

Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers

Ravi K. Srivastava and Robert E. Hall

*U.S. Environmental Protection Agency, National Risk Management Research Laboratory,
Air Pollution Prevention and Control Division, Research Triangle Park, NC*

Sikander Khan and Kevin Culligan

*U.S. Environmental Protection Agency, Office of Air and Radiation, Clean Air Markets Division,
Washington, DC*

Bruce W. Lani

*U.S. Department of Energy, National Energy Technology Laboratory, Environmental Projects
Division, Pittsburgh, PA*

ABSTRACT

Recent regulations have required reductions in emissions of nitrogen oxides (NO_x) from electric utility boilers. To comply with these regulatory requirements, it is increasingly important to implement state-of-the-art NO_x control technologies on coal-fired utility boilers. This paper reviews NO_x control options for these boilers. It discusses the established commercial primary and secondary control technologies and examines what is being done to use them more effectively. Furthermore, the paper discusses recent developments in NO_x controls. The popular primary control technologies in use in the United States are low-NO_x burners and overfire air. Data reflect that average NO_x reductions for specific primary controls have ranged from 35% to 63% from 1995 emissions levels. The secondary NO_x control technologies applied on U.S. coal-fired utility boilers include reburning, selective noncatalytic reduction (SNCR), and selective catalytic reduction

(SCR). Thirty-six U.S. coal-fired utility boilers have installed SNCR, and reported NO_x reductions achieved at these applications ranged from 15% to 66%. Recently, SCR has been installed at >150 U.S. coal-fired utility boilers. Data on the performance of 20 SCR systems operating in the United States with low-NO_x emissions reflect that in 2003, these units achieved NO_x emission rates between 0.04 and 0.07 lb/10⁶ Btu.

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 and elsewhere. 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 2000 from each of the applicable source categories in the United States.² It is evident from these data that stationary combustion sources (electric utility, industrial, and other combustion sources) accounted for a significant portion, ~39%, of these emissions. Moreover, electric utilities accounted for ~22% of NO_x emissions and comprised the largest emitting source category within stationary sources. Plumes emitted from power plants can traverse regional distances and thereby contribute to environmental impacts over large geographic regions. Furthermore, the percentage of contribution from coal-fired power plants to state or local NO_x emissions inventories can be higher than that on a national basis. Recent

IMPLICATIONS

To comply with recent regulatory requirements, it is increasingly important to implement state-of-the-art NO_x control technologies on coal-fired utility boilers. This paper reviews NO_x control options for these boilers. In doing so, it not only discusses the established commercial primary and secondary control technologies, but also examines what is being done to use them more effectively. Further, the paper discusses recent developments in NO_x controls. The paper is expected to be a state-of-the-art reference on NO_x control technologies for regulators, utility industry personnel, and others stakeholders.

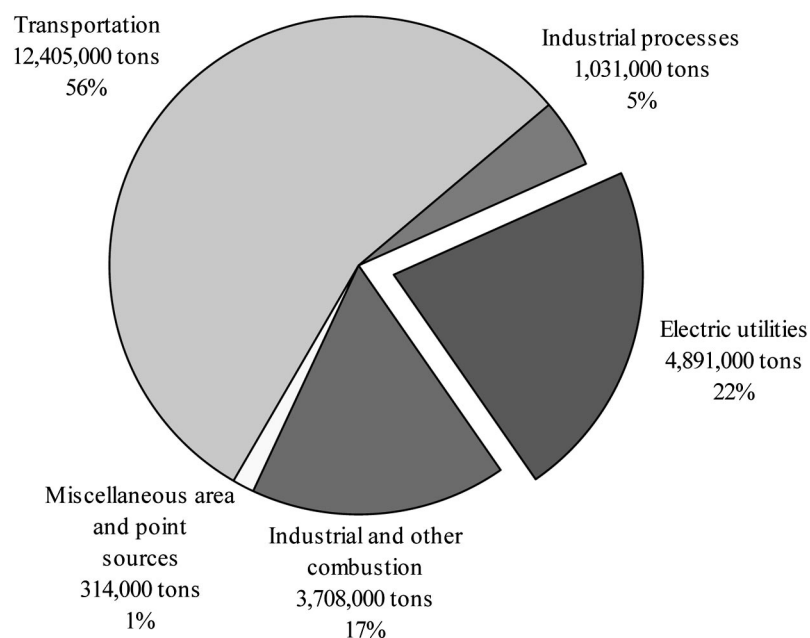


Figure 1. U.S. sources of NO_x emissions in 2001 (to convert emissions in t to kg, multiply by 907.18).

data reflect that electricity-generating sources are an important source of NO_x in many of the states.³ For example, in 2001, an estimated 754,446 t of NO_x were emitted in the state of Indiana, with 310,456 t, or ~41%, of these emissions attributed to electricity-generating sources. Based on the above considerations, the reduction of NO_x emissions from stationary sources, particularly electric utility sources, has been focused on recently to address the associated environmental concerns. Accordingly, a number of regulatory actions that are focused on reducing NO_x emissions from stationary combustion sources have recently been taken in the United States. These actions include the Acid Rain NO_x regulations,^{4,5} the Ozone Transport Commission NO_x Budget Program,⁶ revision of the New Source Performance Standards for NO_x emissions from utility sources,⁷ and the Ozone Transport rulemakings,⁸ and the Clean Air Interstate Rule.⁹

Control technology applications necessarily play a key role in the formulation and implementation of air pollution-reduction strategies. The current focus on the 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 United States but also examines those that can be considered to be relatively new or in an advanced stage of development.

NO_x Formation in Combustion

Before examining the control technologies, it is 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 the following three chemical mechanisms:¹⁰⁻¹² (1) "thermal" NO_x resulting from oxidation of molecular nitrogen in the combustion air,¹³ (2) "fuel" NO_x resulting from oxidation of chemically bound nitrogen in the fuel, and (3) "prompt" NO_x resulting from reaction between molecular nitrogen and hydrocarbon radicals.

Thermal NO_x can typically represent up to 20% of the NO_x emitted during pulverized coal combustion in utility boilers.¹⁴ Its rate of formation is directly proportional to the exponential of temperature and to the square root of the oxygen concentration.^{13,15} As combustion zone temperatures approach or

exceed 2800 °F, significant amounts of thermal NO_x are produced through dissociation and oxidation of molecular nitrogen from the combustion air.¹⁴ Formation of thermal NO_x can be controlled by reducing oxygen concentrations in the furnace, combustion zone temperatures, and residence time of flue gas in high-temperature areas of the boiler. For coal-fired boilers, practical methods include the following: (1) increasing the size of the combustion zone for a given thermal input and (2) reducing the rate of combustion and, consequently, peak flame temperatures with specially designed burners. The size of the combustion zone may be increased by using an overfire air (OFA) system with an existing boiler or by increasing the furnace dimensions in the burner area for a new boiler.

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.¹⁶ In pulverized coal combustion in a utility boiler, fuel NO_x may typically contribute up to 80% of the NO_x emissions.¹⁴ Formation of fuel NO_x depends on the nitrogen content in the fuel and the amount of oxygen available to react with the nitrogen during coal devolatilization in the early stages of combustion. Accordingly, fuel NO_x formation can be reduced by switching to, or cofiring with, fuel with lower nitrogen content and/or by limiting oxygen availability during the early stages of combustion. Methods for reducing oxygen availability include lowering the excess air level and/or controlling the rate at which the

fuel and air mix (i.e., staging the combustion process) such that an initial fuel-rich zone is followed by a burnout zone. The flue gas in the burnout zone has adequate oxygen concentration needed to complete the combustion process but has sufficiently low temperature to minimize thermal NO_x production. Prompt NO_x contributes a relatively minor fraction of total NO_x emissions for coal-fired boilers.¹²

NO_x CONTROL TECHNOLOGIES

In general, NO_x control technologies may be placed in two 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 away from the primary combustion zone. Some of the secondary control technologies actually use a second stage of combustion, such as reburning.

In addition to the primary and secondary control technologies applied exclusively for NO_x control, other technologies have also been developed to provide simultaneous reduction of more than one pollutant. These multipollutant technologies reduce NO_x along with other pollutants, including sulfur dioxide (SO_2), mercury (Hg), particulate matter (PM), and/or air toxics.

Primary Control Technologies

In the United States, popular primary control technologies are low- NO_x burners (LNB) and OFA. These technologies use staged combustion techniques to reduce NO_x formation in the primary combustion zone. LNB and OFA are described below. The optimum control system design may incorporate one or both of these, selected based on the capacity of the unit, fuels to be fired, and NO_x reduction requirements.

LNB. A LNB limits NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process.^{17,18} 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 both thermal and 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 the complete mixing of fuel and air 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. Conceptually, working of an

LNB with gradual mixing of combustion air to a fuel-rich flame core is shown schematically in Figure 2. The hardware used to influence the fuel/air mixing varies from manufacturer to manufacturer. LNBs can provide NO_x reductions of 50% or more from uncontrolled levels, with higher reductions possible for boilers with more facilitating design features.

Certain coal properties and boiler characteristics may have an impact on the effectiveness of a LNB. In general, coal rank, fineness, volatile matter content, and nitrogen content affect NO_x formation in pulverized coal combustion. Of these properties, coal rank and volatile matter content have a more significant impact on NO_x formation compared with typical variations in the nitrogen content and pulverized coal fineness. However, boilers equipped with pulverizers to provide a finer coal grind can achieve greater NO_x reductions with LNBs. Generally, lower rank coals (e.g., subbituminous coals) are characterized by higher volatile matter contents. The firing of such coals results in greater volatile release in the near burner zone. NO_x formation is inhibited because of enhanced fuel nitrogen release in a locally fuel-rich environment available in a LNB, thereby leading to greater conversion of fuel nitrogen to N_2 , and reduced fuel nitrogen retention in the char, which limits the NO_x formed, because the char is oxidized in a fuel-lean region away from the burner.¹⁹ In addition to coal properties, boiler characteristics, such as furnace size and volumetric and planar heat-release rates, affect the flue gas temperature and residence time in the combustion zone and thereby impact the LNB effectiveness.

Longer LNB flames require deeper furnaces to avoid flame impingement on the furnace walls facing the burners. In a retrofit situation, this may require LNB adjustments, affecting the NO_x reduction capability of the system in some cases. In certain situations, LNB retrofits may result in changed heat transfer patterns within the furnace, increased corrosion of the furnace walls, and increased furnace fouling.

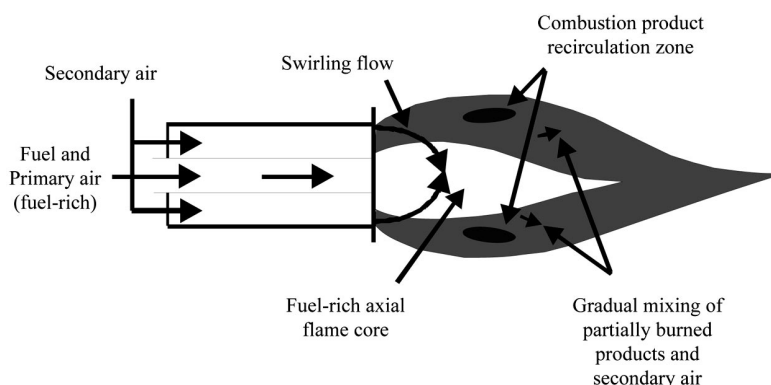


Figure 2. Schematic of a low- NO_x burner.

Unburned carbon (UBC) levels typically increase when a boiler is converted with a low-NO_x firing system. In general, the extent of this increase depends on coal properties, design of burners and air registers, size of the furnace, firing configuration of the burners, and excess air level. An increase in UBC level affects boiler efficiency. For example, combustion modifications on an eight corner tangential-fired unit resulted in a 2% increase in UBC, which corresponds to a 0.08% efficiency loss.²⁰ Also, increase in UBC levels in fly ash can make it unsuitable for cement replacement in ready-mix concrete and can thereby affect the salability of fly ash. ASTM C618 specification limits UBC content in fly ash to 6%, largely because higher levels of UBC can cause discoloration, poor air entrainment, and segregation of mix components in the ready mix.²¹ Counter design measures undertaken to improve UBC levels may be at the cost of NO_x reduction effectiveness. The most significant impacts on UBC have been observed on smaller (cooler) boilers, where baseline UBC levels were high (>10%). In such boilers, LNB retrofits can increase UBC by 2–5% points. In some cases, however, the UBC levels did not change after the retrofit, and it was possible to maintain these levels at <0.5% in Powder River Basin (PRB) coal-fired boilers, and below ~3–3.5% in the larger bituminous coal-fired units.²²

OFA. OFA, also referred to as air staging, is a combustion control technology in which a fraction, 5–20%, of the total combustion air is diverted from the burners and injected through ports located downstream of the top burner level.^{17,18} OFA is 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 on wall-fired boilers may increase the reductions by an additional 10–25%.

OFA is an inherent part of all of the primary control technology applications on tangentially fired boilers. These applications use OFA in three different configurations: close-coupled to the burner, separated from the burner, or both. Reductions with OFA range from 20% to >60% depending on the initial NO_x levels of a boiler, fuel combustion equipment design, and fuel type.²³ However, while reducing (substoichiometric) conditions result in significant NO_x reduction, increased levels of UBC and CO can occur. The extent of these increases is dependent on the design of the OFA system and fuel properties. Waterwall wastage can also occur with the extent dependent on factors such as degree of staging, unit aerodynamics, heat release rates, coal composition (high versus low sulfur), UBC, and tube temperature. These impacts can be minimized by an appropriately designed OFA system.²⁴ Recent experience reflects that the application of OFA on tangentially fired boilers can provide NO_x reductions in excess of 50%, with moderate (25–35% from baseline) increases in UBC levels and CO emissions of <50 ppm (corrected to 3% O₂).²³

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 the Title IV NO_x Program. Table 1 provides a summary of primary control applications through 2003.²⁵ These data reflect that primary control technologies have resulted in average reductions for specific technologies ranging from 35% to 63%, from 1995 emissions levels. In particular, applications of LNB resulted in reductions of >35%, on average, from 1995 levels.

