WHITE PAPER

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO$_x$ EMISSIONS

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INSTITUTE OF CLEAN AIR COMPANIES

The Institute of Clean Air Companies (ICAC) is the national association of companies that supply stationary source air pollution monitoring and control systems, equipment, and services. It was formed in 1960 as a nonprofit corporation to promote the industry and encourage improvement of engineering and technical standards.

The Institute's mission is to assure a strong and workable air quality policy that promotes public health, environmental quality, and industrial progress. As the representative of the air pollution control industry, the Institute seeks to evaluate and respond to regulatory initiatives and establish technical standards to the benefit of all.

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PURPOSE

To comply with acid rain and ozone non-attainment rules, both regulators and regulated industry seek nitrogen oxide (NO_x) controls which offer the greatest reliability and effectiveness at the least cost. One such NO_x control technology is selective non-catalytic reduction (SNCR). Although SNCR will not be universally applicable, or always the most cost effective control strategy, in many cases it will meet the dual requirements of high performance and low cost, and so should be considered by affected sources and permitting authorities. Unfortunately, misconceptions regarding SNCR have hindered its acceptance, and occasionally even its consideration.

The SNCR Committee of the Institute of Clean Air Companies, Inc. (ICAC) prepared this white paper to educate all interested parties on the capabilities, limitations, and cost of SNCR.

ICAC is the nonprofit national association of companies which supply stationary source air pollution monitoring and control systems, equipment, and services. Its members include suppliers of SNCR systems, and of competing NO_x control technologies.

EXECUTIVE SUMMARY

Selective non-catalytic reduction (SNCR) is a chemical process for removing nitrogen oxides (NO_x) from flue gas. In SNCR, a reagent, typically urea or ammonia, is injected into hot flue gas, and reacts with the NO_x, converting it to nitrogen gas and water vapor. No catalyst is required for this process. Instead, it is driven by the high temperatures normally found in combustion sources.

SNCR performance depends on factors specific to each source, including temperature, residence time of the reagent, amount of reagent injected, reagent distribution, and uncontrolled NO_x level. However, reductions in emissions of 30-75% are common. Using appropriately designed SNCR systems, these levels of control are not accompanied by excessive emissions of unreacted ammonia (ammonia slip) or of other pollutants, particularly using recent design upgrades demonstrated on commercial systems. Further, SNCR does not generate any solid or liquid wastes.

SNCR also may be combined with a downsized selective catalytic reduction (SCR) system to provide deeper emissions reductions for a moderate capital investment.

SNCR is a proven and reliable technology. SNCR first was applied commercially in 1974, and significant advances in understanding the chemistry of the SNCR process since then have led to improved NO_x removal capabilities. As a result, approximately 300 SNCR systems have been installed worldwide. Applications have included utility and industrial boilers, process heaters, municipal waste combustors, and other combustion sources.

SNCR is not a capital-intensive technology. Low capital costs, e.g., $5-15/kWe on electric utility boilers, make SNCR particularly suitable for use on low capacity factor units and on units with short remaining service lives, and for seasonal control. SNCR also is well suited for NO_x "trimming," and can provide 10-25% reductions in utility boiler NO_x emissions for total costs below 1 mill/kWh. Removal cost effectiveness values for SNCR center around $1000 per ton of NO_x removed.

The performance and cost of SNCR make this technology attractive for export, including to developing and former Communist countries.

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO$_x$ EMISSIONS

What is SNCR?

Selective non-catalytic reduction (SNCR) is a chemical process that changes nitrogen oxides (NO$_x$) into molecular nitrogen (N$_2$). A reducing agent, typically ammonia or urea, is injected into the combustion/process gases. At suitably high temperatures (1,600 - 2,100 °F)[1], the desired chemical reactions occur. Other chemicals can also be added to improve performance, reduce equipment maintenance, and expand the temperature window within which SNCR is effective.

Conceptually, the SNCR process is quite simple. A gaseous or aqueous reagent of a selected nitrogenous compound is injected into, and mixed with, the hot flue gas in the proper temperature range. The reagent then, without a catalyst, reacts with the NO$_x$ in the gas stream, converting it to harmless nitrogen gas and water vapor. SNCR is "selective" in that the reagent reacts primarily with NO$_x$, and not with oxygen or other major components of the flue gas. A schematic depicting the SNCR process in a stoker-fired combustor is shown in Figure 1.[2]

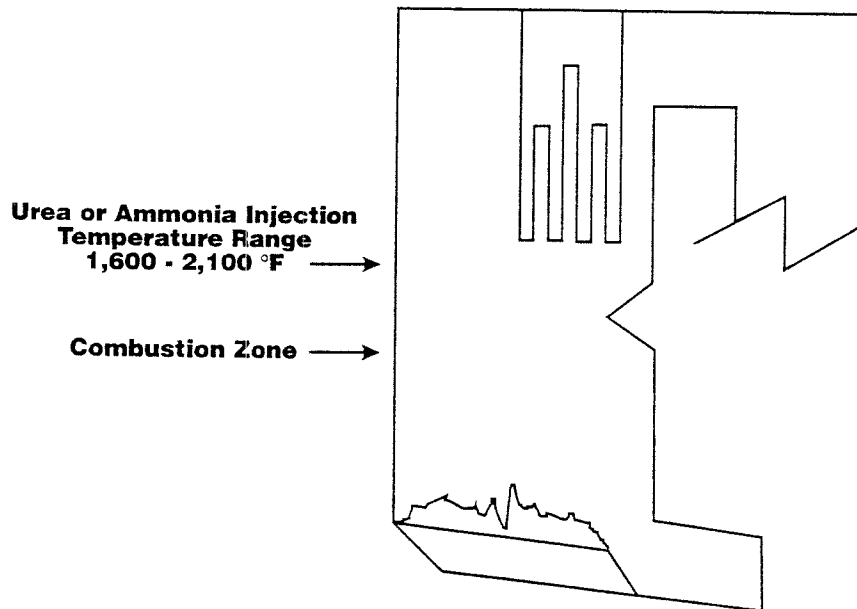Urea or Ammonia Injection Temperature Range 1,600 - 2,100 °F ⟶

Combustion Zone ⟶

Figure 1

No solid or liquid wastes are created in the SNCR process.

