

**CONTROL OF NO_x EMISSIONS FROM
U.S. COAL-FIRED ELECTRIC UTILITY BOILERS**

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ABSTRACT

Recently, several regulations have been promulgated in the U.S. requiring reductions in emissions of nitrogen oxides (NO_x) from electric utility boilers. To comply with these regulations, state-of-the-art NO_x control technologies have been applied to a large number of coal-fired U.S. utility boilers. This paper reviews these technologies and their applications.

In general, NO_x control technologies are categorized as being either *primary control technologies* or *secondary control technologies*. Primary control technologies reduce the formation of NO_x in the primary combustion zone. In contrast, secondary control technologies destroy the NO_x present in the flue gas from the primary combustion zone. Primary control technologies being used in the U.S. are low NO_x burner (LNB) and overfire air (OFA). Data reflect that these technologies have been used on 177 boilers and have resulted in NO_x reductions between 33 and 48 percent, on average, from 1990 emissions levels.

The secondary NO_x control technologies in use on U.S. coal-fired utility boilers include reburning, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). More than 100 boilers either have used, or will use, these technologies to achieve the desired NO_x reductions. The NO_x reductions achieved, or projected, at these applications range from 20 to more than 80 percent. In the last 3 years, SCR has been chosen as the preferred secondary technology at numerous U.S. coal-fired utility boilers. Current data indicate that 79 boilers either use, or will use, SCR for NO_x control.

INTRODUCTION

Emissions of nitrogen oxides (NO_x) are associated with a variety of environmental concerns including increasing ground level ozone, formation of acid rain, acidification of aquatic systems, forest damage, degradation of visibility, and formation of fine particles in the atmosphere.¹ Such concerns have resulted in a need to reduce these emissions in the United States (U.S.) and elsewhere. In order to implement controls efficiently, it is important to determine which sources are significant emitters of NO_x . Shown in Figure 1 is the contribution to NO_x emissions in 1997 from each of the applicable source categories in the U.S.² It is evident from these data that stationary combustion sources (electric utility, industrial, and other combustion sources) accounted for a significant portion, about 45 percent, of these emissions. Moreover electric utilities accounted for about 26 percent of NO_x emissions and comprised the largest emitting source category within stationary sources. Based on these data, reduction of NO_x emissions from stationary sources, particularly electric utility sources, needs to be considered in efforts undertaken to address the environmental concerns associated with NO_x .

Recently, a number of regulatory actions have been taken in the U.S., focused on reducing NO_x emissions from stationary combustion sources. These actions include the Acid Rain NO_x regulations^{3,4}, the Ozone Transport Commission's NO_x Budget Program⁵, revision of the New Source Performance Standards (NSPS) for NO_x emissions from utility sources⁶, and the Ozone Transport rulemakings⁷.

Control technology applications necessarily play a key role in the formulation and implementation of air pollution reduction strategies. The current focus on reduction of NO_x from stationary combustion sources establishes a need to review current information on pertinent control technologies. This paper reviews the technologies for controlling NO_x from coal-fired power plants. The review not only includes the established commercial technologies that are being used in the U.S., but also examines those that can be considered to be relatively new or in an advanced stage of development. There are several reasons for focusing this review on coal-fired power plants. First, data are available from technology applications at such plants. Second, it is more cost-effective to control NO_x from large sources and, as such, it is expected that the technologies would be applied to such sources. Third, based on data in Reference 2, coal-fired power plants account for approximately 90 percent of the NO_x emissions from the U.S. electric utility industry.

It is expected that this review will be useful to a broad audience including:(1) individuals responsible for developing and implementing NO_x control strategies at sources, (2) persons involved in developing NO_x and other regulations, (3) state regulatory authorities implementing NO_x control programs, and (4) the interested public at large. Moreover, persons engaged in research and development (R&D) efforts aimed at improving the cost-effectiveness of controls may also benefit from this review. Finally, this review will also be useful for technology applications on large coal-fired industrial boilers, which are quite similar to electric utility boilers.

REGULATORY OVERVIEW

The 1990 Clean Air Act Amendments (CAAA)⁸ authorize EPA to establish standards for a number of atmospheric pollutants, including NO_x. Two major portions of the CAAA relevant to stationary source NO_x control are Titles I and IV. Title I established National Ambient Air Quality Standards (NAAQS) for six criteria pollutants, including ozone. Title IV includes provisions designed to address acid deposition resulting from emissions of NO_x and sulfur dioxide (SO₂) from electric power plants. Table 1 presents an overview of the regulatory actions affecting NO_x sources. NO_x reduction requirements under Titles I and IV are discussed below.

Title I NO_x Requirements

Title I of the CAAA of 1990 included provisions designed to address both the continued nonattainment of the existing ozone NAAQS and the transport of air pollutants across state boundaries. These provisions also allow downwind states to petition for tighter controls on upwind states that contribute to their NAAQS nonattainment status. In general, Title I NO_x provisions require: (1) existing major stationary sources to apply reasonably available control technologies (RACT); (2) new or modified major stationary sources to offset their new emissions and install controls representing the lowest achievable emissions rate (LAER); and (3) each state with an ozone nonattainment region to develop a State Implementation Plan (SIP) that, in some cases, includes reductions in stationary source NO_x emissions beyond those required by the RACT provisions of Title I.

*Ozone Transport Commission (OTC) NO_x Budget Program*⁵. Section 184 of the CAAA delineated a multi-state ozone transport region (OTR) in the northeast and required specific additional NO_x and volatile organic compound (VOC) controls for all areas in this region. Section 184 also established the OTC for the purpose of assessing the degree of ozone transport in the OTR and recommending strategies to mitigate the interstate transport of pollution. The OTR consists of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, parts of northern Virginia, and the District of Columbia. The OTR states confirmed that they would implement RACT on major stationary sources of NO_x (Phase I), and agreed to a phased approach for additional controls, beyond RACT, for power plants and other large fuel combustion sources (Phases II and III). This agreement, known as the OTC Memorandum of Understanding (MOU) for Stationary Source NO_x Controls was approved on September 27, 1994.⁹ All OTR states, except Virginia, are signatories to the OTC NO_x MOU.

The MOU establishes an emissions trading system to reduce the costs of compliance with the control requirements under Phase II (which began on May 1, 1999) and Phase III (beginning on May 1, 2003). The OTC program caps summer-season (May 1 - September 30) NO_x emissions for all 13 OTC jurisdictions at approximately 219,000 tons in 1999, and 143,000 tons in 2003, which represent approximately 55 and 70 percent reductions in NO_x, respectively, from the 1990 baseline emission level of 464,898 tons. The actual reductions during the 1999 season, however, reflect participation by only 8 of the 13 jurisdictions. This subset includes Connecticut,

Delaware, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island.

*NO_x SIP Call*⁷. To address the long-range transport of ozone, in October 1998, EPA promulgated a rule to limit summer-season NO_x emissions in 22 Northeast states and the District of Columbia that the Agency believes are significant contributors to ozone non-attainment in downwind areas. These states were required to amend their state implementation plans (SIPs) through a procedure established in Section 110 of the CAAA. EPA finalized a summer-season state NO_x budget (in tons of NO_x) and developed a state implemented and federally enforced NO_x trading program to provide for emissions trading by certain electric and industrial stationary sources. The state NO_x budget is based on the application of a population-wide 0.15 lb/10⁶ Btu NO_x emission rate for large electricity generating units (EGUs) and a 60 percent reduction from uncontrolled emissions for large non-EGUs. The NO_x SIP call is projected to reduce summer-season NO_x emissions by 1.1 million tons in the affected 22 states and DC. In response to litigation, on March 3, 2000, the D.C. Circuit Court issued its decision on the NO_x SIP call, ruling in favor of EPA on all major issues, including the findings of significant contribution by the 23 states and the emissions reductions that must be achieved. On August 30, 2000, the D.C. Circuit Court extended the deadline for the full implementation of the NO_x SIP call from May 1, 2003, to May 31, 2004.

*Section 126 Petitions*¹⁰. In addition to promulgating the NO_x SIP call, EPA responded to petitions filed by eight Northeastern states under Section 126 of the CAAA. The petitions request that EPA make a finding that NO_x emissions from certain major stationary sources significantly contribute to ozone nonattainment problems in the petitioning states. The final Section 126 rule requires upwind states to take action to reduce emissions of NO_x that contribute to nonattainment of ozone standards in downwind states. The findings affect large EGUs and both non-EGU boilers and turbines located in 12 northeast states and the District of Columbia. Like the NO_x SIP call, EPA has finalized a federal NO_x Budget Trading Program based on the application of a population-wide 0.15 lb/10⁶ Btu NO_x emission rate for large EGUs and a 60 percent reduction from uncontrolled emissions for large non-EGUs. The final Section 126 actions are projected to reduce summer-season NO_x emissions by 510,000 tons in the 12 affected states and D.C. The compliance deadline is May 1, 2003.

Title IV NO_x Requirements

Title IV of the CAAA authorized EPA to establish an Acid Rain Program to reduce the adverse effects of acidic deposition on ecosystems, natural resources, materials, visibility, and public health. Emissions of SO₂ and NO_x from the combustion of fossil fuels are important contributors to acidic deposition from the atmosphere. Title IV includes provisions designed to address NO_x emissions from existing power plants.