Enhancements in Primary Control Technologies

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

Table 1. NO_x reduction performance of primary control technology applications on coal-fired boilers.

Boiler Type ^a	Coal Type	Primary Control Technology	1995 Average Baseline NO _x Emission (lb/10 ⁶ Btu)	2003 Average Controlled NO _x Emission (lb/10 ⁶ Btu)	Average NO _x Reduction Efficiency (%)	Range of NO _x Reduction Efficiencies (%)	No. of Boilers
Wall-fired	Bituminous	LNB	0.71	0.41	39.2	8.6–70.1	62
Wall-fired	Bituminous	LNBO	0.81	0.35	53.3	32.7–71.9	16
Wall-fired	Subbituminous	LNB	0.59	0.28	45.5	19.4–80.3	16
Wall-fired	Subbituminous	LNBO	0.41	0.14	63.4	40.0–80.9	4
Tangential-fired	Bituminous	LNC1	0.62	0.39	35.0	17.2–65.4	26
Tangential-fired	Bituminous	LNC2	0.48	0.31	36.6	23.3–70.8	15
Tangential-fired	Bituminous	LNC3	0.56	0.25	54.9	38.1–72.2	19
Tangential-fired	Subbituminous	LNC1	0.38	0.21	45.4	11.3–74.4	18
Tangential-fired	Subbituminous	LNC2	0.43	0.23	45.6	33.9–65.4	3
Tangential-fired	Subbituminous	LNC3	0.35	0.14	60.5	48.2–77.2	23

Notes: LNB = low-NO_x burner; LNBO = LNB with OFA; LNC1 = LNB with close-coupled OFA; LNC2 = LNB with separated OFA; and LNC3 = LNB with both close-coupled and separated OFA. ^aAll boilers are dry-bottom type.

LNB with Multilevel OFA. A concentric firing system with multilevel OFA is now available for tangentially fired boilers. This combustion technology has achieved NO_x emissions <0.15 lb/10⁶ Btu, equating to >60% reduction, while firing PRB subbituminous coal,²⁶ which reflects the potential for achieving low-NO_x emissions with this technology. Note, however, that for other coals with lower fuel-volatile contents than PRB coals (e.g., eastern bituminous coals), relatively higher NO_x emissions may be expected with this technology. For impacts of coal properties on combustion staging, please refer to the LNB section above.

Rotating Opposed Fire Air. The rotating opposed fire air (ROFA) design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion.²⁷ The difference between ROFA and conventional OFA is that ROFA uses a booster fan to increase the velocity of air to promote better mixing 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 one U.S. and six Swedish boilers, firing a variety of fuels (coal, wood waste, municipal waste, and heavy residual oil).²⁸ On Swedish installations, NO_x reduction in the range of 45–60% has been obtained.²⁸ Based on changes in CO levels experienced with ROFA application at four plants, the impact of ROFA on the overall plant heat rate may vary from a small increase to an actual reduction.²⁹ These data show that the UBC and/or excess air levels at the economizer outlets of these plants either did not change or decreased. Reductions in these operating parameters improved boiler efficiency and reduced the draft fan duties, thereby more-than-compensating for any increase in the auxiliary power consumption due to the fan supplying high-velocity air to the OFA ports. With improvements in the UBC and excess air levels, the plant heat rate can be expected to improve. However, without such improvements, a small increase in the heat rate may occur because of the additional power consumption by the booster fan. Therefore, any impact of ROFA on the plant heat rate can be site specific.

Combustion Improvement Techniques. Other than the application of control technologies described above, improvements in combustion conditions are also being undertaken at power plants as additional cost-effective control measures.^{30,31} Imbalances in coal and airflow rates to burners pose a constraint to reducing NO_x emissions from some pulverized coal boilers. Such imbalances are being addressed by installing equipment to dynamically

monitor and control fuel flow^{32,33} and/or airflow to each burner level and, if present, OFA.³⁴ In addition, distributed control systems with state-of-the-art optimizing algorithms are being used to adjust boiler firing while maintaining the required NO_x emission level.^{35–37}

To comply with Title IV NO_x regulations, some cyclone boilers currently use OFA, but some of these boilers may want to further lower NO_x emissions to comply with additional emission reduction requirements (e.g., ozone transport rulemakings). Achieving lower NO_x through additional combustion staging on some units, however, may be impractical, because cyclone boilers operate near their slag-tapping limit. Additionally reducing the local stoichiometric air-fuel ratio may lead to slag taps freezing, especially on low-sulfur coal-fired units. Oxygen injection into cyclone boilers offers a possibility of not only decreasing NO_x but of also increasing barrel temperatures to prevent frozen slag.³⁸

Computational fluid dynamic modeling is increasingly being used at power plants to design and fine-tune control technology applications. Such modeling can help identify initial burner settings for desired NO_x reduction performance, determine the location(s) of OFA, optimize its application with regard to reducing NO_x, avoiding boiler wall corrosion, and provide insights into potential combustion staging strategies for uncommon boiler designs (e.g., a four-wall-fired unit).³⁹

Secondary Control Technologies

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 control technologies and/or combustion improvement techniques alone. These units may require secondary controls (with or without primary controls). In the United States, popular secondary control technologies are reburning, selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). These technologies are described below.

Reburning. In reburning up to 25% 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 ~90% 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 nitrogen-containing species. These species are ultimately reduced to N₂. Finally, completion air is added above the reburn zone to complete burnout of reburning fuel.^{40–43} The reburning process is shown schematically in Figure 3.

Furnace dimensions impact several key design parameters for reburning systems, including mixing of reburn fuel and flue gas, gas residence time within the reburn and burnout zones, and heat transfer in the burner zone and the upper furnace. Sufficient residence time is required to achieve adequate flue gas mixing, 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. This 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 the 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: (1) flame stability considerations in the primary burner zone and, if applicable, reburn zone; (2) the potential for unacceptable levels of carbon burnout (CO or fuel) that may result from the addition of relatively large amounts of reburn fuel needed to achieve the desired NO_x reduction; and (3) the potential for increased boiler tube corrosion within the reburn zone. In addition, the temperature at the point of burnout air addition can place a lower limit on the achievable NO_x because of reformation of thermal NO_x . In general, these considerations are site specific.

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

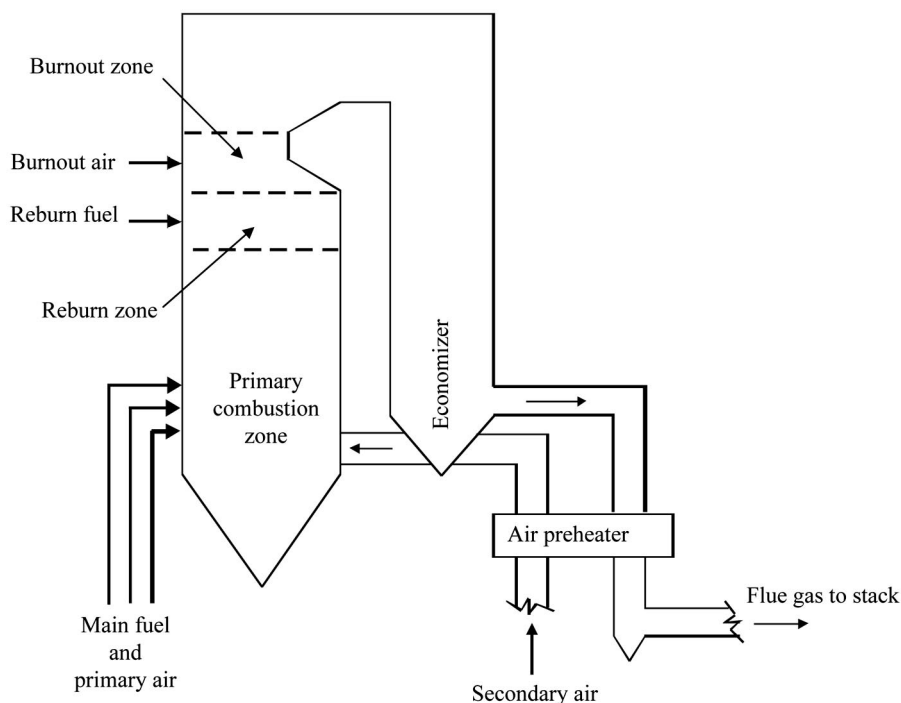


Figure 3. Schematic of a reburning application.

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 with natural gas reburning (NGR), coal reburning requires a relatively longer residence time through the reburn zone and a larger upper furnace to achieve adequate carbon burnout. Because carbon burnout can be a constraint limiting the amount of reburn fuel that can be injected, the reburning coal particle size distribution is a key parameter. In some applications, pulverizer improvements (e.g., addition of dynamic classifiers) or replacement with micronized coal (i.e., coal pulverized to a very high fineness) pulverizers may be necessary to achieve acceptable NO_x reduction and carbon burnout performance. Micronized coal may be used as a reburning fuel on boilers that may not have enough volume for normal coal reburning. However, micronized coal reburning requires specialized coal pulverizers, which increases its capital cost over gas or conventional coal reburning. In addition, it is necessary to use recirculated flue gas as the reburning fuel carrier for any coal reburning system.

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% NO_x reduction was achievable with NGR technology on wet-bottom, wall-fired boilers. In general, reburn technology has demonstrated >50% NO_x reduction on several coal-fired boiler types, such as cyclone-fired, dry-bottom wall-fired, and wet-bottom wall-fired.^{44,45}

More than 40 boilers worldwide have either used or will use reburning as their secondary NO_x control technology.⁴⁶ The NO_x reductions at these boilers either achieved or expected to be achieved range from 25 to 78%.

Table 2 reflects the status of reburning applications on U.S. coal-fired boilers.^{46,47} As seen in this table, many of the applications are not operational at this time, probably because of plant-specific economics associated with elevated natural gas prices and other factors. The data on currently operational reburning applications on coal-fired U.S. electric utility boilers shown in Table 2 reflect that in 2003, these units achieved NO_x emission rates between 0.277 and 0.385 lb/10⁶ Btu.

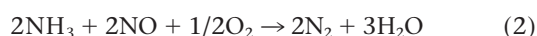
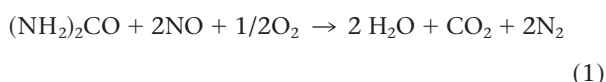
SNCR. SNCR is a postcombustion technology in which a reagent (ammonia [NH_3] or urea) is injected into

Table 2. Reburning applications on coal-fired U.S. boilers.

Technology Project Description	Plant	Unit	Unit Size (MW)	2003 NO _x Rate (lb/10 ⁶ Btu)	NO _x Reduction Efficiency (%)	Status and Comments
Gas reburning + sorbent injection	Hennepin	1	80	NA	67	Demo 1/91–1/93; not operating
Gas reburning + sorbent injection	Lakeside	7	40	NA	60	Demo 5/93–10/94; not operating
Gas reburning + low-NO _x burners	Cherokee	3	172	NA	64	Demo 11/92–1/95; decommissioned
Coal reburning	Nelson Dewey	2	110	NA	Lamar 52, PRB 55	Demo 12/91–12/92; decommissioned
Micronized coal reburning	Milliken	1	148	0.277	29	Demo 3/97–4/99; operating
Gas reburning	Greenidge	6	109	NA	50	Setup 1996; not operating
Gas reburning	Niles	1	108	NA	50	Installed and operated 1988; decommissioned
Gas reburning	C.P. Crane	1	200	NA	65	Startup 1998; not operating
Gas reburning	C.P. Crane	2	205	NA	68	Startup 1998; not operating
Gas reburning	Allen	1	330	NA	65	1998; not operating
Gas reburning	Edge Moor	4	177	NA	48	1999; not operating
Gas reburning	Chalk Point	1	364	NA	55	2000; not operating
Gas reburning	Chalk Point	2	364	NA	55	2000; not operating
Gas reburning	Hatfield	2	576	NA	68	1999; brief test; successful; not operating
Gas reburning	Hatfield	1	576	NA	NA	2002; installed; never tested
FLGR	Elrama	1–3	3x100	NA	25–30	Startup 1999; not operating
Amine-enhanced FLGR	Mercer	1–2	2x320	NA	25–30	Startup 1999; not operating
Amine-enhanced FLGR	Hudson	2	600	NA	25–30	Startup 2000; not operating
FLGR	Riverbend	7	140	NA	25–30	Startup 1998; decommissioned
FLGR	Joliet	6	340	NA	25–30	Startup 1997; decommissioned
Amine-enhanced FLGR	Asheville	1	207	NA	25–30	Startup 2000; not operating
FLGR	Pleasant Prairie	1	616	NA	25–30	Startup 1999; not operating
Coal reburning	R.D. Green	2	250	0.385	44	2002; operating
Coal reburning	R.D. Green	1	250	0.339	44	2004; operating
Gas reburning	Scherer	1	870	NA	40	2001; not operating
Gas reburning + SNCR	Somerset	8	115	0.277	57 (with reburning)	2003; operating

Note: NA = not available; FLGR = fuel-lean gas reburning.

the furnace above the combustion zone, where it reacts with NO_x to reduce it to N₂ and water.^{48,49} In general, SNCR reactions are effective in the range of 1800–2100 °F. The high temperature necessary for the reaction to proceed requires that the reagent normally be injected into the upper furnace region of the boiler, as shown in Figure 4. Although the actual reactions are more complex, the overall stoichiometric reactions for urea and NH₃ SNCR are:



In general, NH₃ may reduce NO_x, oxidize to form NO_x, or remain unreacted and pass through the stack. This unreacted portion is referred to as “NH₃ 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 NH₃ slip. Relatively high concentrations of NH₃ 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 (APH) passages. Furthermore, NH₃ slip can also reduce the marketability of fly ash by making it odorous. For these reasons, NH₃ 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 the reduction of NO_x to N₂, a significant competing reaction is the oxidation of the SNCR reagent to form NO_x. This oxidation reaction becomes more significant at relatively higher temperatures. 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 NH₃ 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 1800 and 2100 °F. Because of this misconception, in the past it was believed that SNCR could not be used on cyclone or wall-fired wet-bottom