In almost all commercial SNCR systems, either ammonia or urea is used as the reagent. Ammonia may be injected in either anhydrous or aqueous form, and urea, as an aqueous solution.

The principal components of an SNCR system are a reagent storage and injection system, which includes tanks, pumps, injectors, and associated controls, and often NO_x continuous emissions monitors. Given the simplicity of these components, installation of SNCR is easy relative to the installation of other NO_x control technologies. SNCR retrofits typically do not require extended source shutdowns.

How much NO_x can SNCR remove?
While SNCR performance is specific to each unique application, NO_x reduction levels ranging from 30% to more than 75% have been reported.

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, and uncontrolled NO_x level are important in determining the effectiveness of SNCR.[3] In general, if NO_x and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NO_x level.

SNCR will remove the most NO_x within a specified temperature range or window. A typical removal effectiveness curve as a function of temperature within this window is shown in Figure 2. At temperatures below the window, reaction rates are extremely low, so that little or no NO_x reduction occurs. On the left side of the curve, the extent of NO_x removal increases with increasing temperature because reaction rates increase with temperature. Residence time typically limits the NO_x reduction in this range. At the plateau, reaction rates are optimal for NO_x reduction. A temperature variation in this range will have only a small effect on NO_x reduction.
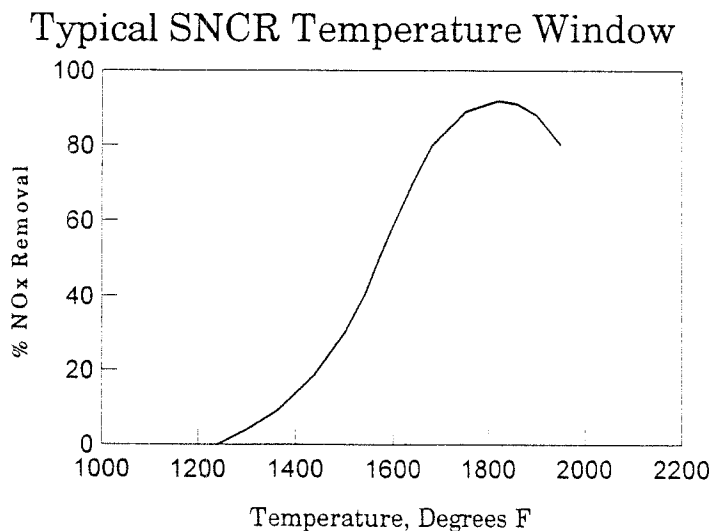
Typical SNCR Temperature Window

Figure 2

A further increase in temperature beyond the plateau decreases NO_x reduction. On the right side of the curve, the oxidation of reagent becomes a significant path and competes with

the NO_x reduction reactions for the reagent. Although the reduction is less than the optimum, operation on the right side is practiced and recommended to minimize reaction times and byproduct emissions.

The temperature window becomes wider as the residence time increases, thus improving the removal characteristics of the process. Long residence times (>0.3 second) at optimum temperatures promote high NO_x reductions even with less than optimum mixing.

Normal stoichiometric ratio (NSR) is the term used to describe the N/NO molar ratio of the reagent injected to uncontrolled NO_x concentrations. If one mole of anhydrous ammonia is injected for each mole of NO_x in the flue gas, the NSR is one, as one mole of ammonia will react with one mole of NO_x. If one mole of urea is injected into the flue gas for each mole of NO_x, the NSR is two. This is because one mole of urea will react with two moles of NO_x. For both reagents, the higher the NSR, the greater the NO_x reduction.[3] Increasing NSR beyond a certain point, however, will have a diminishing effect on NO_x reduction, with reagent utilization decreasing beyond this point.

Is SNCR a new technology?
No. Commercial installations using SNCR have been in existence for more than 20 years.

The first commercial application of SNCR was in Japan in 1974.[4] This installation used anhydrous ammonia. At about the same time, the anhydrous ammonia injection process was patented in the U.S. by Exxon Research and Engineering Co. This process is commonly known as the Thermal DeNO$_x$ process.

Fundamental thermodynamic and kinetic studies of the NO_x-urea reaction occurred during 1976-1981 under the direction of the Electric Power Research Institute (EPRI). Patents granted to EPRI for this process were licensed to Nalco Fuel Tech, which with its implementors or sub-licensees has marketed the urea-based NOxOUT[R] process with improvements to the original patents.

Is SNCR commercially demonstrated?
SNCR systems are in commercial application in the United States, as well as in Europe and Asia.

SNCR is a fully commercial NO_x reduction technology, with successful application of the ammonia- and urea-based processes at approximately 300 installations worldwide, covering a wide array of stationary combustion units firing an equally large number of fuels.

In the U.S., commercial installations or full-scale demonstrations include virtually every boiler configuration and fuel type, as well as other major NO_x emitting process units, such as cement kilns. Urea-based SNCR has been applied commercially to sources ranging in size from a 60 MMBtu/hr (gross heat input) paper mill sludge incinerator to a 320 MWe pulverized coal-fueled, wall-fired electric utility boiler. The longest running commercial urea-based SNCR

system in the U.S. was installed in early 1988 on a 614 MMBtu/hr CO boiler in a Southern California oil refinery. This SNCR system reduces NO_x emissions 65% from a baseline of 90 ppm.

Industrial boilers, process units, municipal waste combustors, and IPP boilers make up the largest share of commercial SNCR installations in the U.S. This distribution is determined more by NO_x control regulations than by SNCR process limitations. Examples of commercial installations include:

- Two 75 MWe pulverized coal tangentially fired power boilers in California equipped with low NO_x burners and overfire air required the installation of SNCR to meet a 165 ppm permit limit.[5]

- SNCR systems installed on the coal-burning, wall-fired New England Power Company's Salem Harbor Station Units 1, 2 (84 MWe each), and 3 (156 MWe) in 1993 can reduce NO_x emissions 50-75% from a baseline of 0.85-1.12 lb/MMBtu.

- Commercial SNCR systems retrofit on 320 MWe wet-bottom, twin furnace boilers in New Jersey provide 30-35% NO_x reductions.[6]

- Commercial SNCR systems retrofit on cyclone-fired boilers in New Jersey reduce NO_x emissions by 35-40%.

