is used at one adipic acid plant in the U.S. The estimated NO_x emission factor for this plant ranges from 0.41 to 1.23 Kg per metric ton (0.81 to 2.45 lb/ton) of acid produced.

The thermal reduction technique is used at two domestic adipic acid plants. For these plants, estimated emission factors for controlled NO_x emissions are about 1.6 and 4.6 Kg per metric ton (3.3 and 9.3 lb/ton) of acid produced, respectively, corresponding to estimated average NO_x control efficiencies of 94 and 69 percent, respectively.

3.7.3 Explosives Manufacturing Plants

The major emissions from the manufacture of explosives are nitrogen oxides and nitric acid mists. Emissions of nitrated organic compounds may also occur from many of the trinitrotoluene (TNT) process units. In the manufacture of TNT, vents from the fume recovery system and nitric acid concentrators are the principal sources of emissions. Emissions may also result from the production of Sellite solution and the incineration of "red water." The molecular sieve abatement system is used at the Holston Army Ammunition Plant in Kingsport, Tennessee, and at the Radford Army Ammunition Plant in Radford, Virginia, to treat vent gas streams from nitrocellulose operations[3].

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16. ABSTRACT

This Technical Report is a summary of previous documents dealing with NOx control technologies. It provides a brief description of existing NOx control technologies. The report also discusses the availability and extent of application of these technologies for several industrial categories that are the main stationary sources of NOx emissions. Where available, achievable controlled NOx emission levels and percent reduction for each control technology are presented.

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