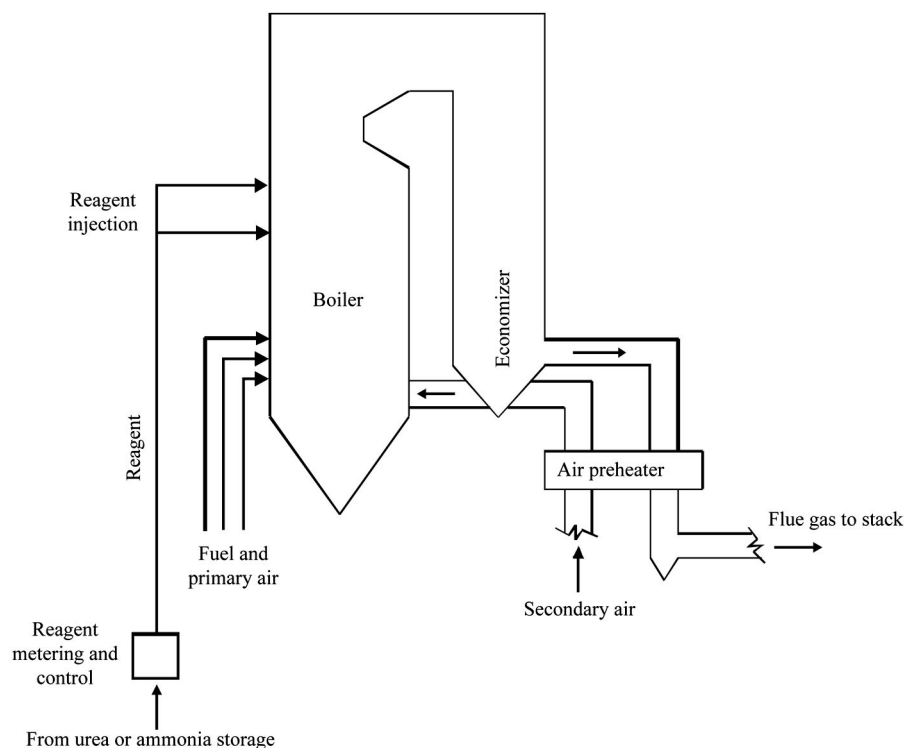


Figure 4. Schematic of a SNCR application.

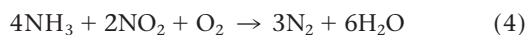
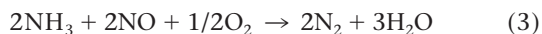
boilers. However, commercial SNCR systems on these boiler types exist today.⁴⁹ In fact, most electric utility SNCR systems operate effectively with reagent injection where gas temperatures are >2100 °F. In such cases, sufficiently high initial NO_x concentrations cause the reduction kinetics to still 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, <1800 °F, 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 NH₃ slip.

Urea reagent is injected as an aqueous solution. NH₃ can be injected as a gas (anhydrous NH₃) or as an aqueous solution. In general, mixing of flue gas with injected aqueous solution of NH₃ or urea is better than that with injected anhydrous NH₃. This is because aqueous droplets penetrate farther into flue gas than gaseous anhydrous NH₃. Furthermore, because a urea solution is less volatile than a NH₃ solution, its droplets generally penetrate farther into the flue gas. Because of somewhat poorer mixing in SNCR systems with NH₃ injection compared with those using urea, the former require more elaborate injection schemes in the boiler.⁵⁰

Boiler load changes can impact the performance of an SNCR application because of changes in two key parameters: temperature of flue gas at the furnace exit and gas residence time in the furnace.⁵¹ Therefore, the following two measures are usually included in the design of SNCR systems: (1) a multilevel injection system, and (2) an ability to change the amount of reagent to be injected.⁵² An SNCR system on a load-following boiler generally has two or three injection zones, each with several injectors. Because each of these injection zones is switched on and off automatically by the plant control system, this does not add complexity to the plant operation.⁴¹ SNCR effectiveness may depend on the size of the boiler. At larger boiler sizes, the capability to uniformly distribute a chemical reagent, urea or NH₃, throughout the furnace volume may diminish, which, therefore, may negatively impact NO_x removal efficiency.

SNCR has been applied in the United States on a wide variety of boilers firing a range of fuels.⁵³ A summary of available SNCR performance data is shown in Table 3. These data show that NO_x reduction efficiencies of these SNCR systems ranged from 15 to 66%. Data also show that whereas smaller boilers (e.g., 78 and 76 MW Salem Harbor units 1 and 2) may be able to achieve >60% NO_x reduction, larger boilers (e.g., 500 MW Cardinal Unit 1) may be capable of achieving reductions of only ~30%.

SCR. SCR is a postcombustion NO_x reduction technology in which NH₃ is added to the flue gas, which then passes through layers of a catalyst.^{41,54} The NH₃ and NO_x react on the surface of the catalyst, forming N₂ and water. SCR reactions are generally effective in a temperature range of 650–750 °F. In general, SCR is capable of providing high levels of NO_x reduction, ranging from 80% to >90%. The overall stoichiometric SCR reactions are:



Note that the NO_x reduction reactions above are the same as the ones occurring in SNCR at higher temperatures, but the SCR catalyst makes them effective at lower temperatures.

Table 3. SNCR performance for electric utility coal-fired units.

Plant Name ^a	Unit ^a	Unit Size (MW) ^a	2003 NO _x Rate (lb/10 ⁶ Btu) ^b	NO _x Reduction Efficiency (%) ^c
B L England	1	129	0.513	31.3
B L England	2	155	0.451	36
Cardinal	1	500	0.53	30
Clover Power Station	1	441	0.271	25
Clover Power Station	2	441	0.266	25
Cromby	1	144	0.306	25
Mercer Generating Station	2	321	0.755	35
Miami Fort	6	163	0.669	35
Rochester 7 - Russell Station	1	47	0.389	15 - 27.5
Rochester 7 - Russell Station	2	65	0.382	15 - 27.5
Rochester 7 - Russell Station	3	65	0.294	15 - 27.5
Rochester 7 - Russell Station	4	80	0.304	15 - 27.5
Salem Harbor	1	78	0.265	66
Salem Harbor	2	76	0.262	66
Salem Harbor	3	142	0.278	66
Schiller	4	47	0.317	30
Schiller	5	50	0.288	30
Schiller	6	48	0.274	30
Seward	15	136	0.384	35
Yorktown Power Station	2	167	0.335	25 - 30

^aThe 20 units shown were selected from the list of 36 utility coal-fired units equipped with SNCR in the EPA emissions database at <http://www.epa.gov/airmarkets/emissions/raw/index.html>. Because information on NO_x removal efficiency was not available for the remaining 16 units, these units are not shown in the table; ^bAll emissions data shown are from the EPA emissions database at <http://www.epa.gov/airmarkets/emissions/raw/index.html>; ^cNO_x reduction efficiencies were taken from the "Fuel Tech NO_x Out Process Experience List," available at <http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d480271c93>.

In most utility boiler applications, the catalyst is installed in a separate reactor positioned downstream of the boiler economizer and immediately upstream of the APH (see Figure 5). Under low-load conditions, an economizer bypass is sometimes used to ensure proper flue gas temperature at the SCR reactor inlet. The installation shown in Figure 5 is called a "high-dust," SCR installation. A "low-dust" application may be used at facilities with hot-side electrostatic precipitators (ESPs). In this case, the SCR reactor would be installed immediately downstream of the ESP and before the APH. An alternative is a "tail-end" SCR installation in which the SCR reactor is located after the flue gas desulfurization system. This installation requires reheating of flue gas with auxiliary fuel or other means before entry into the SCR reactor. Because of cost considerations, the majority of SCR installations on utility units are of the high-dust type.⁵⁵

An NH₃ injection grid is located upstream of the SCR catalyst. As the flue gas with NH₃ passes through the catalyst, which may be of the ceramic honeycomb or coated parallel metal plates construction, it provides the active sites (typically vanadia-titania [V₂O₅-TiO₂]) where the NH₃ and NO_x reduction reactions take place. At the

temperature where this reduction occurs, the competing NH₃ oxidation reaction is not significant. This results in two advantages over SNCR: much lower outlet NO_x concentrations are possible and NH₃ slip can be reduced. Because most of the NO_x is in the form of NO in coal-fired boilers, the ratio of NH₃ added to NO_x reduced is typically close to 1:1 (see eq 4).

The local molar ratio of NH₃ 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 both proper NH₃: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 NH₃ injection grid at SCR system start up and periodically thereafter.⁵⁶

Catalyst deactivation occurs as a result of impurities in the gas stream that can cause poisoning of the catalyst material or blinding deposits. Therefore, catalyst management plans are used at SCR installations to maintain the needed catalyst activity while minimizing costs.⁵⁷⁻⁵⁹ In such plans, the catalyst is usually installed in layers to permit the periodic replacement of portions of the total catalyst loading. In certain designs, an empty layer is provided to allow the addition of catalyst to this layer while maintaining the existing catalyst with reduced effectiveness in place over a longer period of time. Pressure drop across most SCR systems is 6-8 in. water gage (w.g.), and in some cases it may be ≥10 in. w.g.⁶⁰ SCR systems are equipped with soot blowers that are periodically cycled to clean the SCR catalyst and the APH.⁶¹

Comprehensive catalyst planning involves minimizing the costs associated with a catalyst in concert with optimizing the operation of the plant to produce power at minimum cost.⁵⁸ To achieve these objectives, tradeoffs are needed among catalyst loading, catalyst replacement frequency, pressure drop associated with catalyst loading, the level of NO_x reduction desired, and the level of NH₃

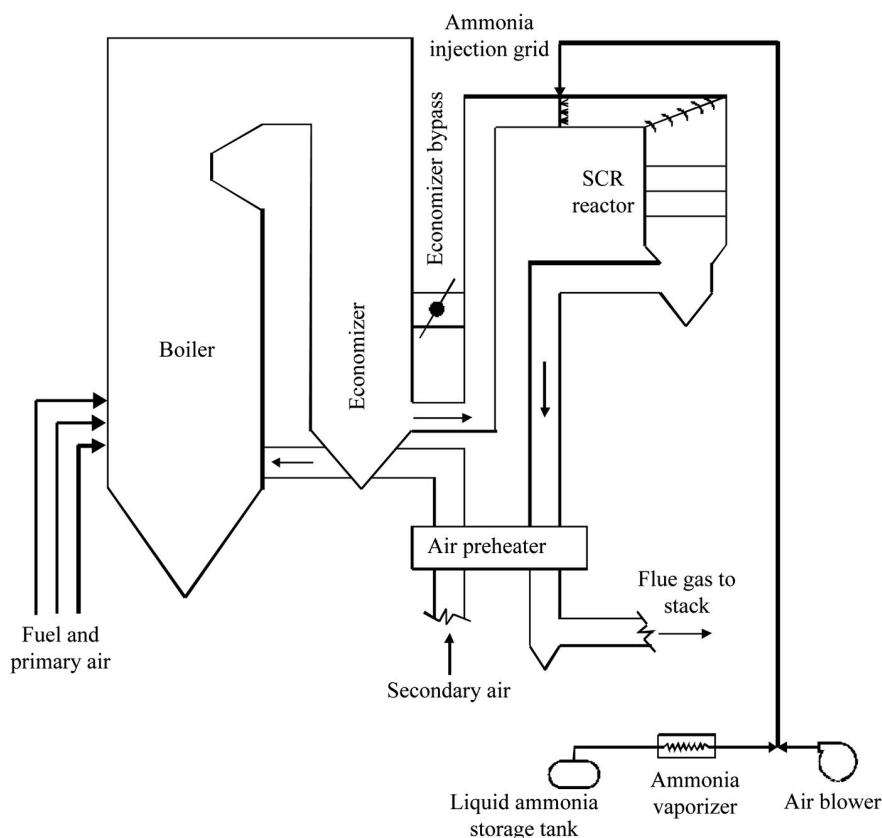


Figure 5. Schematic of a SCR application.

slip desired. For example, a plant may want to extend the time between catalyst replacements by increasing the catalyst loading beyond the initial design level. However, increased catalyst loading would add catalyst cost and increases parasitic load because of the pressure drop across the catalyst. Again, a plant may consider reducing more NO_x in an emissions-trading framework. However, increased NO_x reduction would come at a price of increased NH₃ consumption, increased frequency of catalyst replacement, increased catalyst loading, or increased pressure loss. Similarly, a plant may consider tolerating a higher NH₃ slip from its SCR system than originally envisioned. This can provide benefits of reduced catalyst loading, extended time periods between catalyst replacement events, or increased NO_x reduction. Finally, a catalyst management plan has to take into account a comparison of costs associated with a new catalyst and a corresponding regenerated catalyst.⁵⁹

European experience with SCR reflects that ~15% of the catalyst is replaced annually. Similarly, recent experience at a U.S. coal-fired boiler reflects a catalyst replacement frequency of one-half layer annually or ~16% of the catalyst replaced annually.⁶² On dry-bottom, coal-fired U.S. boilers equipped with full SCR, the planned time between catalyst changes on a typical unit is typically ~24,000 operating hours or ≥3 years of operation.^{41,60}

The catalyst replacement frequency for boilers that reinject fly ash may be on the order of 14,000 hr, or nearly ≥2 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.