- SNCR is allowing compliance with RACT limits at coal-fired boilers in Massachusetts[7] and Delaware.[8]

- An SNCR system installed on a circulating fluidized bed boiler designed to produce 350,000 lb/hr of steam can reduce NO_x emissions from a baseline of 0.2-0.35 lb/MMBtu to below 0.15 lb/MMBtu over a load range of 40-100%.[9]

Among significant demonstrations in the U.S.:

- An SNCR system designed for automatic load following provided consistent 30-50% emissions reductions at a 185 MWe oil-burning tangentially fired utility boiler which cycles from 60 to 185 MWe. Average uncontrolled NO_x emissions were 250 ppm.[10]

- SNCR provided an 80+% reduction from uncontrolled emissions of 3.5-6.0 lb NO_x per ton of clinker in a demonstration at a West Coast cement kiln.[11]

SNCR also has been commercially installed and demonstrated in Asia. For example, an SNCR system installed on a 331 MMBtu/hr pulverized coal-fired industrial boiler in Kaohsuing, Taiwan, in 1992 reduced NO_x emissions from this front-fired boiler from 300 to 120 ppm.

In addition, SNCR has been commercially installed throughout Europe. Installations include coal-fueled district heating plant boilers, electric utility boilers, municipal waste incinerators, and many packaged boilers.

For example, in Germany, commercial SNCR systems installed on municipal waste incinerators in Hamm, Herten, and Frankfurt reduce NO_x emissions 40-75% from baselines of 160-185 ppm. SNCR also has been installed on more than 20 heavy oil-fired Standardkessel packaged boilers.

In Sweden, a commercial SNCR system on a 275 MMBtu/hr coal-fueled, stoker-fired boiler at the Linkoping P1 district heating plant reduces NO_x emissions 65% from a baseline of 300-350 ppm. At the Nykoping demonstration on a 135 MMBtu/hr coal-fueled circulating fluidized-bed boiler, SNCR achieves a 70% NO_x reduction from a 120-130 ppm baseline. Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill kraft recovery boiler, where a 60% reduction from uncontrolled emissions of 60 ppm was attained.[12]

To meet new environmental demands in Eastern Europe, SNCR systems were commercially installed on five coal-fired industrial boilers in the Czech Republic since 1992.

Are there applications for which SNCR is particularly suited?
Yes. Some applications have combinations of temperature, residence time, unit geometry, and uncontrolled NO_x level which make them well-suited for cost-effective reduction of NO_x by SNCR.

Certain applications are technically well suited to the use of SNCR. These include combustion sources with temperatures in the 1550-1950 °F range and residence times of one second or more, examples of which are many municipal waste combustors, sludge incinerators, CO boilers, and circulating fluidized bed boilers. Furnaces or boilers with high NO_x levels or which are not suited to combustion controls, e.g., cyclone or some wet bottom boilers and stokers and grate-fired systems, also are good candidates for SNCR.

Other applications are well suited to the use of SNCR for economic reasons. For these applications, controls with minimized capital cost, even at the expense of somewhat higher operating costs, will be the least expensive to operate. Applications meeting these criteria include units with low capacity factors, such as peaking and cycling boilers, old units with short expected service lives, and units requiring limited control, e.g., additional "trim" beyond combustion control or seasonal control.

How much does SNCR cost?
The capital costs of selective non-catalytic reduction are among the lowest of all NO_x reduction methods. Recent innovations in the control of reagent injection at commercial SNCR systems make SNCR operating costs also among the lowest of all NO_x reduction methods.

SNCR is an operating expense-driven technology, so that the absolute cost of applying SNCR varies directly with the NO_x reduction desired.

Typical SNCR capital costs for utility applications are $5-15/kW, vendor scope, which corresponds to a maximum of $20/kW if balance-of-plant capital requirements are included. For example, the total capital requirement for the commercial installation of SNCR at New England Electric's Salem Harbor Station (three pulverized coal-fired boilers) was $15/kW.[13] Similarly, total capital requirements for Public Service Electric and Gas' Mercer Station unit 2 and B.L. England Station unit 1 were $10.6/kW and $15/kW, respectively.[14] Southern California Edison reported an even lower capital requirement of $3/kW for installing "urea injection" on 20 units totaling 5600 MW[15].

In the industrial sector, SNCR capital costs have been on the order of $900/MMBtu/hr (equivalent to $9/kWe on an electric utility boiler) for CO boilers, industrial power boilers, and waste heat boilers. Waste-to-energy plants and process heaters typically require $1,500/MMBtu/hr (equivalent to $15/kWe).

For similar sources, the installed capital cost per unit of output (e.g., $/kWe) decreases with source size, i.e., total capital outlay increases less than linearly with increasing boiler capacity.

Given such low capital requirements, most of the cost of using SNCR will be operating expense. A typical breakdown of annual costs for utilities will be 15% for capital recovery and 85% for operating expense. For industrial sources, annual costs will be 15-35% for capital recovery and 65-85% for operating expense. For an operating expense-driven technology, little cost will be incurred if the source is not operating, and cost effectiveness (the cost per ton of NO_x removed) will be relatively insensitive to capacity factor or duty cycle. This makes SNCR attractive for seasonal control of NO_x emissions. (For capital-intensive technologies, cost effectiveness becomes worse with decreasing capacity factor.)

Demonstrated cost-effectiveness values for SNCR are low, ranging from $400 to $2,000 per ton of NO_x removed, depending upon site-specific factors. For example, the cost effectiveness of SNCR at New England Electric's Salem Harbor Station unit 2 is $670/ton.[16] The SNCR system at Public Service Electric & Gas Mercer Station has a cost effectiveness of $701/ton, and that at B.L. England Station, $937/ton.[14] The wide range exists because of differing conditions found across industries. For utility boilers alone, cost effectiveness varies with factors such as uncontrolled NO_x level, required emission reduction, unit size, capacity factor (or duty cycle), heat rate (or thermal efficiency), degree of retrofit difficulty, and economic life of the unit.[17]

For many utility boilers, SNCR and combustion modifications have similar cost effectiveness. The reported cost effectiveness range for stand-alone use of SNCR on coal-fired units has been reported as $500-1,100/ton, while that for combustion modifications of all types, as $200-1,000/ton.[18]

Of primary interest to electric utilities is the cost of pollution controls per unit of electricity generated, expressed on a busbar basis (mills/kWh). For SNCR, the busbar cost varies directly with the amount of NO_x to be removed. Costs range from less than 1.0 mills/kWh for "trim reduction" on a coal-fired unit or RACT-level reduction on an oil fired unit, to 3.5 mills/kWh for a 75% reduction on a unit with uncontrolled emissions greater than

1 lb NO_x/MMBtu.[19] A commercial installation of urea-based SNCR on a New England Electric unit has a busbar cost of 2.7 mills/kWh, and a cost effectiveness of approximately $1,000/ton. (To convert the busbar costs of SNCR to a cost increment relative to fuel price, 0.5-3.5 mills/kWh is roughly equivalent to $0.05-$0.35/MMBtu.)