Acid Rain NO_x Reduction Program^{3,4}. Under Title IV of the CAAA, the Acid Rain Program uses a two-phased strategy to achieve the required annual reductions in NO_x emissions. Effective January 1, 1996, Phase I established regulations for "Group I" boilers, which include dry-bottom, wall-fired boilers, and tangentially fired (T-fired) boilers. In Phase II, which began

on January 1, 2000, lower emissions limits are set for certain Group 1 boilers, and regulations are established for Group 2 boilers, which include cell-burner, cyclone, and wet-bottom, wall-fired coal-fired boilers. The regulations allow for emissions averaging in which the emissions levels established by EPA are applied to an entire group of boilers owned or operated by a single company.

By January 2000, the Acid Rain Program required annual average emission rates of 0.46 lb/10⁶ Btu for dry-bottom wall-fired boilers and 0.40 lb/10⁶ Btu for tangentially fired boilers. The limits are 0.68 lb/10⁶ Btu for cell burners, 0.86 lb/10⁶ Btu for cyclones greater than 155 MW_e, 0.84 lb/10⁶ Btu for wet-bottom boilers greater than 65 MW_e, and 0.80 lb/10⁶ Btu for vertically fired boilers. The Phase I compliance results for 1996 show that, from 1990 to 1996, the overall NO_x emission reductions for the affected boilers totaled about 340,000 tons; i.e., a reduction of 33 percent. In Phase II, approximately 1.17 million tons per year of NO_x reductions are projected to result from the Acid Rain NO_x Program requirements.

*New Source Performance Standards (NSPS)*⁶. Under the CAAA, new power plants are subject to NSPS that represent maximum allowable emission rates and are based upon the best adequately demonstrated technology. EPA promulgated a revised NSPS for fossil-fuel-fired utilities in 1998. The new standards revise the NO_x emission limits for steam generating units and affect only units for which construction, modification, or reconstruction commenced after July 9, 1997. The NO_x emission limit in the final rule is 201 nanograms per joule (ng/J) [1.6 lb/megawatt-hour (MWh)] gross energy output regardless of fuel type. For existing sources that become subject to regulation through modification or reconstruction, the NO_x emission limit is 0.15 lb/10⁶ Btu heat input. The estimated decrease in baseline nationwide NO_x emissions is 25,800 tons per year, which represents about a 42 percent estimated reduction in growth of NO_x emissions from new utility and industrial steam generating units subject to NSPS.

NO_x FORMATION IN COMBUSTION

Before examining the control technologies, it would be helpful to review the mechanisms of NO_x formation in combustion. These mechanisms form the basis for practical NO_x control strategies, particularly those based on modification of the combustion process. NO_x is formed during most combustion processes by one or more of three chemical mechanisms^{11, 12, 13}: (1) “thermal” NO_x resulting from oxidation of atmospheric molecular nitrogen¹⁴, (2) “fuel” NO_x resulting from oxidation of chemically bound nitrogen in the fuel, and (3) “prompt” NO_x resulting from reaction between atmospheric molecular nitrogen and hydrocarbon radicals. Figure 2 depicts a simplified picture of the major reaction pathways for NO_x formation and reduction in combustion.

In fuel-lean combustion of nitrogen-free fuels, thermal NO_x is the primary component of NO_x emissions. Thermal NO_x formation is quite sensitive to temperature and can be controlled by appropriately controlling peak temperature in the furnace. In fuel-lean combustion of fuels containing nitrogen (e.g., coal), fuel NO_x contributes significantly to total NO_x emissions, depending on the weight percent of nitrogen in the fuel.¹⁵ Formation of fuel NO_x depends on the availability of oxygen to react with the nitrogen during coal devolatilization and the initial stages

of combustion. Under fuel-rich conditions, the formation of NO_x may compete with the formation of molecular nitrogen (N_2) and may result in a reduction of NO_x emissions. Prompt NO_x contributes a relatively minor fraction of total NO_x emissions for both nitrogen-free and nitrogen-containing fuels.

The factors identified above that dictate NO_x formation (devolatilization of fuel-bound nitrogen, oxygen concentration, and flame temperature) can all be adjusted by controlling the rate at which the fuel and air mix or staging the combustion process such that an initial fuel-rich zone is followed by a burnout zone that is high in oxygen to complete the combustion process, but low enough in temperature to minimize thermal NO_x production. Combustion modification NO_x controls utilize this combustion staging.

NO_x CONTROL TECHNOLOGIES

In general, NO_x control technologies may be placed in two general categories: *primary control technologies* and *secondary control technologies*. Primary control technologies reduce the amount of NO_x produced in the primary combustion zone. In contrast, secondary control technologies reduce the NO_x present in the flue gas from the primary combustion zone. Some of the secondary control technologies actually employ a second stage of combustion, such as reburning.

Primary Control Technologies

In the U.S., popular primary control technologies are low NO_x burners (LNB) and overfire air (OFA). These technologies utilize staged combustion techniques to reduce NO_x formation in the primary combustion zone. LNB and OFA are described below.

Widely Used Primary Control Technologies

LNB^{16, 17}. A LNB limits NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, thereby yielding one or more of the following conditions: (1) reduced oxygen in the primary flame zone, which limits fuel NO_x formation; (2) reduced flame temperature, which limits thermal NO_x formation; and (3) reduced residence time at peak temperature, which limits thermal NO_x formation. In general, LNBs attempt to delay complete mixing of fuel and air mixing as long as possible, within the constraints of furnace design. This is why the flames from LNBs are usually longer than those from conventional burners. The gradual mixing of the combustion air to a fuel-rich flame core is shown schematically in Figure 3. The hardware used to influence the fuel/air mixing varies from manufacturer to manufacturer. LNBs can provide NO_x reductions in excess of 50 percent from uncontrolled levels.

Overfire Air (OFA)^{16, 17}. OFA, also referred to as air staging, is a combustion control technology in which a fraction, 5 to 20 percent, of the total combustion air is diverted from the burners and injected through ports located downstream of the top burner level. OFA is generally

used in conjunction with operating the burners at a lower-than-normal air-to-fuel ratio, which reduces NO_x formation. The OFA is then added to achieve complete combustion. OFA can be used in conjunction with LNBs. The addition of OFA to LNB may increase the reductions by an additional 10 to 25 percent.

Primary control technologies, described above, have been widely implemented on U.S. coal-fired utility boilers to comply with the NO_x emissions reduction requirements of Phase I of the Title IV NO_x Program. Table 2 provides a summary of primary control applications through 1998.¹⁸ These data reflect that primary control technologies have been applied on 177 boilers and have resulted in reductions ranging from 33 to 48 percent, on average, from 1990 emissions levels. In particular, applications of LNB resulted in reductions of greater than 40 percent, on average, from 1990 levels.

Recently, advances have been made in primary control technologies aimed at providing greater NO_x reduction. These advances are described below.

Advances

LNB with Multi-level OFA. A concentric firing system with multi-level OFA is now available for tangentially fired boilers. This system incorporates deep air staging to achieve significantly lower NO_x emissions. This combustion technology has achieved NO_x emissions under 0.15 lb/10⁶ Btu while firing Powder River Basin (PRB) subbituminous coal¹⁹, which reflects the potential for achieving low NO_x emissions with this technology. Note, however, that for other coals that are lower in fuel volatile content than PRB coals (e.g., eastern bituminous coals) higher NO_x emissions may be expected with this technology.

Rotating Opposed Fire Air (ROFA)²⁰. The ROFA design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. The difference between ROFA and conventional OFA is that ROFA utilizes a booster fan to increase the velocity of air to promote better mixing and to increase the retention time in the furnace. Specific advantages of ROFA include more even distribution of combustion products, less temperature variation across the furnace, and less excess air needed for complete combustion. The technology has been installed on a 175 MW_c boiler, and NO_x reduction obtained has been over 50 percent.

For many coal-fired boilers, it may not be possible to achieve sufficiently low NO_x emissions to comply with existing or future NO_x regulations by using primary measures alone. These units may require additional primary controls and/or secondary controls for future NO_x compliance. Described below are the secondary control technologies applicable to coal-fired electric utility boilers.

Secondary Control Technologies

In the U.S., popular secondary control technologies are reburning, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). These technologies are described below.

Widely Used Secondary Control Technologies

Reburning^{21, 22}. In reburning, between 15 and 25 percent of the total fuel heat input is provided by injecting a secondary (or reburning) fuel above the main combustion zone to produce a slightly fuel-rich reburn zone with a stoichiometry of about 90 percent theoretical air. Combustion of reburning fuel at fuel-rich conditions results in hydrocarbon fragments, which react with a portion of incoming NO_x to form hydrogen cyanide (HCN), isocyanic acid (HNCO), isocyanate (NCO), and other species. These species then pass through an amine (NH_3) + carbon monoxide (CO) step, and the NH_3 is ultimately reduced to N_2 . Finally, completion air is added above the reburn zone to complete burnout of reburning fuel. Reburning reaction pathways are shown in Figure 2, and a reburning application is schematically shown in Figure 4.