Difficulties with arsenic poisoning of a 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 will increase catalyst replacement frequency and/or increase catalyst loading compared with low-arsenic applications. For example, at Merrimack 2, a cyclone boiler with 100% fly ash reinjection, the expected time between the replacement of layers is 14,000 operating hours, which is less

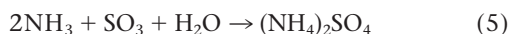
than the typical time between the replacement of catalyst layers for SCR systems on dry-bottom, pulverized-coal boilers (~24,000 operating hours).^{41,63,64}

In the United States, low-sulfur, high-calcium subbituminous PRB coals are used at many power plants to comply with SO₂ regulations. Because these coals are unique to the United States, there was no experience with SCR on facilities firing these coals until recently. There is some concern that firing of such coals may lead to deposits on SCR catalysts, which, in turn, may experience accelerated deactivation. According to one supplier, the rate of catalyst deactivation is expected to be within an acceptable range for commercial use.⁶⁵ The operating experience of the first year for a SCR system on a PRB coal-fired electric utility boiler has demonstrated the system to be capable of 93% NO_x removal with a maximum of 3 ppm NH₃ slip.⁶⁶

Another issue 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 that of European coals). However, these coals sometimes have unusually low contents 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 ~2.5% 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 and is permanently poisoned. To address this issue, some facilities have accelerated their catalyst management plans, and others are adding small amounts (1–2% of coal feed rate) of pulverized limestone to their coal.⁶⁰ At two boilers in the United States, a limestone addition to keep CaO level in fly ash at ~3–6% has been used to maintain the SCR catalyst deactivation rate at desired levels.⁶⁷

One of the concerns with high-dust SCR systems is the potential for ammonium bisulfate (NH_4HSO_4) formation downstream of the catalyst leading to fouling of APH baskets over time. Several units appear to have experienced this impact.^{60,68} APH fouling by NH_4HSO_4 is driven by the following: (1) the presence of sufficient SO_3 and NH_3 and favorable conditions (e.g., temperature) for the NH_4HSO_4 formation to occur; and (2) APH operational and design characteristics that are favorable for deposition of the formed NH_4HSO_4 . The SCR catalyst will enhance the concentration of SO_3 in the flue gas by oxidizing a portion of the SO_2 in the flue gas into SO_3 . Consequently, SO_3 will react with any NH_3 slip from the SCR reactor to form the ammonium sulfate ($(\text{NH}_4)_2\text{SO}_4$) and/or bisulfate as follows:



Normally, dry $(\text{NH}_4)_2\text{SO}_4$ does not create a fouling problem. However, NH_4HSO_4 combined with fly ash constituents forms a moist and sticky material that will tend to deposit on the APH in regions where the gas temperature falls below 450 °F.^{68,69} The potential for APH fouling can be alleviated by maintaining NH_3 slip levels between 2 and 5 ppm.⁷⁰ Other methods to reduce this potential include:⁶⁰ sootblower additions, modification of air heater hot-end surfaces to enhance cleaning, modification of air heater cold-end surfaces to minimize and isolate fouling (e.g., install enamel coated baskets), and more frequent water washings at higher flows and pressures. It is industry practice to install enamel-coated baskets on the cold end of the air heater to prevent APH fouling, to improve cleanability, and to protect the baskets from corrosion.⁶⁹

SCR has been extensively used to control NO_x from hundreds of utility and industrial boilers in Japan and Germany and in several U.S. coal-fired and gas-fired utility boilers. Deployment of SCR at U.S. coal-fired plants for new and retrofit applications initially took place in 1991 and 1993, respectively.⁷¹ Since then, >150 SCR systems

have been installed on utility coal-fired boilers.⁷² Many of these applications are designed to provide NO_x reductions of $\geq 80\%$, sometimes as much as 90% reduction, with <2 ppm NH_3 slip.⁷³

It is informative to examine the extent of NO_x reduction being achieved by SCR installations. The performance of 20 SCR systems operating in the United States with low- NO_x emissions is shown in Table 4. The data in this table reflect that in 2003 these units achieved NO_x emission rates between 0.04 and 0.07 lb/10⁶ Btu, likely with NO_x reduction efficiencies >85%.

Enhancements in Secondary Control Technologies

Recent enhancements in secondary control technologies have been aimed at providing large NO_x reductions, using reagents more efficiently, and addressing any public concerns with the transport and handling of the NH_3 reagent

Table 4. SCR performance for electric utility coal-fired units.

Plant Name ^a	Unit ^a	Unit Size (MW) ^a	NO _x Rate	NO _x Reduction Efficiency (%) ^c
			(lb/10 ⁶ Btu) Third Quarter 2003 ^b	
Allen	2	248	0.07	86
Bowen	1BLR	706	0.06	88
Bowen	2BLR	704	0.06	88
Bowen	3BLR	893	0.06	88
Bowen	4BLR	913	0.06	88
Chesapeake	3	156	0.07	86
Chesterfield	4	166	0.07	86
Cheswick	1	562	0.05	90
Dan E. Karn	2	260	0.05	90
East Bend Station	2	600	0.07	86
Gavin	2	1,300	0.07	86
Hammond	4	505	0.06	88
Keystone	1	850	0.04	92
Keystone	2	850	0.05	90
Miller	3	670	0.06	88
Miller	4	669	0.07	86
Montour	1	760	0.04	92
Montour	2	745	0.04	92
Mountaineer	1	1,300	0.06	88
Trimble County	1	435	0.07	86
Wansley	1	864	0.05	90
Wansley	2	868	0.05	90

^aThe units shown are those that achieved NO_x emission rates ≤ 0.07 lb/10⁶ Btu, as reflected in the EPA emissions database at <http://www.epa.gov/airmarkets/emissions/raw/index.html>; ^bThe NO_x rates reported are for SCR systems installed and operated only during the ozone season, as required under the Ozone Transport Commission Budget Program. Emissions data are from the EPA emissions database at <http://www.epa.gov/airmarkets/emissions/raw/index.html>; ^cIn the absence of reliable SCR inlet NO_x data, the SCR efficiencies are estimated using an inlet NO_x level of 0.5 lb/10⁶ Btu, assuming this level can be achieved with primary controls.

used in SCR applications. These enhancements are described below.

Advanced Gas Reburning. With advanced gas reburning (AGR), a nitrogen compound (typically urea or NH_3) 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.⁴¹ AGR systems can be designed in the following two ways: (1) nonsynergistic, which is essentially the sequential application of NGR and SNCR (i.e., the nitrogen agent [urea or NH_3] 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 NH_3 slip in nonsynergistic systems, the nitrogen compound must be injected so that it is available for reaction with the furnace gases within a temperature zone of $\sim 1000^\circ\text{C}$. 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%. However, it could not reduce NH_3 slip to <10 ppm.⁷⁴

Fuel-Lean Gas Reburning. Fuel-lean gas reburning (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 .⁴¹ The gas is normally injected into a lower temperature zone than that in NGR. Whereas NGR requires 15–20% of furnace heat input from gas and requires burnout air, the FLGR technology achieves NO_x control using $<10\%$ gas heat input and no burnout air. FLGR has been demonstrated to reduce NO_x emissions by ~ 33 –45% at full load, with $<7\%$ of the heat input attributed to the reburn fuel.⁷⁵ The technology has been installed at 12 U.S. boilers.⁷⁶

Amine-Enhanced Fuel-Lean Gas Reburn. Amine-enhanced fuel-lean gas reburn (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.⁴¹ 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 NH_3 or urea is used in SNCR. In SNCR, the NO_x reduction occurs in an oxidizing environment, whereas in AEFLGR, the NH_3 or urea is injected into a locally 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.

AEFLGR has been tested at Carolina Power and Light 198 MW Ashville Unit 1 to achieve NO_x emissions of ≤ 0.28 lb/10⁶ Btu at all loads. Average NH_3 slip in this testing was reported to be 3 ppm.⁷⁷ The technology has also been installed for commercial operation at Public Service Electric & Gas (PSE&G) Mercer Station Units 1 and 2. In optimization testing on Unit 2, AEFLGR application achieved 55–70% NO_x reductions using 7–10% natural gas heat input, with NH_3 slip maintained at ≤ 5 ppm.⁷⁸

Hybrid-Selective Reduction. In hybrid-selective reduction (HSR), a SNCR system is used to achieve some NO_x reduction and to produce a controlled amount of NH_3 slip that is used in a downstream in-duct SCR reactor for additional NO_x reduction.^{41,79} The HSR technology has lower capital costs than SCR, allows installation to be phased in, provides better reagent utilization than SNCR, and can provide very good NH_3 slip control. A test conducted using this hybrid system on a full-scale boiler showed 95% NO_x reduction with <5 ppm NH_3 slip and 55% reagent utilization.

In-Duct SCR. There has been one full-scale demonstration installation of in-duct SCR on a coal-fired unit at the PSE&G Mercer Generating Station. The approach entailed installing the catalyst in an expanded duct rather than a separate reactor, and it was selected because the site did not have the necessary room for a full SCR and the associated ductwork; using a full SCR would have required substantial, costly modifications to the facility. At Mercer, the in-duct SCR handles 25% 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% NO_x reduction with <10 ppm NH_3 slip at the air-heater inlet.⁸⁰ Another application on the natural gas/fuel oil-fired 530 MW Lake Hubbard Station Unit 2 boiler demonstrated 90% NO_x removal with a 10 ppm NH_3 slip.⁸¹

To enhance the performance of in-duct SCR, some vendors can offer catalyst-coated air-heater baskets for Lungstrom-type air heaters. In these situations, the existing hot-end baskets are removed from the Lungstrom APH and replaced with baskets coated with a catalyst. These catalyst-coated baskets may be used separately or in addition to in-duct SCR. Testing at Mercer Generating Station and experience in Europe demonstrate that this approach is capable of providing some additional NO_x reduction and, more importantly, can be very effective in controlling NH_3 slip. For example, the catalytic air-heater baskets installed at Mercer Station provided sufficient NH_3 slip control so that an additional 20% reduction was achieved while maintaining

the NH₃ slip limit.⁸⁰ However, catalytic air heater technology generally will not provide sufficient reduction of NO_x to be a stand-alone technology.⁸²

Urea-to-NH₃ Processes. Typically, anhydrous (pure liquefied) or aqueous (19–29% solution in water) NH₃ has been used as the reagent in SCR applications. However, public concerns with transport and handling of NH₃ and associated Occupational Safety and Health Administration requirements have led to the development of processes in which a NH₃ reagent is produced from urea at the SCR application site.⁸³ On the basis of equivalent NH₃ delivered, anhydrous NH₃ is less expensive than urea. However, urea is generally lower in cost than aqueous NH₃, especially more dilute solutions of aqueous NH₃. There are several alternative urea-to-NH₃ processes being offered commercially. Typically, these processes use on-site hydrolysis to produce NH₃ reagent from urea.

Emerging NO_x Control Technologies

In response to the environmental concerns of NO_x emissions and the corresponding regulations, the U.S. Department of Energy-National Energy Technology Laboratory (DOE-NETL) is carrying out a comprehensive research and development effort under its Innovations for Existing Plants Program. This effort focuses primarily on enhancing the efficiency and environmental performance of the existing fleet of fossil fuel-fired power systems by developing new technologies capable of controlling NO_x emissions to a level ≤ 0.15 lb/10⁶ Btu at a cost significantly lower than state-of-the-art technology, SCR. The research also addresses related issues, such as UBC and waterwall wastage. NO_x control technologies under development by DOE-NETL include layered NO_x control for cyclone boilers, oxygen-enhanced combustion, refinements for low-NO_x tangential firing systems, and preheat combustion. These are described below.

Layered NO_x Control for Cyclone Boilers. Cyclone burners create an intense flame that melts the ash to form slag. The high temperature generated by this burner results in higher uncontrolled NO_x emissions, typically >1.2 lb/10⁶ Btu. These units, which account for only 8% of the U.S. generating capacity, emit nearly 20% of the coal-fired NO_x emissions. Research has shown that the injection of NH₃ or urea into the high-temperature region of the boiler can lead to significant noncatalytic NO_x reductions. This concept, when applied to staged cyclone-fired furnaces, uses the nitrogen-containing additive to increase the NO_x reduction rate in the lower furnace. Field testing has confirmed that this technology can reduce NO_x emissions by 25–30% beyond OFA levels with <1 ppm NH₃ slip.⁸⁴ The inclusion of SNCR can be used for an

additional 35% NO_x reduction with <5 ppm NH₃ slip.⁸⁴ Commercial scale tests at the Conectiv 138 MW B.L. England Unit 1 and the AmerenUE 500 MW Sioux Unit 1 have demonstrated that NO_x emissions of 0.25 lb/10⁶ Btu are achievable.

Oxygen-Enhanced Combustion. This novel technology replaces a small fraction of the combustion air at the burner with oxygen.^{85,86} By generating a higher-flame temperature, nitrogen compounds from the coal are released in the lower sections of the boiler enabling air staging to be more effective in reducing NO_x. Experimental work using a burner fired at 24 million Btu/hr with high-volatile and medium-volatile bituminous coals demonstrated that NO_x concentrations as low as 0.11 lb/10⁶ Btu are achievable. Data from the experiments show that even when the baseline (without oxygen) NO_x emissions are very low, oxygen addition can reduce the NO_x even further and that the reductions are relatively independent of the initial NO_x concentration. In addition to the reduction in NO_x, benefits are achieved in the areas of reduced UBC and opacity, increased boiler efficiency, and reduced fan limits. The data suggest that there is little or no impact of oxygen purity resulting from current production methods on the effectiveness of the technology. In achieving NO_x reductions of 50%, the parasitic load requirements for this technology are estimated to be $<1\%$ of a plant output. Demonstrations at two utility boilers have proven the benefits of the technology. Preliminary economic analysis indicates that cost savings of 40–50% can be realized when compared with SCR.

Refinements for Low-NO_x Tangential-Firing Systems. A recently completed comprehensive study identified low-cost, efficient NO_x control refinements for pulverized coal tangential-fired boilers.⁸⁷ The testing evaluated a number of low-NO_x subsystems under realistic boiler combustion system conditions at a large-pilot scale of 50–60 million Btu/hr. Among the technologies evaluated were finer coal grinding, oxidative pyrolysis burners, windbox auxiliary air optimization, and various burner zone-firing arrangements in concert with strategic deployment of OFA. Other technologies, such as an advanced boiler control system, coal and airflow balancing, and a Carbon BurnOut combustor, were also evaluated.