Innovations in SNCR control systems and continued system optimization during operation have reduced reagent usage at commercial installations, thus decreasing operating costs further. At one coal-fired utility boiler, a control upgrade, including continuous ammonia and temperature monitors, improved control hardware and software, and additional injector pressure controls, allow over a 50% decrease in reagent use from baseline levels.[20] At a second coal- and oil-fired unit, system optimization after start-up has lowered reagent consumption 35% below predicted levels.[21] Given that reagent dominates SNCR operating cost, such large reductions in reagent use translate to significant reductions in operating cost.

What about ammonia slip?
Ammonia slip, or emissions of ammonia which result from incomplete reaction of the NO_x reducing reagent, typically can be limited to low levels.

Ammonia slip may result in one or more problems, including:

- Formation of ammonium bisulfate or other ammonium salts which can plug or corrode the air heater and other downstream components;

- Ammonia uptake by fly ash, which may make disposal or reuse of the ash difficult;

- Formation of a white ammonium chloride plume above the stack; and,

- Detection of an ammonia odor around the plant.

Ammonia slip is controlled by careful injection of reagent into regions of the furnace or other source where proper conditions (temperature, residence time, concentration) for the SNCR reaction exist. If the reagent is injected into a region where the temperature is too low for the NO_x-reducing reaction to occur in the available residence time, then some unreacted ammonia will be emitted. Further, if reagent is injected in such a way that some regions of the furnace are overtreated, the excess reagent can lead to ammonia slip. Thus, it is critical that the SNCR injection system be designed to provide the appropriate reagent distribution.

While the difficulty in controlling ammonia slip will vary from application to application, slip generally can be controlled to less than 25 ppm at the stack (see Appendix A). At many commercial installations, particularly in electric utilities, ammonia slip has been guaranteed to less than 5-10 ppm upstream of the air heater on SNCR systems to meet the requirements of owners or permitting authorities. This is a far more stringent criterion than stack emissions. In any case, ammonia concentrations at ground level will be well below thresholds for both odor and toxicity.

Control system upgrades and process optimization after installation can lower slip below guaranteed levels. Thus, at a commercial SNCR system on a coal-fired boiler, improved controls have lowered ammonia slip from 10-15 ppm to below 5 ppm, and have reduced ammonia on the fly-ash by half.[22]

Use of in-duct SCR downstream from SNCR also increases the applicability of SNCR to ammonia-sensitive units.

Does SNCR have other limitations?
As do all pollution control technologies, SNCR has limitations which must be understood in order to use it properly for the control of NO_x emissions.

High temperature and critical NO_x concentration. As temperature increases, the "critical" or equilibrium NO_x concentration at a given oxygen concentration increases. At high enough temperatures, any reduction of NO_x to below the critical level by SNCR or other means will be counteracted by the rapid oxidation of nitrogen to re-form NO_x. For this reason, at sufficiently high temperatures and baseline NO_x levels below the critical concentration, injection of ammonia or urea into the flue gas will result in *increased* NO_x levels. If, however, the baseline NO_x concentration is above the critical level, NO_x reduction will result. For typical coal- and oil-fired steam boilers, critical NO_x levels are 70-90 ppm (ca. 0.1 lb/MMBtu) in the upper furnace.

High furnace carbon monoxide concentration. High CO concentrations can shift the temperature window of the SNCR process. When CO concentrations in the region of reagent injection are above 300 ppm, the critical NO_x level and SNCR reaction rate will increase above what they would have been had little CO been present, as if the temperature were slightly higher. Therefore, in some furnaces with high CO levels, it is preferable to inject reagent at lower temperatures to effect good NO_x control.

Carbon monoxide emissions. In a well-controlled urea-based SNCR system, the carbon contained in the urea is fully oxidized to carbon dioxide. Normally, steps taken to control ammonia slip impose sufficient restrictions on reaction temperature to prevent substantial emissions of CO.

Nitrous oxide (N_2O) emissions. Nitrous oxide is a by-product of the SNCR process, with urea-based systems typically producing more nitrous oxide than ammonia-based systems. At most, about 10% of the NO_x reduced in urea-based SNCR is converted to nitrous oxide. With proper control, the nitrous oxide production rate may be limited to significantly lower levels. Nitrous oxide contributes to neither ground level ozone nor acid rain formation, and biogenic sources dominate the atmospheric budget of N_2O.

What are common misconceptions regarding SNCR?
Several common misconceptions have slowed the acceptance of SNCR by utilities.

Misconception: As boiler size increases, SNCR efficiency decreases. As long as reagent can be distributed, there is no technical limitation to the size of boilers on which

SNCR will be effective. This misconception arose in part from the earliest experiences at large utility boilers in California. These boilers were equipped with low NO_x combustion systems, had high furnace exit gas temperatures, and very rapid cooling of the gases in the boiler convective regions. Low baseline NO_x levels and rapid cooling led to low SNCR NO_x efficiencies and high ammonia slips. Increased technical knowledge and experience have allowed better delineation of the limitations of the SNCR process, which since then has been used to achieve over 60% NO_x reductions on some electric utility boilers.

It may in fact be more difficult to distribute SNCR reagent in a large boiler. However, this challenge is being overcome with new injection systems which enable delivery of reagent across the boiler, as has been demonstrated both in the U.S. and abroad. The largest commercial installation to-date is at a 321 MW twin-furnace boiler.