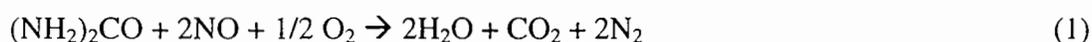
Boiler size, in particular furnace height, can have an impact on one of the key design parameters – gas residence time within the reburn and burnout zones – responsible for a successful reburning application. Sufficient residence time is required to achieve adequate flue gas mixing and to accommodate the NO_x reduction kinetics in the reburning zone, and for complete combustion in the burnout zone. Given sufficient time in the reburn zone, reburn zone stoichiometry is another critical parameter that influences NO_x reduction. However, reburn zone stoichiometry is directly related to the heat input split between the primary and reburn zones. In general, an increase in the reburn heat input and a commensurate decrease in primary heat input will decrease the stoichiometry in the reburn zone and improve the NO_x reduction efficiency. However, this heat splitting is constrained by flame stability considerations in the primary and reburn zones, the potential for unacceptable levels of CO emissions resulting from addition of relatively large amounts of reburn fuel, and the potential for increased boiler tube corrosion within the reburn zone. In addition to the above considerations, the temperature at the point of burnout air addition can place a lower limit on the achievable NO_x due to reformation of thermal NO_x .

The choice of the reburning fuel is determined largely by fuel availability, a balancing of operating costs versus capital costs, and the specifics of the boiler. If natural gas is available on site, it may be used as the reburning fuel, depending on the price of gas with respect to other fuels such as coal and oil. Compared to natural gas reburning (NGR), coal reburning requires a relatively longer residence time through the reburn zone and a larger upper furnace to achieve adequate burnout. Further, coal reburning requires addition of dynamic pulverizers to produce reburning fuel grade coal. Micronized coal (i.e., coal pulverized to a very high fineness) may be used as a reburning fuel on some boilers that may not have enough volume for normal coal reburning. However, micronized coal reburning requires specialized coal processing equipment, which increases its cost over gas or conventional coal reburning. In addition, for any coal reburning system it is necessary to use recirculated flue gas as the reburning fuel carrier.

The first application of reburning technology to a wet-bottom, wall-fired unit was to the 300 MW_e Ladyzhin plant in Ukraine. This application demonstrated that 50 percent NO_x reduction was achievable with natural-gas-based reburning technology on wet-bottom, wall-fired boilers. In general, reburn technology has demonstrated greater than 50 percent NO_x reduction on several coal-fired boiler types such as cyclone-fired, dry-bottom wall-fired, and wet-bottom wall-fired.^{23, 24}

Table 3 presents the reburning applications at coal-fired utility boilers. As seen in this table, 16 utility boilers worldwide and 14 in the U.S. have either used, or will use, reburning as their secondary NO_x control technology. The NO_x reductions at these boilers either achieved or expected to be achieved range from 39 to 67 percent. The largest application of reburning is at Southern Company's 818 MW_e Shearer Unit 1, which utilizes coal reburning. This application started in 2001.²⁵ The largest application of NGR is at Scottish Power's ~600 MW_e Longannet Unit 2.²⁶ EPA is currently participating in a demonstration of a multifuel reburn system (gas, oil, and/or coal) on a 300 MW_e wet-bottom wall-fired boiler in Ukraine.

SNCR^{22, 27, 28}. SNCR is a postcombustion technology in which a reagent (ammonia or urea) is injected into the furnace above the combustion zone, where it reacts with NO_x to reduce it to N₂ and water. In general, SNCR reactions are effective in the range of 980 to 1150 °C. The high temperature necessary for the reaction to proceed requires that the reagent normally be injected into the boiler's upper furnace region, as shown in Figure 5. Although the actual reactions are more complex, the overall stoichiometric reactions for urea and ammonia SNCR are:



After being injected into hot flue gas, urea decomposes into ammonia, which participates in SNCR chemistry. In general, ammonia may reduce NO_x, oxidize to form NO_x, or remain unreacted and pass through the stack. This unreacted portion is referred to as ammonia slip. Inadequate flue gas temperature and/or reaction time for SNCR kinetics, and mixing of the reagent with flue gas can contribute to an increase in ammonia slip. Relatively high concentrations of ammonia slip can react with SO₂ and sulfur trioxide (SO₃) in the flue gas and form ammonium sulfates and bisulfates which, in turn, can cause plugging of the air preheater passages. Furthermore, ammonia slip can also reduce the marketability of flyash by making it odorous. For these reasons, ammonia slip is normally well controlled through proper specification, design, and operation of an SNCR system.

Although the dominant reactions in the SNCR process result in reduction of NO to nitrogen, a significant competing reaction is the oxidation of the SNCR reagent to form NO_x. This oxidation reaction becomes more significant as temperature is increased. Because of this competing oxidation reaction, there is not a one-to-one relationship between reagent injected and

NO_x reduced. It typically requires more urea or ammonia to reduce NO_x than is suggested by the stoichiometric equations above.

A common misunderstanding of the SNCR process is that the reagent must be injected into the flue gas where the gas is between 980 and 1150 °C. Because of this misconception, in the past it was believed that SNCR could not be used on cyclone- or wall-fired wet-bottom boilers. However, commercial SNCR systems on these boiler types exist today.²² In fact, most electric utility SNCR systems operate effectively with reagent injection where gas temperatures are above 1150 °C. In such cases, sufficiently high initial NO_x concentrations cause the reduction kinetics to still dominate over the oxidation kinetics. Also, the reactions normally occur downstream of the injection location, after some cooling of the flue gas. At the low end of the SNCR temperature range, below 980 °C, the SNCR kinetics becomes slow. Nevertheless, there are applications on fluidized bed combustors where sufficient mixing time is available at these temperatures for the SNCR reactions to reach completion, and result in high levels of NO_x reduction with low levels of ammonia slip.

Urea and ammonia reagents require different injection approaches. Urea reacts over a somewhat broader and slightly higher temperature range than ammonia (about 55-83 °C higher), making it somewhat more compatible with the temperatures found in most utility furnaces. Further, reagent droplets containing urea penetrate well into flue gas before complete vaporization. In general, this results in improved mixing of the reagent in large flue gas volumes compared to that possible with ammonia injection. Finally, safety associated handling of urea handling may be more acceptable than that associated with handling of ammonia. For these reasons, urea is the preferred reagent in current SNCR applications on utility boilers.

Boiler load changes can impact the performance of an SNCR application due to changes in two key parameters: temperature of flue gas at the furnace exit and gas residence time in the furnace. Two measures are usually included in the design of SNCR systems, namely: (1) a multi-level injection system, and (2) an ability to change the amount of reagent to be injected. It is not unusual for an SNCR system on a load-following boiler to have three injection zones, each with several injectors. Since each of these injection zones is switched on and off automatically by the plant's control system, this does not add complexity to plant operation.

SNCR has been applied in the U.S. on a wide variety of boilers firing a range of fuels. Table 4 shows SNCR applications on electric utility boilers in the U.S.²⁹ As boiler size increases, the capability to uniformly distribute a chemical reagent, urea or ammonia, throughout the furnace volume may diminish, and, therefore, may negatively impact NO_x removal efficiency. Data in Table 4 show that, while smaller boilers (e.g., Salem Harbor) may be able to achieve greater than 40 percent NO_x reduction, larger boilers (e.g., Cardinal) may be capable of achieving reductions of only 30 percent or less.

SCR^{22, 30}. SCR is a postcombustion NO_x reduction technology in which ammonia is added to the flue gas, which then passes through layers of a catalyst. The ammonia and NO_x react on the surface of the catalyst, forming N₂ and water. SCR reactions are generally effective in a temperature range of 350 to 400°C. In general, SCR is capable of providing high levels of NO_x

reduction, ranging from 80 to greater than 90 percent. The overall stoichiometric SCR reactions are:



In most utility boiler applications, the catalyst is installed in a separate reactor positioned downstream of the boiler economizer and immediately upstream of the air preheater (see Figure 6). Under low-load conditions, an economizer bypass is sometimes utilized to ensure proper flue gas temperature at the SCR reactor inlet. The installation shown in Figure 6 is called a “hot-side” and/or “high-dust” SCR installation. A “low-dust” application may be used at facilities with hot-side ESPs. In this case, the SCR reactor would be installed immediately downstream of the ESP and prior to the air preheater. An alternative is a “cold-side” or “tail-end” SCR installation in which the SCR reactor is located after the FGD system. This installation requires reheating of flue gas with auxiliary fuel or other means prior to entry into the SCR reactor. Because of cost considerations, the majority of SCR installations on utility units are of the “high-dust” type.

An ammonia injection grid is located upstream of a titania-vanadia ($\text{TiO}_2\text{-V}_2\text{O}_5$) catalyst. Flue gas with ammonia passes through the catalyst, which may be of the ceramic honeycomb or coated parallel metal plates type. The catalyst provides the active sites where the ammonia and NO_x reduction reactions take place. Because of the temperature at which this reaction occurs, the competing ammonia oxidation reaction is not significant. This results in two advantages over SNCR: (1) much lower outlet NO_x concentrations are possible, and (2) the reagent is more efficiently utilized. Since most of the NO_x is in the form of NO in boilers, the ratio of ammonia added to NO_x reduced is typically close to 1:1 [see Eq. (3)].