Testing of the refinements with three test coals showed that both NO_x and combustion performance are a strong function of coal properties. From the standpoint of combustibles in the flue gas, the subbituminous coal showed the lowest combustibles (carbon in ash and CO), followed by the high-volatile bituminous and medium-volatile bituminous coals. Conversely, the more reactive

subbituminous coal showed the lowest NO_x (0.08 lb/10⁶ Btu) followed by the moderately reactive, high-volatile bituminous (0.12 lb/10⁶ Btu) and least-reactive, medium-volatile bituminous (0.17 lb/10⁶ Btu) coals. Many of the firing system components described in the study above can be retrofitted to an existing system, resulting in improved NO_x emissions without significantly impacting the carbon in fly ash levels. Nineteen commercial boilers firing subbituminous coal that use aspects of the technologies demonstrated in this study are achieving NO_x emissions ≤ 0.15 lb/10⁶ Btu.

Preheat Combustion System. The preheat combustion system, also known as Methane de-NO_x, uses gas-fired coal preheating to destroy NO_x precursors and prevent NO_x formation.⁸⁸ In this process, a concentrated pulverized coal stream enters a preheat chamber where flue gas from natural gas combustion (3–5% thermal input) is used to rapidly heat the coal up to ~1500 °F before coal combustion in the burner. This thermal pretreatment releases coal volatiles, including fuel-bound nitrogen compounds, into an oxygen-deficient atmosphere, which converts the nitrogen compounds into N₂ rather than NO_x. Testing with a 3-million Btu/hr burner has achieved NO_x levels <0.15 lb/10⁶ Btu without postcombustion flue-gas cleanup technology.

MULTIPOLLUTANT CONTROL TECHNOLOGIES

The technologies addressed up to this point are those applied exclusively for NO_x control. A number of multipollutant technologies that control NO_x along with other pollutants from coal-fired sources and are in more advanced stages of development commercialization are described below.

Electron Beam Process

The Electron Beam (E-Beam) Process provides simultaneous removal of NO_x and SO₂.^{89–91} The process equipment is located downstream of the plant PM control device (ESP or baghouse). The first component is an evaporative spray cooler, where flue gas is cooled down to 140–150 °F. Gaseous NH₃ is injected into the flue gas stream, either before or after the spray cooler. In the main process vessel, which follows the spray cooler, flue gas is irradiated by a beam of high-energy electrons, while water is added to counteract the temperature rise. The irradiation generates hydroxyl radicals and oxygen atoms, which oxidize NO_x and SO₂. These oxidized species mix with water present in the flue gas to form sulfuric and nitric acids, which are neutralized by NH₃.

The byproducts of the E-Beam process are ammonium sulfate and ammonium sulfate-nitrate. These solids

are collected in either an ESP or a baghouse, located downstream of the main process vessel, and can be used as fertilizer after processing into a granular form. The solids are small and sticky and may pose problems to the collection device. A combination of ESP and baghouse has been proposed as being more effective. In addition, the use of an inert material (e.g., diatomaceous earth) has been considered to make it easier to clean the bags in a baghouse.

The E-Beam process can achieve NO_x reductions as high as 90% and SO₂ reductions of ≥95%. NO_x removal primarily depends on the E-beam dosage. A dose of ~0.3–0.6 mrad is required to achieve 50% NO_x reduction, whereas 90% NO_x removal requires ≥2.7 mrad. Also, higher NO_x removals are obtained at higher flue-gas temperatures. In contrast, SO₂ removal requires smaller E-beam dosages and is promoted by lower gas temperatures. NO_x removal is also aided by higher flue-gas SO₂ concentrations, making the process better suited for high-sulfur applications.

A significant impact of incorporating the E-Beam process in a plant is its relatively high auxiliary power requirement. This requirement depends heavily on the NO_x reduction being sought. For low-NO_x reductions (~10%), the auxiliary power is generally limited to 2% of the plant output; however, for NO_x reductions >60%, it can reach 5%.

The E-Beam technology is in an early commercialization stage with a number of demonstration projects, but there are no operating commercial applications on coal. The coal/oil demonstrations include a 1986 pilot-scale testing of an 8-MW slipstream at the Indianapolis Power and Light Stout Station, a 1992 pilot-scale testing of 12,000 Nm³/hr slipstream at Nishi-Nagoya Plant in Japan, and full-scale testing at the 90 MW Chengdou Power Plant in China. The demonstrated reductions at these sites were between 15% and 60% for NO_x and 85% and 92% for SO₂. After a successful demonstration, the process was installed in the Nishi-Nagoya Unit 1, which burns high-sulfur residual oil.

ROFA-ROTAMIX

This technology involves use of the ROTAMIX system in conjunction with the ROFA system described earlier for NO_x control only.^{28,92} The ROTAMIX system is comprised of lances and other supporting equipment for injection of various chemicals or additional fuel (e.g., reburn gas). So far, urea or NH₃ has been used in the ROTAMIX for NO_x control and limestone and trona for SO₂ control. Future plans include injection of sorbents for the removal of heavy metals, including Hg.

ROFA and ROTAMIX systems together can provide greater NO_x reduction levels and simultaneous removal of SO₂. The actual performance in each application would be determined by key boiler features, including the height between the top burner level and furnace outlet, furnace

dimensions, and top furnace-level temperature. The first and second of these features determine whether adequate residence time is available to ensure the complete combustion of unburned fuel particles that increase because of the withdrawal of combustion air from the main burner region (resulting from operation of ROFA). The second and third features affect the penetration/mixing of injected air and chemicals into the furnace flue gases and reaction of the chemicals with the flue gas pollutants, respectively.

The major impacts of this technology on the plant performance include increased auxiliary power consumption (<1% of plant output) and introduction of new consumables (chemicals). Other minor impacts, which vary with site-specific factors, may include a small increase in UBC level and small reductions in steam temperatures and boiler/plant efficiencies.

ROFA-ROTAMIX technology has 10 operating commercial applications in Sweden and 16 in the United States.²⁸ The Carolina Power and Light 150 MW_e Cape Fear Unit 5 and 175 MW_e Cape Fear Unit 6 have achieved >70% NO_x reductions with the technology.²⁸ At present in the United States, sorbent injection tests have been conducted only at Cape Fear Unit 5.⁹³ These tests used limestone and trona to examine sustainable SO₂ and Hg reductions at low capital and operating costs. Stable SO₂ reductions of 69% were achieved with trona and 64% with limestone. Hg reductions of 89% were achieved with limestone and 67% with trona. Slagging in the superheater section was found to be a major operational concern in the sorbent injection tests.

SNOX

The SNOX technology involves removal of both NO_x and SO₂ in separate catalyst vessels.⁹⁴⁻⁹⁷ In addition, reductions in PM and trace metals are also achieved with this technology. The main components of the system are a high-efficiency baghouse, gas-to-gas heat exchanger, SCR catalyst vessel, SO₂ reactor vessel, and a glass-tube condenser, installed in that order. The baghouse removes PM to minimize cleaning frequency of the downstream catalysts. The heat exchanger transfers heat from the hotter gases exiting the SO₂ reactor to the gas stream entering the SCR vessel, thereby reducing the external energy use. NH₃ is injected upstream of the SCR vessel to remove NO_x, which is converted to nitrogen and water by the reactions taking place in the vessel.

The SO₂ reactor consists of a burner and a catalyst to oxidize SO₂ to SO₃. Flue gases exiting the SO₂ reactor pass through the above heat exchanger and then to the glass-tube condenser (wet gas sulfuric acid [H₂SO₄] condenser) that allows SO₃ to hydrolyze to concentrated H₂SO₄. Ambient air is used as the cooling medium in the condenser. The heated air is recirculated to the burner in the SO₂

reactor and to a heater installed to reheat flue gases discharging to the stack from the condenser. The SO₂ reactor also oxidizes any NH₃ slip from the SCR operation, eliminating concerns with the downstream equipment fouling by ammonium compounds and permitting SCR operation at higher-than-normal stoichiometry. These higher stoichiometries allow the use of smaller catalyst volumes and higher NO_x reduction efficiencies.

The NO_x and SO₂ reduction capabilities of the SNOX technology can exceed 90% each. Improved PM and trace element removals are also obtained through the use of the high-efficiency baghouse.

The major impacts of SNOX technology on plant performance include increased auxiliary power consumption and introduction of NH₃ as a consumable. The technology produces a salable H₂SO₄ byproduct.

The SNOX technology is in an early commercial development stage. Five demonstration projects have been completed to date, one in the United States and the other four in Europe and Japan. The U.S. demonstration was on a 35-MW_e equivalent slipstream of flue gas from the Ohio Edison Niles Unit 2, firing a 3.4% sulfur coal. At this plant, an average NO_x reduction of 94% and SO₂ reduction in excess of 95% were demonstrated. The first commercial application of the SNOX technology started operation in 1999 at the AGIP Petroli SAP Gela plant in Italy. The system is designed for 90% NO_x and 94% SO₂ removal at this petroleum coke-fired facility.

SO_x-NO_x-Rox-Box

The SO_x-NO_x-Rox-Box (SNRB) technology provides simultaneous removal of NO_x, SO₂, and PM in one unit—a high-temperature baghouse.^{91,98} NO_x removal is achieved by injecting NH₃ into the flue gas stream ahead of a SCR catalyst, which is placed on the baghouse high-temperature ceramic filters. SO₂ removal is achieved by injecting either a calcium-based or sodium-based sorbent (e.g., hydrated lime, calcium bicarbonate, or sodium bicarbonate) upstream of the baghouse. As its primary design function, the baghouse also removes PM.

SNRB has been demonstrated to provide up to 90% NO_x reduction and 80–90% SO₂ reduction. Increased auxiliary power consumption and introduction of NO_x and SO₂ control reagents are the major related impacts on plant performance.

Experience with the SNOX technology is restricted to a 5-MW_e slipstream demonstration at the Ohio Edison Burger Unit 5, a 156-MW unit burning high-sulfur bituminous coal. Additional demonstrations and commercial experience are required to confirm full-scale NO_x/SO₂ reduction effectiveness and operating life of the ceramic bag filters. A 3800-hr test was conducted in 1992 on three

filters at a testing facility (Fabric Filter Development Test Facility in Colorado) that showed no signs of failure.

Activated Coke Process

This process provides simultaneous removal of NO_x , SO_2 , and Hg and consists of the following three steps: (1) adsorption, (2) desorption, and (3) optional by-product recovery.^{99–101} In the adsorption step, flue gases pass through a bed of activated coke moving downwards in a two-stage adsorber at a constant flow rate. In the first stage, SO_2 is removed by adsorption into the activated coke, where it forms H_2SO_4 and is maintained on the coke inner surface at temperatures ranging from 212 to 392 °F. More than 90% of the PM is also removed in this first stage. In the adsorber second stage, activated coke acts as a catalyst in the decomposition of NO_x to nitrogen and water after the injection of NH_3 in the activated coke bed. This chemical reaction occurs in the 212–392 °F temperature range.

Over time in operation, the adsorption capacity of the activated coke bed declines. The spent bed material is then conveyed by a bucket elevator to the desorber vessel, where activated coke is regenerated in a reaction occurring between 572 and 932 °F. During this regeneration, contaminants adsorbed previously in activated coke decompose to nitrogen, SO_2 , and water. After cooling, the regenerated coke passes through a vibrating screen to remove fines, and then it is returned to the adsorber. The fines are conveyed to the boiler for combustion.

Hg is also removed by adsorption. Once adsorbed, Hg must be collected in a form suitable for disposal. In one method, a selenium filter is used, which absorbs Hg from flue gases and forms HgSe , a chemically stable compound. The selenium filter has an operating life of four to five years and, once spent, it must be disposed of in a hazardous waste facility. Other methods of Hg removal have been considered (e.g., H_2SO_4 plant off-gas, SO_2 -rich gas off-gas, etc.), but none have been tested.

Two of the possible byproducts for the activated coke process are elemental sulfur and H_2SO_4 . Additional equipment (e.g., a reduction column, Claus unit) must be incorporated to obtain these byproducts.

The demonstrated NO_x and SO_2 control efficiencies for this process have ranged from 60 to 80% and 90 to 98%, respectively. Higher NO_x reduction efficiencies can be obtained with lower flue-gas SO_2 concentrations. Also, based on pilot test results, 90–99% Hg removal is projected for this process.

The impacts of the activated coke process on the plant performance include increased auxiliary power consumption and use of activated coke and NH_3 . Activated coke is a carbonaceous material with large porous inner-surface area. One issue with the application of this process is the high cost of this reagent.

The activated coke process is commercially available in Europe and Japan. Several full-scale installations exist, including coal-fired power plants (up to 600 MW). These installations were designed for only NO_x and/or SO_2 removal. At present, no commercial installations with Hg control exist. Also, there are no demonstrations of this process in the United States thus far.

Electrocatalytic Oxidation

The electrocatalytic oxidation (ECO) process provides simultaneous removal of NO_x , SO_2 , and Hg.^{102–104} The main components of this process include a barrier discharge reactor (BDR), an absorber tower (AT), a wet ESP (WESP), and a coproduct processing/Hg removal (CPMR) system. The BDR is located downstream of the plant PM control device (ESP or baghouse). Its main function is to oxidize the flue gas pollutants into forms readily removable in the downstream equipment. Large amounts of NO_x and Hg present in the flue gas oxidize to NO_2 , nitric acid, and mercuric oxide, whereas a relatively small amount of SO_2 oxidizes to H_2SO_4 .

The BDR uses a dielectric discharge, which is formed by placing a dielectric insulating material between two discharge electrodes. High voltage is applied to these electrodes, causing the flue gas to breakdown and form gas phase radicals, such as hydroxyl and atomic oxygen, through the collision of electrons with water and oxygen molecules present in the flue gas stream. These radicals are responsible for the oxidation reactions taking place within the reactor. These reactions can be made to occur at relatively low gas temperatures (150–300 °F).

Flue gases from the BDR are treated in the AT, which also houses the WESP. The AT is a two-stage process with an absorption stage for absorbing the pollutants (mainly unoxidized SO_2 and NO_2) and a concentrating stage at the bottom. An aqueous NH_3 solution and certain vendor-proprietary chemical are used as scrubbing agents in the AT. These react with the pollutants to form ammonium nitrate and sulfate, which collect in the AT bottom. The WESP, located at the top of the AT, captures acid aerosols, fine PM, and oxidized Hg, which are all washed down into the tower bottom.