Misconception: SNCR cannot be used on boilers equipped with low NO_x combustion controls. SNCR has been installed commercially on boilers equipped with low NO_x burners, overfire air, and flue gas recirculation, and has been shown to operate effectively with all of these technologies.[23]

Misconception: Use of SNCR on coal-fired plants results in fly ash which cannot be sold and the disposal of which is expensive. The tendency of fly ash to absorb ammonia is a function of many factors beyond the amount of ammonia slip. Ash characteristics such as pH, alkali mineral content, and volatile sulfur and chlorine content help to determine whether or not ammonia will be absorbed readily by fly ash. In most applications, properly designed SNCR systems will keep the ammonia slip levels low enough so that the salability of the ash should be unaffected.

Can SNCR be used in combination with selective catalytic reduction (SCR)? Hybrid SNCR-SCR systems have been demonstrated at a number of utility plants, and are being commercially installed to meet post-RACT NO_x limits.

SNCR may be combined with selective catalytic reduction (SCR). While achievable NO_x reductions using SNCR normally are limited by ammonia slip requirements, in a combined SNCR/SCR system, ammonia slip is generated intentionally as the reagent feed to the SCR catalyst, which provides additional NO_x removal. The quantity of catalyst required in a hybrid system is reduced from that in an SCR-only application, so that the hybrid system will have lower capital requirements. This hybrid approach has been demonstrated in several full-scale utility applications.

For example, at two gas-fired utility boilers in Southern California, hybrid systems gave emissions reductions of 72-91%.[24] At a wet bottom coal-fired boiler in New Jersey, a hybrid system reduced NO_x emissions by up to 98%.[25]

A utility in Pennsylvania is installing a full-scale SCR-SNCR hybrid system on a 148 MW coal-fired boiler. An SNCR system currently operating at that boiler reduces emissions from 0.78 lb/MMBtu to 0.45 lb/MMBtu. With the installation of in-duct SCR catalyst, the

utility expects to further reduce NO_x emissions to below 0.35 lb/MMBtu, with less than 2 ppm ammonia slip.[26]

What developments in SNCR technology are expected?
Efforts are in progress to optimize the combination of SNCR with other technologies for controlling NO_x and other air pollutants.

SNCR Combination with Gas Reburn. Reburning under fuel-rich conditions converts NO_x to reduced nitrogen-containing compounds.[27] During burnout, which occurs at lower temperatures than normal combustion, a substantial fraction of these compounds are converted to N_2 (with the remainder oxidized back to NO_x). Pilot scale demonstrations have shown that conditions in the burnout zone are appropriate for SNCR.[28] Thus, reburn and SNCR may be combined to achieve NO_x reductions of over 70%, and a full-scale demonstration with the electric utilities is underway.

SNCR Combinations for Control of Other Pollutants. Many sources must control flue gas constituents other than NO_x, such as SO_2, chlorides, heavy metals, and dioxins and furans. It has been found that co-injection of a lime slurry with aqueous urea provides effective control of SO_2 and chlorides, in addition to NO_x.[29] With a reduction in chlorides, there is an associated reduction in dioxin and furan emissions.[30] In-furnace lime injection has also been shown to reduce emissions of heavy metals.[31] Thus, the combination of SNCR and lime injection has the potential for simultaneous control of NO_x, SO_2, HCl, heavy metals, and dioxins and furans.

SNCR and Wastewater Disposal. In many cases, the ability to discharge wastewater into local streams, rivers, and sewers is restricted, with no discharge allowed in sensitive locations. As an accessory pollution control program to SNCR using aqueous reagents, wastewater can be disposed of by injection into a furnace or other combustion source with simultaneous control of NO_x. The dilution or "motive" water needed to inject urea reagent ranges from 100-500% of the reagent flow. For larger sources, such as utility plants where 500-1000 gallons per hour reagent could be used, typical dilution water use is 1000-5000 gallons per hour or 20-85 gallons per minute, thus offering a significant opportunity for maintenance of plant water balance or wastewater minimization.

How can SNCR be used to best advantage?
The features of being a low hazard, low capital cost, expense-driven technology that requires little space and little unit down-time to implement suggests various appropriate uses to comply with U.S. clean air regulations.

Beyond-RACT Controls for Ozone Attainment. States not meeting the ozone National Ambient Air Quality Standard after application of RACT controls will require greater NO_x reductions from sources within their borders. Many states presume that these reductions will be based on the addition of post-combustion controls, including SNCR. In some cases, SNCR could be retrofit to units that already have implemented combustion modifications.

Where SNCR has been used to meet RACT limits, the reagent use rate could be increased to meet new, lower limits.

Seasonal Controls for Ozone Attainment. In a seasonal approach, NO_x reductions beyond RACT would be required only during the warmer months when ozone exceedances normally occur. For example, the states of the northeast Ozone Transport Region have committed to a plan calling for control of ozone precursors only during the May-September ozone season to help meet regional ozone attainment goals. SNCR is particularly well-suited for seasonal control in that it may provide deep reductions in NO_x emissions, but incurs little cost when the system is not in use. For urea-based SNCR, the incremental cost of control during the ozone season would be on the order of $0.30/MMBtu on a unit without low-NO_x burners, expressed as a fuel cost adder relative to the "off" season.

Acid Rain Control. Under the acid rain provisions (Title IV) of the Clean Air Act Amendments, NO_x limits for Group 2 coal-fired utility boilers, which include cyclones, wet-bottom wall-fired boilers, cell-burner-fired boilers, and all other types of boilers, were promulgated in 1996 based upon the capabilities and costs of available control technologies.

Commercial applications of SNCR now exist on circulating fluidized bed boilers, stokers, and cyclone and other wet-bottom boilers. Although SNCR has not been demonstrated on a boiler fired with cell burners, there is no technical reason significant NO_x reductions could not be realized from this boiler type.

Overcontrol. The low capital cost and ease of retrofit of SNCR suggest its use as an add-on to other NO_x control technologies to provide overcontrol, or control to below permit limits. Overcontrol can be useful where the marginal cost of control on one unit is lower than on other units, and where averaging or trading emissions or emissions reductions is permitted. Averaging provisions of state NO_x RACT rules, the Regional Clean Air Incentives Market (RECLAIM) instituted by the California South Coast Air Quality Management District, the acid rain NO_x rule, and proposed rules for generation of emissions reduction credits[32] all authorize strategies based on overcontrol.