The local molar ratio of ammonia to NO_x in the flue gas has a great impact on SCR performance. This process parameter becomes more critical for SCR systems designed for high reduction efficiencies. If appropriate distribution of this parameter is not possible, then additional catalyst is needed to ensure adequate performance. Gas velocity and spatial temperature distribution at the catalyst face are somewhat less critical, but are still important. Achieving proper ammonia/ NO_x ratio throughout the flow field and proper gas flow and temperature distribution are addressed in the design stage through flow modeling and through optimization of the ammonia injection grid at SCR system start up and periodically thereafter.

Catalyst deactivation occurs as a result of impurities in the gas stream that can produce poisoning of the catalyst material or blinding deposits. However, for coal-fired boilers, catalysts have been developed that can tolerate coal impurities and provide reasonable catalyst lifetimes, typically, in the range of about 14,000-32,000 operating hours before replacing a portion -- about 25 or 35 percent -- of the total catalyst loading.²²

The cost of catalyst replacement has been addressed by developing catalyst management plans, which minimize the cost of catalyst replacement over the projected lifetime of the SCR system's operation. In such plans, the catalyst is usually installed in layers to permit periodic

replacement of portions of the total catalyst loading. In this manner, the activity of the catalyst is more fully utilized over the life of the installation. The time between catalyst layer replacements is measured in years. At the dry-bottom coal-fired U.S. boilers equipped with full SCR, the planned time between catalyst changes is typically about 24,000 operating hours and at one boiler it is 32,000 hours, or 3 or more years of operation on a typical unit.²² The catalyst replacement frequency for boilers that reinject fly ash may be on the order of 14,000 hours, or nearly 2 or more years of operation. SCR operators and catalyst manufacturers periodically monitor the activity of portions of the catalyst to ensure that the catalyst is maintaining the planned amount of activity. With this testing, it is possible to predict future catalyst replacement schedules.

As mentioned before, difficulties with arsenic poisoning of SCR catalyst on wet-bottom boilers that reinject their fly ash are well known. Most operators of these facilities add limestone to their coal as a slag fluxing agent and also have an accelerated catalyst management plan. In general, a high arsenic concentration in the flue gas in contact with the catalyst will increase catalyst replacement frequency and/or increase catalyst loading compared to low arsenic applications. For example, at Merrimack 2, a cyclone boiler with 100 percent fly ash reinjection, the expected time between replacement of layers is 14,000 operating hours. However, this is less than the typical time between replacement of catalyst layers for SCR systems on dry-bottom pulverized-coal boilers (~24,000 operating hours).^{22, 31, 32}

In the U.S., low-sulfur, high-calcium subbituminous coals from the Powder River Basin (PRB) are used at many power plants to comply with SO₂ regulations. Since these coals are unique to the U.S., until recently, there was no experience with SCR on facilities firing this coal. There is some concern that firing of such coals may lead to deposits on SCR catalysts and accelerated deactivation of these catalysts. According to one supplier, the rate of catalyst deactivation is expected to be within an acceptable range for commercial use.³³ Commercial experience with PRB coal-fired electric utility boilers that have recently commenced operation with SCR will shed more light on this issue.³⁴

Another issue that has recently surfaced is catalyst arsenic poisoning on dry-bottom boilers firing coals from western Pennsylvania and West Virginia. These coals do not have unusually high arsenic contents (although higher than for European coals). However, these coals sometimes have unusually low content of free calcium oxide (CaO) in the fly ash. CaO acts to scavenge gaseous forms of arsenic to form calcium arsenide. If free CaO is too low (below about 2.5 percent by weight of the fly ash), it is possible that arsenic will not be scavenged and will lead to poisoning of the catalyst. Note that arsenic oxide chemically bonds to the catalyst surface so that the catalyst cannot be cleaned. As a result, the catalyst is permanently poisoned. To address this issue, some facilities have accelerated their catalyst management plans, and others are adding small amounts of pulverized limestone to their coal.³⁵

SCR has been extensively used to control NO_x from hundreds of utility and industrial boilers in Japan and Germany, and several coal- and gas-fired utility boilers in the U.S. Table 5 shows a list of U.S. utility facilities where SCR is currently in operation, under construction, or under agreement for installation.²⁹ Many of these applications are designed to provide NO_x reductions of 80 percent or greater.²⁹ This table also indicates those facilities at which SCR was

in operation in 1998. Based on the data in Table 5, SCR has become a popular NO_x control technology in the U.S. in the last 3 years.

Recently, advances have been made in secondary control technologies aimed at providing large NO_x reductions, more efficient use of reagents, and eliminating any public concerns with the transport and handling of the ammonia reagent used in SCR applications. These advances are described below.

Advances

*Advanced Gas Reburning (AGR)*²². With AGR, a nitrogen compound (typically urea or ammonia) is added downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_x reduction to produce free radicals that enhance SNCR NO_x reduction. AGR systems can be designed in two ways: (1) non-synergistic, which is essentially the sequential application of NGR and SNCR [i.e., the nitrogen agent (urea or ammonia) is injected downstream of the burnout air]; and (2) synergistic, in which the nitrogen agent is injected either with or before the burnout air. To obtain maximum NO_x reduction and minimum ammonia slip in non-synergistic systems, the nitrogen compound must be injected so that it is available for reaction with the furnace gases within a temperature zone around 1000 °C. A synergistic AGR system was demonstrated on the 104 MW_e Greenidge Unit 6 in New York to reduce NO_x emissions by 68-76 percent. However, it could not reduce ammonia slip to less than 10 ppm.³⁵

*Fuel-Lean Gas Reburning (FLGR)*²². FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_x. The gas is normally injected into a lower temperature zone than that in NGR. Whereas NGR requires 15-20 percent of furnace heat input from gas and requires burnout air, the FLGR technology achieves NO_x control using less than 10 percent gas heat input and no burnout air. Lower NO_x reductions are achieved with FLGR when compared with NGR. FLGR has been demonstrated to reduce NO_x emissions by roughly 33-45 percent at full load, with less than 7 percent of the heat input attributed to the reburn fuel. Table 6 lists FLGR applications.³⁵

*Amine-Enhanced Fuel-Lean Gas Reburn (AEFLGR)*²². AEFLGR is similar to AGR, except that burnout air is not used, and the SNCR reagent and reburn fuel are injected to create local, fuel-rich NO_x reduction zones in an overall fuel-lean furnace. The fuel-rich zone exists in local eddies, as in FLGR, with the overall furnace in an oxidizing condition. However, the SNCR reagent participates with natural gas (or other hydrocarbon fuel) in a NO_x reduction reaction, which is believed to be different than the reaction that occurs when ammonia or urea is used in SNCR. In SNCR the NO_x reduction occurs in an oxidizing environment, while in AEFLGR the ammonia or urea is injected into the reducing zone. High reductions are possible because, with the local low oxygen environment, the AEFLGR NO_x reduction reaction does not have to compete as much with the Zeldovich thermal NO_x reaction that limits SNCR performance. Preliminary results at a demonstration plant show approximately 73 percent reduction at about 40 percent load, 60 percent reduction at 60 percent load, and 30-40 percent reduction at full load.

AEFLGR is in commercial operation at PSE&G's Mercer station units 1 & 2. PSE&G is also planning a commercial AEFLGR system at Hudson, unit 2. AEFLGR was also commercially demonstrated at Wisconsin Electric Power Company's Pleasant Prairie 1. Table 6 lists AEFLGR applications.³⁵

*Hybrid Selective Reduction (HSR)*²². HSR is a combination of SNCR and SCR that is designed to provide the performance of full SCR with significantly lower costs. In HSR, an SNCR system is used to achieve some NO_x reduction and to produce a controlled amount of ammonia slip that is used in a downstream in-duct SCR reactor for additional NO_x reduction. The HSR technology has lower capital costs than SCR, allows installation to be phased in, provides better reagent utilization than SNCR, and has very good ammonia slip control. A test done with this hybrid system showed 95 percent NO_x reduction with less than 5 ppm ammonia slip and 55 percent reagent utilization.