Liquid effluent from the bottom of the AT is treated in the CPMR system. This system includes a filter to remove ash and an activated carbon filter to remove Hg. The liquid effluent can be additionally processed to produce ammonium sulfate and nitrate fertilizer.

The reactor in the ECO process can be designed in a variety of configurations, including coaxial cylinders, cylindrical electrodes with plates, and parallel plate electrodes. For retrofit installations, the reactor components can also be installed in the last fields of an ESP if the remaining ESP fields can provide adequate PM removal.

The emission reduction capabilities of the ECO process can be as high as 90% for NO_x , 98–99% for SO_2 , and

95% for Hg. In addition, high removal rates (up to 95%) for fine particles are also achievable. The best efficiencies are achieved when the $\text{SO}_2:\text{NO}_x$ molar ratio is ≥ 3 .

A relatively high auxiliary power consumption requirement is one of the main impacts of the ECO process on the plant performance. The BDR, fans, and pumps are the major power users. The power for the BDR is largely determined by the amount of the required NO_x reduction. Other impacts of the ECO process include both the use of NH_3 and certain vendor-proprietary chemicals as scrubbing agents and the need for steam to provide heat for by-product crystallization.

The ECO process is in the demonstration stage of development. The experience to date includes laboratory testing and pilot-scale (2000 std ft^3/min of gas flow) testing conducted at the First Energy Burger Plant. Construction of a 50-MW commercial slipstream demonstration (110,000 scfm of gas flow) has been recently completed at the Burger Station (156 MW), and shakedown testing of the process has been initiated in the fall of 2004.

NOXSO

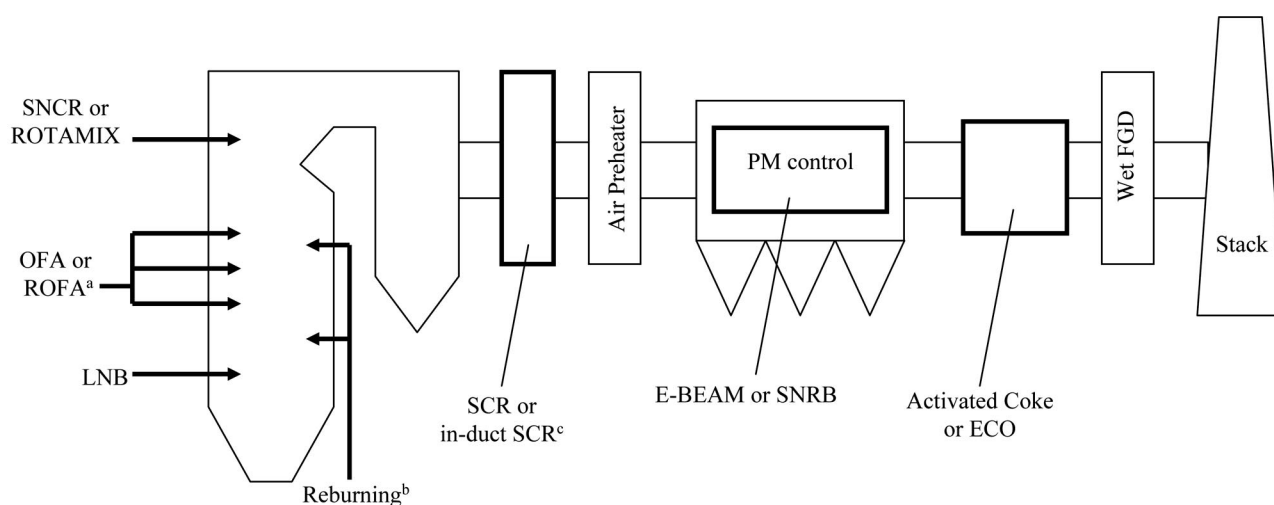
The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium-to-high sulfur coals.¹⁰⁵ In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; SO_2 and NO_x are adsorbed by the sorbent, which consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. Cleaned flue gas then passes through a baghouse to the stack.

The NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air to 1200 °F. The desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x . The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at a high temperature to produce an off-gas with high concentrations of SO_2 and hydrogen sulfide. This off-gas is processed to produce elemental sulfur, which can be additionally processed to produce liquid SO_2 , a higher-valued by-product.

The process is expected to achieve SO_2 reductions of 98% and NO_x reductions of 75–90%. Current experience with the process has been limited to proof-of-concept (<10 MW) evaluations at the Ohio Edison Toronto Station and at the combined heat and power plant located at the University of Denmark. FLS miljo, a licensee of the technology, was responsible for the installation in Denmark.

Copper-Oxide

The copper-oxide (CuO) process is a flue-gas treatment process that is capable of simultaneously removing SO_2 and reducing NO_x from flue gas of a conventional coal-fired boiler.¹⁰⁶ CuO takes advantage of the chemical absorption of SO_2 on 1/8-in. alumina spheres impregnated with copper to form copper sulfate and the subsequent ability of this sulfate to act as a selective reduction catalyst of NO_x in the presence of NH_3 . The process is uniformly effective for various coals and is independent of the sulfur, nitrogen, and ash content of the coal. Unlike wet scrubber processes, no waste is generated. The captured SO_2 can be reduced to elemental sulfur, a marketable by-product.



^a ROFA adds a booster fan to promote mixing

^b Advanced reburning adds nitrogen compound downstream of reburning

^c Hybrid selective reduction = SNCR + in-duct SCR

Figure 6. Locations of NO_x control processes relative to power plant hardware and other emission control equipment.

Table 5. A summary of NO_x control technologies.

Technology	NO _x Removal Efficiency (%) ^a	Potential Plant Impacts	Comments
LNB	Up to 50	Requires deeper furnaces May increase corrosion of furnace walls May increase furnace fouling	Greater reduction possible for boilers with more facilitating design features
OFA	Additional 10–25% beyond LNB	May reduce boiler efficiency (increased UBC) May affect fly ash quality	May be used in conjunction with LNB
LNB with multilevel OFA	>50% with PRB coal	Higher NO _x emissions expected for coals with lower fuel volatile content	—
ROFA	45–60	Uses booster fan	Offers improved distribution of combustion products and temperature variation across the furnace
Reburning	39–67	Flame stability May increase CO emissions Potential for increased boiler tube corrosion	Choice of reburning fuel affects plant design
SNCR	30–66	Efficiency higher for smaller boilers May need multiple injection zones	Choice of chemical affects plant design Effective operation even beyond 1150°C
SCR	80–90+	Catalyst deactivation requires implementation of catalyst management plans As poisoning on wet-bottom boilers requires CaCO ₃ addition and/or accelerated catalyst replacement	Good distribution of ammonia critical PRB coals may cause accelerated catalyst deactivation
AGR	68–76	Minimum ammonia slip of 10 ppm for synergistic design Nitrogen compound must be injected ~1000 °C for nonsynergistic design	Natural gas reburning/SNCR synergistic and nonsynergistic design options
FLGR	30–45	Careful injection and controlled mixing of natural gas required No burnout air required	Lower percent of heat input required from reburn fuel than for reburning
AEFLGR	55–73	Nitrogen compound injected into reducing zone	Design similar to AGR; NO _x removal efficiency is load dependent
HSR	Up to 95	Lower capital cost than standalone SCR Ammonia slip <5 ppm	Allows phased installation Improves reagent utilization
In-duct SCR	85–90	Allows SCR installation on space constrained units May supplement SNCR process	Catalytic air heater baskets add-ons available
Layered NO _x control for cyclone boilers	Additional 25–30% beyond OFA	Ammonia slip <1 ppm May be supplemented by SNCR for an additional 35% reduction (<5% ammonia slip)	Commercial scale tests conducted (138 MW)
Oxygen-enhanced combustion	50	Auxiliary power requirements <1% Reduced unburnt carbon and opacity compared to baseline conditions	Reductions relatively independent of the initial NO _x concentration. Demonstrations completed at two utility boilers
Refinements for low-NO _x tangential-firing systems	76–84	Does not significantly affect unburnt carbon levels in ash Combustion performance strong function of coal properties May require finer grinding of coal	OFA may also be used
Preheat combustion system	42–67	3–5% thermal input used for preheating of coal	Also known as Methane de-NO _x

^aPossible or reported.

The CuO process has four major processing elements: absorber, regenerator, solids heater, and combustor. The absorber is installed upstream of the boiler APH. In the absorber, SO₂ is absorbed by the sorbent, and NO_x is reduced by injecting NH₃ into the incoming flue gas stream. From the absorber, the treated flue gas is transported to the remaining portions of the flue gas train.

The spent sorbent is pneumatically transported from the absorber to a solids heater. In the solids

heater, the sorbent temperature is elevated to the target reaction temperature for regeneration. This is accomplished by contacting the sorbent with the hot combustion gas of the combustor fired on natural gas. The heated spent copper sulfate sorbent enters the regenerator, where it is reduced with natural gas to regenerate the copper. The regeneration step results in a concentrated stream of SO₂ that can be processed in a sulfur recovery plant. From the regenerator, the sorbent is

Table 6. A summary of multipollutant control technologies.

Technology ^a	NO _x Removal Efficiency (%) ^a	Potential Plant Impacts	Comments
E-Beam	SO ₂ : >95 NO _x : ≤90 Hg: zero	Extensive byproduct treatment required Auxiliary power requirements may reach 5% for NO _x reduction >60 %	Nitrogen fertilizer concept has not been demonstrated
ROFA/ROTAMIX	SO ₂ : 64–69 NO _x : ≤80 Hg: 67–89	May increase erosion of boiler tubes May increase in boiler slugging and fouling	Reduction in superheat and reheat temperatures have been experienced Performance of ROFA in large boilers may degrade
SNOX	SO ₂ : >90 NO _x : >90 Hg: zero	Increased auxiliary power requirements Ammonia storage issues	Concentrated sulfuric acid byproduct
SNRB	SO ₂ : 80–90 NO _x : ≤90 Hg: zero	Reliability of fabric filter bags may deteriorate	Technology has not been demonstrated
Activated coke	SO ₂ : 90–98 NO _x : 60–80 Hg: 90–99	NO _x reduction depends on SO ₂ reduction Long time needed to reach operating temperature of de-NO _x process	Limited mercury removal data; Quality of activated coke is critical for performance
ECO	SO ₂ : 98–99 NO _x : ≤90 Hg: 95	3% auxiliary power requirement Cooling water required for wet ESP	Technology in demonstration
NOXSO	SO ₂ : ≤98 NO _x : 75–90 Hg: zero	NO _x desorption with hot air required High temperature reaction with methane required for processing of SO ₂	Limited experience (proof of concept tests and a combined heat and power plant at the University of Denmark)
Copper-oxide	SO ₂ : ≤90 NO _x : ≤90 Hg: zero	Pneumatic transport of solids to regeneration unit required High temperature regeneration of copper sulfate sorbent required	Experience limited to pilot scale

^aReported.

transported back to the absorber for reuse. Once sorbent enters the system from the regenerator, it is quickly oxidized to copper oxide. Testing to date has been limited to pilot scale tests in which efficiencies of SO₂ removal and NO_x reduction have been at 90%.

CONCLUSIONS

Recently, a number of regulatory actions have been taken in the United States that are 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 reviewed these technologies and their applications. Figure 6 shows the locations of NO_x control technologies discussed in this paper, relative to power plant hardware and other emission control equipment. Additionally, Tables 5 and 6 summarize emission reduction performance, potential plant impacts, and benefits/drawbacks for each of these technologies.

Primary control technologies have been widely implemented on U.S. coal-fired utility boilers to comply with the NO_x emissions reduction requirements of the Title IV NO_x Program. Data reflect that average NO_x reductions for specific primary controls have ranged from 35% to 63% from 1995 emissions levels. In particular, applications of LNB resulted in reductions of >35%, on

average, from 1995 levels. Recent advances in primary control technologies have been aimed at providing greater NO_x reduction and include LNB with multilevel OFA, ROFA, and combustion improvement techniques.

The secondary NO_x control technologies applied on U.S. coal-fired utility boilers include reburning, SNCR, and SCR. Of these boilers, 26 have either installed or demonstrated reburning as their secondary NO_x control technology. The NO_x reductions achieved at these boilers ranged from 25 to 68%. Many of the reburning applications are not operational at this time, probably because of plant-specific economics associated with elevated natural gas prices and other factors. In 2003, currently operational reburning applications on coal-fired U.S. electric utility boilers achieved NO_x emission rates between 0.277 and 0.385 lb/10⁶ Btu.

Thirty-six U.S. coal-fired utility boilers have installed SNCR. Reported NO_x reductions achieved at these applications ranged from 15 to 66%. Data also show that whereas smaller boilers may be able to achieve >60% NO_x reduction, larger boilers may be capable of achieving reductions of only ~30%.

Recently, SCR has been installed at >150 U.S. coal-fired utility boilers. Many of these applications are designed to provide NO_x reductions of ≥80%, sometimes as much as 90% reduction, with <2 ppm NH₃ slip. Data on the performance of 20 SCR systems operating in the United States with low-NO_x emissions reflect that in 2003

these units achieved NO_x emission rates between 0.04 and 0.07 lb/10⁶ Btu.

Recent enhancements in secondary control technologies have been aimed at providing large NO_x reductions, using reagents more efficiently, and addressing any public concerns with the transport and handling of the NH₃ reagent used in SCR applications. These enhancements include variants of reburning and SNCR, in-duct SCR, HSR, and urea-to-NH₃ processes.

DOE-NETL is conducting a comprehensive research and development effort focused primarily on developing new technologies capable of controlling NO_x emissions to a level ≤0.15 lb/10⁶ Btu at a cost significantly lower than SCR. NO_x control technologies under development by DOE-NETL include layered NO_x control for cyclone boilers, oxygen-enhanced combustion, refinements for low-NO_x tangential firing systems, and preheat combustion.

In addition to the above control technologies used exclusively for NO_x removal, a number of other technologies are becoming available that can be applied to control NO_x in conjunction with other pollutants, including SO₂, Hg, and PM. In general, experience with these multipollutant control technologies is limited to test demonstrations, with only a few of them applied to date in full-scale commercial installations.