In an overcontrol strategy, a second SNCR system may be used to provide insurance: if the overcontrolled unit in averaged group is forced out of service, the insurance system is available to provide the requisite emissions reductions on a second unit. When the overcontrolled unit is in service, the cost of the insurance SNCR system is limited to a relatively low capital charge.

BACT/New Source Controls. SNCR has been utilized to fulfill best achievable control technology (BACT) requirements for new stoker units in Maine, Vermont, Massachusetts, Connecticut, and Virginia, among other states. In North Carolina, a new pulverized coal-fired unit was permitted recently with SNCR to meet a 0.17 lb/MMBtu NO_x emission limit.

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APPENDIX 1: Selected Applications of Urea-Based SNCR, by Industry

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION (%) (3)
Wood-Fired IPP/Co-Gen Plants					
Black & Veatch Grayling, MI	Zurn Stoker	440	Biomass	150	60
Sierra Pacific Lincoln, CA	Cell-fired	2@130	Biomass	200	46-57
LFC Hillman, MI	Grate-fired	190	Biomass, Tires	170	35
Kenetech Energy Fitchburg, MA	Riley Stoker	225	Wood	210	47
Alternative Energy, Inc. Cadillac, MI	Zurn Stoker	500	Wood	128	50
Alternative Energy, Inc. Livermore Falls, ME	Zurn Stoker	500	Wood	128	50
Alternative Energy, Inc. Ashland, ME	Zurn Stoker	500	Wood	128	50
Ryegate Power Station Ryegate, VT	Riley Stoker	300	Wood	0.2-0.3 (4)	30-50
Zachry Energy Hurt, VA	Riley Stoker	3@390	Wood	0.20 (4)	50
Honey Lake Power Susanville, CA (D)	Stoker-fired	480	Wood	140	52
Ultrasystems Fresno, CA (D)	CFB	280	Wood	150	70
Yankee Energy Dinuba, CA (D)	Grate Type	190	Wood Waste	70-120	42-78
ABB Okeelanta Okeelanta, FL	Grate-fired Stoker	660	Bagasse, Wood, Coal	0.2-0.4 (4)	40-60
ABB Osceola Osceola, FL	Grate-fired Stoker	660	Bagasse, Wood, Coal	110-200	40-60
Black & Veatch Genessee, MI	ABB-CE Stoker	473	Wood	0.47 (4)	60
McMillan Bloedel Clarion, PA	EPI Fluid Bed Combustion	291,000 #/hr steam	Wood Waste, Hog Fuel	100	42

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (3)
Utility Boilers					
NEPCO Unit 1 Salem Harbor, MA	Front-fired	84 MWe	Coal	1.0±0.1 (4)	~66 (5)
NEPCO Unit 2 Salem Harbor, MA	Front-fired	84 MWe	Coal	1.0±0.1 (4)	~66 (5)
NEPCO Unit 3 Salem Harbor, MA	Front-fired	156 MWe	Coal	1.0±0.1 (4)	~66 (5)
WEPCO Valley Power Plt. Milwaukee, WI (D)	Wall-fired	70 MWe	Coal	725	60
LILCO Port Jefferson, NY (D)	T-fired	185 MWe	Oil	250	50
(D)	T-fired	108 MWe	#6 Oil	0.354 (4)	35-60
Niagara Mohawk Oswego, NY (D)	Front-fired	850 MWe	#6 Oil	450	50
Atlantic Electric (3 units) Mays Landing, NJ	Cyclone Cyclone T-fired	138 MWe 160 MWe 160 MWe	Coal Coal #6 Oil	1.31 (4) 1.40 (4) 0.31 (4)	31 36 35
BEWAG	Tower	150 MWe	Heavy Oil	200-225	60-70
RWE C2	T-fired	75 MWe	Brown Coal	150-175	40
RWE (D)	T-fired	150 MWe	Brown Coal	200-250	50
PSE&G of New Jersey Mercer Station)	Wall-Fired Wet Bottom	2@320 MWe Twin Furnace	Pulverized Coal, Gas	2 (4)	35
Eastern Utilities Somerset, MA	Tilting T-Fired Boiler	410-1120	Coal, Oil	0.49-0.89 (4)	28-60
NYSEG Milliken (DOE) Milliken, NY (D)	CE T-Fired, LNCFS III	150 MWe	Coal, Oil	0.37-0.4 (4)	30
Northeast Utilities Norwalk Harbor Station Norwalk Harbor, CT	CE Twin T-fired	172 MW 182 MW	Oil	<0.4 (4)	<0.25 (4)
Penelec Seward #15 Seward, PA	CE T-fired	1147	Coal	0.78 (4)	<0.45 (4)
Delmarva Power Wilmington, DE	T-fired	84 MWe	Coal	0.54 (4)	30
Tire Burners					
Oxford Energy Sterling, CT	Grate-fired	2@170	Tires	80	50
Oxford Energy Modesto, CA (D)	Moving Grate Incinerator	75	Tires	85	40
Chewton Glen Energy	Grate-fired	240.00	Shredded Tires	0.195 (4)	60

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (3)
Pulp and Paper Industry					
S. D. Warren Skowhegan, ME	CE Grate-fired	900	Oil, Bark, Biomass	235	50
P. H. Glatfelter Neenah, WI	Sludge Combustor	60	Paper Sludge	570	50
Garden State Paper Garfield, NJ	Front-fired Ind. Boiler	72	Paper	355	50
Garden State Paper Garfield, NJ	Front-fired Ind. Boiler	172	Fiber Waste	374	50
Boise Cascade International Falls, MN (D)	Hydrogate Stoker	395	Bark, Gas	117-136	35
Sodra Skogsagarna Sweden (D)	Recovery Boiler	900	Black Liquor	60	60
I.P. Masonite Towanda, PA	Towerpak Boiler	204	Wood Waste	0.404 (4)	53
Potlach Bemidji, MN	Wellons 4-Cell Boiler	242	Wood Waste	0.30 (4)	57
Jefferson Smurfit Jacksonville, FL	CE Grate-Fired	540	Coal, Bark, Oil	0.55-0.70 (4)	<0.45 (4)
Minergy Fox Valley Neenah, WI	B&W Cyclone	350	Paper Sludge, Natural Gas	0.8 (4)	62
Refinery Process Units and Industrial Boilers					
MAPCO Petroleum Memphis, TN	Bottom-fired Process Htr.	177	Refinery Gas, NG	75	60
MAPCO Petroleum Memphis, TN	Bottom-fired Process Htr.	50	Refinery Gas, NG	65	50-75
Powerine Santa Fe Springs, CA	Package Boiler	31-62	Refinery Fuel Gas	105	60
Powerine Santa Fe Springs, CA	CO Boiler	31-62	Refinery Fuel Gas	105	60
Mobil Oil Paulsboro, NJ	GT - HRSG	630	Refinery Gas	75	50
Mobil Oil Torrance, CA	CO Boiler	614	Refinery Gas	90	65
Shell Oil Martinez, CA	CO Boiler	3@222	Refinery Gas	230	65
Total Petroleum Alma, MI	CO Boiler	247	Refinery and Natural Gas	1.2 (4)	67