In-duct SCR. There has been one full-scale demonstration installation of In-duct SCR on a coal-fired unit at PSE&G's Mercer Generating Station. The approach entailed installing the catalyst in an expanded duct rather than a separate reactor and was selected because the site did not have the necessary room for a full SCR and the associated ductwork; utilizing a full SCR would have required substantial, costly modifications to the entire facility. At Mercer, the In-duct SCR handles 25 percent of the total flow from a 320 MW_e boiler and follows a commercially operating SNCR system that treats all of the boiler gases. This unit demonstrated between 85 and 90 percent NO_x reduction with under 10 ppm ammonia slip at the air heater inlet. At the outlet of the catalytic air heater, 90 percent reduction was achieved with no measurable ammonia slip.³⁶

To enhance the performance of In-duct SCR, some vendors offer catalyst-coated air heater baskets for Lungstrom type air heaters. In these situations, the plant's existing hot-end baskets are removed from the Lungstrom air preheater, and they are replaced with baskets that are coated with catalyst. These catalyst-coated air heater baskets may be used separately, or in addition to In-duct SCR. Testing at Mercer Generating Station and experience in Europe with this catalyst in coal-fired systems demonstrate that this approach is capable of providing some additional NO_x reduction and, more importantly, can be very effective in eliminating ammonia slip. For example, the catalytic air heater baskets installed at Mercer station provided sufficient ammonia slip control so that an additional 20 percent reduction was achieved while maintaining the ammonia slip limit.³⁶ However, catalytic air heater technology generally will not provide sufficient reduction of NO_x to be a stand-alone technology.³⁷

*Ammonia on Demand (AOD)*³⁸. In AOD, ammonia reagent for SCR application is produced from urea through on-site hydrolysis. In this conversion process, urea pellets are mixed with small amounts of deionized water. This mixture is then pumped to a pressure vessel (the hydrolyzer) where heat and pressure are applied and urea sublimates to ammonia and carbon dioxide (CO₂). Steam is then used to strip out the ammonia gas and the steam/ammonia mixture is then supplied to the SCR system. AOD eliminates any public concerns with transport and handling of ammonia and associated Occupational Safety & Health Administration (OSHA) requirements. However, the incorporation of AOD into an SCR installation would add a small

chemical manufacturing plant and associated complexities. To date it has only been demonstrated at a large 565 MW_e oil-fired utility boiler that slowly changes load.

SUMMARY

Recently, a number of regulatory actions have been taken in the U.S. focused on reducing NO_x emissions from stationary combustion sources, particularly electric utility boilers. As a result of these regulations, state-of-the-art NO_x control technologies have been applied to a large number of coal-fired U.S. utility boilers. This paper reviews these technologies and their applications.

In general, NO_x control technologies may be placed in two general categories: *primary control technologies* and *secondary control technologies*. Primary control technologies reduce the amount of NO_x produced in the primary combustion zone. In contrast, secondary control technologies reduce the NO_x present in the flue gas from the primary combustion zone.

The popular primary control technologies in use in the U.S. are LNB and OFA. These technologies utilize staged combustion techniques to reduce NO_x formation in the primary combustion zone. Primary control technologies have been widely implemented on U.S. coal-fired utility boilers to comply with the NO_x emissions reduction requirements of Phase I of the Title IV NO_x Program. Data reflect that primary control technologies have been applied on 177 boilers and have resulted in reductions ranging from 33 to 48 percent, on average, from 1990 emissions levels. In particular, applications of LNB resulted in reductions of greater than 40 percent, on average, from 1990 levels.

Advances in primary control technologies include LNB with multilevel OFA and ROFA systems. The former system has been able to provide relatively low NO_x emissions of 0.15 lb/10⁶ Btu at a subbituminous coal-fired boiler. The latter system has been used to achieve NO_x reductions in excess of 50 percent at a utility boiler.

The secondary NO_x control technologies being used on U.S. coal-fired utility boilers include reburning, SNCR, and SCR. Of these boilers, 14 have used, or will use, reburning as their secondary NO_x control technology. The NO_x reductions at these boilers, either achieved or expected to be achieved, range from 39 to 67 percent. Twenty-two U.S. coal-fired utility boilers either have used SNCR, or will use it in the future. NO_x reductions achieved, or projected, at these applications range from 20 to 62 percent. In the last 3 years, SCR has been the preferred secondary technology at numerous U.S. coal-fired utility boilers. Current data indicate that 79 boilers either use, or will use, SCR for NO_x control. Many of these applications are designed to provide reductions in excess of 80 percent.

Advances in secondary control technologies include AGR, FLGR, AEFLGR, HSR, Induct SCR, and AOD. FLGR is a variation of NGR, focused on reducing gas usage. AGR and AEFLGR are combinations of NGR and SNCR, focused on obtaining large NO_x reductions. AGR has been demonstrated on a 105 MW_e utility boiler to reduce NO_x emissions by 68-76 percent; however, it could not reduce ammonia slip to less than 10 ppm. FLGR has been applied

at five coal-fired U.S. boilers to achieve NO_x reductions ranging between 27 and ~40 percent. Also, four coal-fired U.S. boilers have used AEFLGR to achieve NO_x reductions ranging between 50 and 70 percent. HSR is a combination of SNCR and SCR that is designed to provide the performance of full SCR with significantly lower costs. A test with HSR showed 95 percent NO_x reduction with less than 5 ppm ammonia slip and 55 percent reagent utilization. In-duct SCR entails installing the catalyst in an expanded duct rather than a separate reactor. This may be an attractive option for plants with constrained footprints. An application of In-duct SCR, in conjunction with SNCR, has demonstrated between 85 and 90 percent NO_x reduction with under 10 ppm ammonia slip at the air heater inlet. In AOD, the ammonia reagent for SCR application is produced from urea through on-site hydrolysis. AOD eliminates any public concerns with transport and handling of ammonia and associated OSHA requirements. To date it has been demonstrated only at a large 565 MW_e oil-fired utility boiler that slowly changes load.

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The research described in this article has been reviewed by the U.S. Environmental Protection Agency and approved for publication. The contents of this article should not be construed to represent U.S. government policy nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Table 1. NO_x reduction regulations under Titles I and IV of the CAAA.

	Regulatory action	Affected regions	Compliance date	Control period	NO _x reductions
Title I	OTC ^a NO _x Budget Program	12 States & DC: CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VT, VA	Phase II: May 1, 1999 Phase III: May 1, 2003	ozone season ^d	246,000 tons ^e in 1999, 322,000 tons in 2003
	NO _x SIP ^b Call	22 States & DC: AL, CT, DE, GA, IL, IN, KY, MD, MA, MI, MO, NJ, NY, NC, OH, PA, RI, SC, TN, VA, WI, and WV	May 31, 2004	ozone season	1.1 million tons in 2007
	Section 126 Rule	12 States & DC: DE, IN, KY, MD, MI, NJ, NY, NC, OH, PA, VA, and WV	May 1, 2003	ozone season	510,000 tons in 2007
Title IV	Acid Rain Program	nationwide	Phase I: January 1, 1996 Phase II: January 1, 2000	annual	340,000 tons per year 2.06 million tons/yr
	NSPS ^c	nationwide	July 9, 1997	annual	25,800 tons/yr

^a OTC = Ozone Transport Commission.

^b SIP = State Implementation Plan.

^c NSPS = New Source Performance Standards.

^d Ozone season = time period May 1 through September 30.

^e Kg = tons * 907.18.

Table 2. Primary NO_x control technology applications on boilers affected under Phase I of Title IV NO_x Reduction Program.

Boiler type	Technology	Number of boilers	1998 average emission rate, lb/10 ⁶ Btu ^b	NO _x reduction from 1990 levels, percent
Dry-Bottom	LNB	66	0.45	44
Wall-Fired	LNB with OFA	21	0.47	48
	LNB	44	0.36	43
Tangential	SOFA ^a	23	0.37	33
	LNB with SOFA	23	0.36	45

^a Separated overfire air.

^b ng/J = lb/10⁶ Btu * 431.0017.

Table 3. Reburning applications on coal-fired utility boilers (demonstration systems not currently in operation shown in *italics*).

Boiler	Rating, MW _e	Furnace	Reburn fuel, heat input percent	FGR ^a	Baseline NO _x , lb/10 ⁶ Btu ^b or (ppm)	Reduction, percent
Chalk Point 1	350	Wall	Gas, c	No	0.80	c
Chalk Point 2	350	Wall	Gas, c	No	0.80	c
Edge Moor 4	160	Tangential	Gas, 23.5	No	0.31	39
Crane 1	200	Cyclone	Gas, 18	No	1.5	60
Crane 2	200	Cyclone	Gas, 18	No	1.5	60
Allen 1	330	Cyclone	Gas, c	No	1.20	65
Hatfield 2	600	Wall	Gas, c	No	0.60	c
Hennepin 1	71	Tangential	Gas, 18	Yes	0.75	67
Greenidge 6	104	Tangential	Gas, 15	No	0.62	52
Longannet 2, Scotland	600	Wall	Gas, ~20	Yes	(~320 ppm)	50
<i>Niles 1</i>	<i>108</i>	<i>Cyclone</i>	<i>Gas</i>	<i>No</i>	<i>(650 ppm)</i>	<i>53</i>
<i>Nelson Dewey 2</i>	<i>100</i>	<i>Cyclone</i>	<i>Coal, 30</i>	<i>Yes</i>	<i>0.75</i>	<i>56</i>
<i>Lakeside 7</i>	<i>33</i>	<i>Cyclone</i>	<i>Gas, 26</i>	<i>Yes</i>	<i>0.95</i>	<i>66</i>
Ladyzhin 6, Ukraine	300	Wall, wet	Gas, 12	Yes	0.82	~50
<i>Cherokee 3</i>	<i>158</i>	<i>Wall</i>	<i>Gas, 22</i>	<i>Yes</i>	<i>0.75</i>	<i>64</i>
Shearer 1	818	Tangential	Coal, c	Yes	c	c

^a FGR = flue gas recirculation.

^b ng/J = lb/10⁶ Btu * 431.0017.

^c Currently, data are not available.