REFERENCES

- Price, D.; Birnbaum, R.; Batiuk, R.; McCullough, M.; Smith, R. *Nitrogen Oxides: Impacts on Public Health and the Environment*; EPA-452/R-97-002 (NTIS PB98-104631); U.S. Environmental Protection Agency, Office of Air and Radiation: Washington, DC, 1997.
- Criteria Pollutant Data, Current Emission Trends Summaries, Trends 1970_2001to CHIEF 082803.xls spreadsheet; U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards: Research Triangle Park, NC, 2001; U.S. Environmental Protection Agency Web site, <http://www.epa.gov/ttn/chief/trends/> (accessed July 1, 2005).
- State-Level Emission Inventory Summaries for All Criteria Pollutants for Each Sector for Years 2001, 2010, and 2015, Base and Control Cases (Excel version of Appendix A of AQ Modeling TSD); U.S. Environmental Protection Agency Web site, <http://www.epa.gov/interstateairquality/technical.htm> (accessed July 1, 2005).
- Revised NO_x Emission Limitations for Group I, Phase II Boilers, U.S. Environmental Protection Agency. *Code of Federal Regulations*, Part 76; Title 40, 2000.
- NO_x Emission Limitations for Group 2 Boilers, U.S. Environmental Protection Agency. *Code of Federal Regulations*, Part 76.6, Title 40, 2000.
- Ozone Transport Commission (OTC) NO_x Budget Program, U.S. Environmental Protection Agency, Washington, DC, June 2001; available on U.S. Environmental Protection Agency Web site, <http://www.epa.gov/airmarkets/otc/index.html> (accessed July 1, 2005).
- Revisions of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units, U.S. Environmental Protection Agency. http://www.epa.gov/ttn.oarpg/t1/fr_notices/noxpref.pdf (accessed July 19, 2005).
- EPA's NO_x Budget Trading Program, U.S. Environmental Protection Agency. <http://www.epa.gov/airmarkets/fednox/index.html> (accessed July 19, 2005).
- Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call, U.S. Environmental Protection Agency http://www.epa.gov/cair/pdfs/cair_final_preamble.pdf (accessed July 19, 2005).
- Miller, J.A.; Bowman, C.T. Mechanism and Modeling of Nitrogen Chemistry in Combustion; *Prog. Energy Combust. Sci.* **1989**, *15*, 287-338.
- Wendt, J.O.L. Fundamental Coal Combustion Mechanisms and Pollutant Formation in Furnaces; *Prog. Energy Combust. Sci.* **1980**, *6*, 201-222.
- Bowman, C.T. In *Fossil Fuel Combustion: A Source Book; Chemistry of Gaseous Pollutant Formation and Destruction*. Bartok, E., Sarofim, A.F., Eds.; John Wiley & Sons: New York, 1991; pp 228-252.
- Zeldovich, Y.B. The Oxidation of Nitrogen in Combustion Explosions; *Acta Physicochimica, U.S.S.R.* **1946**, *21*, 577-628.
- Whitfield, T.; Wilson, C.; Pitsko, D.; Kokkinos, A.; Wasylyuk, D.; Boris, M.; Hicks, J. Comparison of NO_x Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA: Washington, DC, May 19-22, 2003.
- MacKinnon, D.J. Nitric Oxide Formation at High Temperature; *J. Air Pollut. Control Assoc.* **1974**, *24*, 237-239.
- Pohl, J.H.; Sarofim, A.F. Devolatilization and Oxidation of Coal Nitrogen; In *Proceedings of the 16th Symposium (International) on Combustion*, The Combustion Institute: Pittsburgh, PA, 1976; pp 491-501.
- Stamey-Hall, S. *Alternative Control Techniques Document—NO_x Emissions from Utility Boilers*; EPA-453/R-94-023 (NTIS PB94-184165); U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards: Research Triangle Park, NC, 1994.
- Analyzing Electric Power Generation Under CAAA; U.S. Environmental Protection Agency, Office of Air and Radiation: Washington, DC, 1998; available at <http://www.epa.gov/airmarkets/epa-ipm/> (accessed July 1, 2005).
- Mereb, J.B. Assessing the Effects of Coal Properties on NO_x Emissions in Combustion Systems. In *Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA, Atlanta, GA, August 16-20, 1999.
- Conrads, H.G. Increasing Boiler Efficiency by UBC Monitoring. In *Proceedings of the DOE/NETL 2002 Conference on Unburned Carbon on Utility Fly Ash*; National Energy Technology Laboratory, Pittsburgh, PA, May 14, 2002; available at: <http://www.netl.doe.gov/publications/proceedings/02/ubc/conradsummary.pdf> (accessed July 1, 2005).
- Larrimore, L. Effects of Higher Carbon Levels on Ash Utilization. In *Proceedings of the DOE/NETL 2000 Conference on Unburned Carbon on Utility Fly Ash*; DOE/NETL, Pittsburgh, PA, May 14, 2002; available at: <http://www.netl.doe.gov/publications/proceedings/00/ubc00/LARRYMORE.pdf> (accessed July 1, 2005).
- Payne, R., Sommer, T., Melick, T., Johnson, R. Combustion Modification NO_x Control-New Results. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI, Chicago, IL, August 20-23, 2001.
- Kokinos, A., Wasylyuk, D., Adams, D., Yavorsky, R., Brower, M. B&W's Experience Reducing NO_x Emissions in Tangentially-Fired Boilers. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI, Chicago, IL, August 20-23, 2001.
- Whitfield, T.; Wilson, C.; Pitsko, D.; Kokkinos, A.; Wasylyuk, D.; Boris, M.; Hicks, J. Comparison of NO_x Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, May 19-22, 2003.
- Khan, S.; Srivastava, R.K. Updating Performance and Cost of NO_x Control Technologies in the Integrated Planning Model. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30-September 2, 2004.
- Gessner, T.M.; Hoh, R.H.; Ray, B.; Jennings, P. Results from Reliant Energy, W.A. Parish 7 Achieving 0.15 LB NO_x/MMBtu. In *Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA, Atlanta, GA, August 16-20, 1999.
- Ralston, J.; Fischer, E. Application of Mobotec ROFA Technology on a 150 MW Coal-Fired CE Boiler. *EVEC, An Electric Utilities Environmental Conference*; Tucson, AZ, January 2001.
- MobotecUsa; available at <http://www.mobotecusa.com/projects/installations.htm> (accessed July 5, 2005).
- Mobotec Usa; ROFA Experience at Cape Fear Units 5 and 6, Vartaverket Unit P14, and Hasselbyverket Unit 3; available at: <http://www.mobotecusa.com/projects/> (accessed July 19, 2004).
- Fuller, T.A.; Daw, S.C.; Finney, C.E.A.; Musgrove, B.; Stallings, J.; Flynn, T.J.; Bailey, R.T.; Hutchinson, D.; Lassahn, R. Advances in Utility Applications of the Flame Doctor System. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30-September 2, 2004.
- Conn, S.; Frizzell, K.; Dusatko, G.; Vacek, M.; Adams, B. Combustion Optimization at OMU's Elmer Smith Unit 1: Meeting SCR Specifications and Maintaining Plant Heat Rate. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30-September 2, 2004.

32. Davey, T.A. Achieving Uniform Combustion Using Burner Line Orifices to Balance Coal Flow Distribution. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPRI/DOE/EPA, Chicago, IL, August 20–23, 2001
33. Laux, S.; Headman, A.; Grusha, J.; Rosin, T. Benefits and Experience with Coal and Air Flow Measurement and Automatic Control on Pulverized Coal Fired Boilers- Update 2003. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, May 19–22, 2003.
34. Letcavits, J.J.; Early, D. Combustion Optimization of a 150 Mw (Net) Boiler Utilizing Air and Fuel Flow Measurement and Control. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI, Chicago, IL, August 20–23, 2001
35. Warriner, G.H.; Logan, S.; Pascoe, S.; Noblett, J.G. Full-Scale Implementation Results for GNOCIS Plus. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI, Chicago, IL, August 20–23, 2001
36. Smith, S.; Zablocky, P.; Kohn, D.; Noble, G. Combustion Optimization Case Studies and Emerging Applications. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, May 19–22, 2003.
37. Partlow, B.; Marz, P.; Kaltenbach, R.; Grusha, J. NO_x Reduction with Improvement in Plant Efficiency. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, May 19–22, 2003.
38. Bool, L.E. III; Bradley, J. NO_x Reduction from a 44 MW Wall-Fired Boiler Utilizing Oxygen Enhanced Combustion. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30–September 2, 2004.
39. Cremer, M.; Valentine, J.; Shim, H.S.; Davis, K.; Adams, B.; Letcavits, J.J.; Viestra, S. CFD-Based Development, Design, and Installation of Cost-Effective NO_x Control Strategies for Coal-Fired Boilers. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30–September 2, 2004.
40. Wendt, J.O.L.; Sternling, C.V.; Matovich, M.A. Reduction of Sulfur Trioxide and Nitrogen Oxides by Secondary Fuel Injection. In *Proceedings of the 14th International Symposium on Combustion*; The Combustion Institute: Pittsburgh, PA, 1973; p 881.
41. Staudt, J. *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*; Northeast States for Coordinated Air Use Management: Boston, MA, 1998.
42. Folsom, B.; Hartsock, D.; Latham, C.; Payne, R.; Sommer, T.; Scaccia, M. Reburn Scale-Up Experience. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI, Chicago, IL, August 20–23, 2001.
43. Moyeda, D. Reburn Technology Application Guidelines. In *Proceedings of the DOE/NETL 2004 Conference on Reburning for NO_x Control—Reburning on Trial*; National Energy Technology Laboratory, U.S. Department of Energy: Washington, DC, 2004; available at: <http://www.netl.doe.gov/publications/proceedings/04/NOx/e10.35moyeda2-presentation.pdf> (accessed July 5, 2005).
44. Farzan, H.; Maringo, G.J.; Johnson, D.W.; Wong, D.K.; Beard, C.T.; Brewster, S.E. B&W's Advances on Cyclone NO_x Control via Fuel and Air Staging Technologies. In *Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA, Atlanta, GA, August 16–20, 1999.
45. Engelhardt, D.; Folsom, B.; Latham, C.; Moyeda, D.; Payne, R.; Sommer, T.; Brocato, H.; Maziarz, M. Updated Experience Using Reburn Technology for Utility Boiler NO_x Emissions Reduction. In *Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA, Atlanta, GA, August 16–20, 1999.
46. Mann, A.; Ruppel, T. Scorecard on Reburning. In *Proceedings of the DOE/NETL 2004 Conference on Reburning for NO_x Control—Reburning on Trial*; National Energy Technology Laboratory, U.S. Department of Energy: Washington, DC, 2004. Available at: <http://www.netl.doe.gov/publications/proceedings/04/NOx/posters/Reburning%20Scorecard.pdf> (accessed July 5, 2005).
47. Payne, R. GE Energy, Irvine, CA. Personal communication, 2004.
48. Lyon, R.K. Method for the Reduction of the Concentration of NO in Combustion Effluents Using Ammonia. U.S. Patent 3,900,554, August 1975.
49. Selective Non-Catalytic Reduction Committee. *White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions*; Institute of Clean Air Companies: Washington, DC, 2000.
50. Himes, R.M. A Fresh Look at SNCR. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, May 19–22, 2003.
51. Staudt, J.; Kehrner, K.; Poczyniec, J.; Cote, R.; Pierce, R.; Afonso, R.; Sload, A.; Miles, D. Optimizing Selective Non-Catalytic Reduction Systems for Cost-Effective Operation on Coal-Fired Electric Utility Boilers. In *ICAC Forum '98*; Institute of Clean Air Companies, Durham, NC, 1998.
52. Jones, D.G.; Steinberger, N.; Hunt, T.; Barron, C.; Muzio, L.J.; Stallings, J.; Sherrick, R. Design Optimization of SNCR DENOX Injection Lances. In *EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control*; EPRI/EPA: Kansas City, MO, 1995.
53. Foerter, D. Institute of Clean Air Companies, Washington, DC. Personal communication, 2001.
54. *White Paper: Selective Catalytic Reduction (SCR) Control of NO_x Emissions*; Selective Catalytic Reduction Committee, Institute of Clean Air Companies: Washington, DC, 1997.
55. Whiteman, C. Institute of Clean Air Companies, Washington, DC. Personal communication, 2004.
56. Johnson, R.E.; Sigling, R.A.; Rigby, K.; Pajonk, G.; Hums, E.; Klatt, A. U.S. Utility Coal-Fired SCR Applications: SCR Catalyst-Specific Issues and Operating Expenses. In *PowerGen International 2002*; Orlando, FL, 2002.
57. Staudt, J.E. Minimizing the Impact of SCR Catalyst on Total Generating Cost through Effective Catalyst Management. In *Proceedings of the ASME Power Conference*; American Society of Mechanical Engineers, Baltimore, MD, March 30–April 1, 2004; available at: http://www.andovertechology.com/PWR2004_52091.pdf (accessed July 5, 2005).
58. Cichanowicz, J.E.; Muzio, L.J. Factors Affecting Selection of a Catalyst Management Strategy. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA: Washington, DC, May 19–22, 2003.
59. Staudt, J.E.; Engelmeyer, A.J. SCR Catalyst Management Strategies-Modeling and Experience. In *Proceedings of the DOE-EPRI-EPA-AWMA Power Plant Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA: Washington, DC, May 19–22, 2003.
60. McLaughlin, B.R.; Blunden, W.E.; Holstein, D.B. SCR Retrofits for Coal Fired Plants: Lessons Learned. In *Proceedings of the DOE-EPRI-EPA-AWMA Combined Air Pollutant Control Mega Symposium*; DOE/EPRI/EPA/AWMA, Washington, DC, August 30–September 2, 2004.
61. Hanson, R.; Borio, D.; Cohen, M.; Buschmann, J.C.; Brandt, J. Early Operating Experience of the Spurlock SCR System. In *ICAC Forum '03: Multi-Pollutant Emission Controls and Strategies*; Institute of Clean Air Companies: Nashville, TN, 2003.
62. Bullock, D.W.; Hartenstein, H. O&M Cost Reduction of a Coal-Fired U.S. Merchant Plant through an Optimized SCR Management Strategy Involving Catalyst Regeneration. In *Proceedings of the DOE/NETL 2002 Conference on SCR and SNCR for NO_x Control*; DOE/NETL: Pittsburgh, PA, 2002; available at: <http://www.netl.doe.gov/publications/proceedings/02/scr-sncr/Bullock.pdf> (accessed July 5, 2005).
63. Lauber, J.; Cohen, M.; Donais, R. The Integration of Low-NO_x Control Technologies at the Southern Energy, Inc. Birchwood Power Facility. In *Proceedings of the EPRI/DOE/EPA 1997 Combined Utility Air Pollution Control Symposium*; EPRI TR-108683-V1; EPRI/DOE/EPA: Washington, DC, August 1997.
64. Cochran, J.R.; Scarlett, D.; Johnson, R. SCR for a 460 MW Coal Fueled Unit: Stanton Unit 2 Design, Startup, and Operation. In *Proceedings of the EPRI/DOE/EPA 1997 Combined Utility Air Pollution Control Symposium*; EPRI TR-108683-V1; EPRI/DOE/EPA: Washington, DC, August 1997.
65. Pritchard, S.; Hellard, D.; Cochran, J. Catalyst Design Experience for 640 MW Cyclone Boiler Fired with 100% PRB Fuel. In *Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The MEGA Symposium*; EPRI TR-113187-V2; EPRI/DOE/EPA: Atlanta, GA, August 16–20, 1999.
66. Harris, D.; Pritchard, S. First Year's Operating Experience with SCR on 600 MW PRB-Fired Boiler. In *Proceedings of the 2001 Conference on Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) for NO_x Control*; Pittsburgh, PA, 2001; available at: <http://www.netl.doe.gov/publications/proceedings/01/scr/pritchard.pdf> (accessed July 5, 2005).
67. Ake, T.; Erickson, C.; Medeiros, W.; Hutcheson, L.; Barger, M.; Ruthersford, S. Limestone Injection for Protection of SCR Catalyst. In *Proceedings of the EPA-EPRI-NETL-AWMA Combined Power Plant Air Pollutant Control Mega Symposium*; EPA/EPRI/NETL/AWMA Washington, DC, May 19–22, 2003.
68. Marshall, L.; Afonso, R.; Tavoulareas, S.; Stallings, J. Prediction and Mitigation of Air Preheater Fouling Due to Ammonium Bisulfate. In *Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA: Chicago, IL, August 20–23, 2001.
69. Butler, B.; Gaikwad, R.P. Operating Experience of SCRs at Texas Genco's Coal and Gas Fired Power Plants. In *Proceedings of the EPRI-EPA-DOE Combined Air Pollutant Control Mega Symposium*; EPRI/EPA/DOE: Washington, DC, August 30–September 2, 2004.
70. Cichanowicz, J.E.; Smith, L.L.; Muzio, L.J. Twenty-Five Years of SCR Evolution: Implications for US Application and Operation. In *Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA: Chicago, IL, August 20–23, 2001.
71. Cichanowicz, J.E.; Smith, L.L.; Muzio, L.J.; Marchetti, J. 100 GW of SCR: Installation Status and Implications of Operating Performance on Compliance Strategies. In *Proceedings of the EPA-EPRI-NETL-AWMA Combined Power Plant Air Pollutant Control Mega Symposium*; EPA/EPRI/NETL/AWMA: Washington, DC, May 19–22, 2003.