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (3)
Mobil Oil/Macchi Yanbu, Saudi Arabia	Package Boiler	3@265	Vac. Tower Bottoms, Propane		
ARCO CQC Kiln Los Angeles, CA (D)	Calciner HRSG		Petroleum Coke	25	34
UNOCAL Santa Maria, CA (D)	Calciner HRSG		Petroleum Coke	45	53
UNOCAL Los Angeles, CA (D)	CO Boiler	400	Refinery Gas	140	68
Chemical Industry					
North American Chemical Corp. Trona, CA	T-fired	2@75 MWe	Coal	200	40
Formosa Plastics Kaohsiung, Taiwan	Front-fired	331	Coal	200	60
Miles, Inc. Kansas City, MO	Carbon Furnace Afterburner	16	Chemical Waste	150	35
BP Chemicals Green Lake, TX (D)	AOG Incin. HRSG	34	Waste Gas	330	80+
BP Chemicals (3 units) Green Lake, TX	AOG Incin. HRSG	399 399 238 (lb flue gas/hr)	Absorber Off Gas	238 238 150	50 50 50
Coal-Fired Industrial and IPP Co-Generation Boilers					
Cogentrix Richmond, VA	CE Stoker	8@28 MWe	Coal	350	40
Michigan State Univ. East Lansing, MI	CFB	460	Coal	247	57
Standardkessel	Packaged Firetube	31@ 10-20 MWe	Heavy Oil	700-800 mg/Nm^3	40-50
Strakonice	Wall Fired, Grate Fired	2@36-40	Lignite, Brown Coal	600 mg/Nm^3	50
Tekniskaverken Linkoping P1	Stoker	275	Coal	300-350	65
Tekniskaverken Linkoping P3 (D)	Stoker		Wood	200	50
Nykoping	CFB	135	Coal	120-130	70
Far East Textiles Hsihpu, Taiwan	Stork Boiler	190	Coal	550 @ 6% O$_2$	50.00
Sonoco Huntsville, SC	Foster-Wheeler/ Pyropower CFB	145	Coal	195	67.00

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (3)
Riley Ultrasystems II Weldon, NC	Riley Front-Fired	505	Pulverized Coal	0.33 (4)	50
General Electric Lynn, MA (D)	B&W Packaged D-Type	236	#6 Oil, Gas	0.28-0.31 (4)	40-60
NFT GmbH	Fire Tube Package Boilers	5@10-20 MWe	Heavy Oil	700-800 mg/Nm^3	40-50
Municipal Waste Combustors					
New Hanover County Wrightsville Beach, NC	Volund MWC	108	MSW	300	60
Hamm Germany	Moving Grate	3@528	MSW	170	41
Herten Germany	Moving Grate	2@242	MSW	185	60
Frankfurt Germany	Moving Grate	4@660	MSW	170	70
SEMASS Rochester, MA	Riley Stoker	375	MSW	220	50
Emmenspitz Zuchwil, Switzerland (D)	Moving Grate	121	MSW	200	68
(D)	Detroit Stoker	137.5	MSW	110	60
City of Berlin Berlin, Germany (D)	Moving Grate		MSW	160	69
(D)	Zurn Stoker	167	MSW	275	75
Tekniskaverken Garstad (D)	Moving Grate		MSW		
American Ref-Fuel Niagara Falls, NY	Riley Grate	2@414	RDF, MSW	300	50
Connecticut Resource Recovery Authority Hartford, CT	CE VU 40	325	RDF, Coal	0.33-0.52 (4)	35-40
Montenay Resource Recovery Facility Montgomery, PA	Steinmuller MWC	2@260		0.385 (4)	50
Robbins Resource Recovery Facility Robbins, IL	Foster-Wheeler CFB	2@309		0.39 (4)	48.72
Kwang Myung Korea	Steinmuller MWC	2@58	MSW	200	65
De Canderas Cremona, Italy	MWC		MSW, RDF	250 @11% O$_2$	60
Ravenna, Italy	MWC	45,000 Nm^3/hr	MSW	400	62.5

COMPANY/LOCATION (1),(2)		UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (3)
Fort Lewis		MWC	60 tons/day	MSW	230 @7% O$_2$	65
Process Units						
Alcan Berea, KY	(2 units)	Decoater/ Afterburner	30,000 lb cans/hour	Gas	90-130	50-80+
Allis Minerals Oak Creek, WI		Rotary Kiln Incinerator	60	Paper Sludge	0.48 (4)	57
Rollins Environmental Deer Park, TX	(D)	Hazardous Waste Incinerator	185	Chlorinated Chemical Waste, Soil	60-250	35-50
Selas/BHP Rancho Cucamonga, CA		Steel Annealing Furnace	29	Natural Gas	105	65
Cement Kilns						
Ash Grove Cement Seattle, WA	(D)	Precalciner	160 tons solids/ hr	Coal, Gas	350-600 lb/hr	>80

(1)   All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.
(2)   Company/Locations which are not named are requirements of Confidentiality Agreements. (D) Denotes "Demonstration."
(3)   NO$_x$ Reduction values are not necessarily the limit of the technology. These values may be the guaranteed limits.
(4)   lb/MMBtu
(5)   Actual limit = 0.33 lb/MMBtu