Table 4. SNCR applications on U.S. coal-fired utility boilers, including commercial demonstrations, systems in operation, or systems under contract.^a

Plant	Rating, MW _e	Furnace	Baseline NO _x , lb/10 ⁶ Btu ^d	Reduction, percent	NH ₃ slip, ppm
Salem Harbor 1	85	Wall	0.42	30	<10
2	85	Wall	0.60	50	<10
3	150	Wall	0.43	30	<10
Somerset 8 ^b	112	Tangential	0.5-0.92	24-62	<5
Mercer 1	320	Wall, wet	1.6-1.8	25-33 ^e	<5
2	320	Wall, wet	1.6-1.8	25-33 ^e	f
Hudson 2	620	Wall	0.65	25 ^e	f
Edge Moor 3	84	Tangential	0.70	45	<5
Indian River 3	178	Wall	0.46	26	f
4	440	Turbo	0.44	34	f
Seward with catalyst ^c	150	Tangential	0.75 0.75	42 ~55	<2
Cromby 1	160	Wall	0.35	25	<10
B. L. England 1	130	Cyclone	1.31	31	<5
2	163	Cyclone	1.40	36	<5
Schiller 4	50	Wall	0.4-0.45	43-55	<10
5	50	Wall	0.4-0.45	43-55	<10
6	50	Wall	0.4-0.45	43-55	<10
Miami Fort 6	150	Tangential	0.55	35	f
Cardinal 2	620	Wall	0.57-0.75	30	<5
East Lake 3	123	Tangential	0.40	20-32.5	f
Sammis 2	185	Wall	0.45	25-30	f
Asheville 1	207	Wall	0.58	25 ^e	f

^a All SNCR applications use urea as the SNCR reagent.

^b Somerset controls to 0.25 lb/10⁶ Btu during the ozone season and to 0.35 the rest of the year.

^c Seward has added a layer of catalyst and operates at levels below 0.40 lb/10⁶ Btu.

^d ng/J = lb/10⁶ Btu * 431.0017.

^e These units are also being equipped with AEFLGR. Percent reduction shown here is that achieved with SNCR only.

^f Currently, data are not available.

Table 5. SCR applications on U.S. coal-fired utility boilers. The applications include systems in operation and systems that are planned. (Applications in *italics* were the only ones in operation in 1998.)

Boiler	Rating, MW _e	Furnace	New or Retrofit
Gorgas 10	700	Tangential	Retrofit
Widows Creek 7	575	Tangential	Retrofit
Widows Creek 8	550	Tangential	Retrofit
<i>Indiantown</i>	<i>330</i>	<i>Wall, dry</i>	<i>New</i>
<i>Stanton 2</i>	<i>460</i>	<i>Wall, dry</i>	<i>New</i>
Bowen 1	805	Tangential	Retrofit
Bowen 2	788	Tangential	Retrofit
Bowen 3	952	Tangential	Retrofit
Bowen 4	952	Tangential	Retrofit
Hammond 4	578	Wall, dry	Retrofit
Wansley 1	950	Tangential	Retrofit
Wansley 2	950	Tangential	Retrofit
Baldwin 1	560	Cyclone	Retrofit
Baldwin 2	560	Cyclone	Retrofit
Baldwin 3	635	Tangential	Retrofit
Coffeen 1	390	Cyclone	Retrofit
Coffeen 2	617	Cyclone	Retrofit
E.D. Edwards 3	365	Wall, dry	Retrofit
Gibson 2	668	Wall, dry	Retrofit
Merom 1	490	Op/Turbo	Retrofit
Merom 2	490	Op/Turbo	Retrofit
Michigan City 12	520.9	Cyclone	Retrofit
R.M. Shahfer 14	511	Cyclone	Retrofit
East Bend 2	669	Wall, dry	Retrofit
Paradise 1	704	Cyclone	Retrofit
Paradise 2	704	Cyclone	Retrofit
Paradise 3	1150	Cyclone	Retrofit
Brandon Shores 1	620	Wall, dry	Retrofit
Brandon Shores 2	685	Wall, dry	Retrofit
Morgantown 1	626	Tangential	Retrofit
Morgantown 2	626	Tangential	Retrofit
Wagner 3	359	Wall, dry	Retrofit
Hawthorn 5	540	Tangential	Retrofit
Iatan	725	Wall, dry	Retrofit
New Madrid 1	600	Cyclone	Retrofit
New Madrid 2	600	Cyclone	Retrofit
Sioux 1	549.8	Cyclone	Retrofit
Sioux 2	549.8	Cyclone	Retrofit
Thomas Hill 2	285	Cyclone	

(Continued)

Table 5. (Cont.)

Boiler	Rating, MW _e	Furnace	New or Retrofit
Roxboro 3A	745	Wall, dry	Retrofit
Merrimack 1	122	Cyclone	Retrofit
<i>Merrimack 2</i>	<i>330</i>	<i>Cyclone</i>	<i>Retrofit</i>
<i>Logan</i>	<i>218</i>	<i>Wall, dry</i>	<i>New</i>
<i>Carney's Point 1</i>	<i>187</i>	<i>Wall, dry</i>	<i>New</i>
2	<i>187</i>	<i>Wall, dry</i>	<i>New</i>
Somerset 1	690	Wall, dry	Retrofit
Eastlake 5	680	Wall, dry	Retrofit
J. M. Stuart 1	610	Wall, dry	Retrofit
J. M. Stuart 2	610	Wall, dry	Retrofit
J. M. Stuart 3	610	Wall, dry	Retrofit
J. M. Stuart 4	610	Wall, dry	Retrofit
Killen Station 2	612.5	Wall, dry	Retrofit
Miami Fort 7	557	Wall, dry	Retrofit
Miami Fort 8	557	Wall, dry	Retrofit
Zimmer 1	1300	Opposed	Retrofit
Beckjord 5	244	Tangential	Retrofit
Beckjord 6	460	Tangential	Retrofit
Bayshore 4	220	Wall, dry	Retrofit
Bruce Mansfield 1	913.8	Wall, dry	Retrofit
Bruce Mansfield 2	913.8	Wall, dry	Retrofit
Bruce Mansfield 3	913.8	Wall, dry	Retrofit
Homer City 1	660	Wall, dry	Retrofit
Homer City 2	660	Wall, dry	Retrofit
Homer City 3	692	Wall, dry	Retrofit
Montour 1	806	Tangential	Retrofit
Montour 2	819	Tangential	Retrofit
Allen 1	330	Cyclone	Retrofit
Allen 2	330	Cyclone	Retrofit
Allen 3	330	Cyclone	Retrofit
Bull Run 1	950	Tangential	Retrofit
Cumberland 1	1300	Wall, dry	Retrofit
Cumberland 2	1300	Wall, dry	Retrofit
Parish 5	734	Wall, dry	Retrofit
Parish 6	734	Wall, dry	Retrofit
<i>Birchwood</i>	<i>240</i>	<i>Tangential</i>	<i>New</i>
Chesterfield 6	694	Tangential	Retrofit
Harrison 1	684	Wall, dry	Retrofit
Harrison 2	684	Wall, dry	Retrofit
Harrison 3	684	Wall, dry	Retrofit

Table 6. FLGR and AEFLGR applications on U.S. coal-fired utility boilers. Demonstration systems not currently in operation shown in *italics*.

Boiler	Rating, MW _e	FLGR or AEFLGR	Furnace	Reburn fuel, heat input percent	NH ₃ slip, ppm	Initial NO _x , lb/10 ⁶ Btu ^c	Reduction, percent
Joliet	340	FLGR	Cyclone	Gas, 6	b	1.106	38
Elrama 1	112	FLGR	Roof	Gas, 5	b	0.59	30-35
Elrama 2	112	FLGR	Roof	Gas, 5	b	0.59	30-35
Elrama 3	112	FLGR	Roof	Gas, 5	b	0.59	30-35
Riverbend	140	FLGR	Tangential	Gas, ~5	b	0.45	~40
Mercer 1	320	AEFLGR	Wall	Gas, 6-7	< 5 ppm	1.5	50-70
Mercer 2	320	AEFLGR	Wall	Gas, 6-7	< 5 ppm	1.5	50-70
Hudson ^a	660	AEFLGR	Wall	Gas, b	<5 ppm	b	b
Asheville 1	207	AEFLGR	Wall	Gas, 5	b	b	50
<i>Pleasant Prairie</i>	<i>600</i>	<i>FLGR</i>	<i>Turbo</i>	<i>Gas, ~5</i>	<i>b</i>	<i>0.46</i>	<i>27</i>
		<i>AEFLGR</i>				<i>0.46</i>	<i>57</i>

^a Hudson is already equipped with an SNCR system.

^b Currently, data are not available.

^c ng/J = lb/10⁶ Btu * 431.0017.