72. *NEEDs (National Electric Energy System) Database for IPM 2004; Clean Air Markets—Programs and Regulations*; U.S. Environmental Protection Agency: Washington, DC, 2004; available at <http://www.epa.gov/airmarkets/epa-ipm> (accessed July 5, 2005).
73. Kokkinos, A.; Cline, H.W. Design and Results of a Selective Catalytic System for a 600 MW Coal-Fired Utility Boiler. In *ICAC Forum 2002: Cutting NO_x*; Institute of Clean Air Companies: Nashville: Houston, TX, 2002.
74. Staudt, J. Andover Technology Management, Andover, MA. Personal communication, 2001.
75. Glickert, R.W.; HerZau, J.S.; Meskimen, R.L.; Pratapas, J.M. Application of Fuel Lean Gas Reburn Technology at Commonwealth Edison's Joliet Generating Station 9. In *Proceedings of the EPRI/DOE/EPA 1997 Combined Utility Air Pollution Control Symposium*; EPRI/DOE/EPA: Washington, DC, August 1997.
76. Breen, B.P.; Schrecengost, R.; Brown, R.C.; Sweterlitsch, J.; Emsick, N. Fuel-Lean Reburn with In-Situ Gasification of Coal, Biomass, and Biomass-Coal Mixtures and with Biomass-Derived Gases. In *Proceedings of the DOE/NETL 2004 Conference on Reburning for NO_x Control—Reburning on Trial*; available at <http://www.netl.doe.gov/publications/proceedings/04/NOx/i01.30breen-presentation.pdf> (accessed July 5, 2005).
77. Killen, D.; Boyle, J.M.; O'Leary, J.H. Fuel Gas Reburn and Urea-SNCR Applied to a 198 MW Coal-fired Boiler. In *Proceedings of the EPA-DOE-EPRI Combined Power Plant Air Pollutant Control Symposium, The MEGA Symposium*; EPA/DOE/EPRI: Chicago, IL, August 20–23, 2001.
78. Schrecengost, R.A.; Gomez, A.F.; Boyle, J.M. Commercial Installation of Amine Enhanced Fuel-Lean Gas Reburn at Public Service Electric & Gas Mercer Station. In *Proceedings of the DOE/NETL 1999 Conference on SCR/SNCR for NO_x Control*; available at <http://www.netl.doe.gov/publications/proceedings/99/99scr-sncr/schrecen.pdf> (accessed July 5, 2005).
79. Albanese, V.M.; Boyle, J.M.; Ferrigan, J.J.; Spokoyny, F.E. Hybrid System for Post-Combustion NO_x Reduction SNCR and Air Heater SCR. In *Proceedings of the DOE Conference on SCR and SNCR*; DOE: Pittsburgh, PA, May 21–22, 1997.
80. Huhmann, A. Evaluation of Retrofitted Post-Combustion NO_x Control Technologies on a Wet Bottom, Coal-Fired Utility Boiler. In *Proceedings of the DOE Conference on SCR and SNCR*; DOE: Pittsburgh, PA, May 21–22, 1997.
81. Gretta, W.J.; Hinton, W.S.; Jones, O.B. Results from the In-Line SCR Retrofit at TXU's Lake Hubbard Station. In *Power Gen International 2002*; PenWell Corp.: Orlando, FL, 2002.
82. Huttenhofer, K.; Beer, J.K.; Smeets, H.; van der Kooij, J. The Deno_x Air Preheater Downstream of a Coal-Fired Boiler. In *Proceedings of the EPRI/EPA 1993 Joint Symposium on Stationary Combustion NO_x Control*; EPRI/EPA: Miami Beach, FL, May 24–27, 1993.
83. Klett, M.G.; Rutkowski, M.D. *Processes for SCR Ammonia Production from Urea*; U.S. Department of Energy, Letter Report, Contract No. DE-AM01-98FE65271, Task No. DE-AT01-99FE65825; U.S. Department of Energy: Washington, DC, 2002.
84. Cremer, M.A.; Adams, B. R.; O'Connor, D. C.; Bhamidipati, V.; Broderick, R. G. Design and Demonstration of Rich Reagent Injection (RRI) for NO_x Reduction at Conectiv's B.L. England Station. In *Proceedings of the EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium: The MEGA Symposium*; EPRI/DOE/EPA, Chicago, IL, August 20–23, 2001.
85. Bool, L.; Kobayashi, H.; Thompson, D.; Eddings, E.; Okerlund, R.; Cremer, M.; Wang, D. Oxygen for NO_x Control—A Step Change Technology? In *19th Annual International Pittsburgh Coal Conference*, University of Pittsburgh; Pittsburgh, PA, September 23–27, 2002.
86. *Oxygen Enhanced Combustion for NO_x Control*; U.S. Department of Energy, Final Report, Contract No. DE-FC26-00NT40756; U.S. Department of Energy: Washington, DC, 2004.
87. Richards, G. H.; Maney, C. Q.; Borio, R. W. *Ultra Low-NO_x Integrated System for NO_x Emission Control from Coal-Fired Boilers*; Department of Energy, Final Report, Contract No. DE-FC26-00NT40754; Department of Energy: Washington, DC, 2002.
88. Nester, S.; Wohadlo, S.; Rabovitser, J.; Bryan, B.; Tumanovsky, A. G.; Lisauskas, R.; Ake, T. Current Status of Development and Testing of a Novel Coal Preheating Technology for NO_x Reduction from Pulverized Coal-Fired Boilers. In *Proceedings of the EPA-EPRI-NETL-AWMA Combined Power Plant Air Pollutant Control Mega Symposium*; EPRI/NETL/AWMA: Washington, DC, May 19–22, 2003.
89. *FGD Handbook*; Report No. IEACR/65; International Energy Agency Coal Research: London; 1994, available at: <http://www.caer.uky.edu/iea/ieacr65.shtml> (accessed July 19, 2005).
90. Frank, N.W.; Hirano, S. Combined SO₂/NO_x Removal by Electron Beam Processing. In *Proceedings of the 4th Symposium on Integrated Environmental Control*; Electric Power Research Institute, Washington, DC, March 1988.
91. *Technology Assessment of Clean Coal Technologies for China: Electric Power Production*, World Bank ESMAP and AIESEG Technical Paper 011; World Bank: Washington, DC, 2001.
92. Moberg, G.; Blid, J.O.; Wallin, S.; Fareid, T.; Ralston, J. Combined DeNO_x/DeSO_x and Additional NO_x Reduction by Cleaning Flue Gas Condensate from Ammonia. In *Proceedings of the PowerGen International Conference*, New Orleans, LA, November 30–December 2, 1999.
93. Haddad, E.; Ralston, J.; Green, G.; Castagnero, S. Full-Scale Evaluation of a Multi-Pollutant Reduction Technology: SO₂, Hg, and NO_x. In *Proceedings of the EPA-EPRI-NETL-AWMA Combined Power Plant Air Pollutant Control Mega Symposium*; EPA/NETL/AWMA: Washington, DC, May 19–22, 2003.
94. *Clean Coal Technology Demonstration Program: Update 2000*; DOE/FE-0437; U.S. Department of Energy: Washington, DC, 2001.
95. Bruno, L.; Ricci, R. Application of SNO_x Technology at the Gela Power Plant in Sicily. In *Proceedings of PowerGen 2000 Europe*; Helsinki, Finland, June 2000.
96. *Final Report for Niles Demonstration, Vol. I: Public Design*; DOE/PC/8955-T21 (NTIS: DE96050312); U.S. Department of Energy: Washington, DC, 1996.
97. *A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing the SNO_x Innovative Clean Coal Technology Demonstrations*; DOE/PC/93251-T3; U.S. Department of Energy: Washington, DC, 1994.
98. Evans, A.P.; Kudlac, G. A.; Wolkinson, J. M.; Chang, R. SO_x-NO_x-Rox-Box-High Temperature Baghouse Performance. In *Proceedings of the 10th Particulate Control Symposium*; Washington, DC, April 1993.
99. Olson, D.G.; Tsuji, K.; Shiraishi, I. The Reduction of Gas Phase Air Toxics from Combustion and Incineration Sources Using the MET-Mitsui-BF Activated Coke Process. In *1999 International Ash Utilization Symposium*; Center for Applied Energy Research, University of Kentucky, Lexington, KY, October 18–20, 1999.
100. Tsuji, K.; Shiraishi, I. Combined Desulfurization, Denitrification, and Reduction of Air Toxics Using Activated Coke; *Fuel* **1997**, *76*, 549-560.
101. *Dry Type Desulfurization Denitrification Technology for Coal-Fired Power Plants*; Mitsui Mining Co. Brochure, Mitsui Mining Co. Ltd.: Tokyo, Japan, 2000.
102. Peltier, R. Mercury Removal Standards Are Coming. Where's the Technology? *Power*, May 2003 <https://online.platts.com/PPS/P=m&e+1096495302758.3584968496075286333/> (accessed July 19, 2005).
103. Powerspan Corporation; available at: <http://www.powerspan.com> (accessed July 5, 2005).
104. Boyle, P.; Steen, D.; DoVale, A.J. Commercial Demonstration of ECO Multi-Pollutant Control Technology. In *Proceedings of Power-Gen International 2003*; Las Vegas, NV, December 9–11, 2003.
105. *Comprehensive Report to Congress on the Clean Coal Technology Program: Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System*; MK Ferguson Company, Office of Clean Coal Technology, U.S. Department of Energy: Washington, DC, 1991; available at: <http://www.netl.doe.gov/cctc/resources/pdfs/noxso/0000015B.pdf> (accessed July 5, 2005).
106. *Fluid-Bed Copper Oxide Process, Phase IV Conceptual Design And Economic Evaluation*; U.S. Department of Energy, Final Report, Contract No. DE-AC22-85PC81004, A.E. Roberts and Associates: Atlanta, Georgia, November 30, 1994; available at: <http://www.netl.doe.gov/cctc/resources/pdfs/misc/fgd/M96005559.pdf> (accessed July 5, 2005).

About the Authors

Ravi K. Srivastava, Project Manager, and Robert E. Hall, Branch Chief, are at the U.S. Environmental Protection Agency, National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. Sikander Khan, Environmental Engineer and Kevin Culligan, Acting Branch Chief, are at the U.S. Environmental Protection Agency, Office of Air and Radiation, Clean Air Markets Division, Washington, DC. Bruce W. Lani, Project Manager, is at the U.S. Department of Energy, National Energy Technology Laboratory, Environmental Projects Division, Pittsburgh, PA. Address correspondence to: R. K. Srivastava, U.S. Environmental Protection Agency, National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC 27711; phone: +1-919-541-3444; fax: +1-919-541-0554; e-mail: srivastava.ravi@epa.gov.