APPENDIX 2: Selected Applications of Ammonia-Based SNCR, by Industry

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (2)
Stoker-Fired and Pulverized Coal-Fired Boilers					
KMW Mainz, Germany	Pulverized Coal	2@450	Coal	600	83
STEAG Herne, Germany	Pulverized Coal	4500	Coal	250	55
Showa Denko Oita, Japan	Pulverized Coal	1000	Coke	315	57
Modesto, CA	Stoker Fired	2@204	Tires	N/A	78
Atavista, VA	Stoker Fired	2@380	Wood/Coal	321	50-65
Hopewell, VA	Stoker Fired	2@385	Coal	324	54-66
Buena Vista	Stoker Fired	2@385	Coal	324	54-66
Coal-Fired Boilers					
Veba Kraftwerke A.G. Gelssenkirchen, Germany	Cyclone	730	Coal		38
Kraftwerke Mainz Wiesbaden/Deutsche Babcock Anlagen AG Germany	Cyclone	2@433	Coal		83
Northeast Utilities Merrimack Station Unit 1 Bow, New Hampshire	Cyclone		Coal		
Rio Bravo Jasmin Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Rio Bravo Poso Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Stockton Cogen Stockton, CA	Circulating Fluid Bed	620	Coal		N/A
Stoker-Fired Wood-Fueled Boilers					
Sacramento, CA	Stoker Fired	164	Wood	220	59
Long Beach, CA	Stoker Fired	200	Wood	325	60
Terra Bella, CA	Stoker Fired	158	Wood	100	50
Burney, CA	Stoker Fired	2@478	Wood	116	52
Shasta, CA	Stoker Fired	3@903	Wood	75-90	40-52
Susanville, CA	Stoker Fired	500	Wood	130	58
Tracy, CA	Stoker Fired	275	Wood	310	75

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (2)
Brawley, CA	Stoker Fired	250	Wood	400	60
Circulating Fluidized and Bubbling Bed Boilers					
Chinese Station, CA	Bubbling Bed	315	Wood	125	80
Fresno, CA	Fluidized Bed	350	Wood	120	76
Mendota, CA	Fluidized Bed	349	Wood	120	80
Woodland, CA	Fluidized Bed	330	Wood	120	76
Rocklin, CA	Fluidized Bed	340	Wood	120	76
El Nido, CA	Bubbling Bed	175	Wood		
Chowilla, CA	Bubbling Bed	152	Wood		
Madera, CA	Bubbling Bed	384	Wood		
Poso, CA	Fluidized Bed	394	Coal	150	80
Jasmine, CA	Fluidized Bed	394	Coal	150	80
Colmac, CA	Fluidized Bed	590 total [2 units]	Coal		
Stockton, CA	Fluidized Bed	620	Coal		
Combustion Power, CA	Fluidized Bed		Coal, Coke		
Municiple Solid Waste Incinerators					
Commerce		300 (3)		200	60
Long Beach, CA		3@470 (3)		200	70
Stanislaus County		2@400 (3)		200	67
Unit "M"		750 (3)		320	65
Minneapolis		2@600 (3)		240	60
Spokane		2@400 (3)		300	45
Munich, Germany		930 (3)		190	70
Huntington, Long Island		3@480 (3)		350	60
Essex County		3@770 (3)		190	60
Bremerhaven, Germany					
Union County		3@480 (3)		350	70
Vapor, Sludge, and Hazardous Waste Incinerators					
Carson, CA		2@204	Sludge	350	65

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COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (2)
Deepwater, NJ		2@103	Sludge	265	77
Gaviota, CA		20	Vapor	112	70
Gladstone, Australia		57	Vapor	2000	91
Germany			Vapor		
Gas- and Oil-Fired Industrial Boilers					
TSK Kawasaki, Japan		215	Oil/Gas		55
TSK Kawasaki, Japan		1135	Oil/Gas		57
TSK Kawasaki, Japan		1135	Oil/Gas		55
Mitsui Petrochemical Japan		340	Oil		53
Tonen Kawasaki, Japan		400	CO/Gas		50
Chanselor-Western Oil Santa Fe Springs, CA		50	Crude		65
Champlin Petroleum Wilmington, CA			Oil/Gas		65
Mohawk Petroleum Bakersfield, CA		[2 units]	Oil/Gas		60-70
Oxnard Refinery Oxnard, CA		18.5	Crude		30
Santa Fe Energy Santa Fe Springs, CA		3@150	Crude		
Getty Oil California			Crude		
TSK Kawasaki, Japan		574	Oil/Gas		65
Golden West Refinery Santa Fe Springs, CA		60	CO		75
Glass Melting Furnaces					
PPG Industries Fresno, CA		150	Gas		60
LOF Glass Lathrop, CA		200	Gas/Oil		51
AGF Industries Los Angeles, CA		125	Gas		61

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO$_x$ BASELINE (ppm)	REDUCTION (%) (2)
Sierra Envr. & GAF Irwindale, CA		29	Gas		70
SHOTT Germany					
Oil- and Gas-Fired Heaters					
Tonen Kawaski, Japan		515 and 190	Gas		63
Kyokuto Petroleum Chiba, Japan		2@250	Oil/Gas		51 to 53
Champlin Petroleum Wilmington, CA		627 total [13 units]	Oil/Gas		50 to 60
Mohawk Petroleum Bakersfield, CA		349 total [4 units]	Oil/Gas		60 to 70
Fletcher Oil and Refining Wilmington, CA		47 total [2 units]	Gas		45 to 65
Independant Valley Energy Bakersfield, CA		165 total [4 units]	Gas		65 to 75
Chevron Research San Francisco, CA		315	Gas		69
Monsanto Carson, CA		23	Oil		43
PPG Industries Fresno, CA	Glass Furnace	150	Gas		60
LOF Glass Stockton, CA	Glass Furnace	200	Gas/Oil		51
Mendota Biomass Mendota, CA	Circ. Fluid Bed	349	Wood		72
Rocklin Rocklin, CA	Circ. Fluid Bed	340	Wood		76
Sierra Envr. and GAF Irwindale, CA	Glass Furnace	29	Gas		70
SHOTT Germany	Glass Furnace		Gas		

(1)   All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.

(2)   NO$_x$ Reduction values are the guarantees.

(3)   Tons/day.