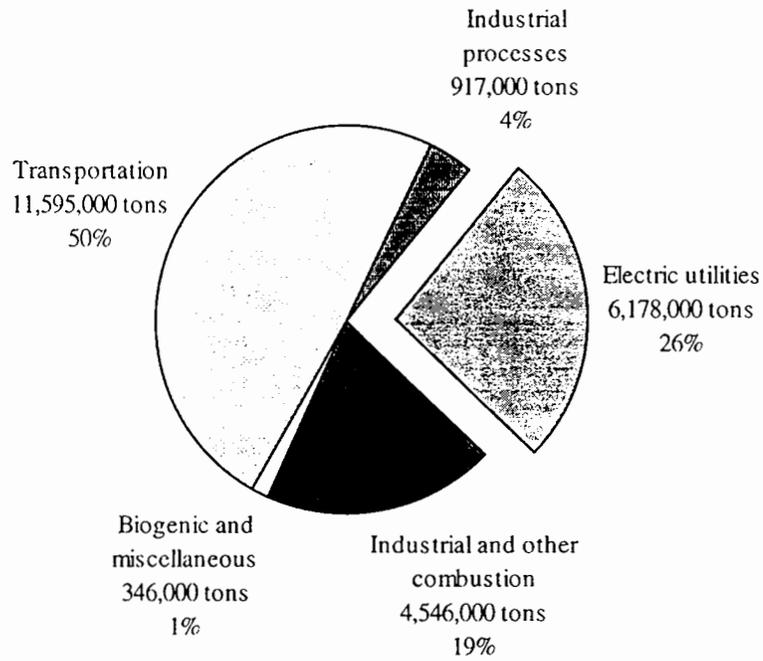


Figure 1. Sources of NO_x emissions in the U.S. in 1997. To convert emissions in tons to kg, multiply by 907.18.

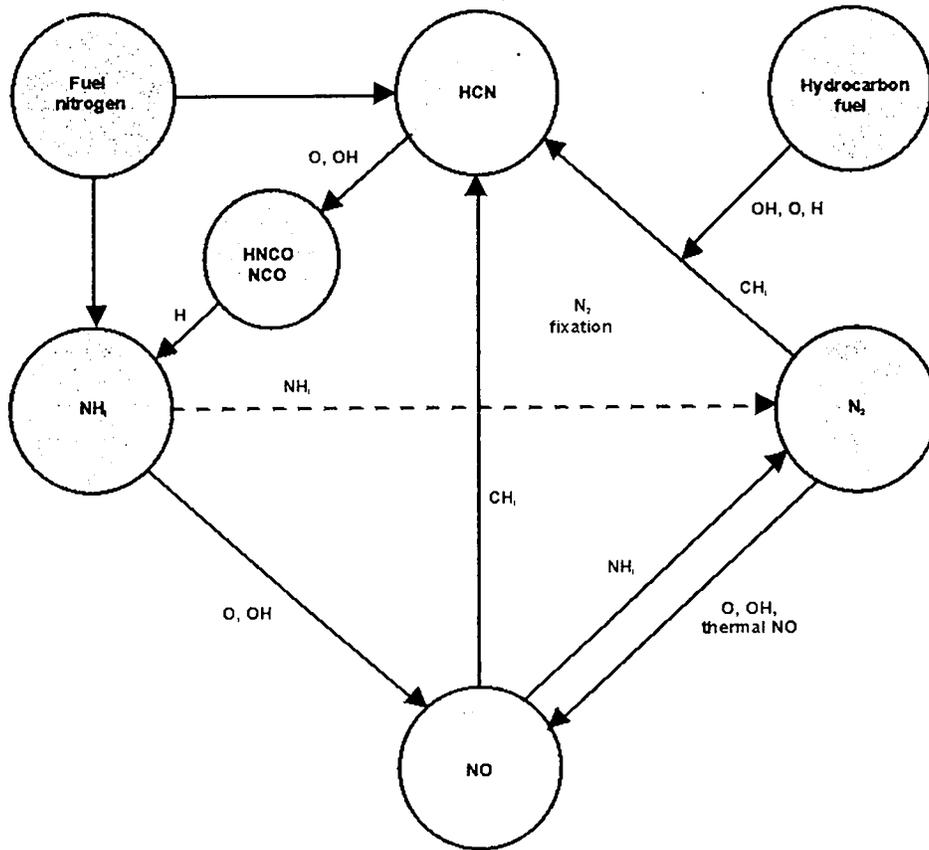


Figure 2. NO_x formation and destruction pathways.

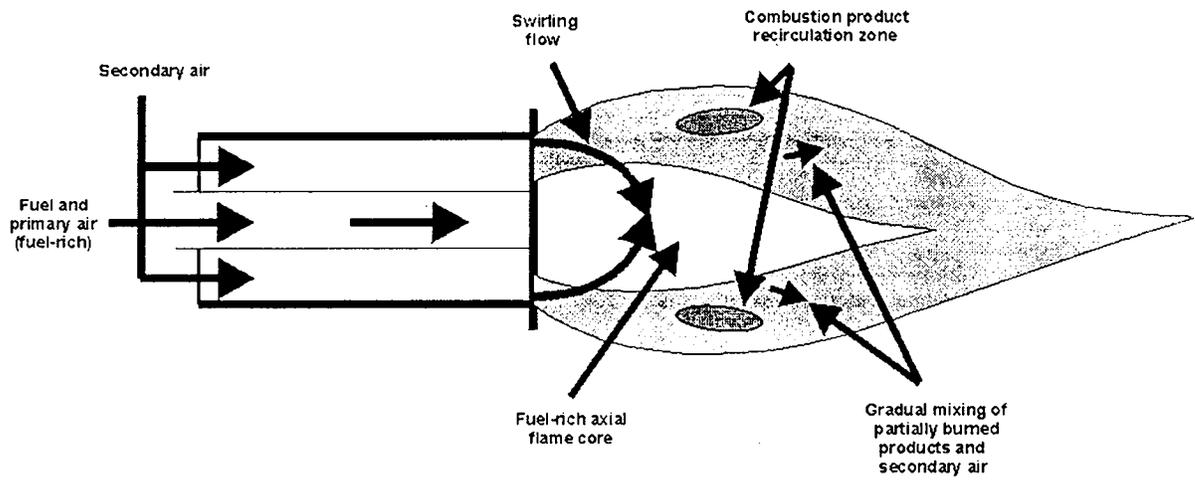


Figure 3. Schematic of a low NO_x burner.

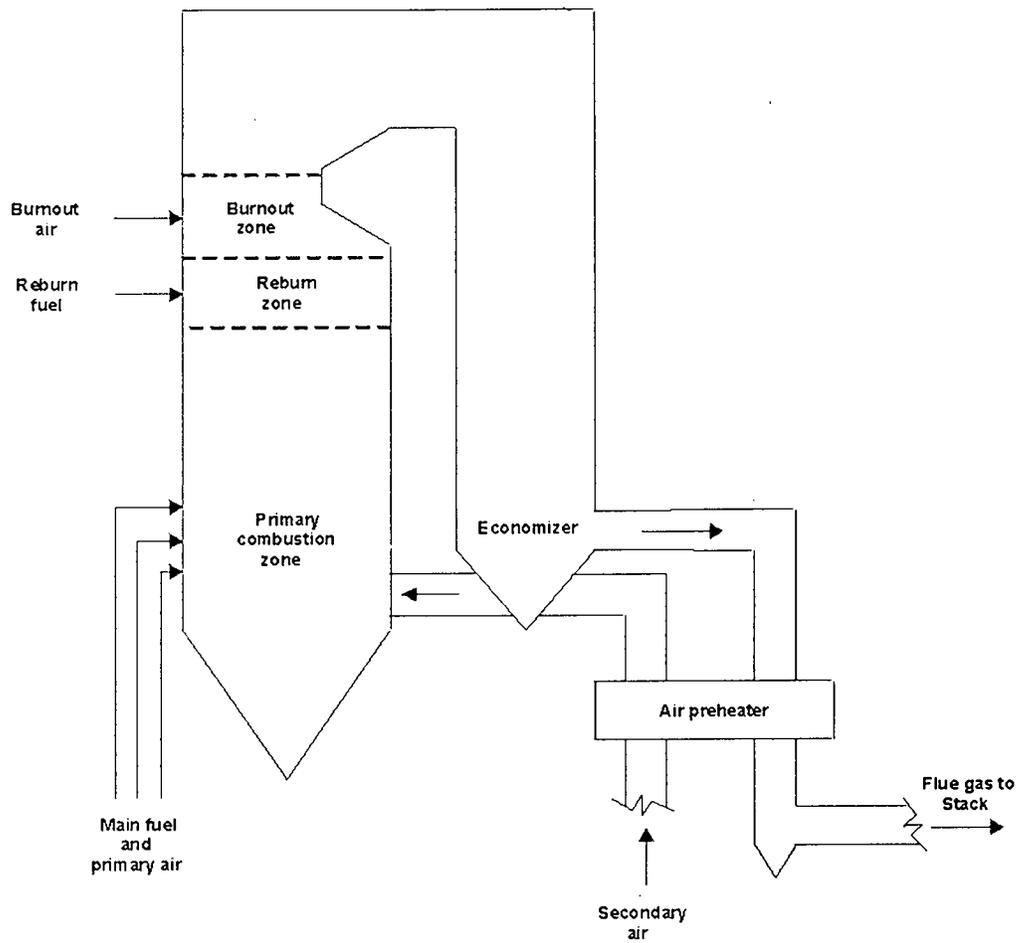


Figure 4. Schematic of a reburning application.

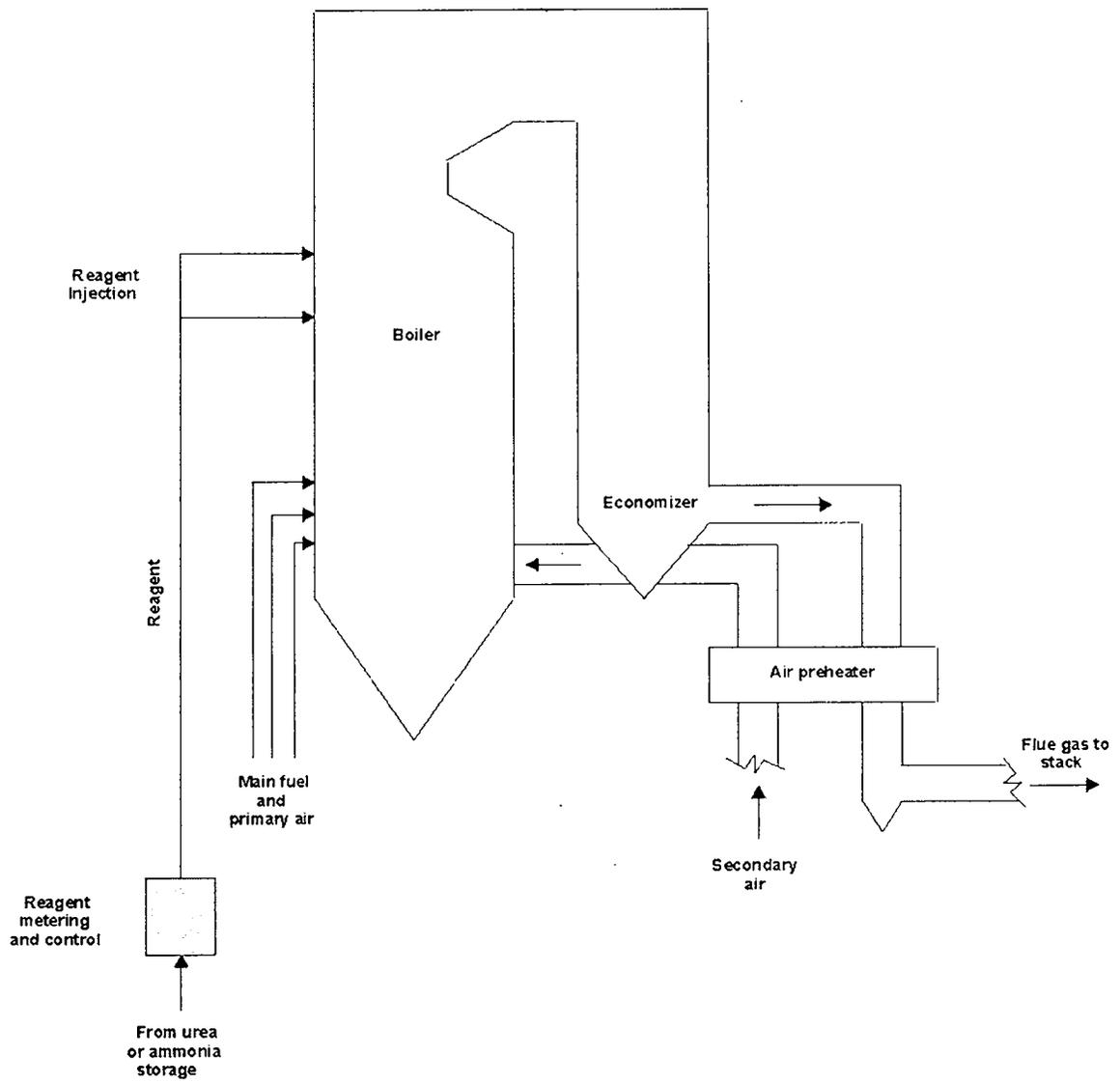


Figure 5. Schematic of an SNCR application.

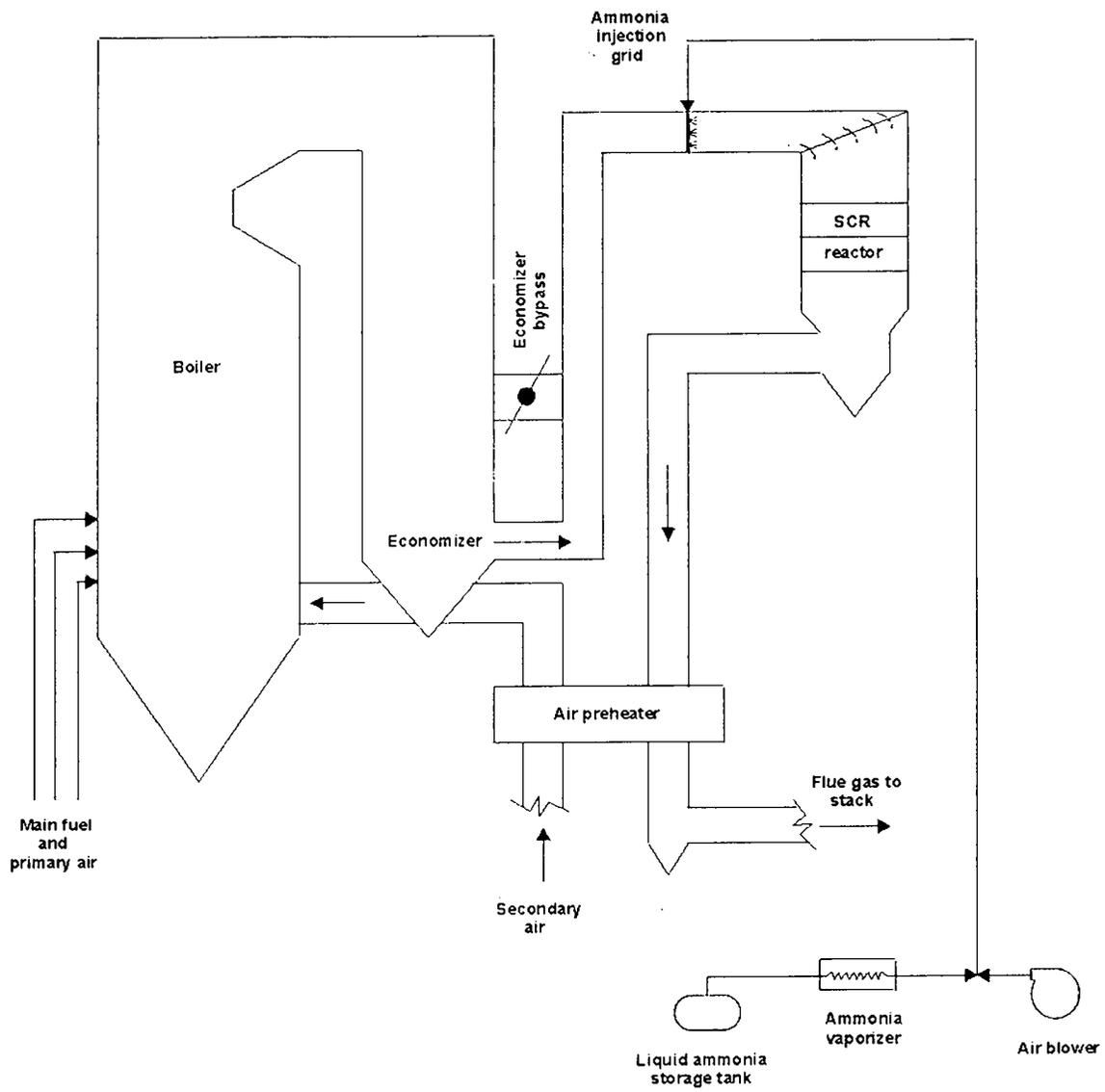


Figure 6. Schematic of an SCR application.

TECHNICAL REPORT DATA		
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16. ABSTRACT The paper discusses the control of nitrogen oxide (NOx) emissions from U. S. coal-fired electric utility boilers. (NOTE: In general, NOx control technologies are categorized as being either primary or secondary control technologies. Primary technologies reduce the amount of NCx produced in the primary combustion zone. Secondary technologies reduce the NOx present in the flue gas from the primary combustion zone.) Primary technologies in use in the U. S. are low NOx burner (LNB) and overfire air (CFA). They utilize staged combustion to reduce NOx formation in the primary combustion zone. Data reflect that primary technologies, applied on 177 boilers, have resulted in reductions of 33-48%, on average, from 1990 emissions levels. In particular, applications of LNB resulted in reductions of >40%, on average, from 1990 levels. Secondary technologies used on U. S. coal-fired utility boilers include reburning, selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Of these boilers, 14 have used, or will use, reburning as their NCx control technology. The NCx reductions achieved, or expected to be achieved, at these boilers range from 39 to 67%. Of the U. S. coal-fired utility boilers, 22 have used, or will use, SNCR. NOx reductions achieved, or projected, at these boilers range from 20 to 62%. Data indicate that 79 boilers will use SCR.		
17. KEY WORDS AND DOCUMENT ANALYSIS		
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