Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers

Version 2

TR-108181

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REPORT SUMMARY

This document reviews and summarizes NO_x control technologies to help utility engineering and operating staff evaluate and select appropriate retrofit strategies for natural gas-and oil-fired boilers. In addition to general discussions of the various technologies, the document includes an accompanying data base on diskette with detailed information on 239 NO_x retrofits.

Background

Almost since its inception, EPRI has been at the center of NO_x control research for utility boilers. This document is an updated version of guidelines on retrofit NO_x control technologies originally produced in 1993 as EPRI report TR-102413. Background information that has not changed since 1993 is not repeated in this document, and the reader is referred to the original version for the following sections: NO_x Formation, Regulatory Overview, and Developing a NO_x Control Strategy.

Objective

To help utility engineers and operating staff evaluate and select the most appropriate and cost effective NO_x control technologies for gas- and oil-fired boilers.

Approach

In order to revise guidelines on NO_x control technologies for gas- and oil-fired boilers, the project team reviewed and summarized NO_x control technology information in the public domain or shared with EPRI by utilities regarding reduction capabilities, controlled emissions levels achieved, retrofit issues, and associated costs. They surveyed utilities to compile on diskette a database of 239 NO_x retrofits that contains information on NO_x performance, cost, and other pertinent information. The team developed a set of spreadsheet cost models to help utilities quickly develop approximate (±25%) budgetary estimates of capital and operating costs for NO_x control retrofits.

Results

This report discusses six general approaches to NO_x reduction:

- Boiler tuning and optimization
- Boiler modifications
- System modifications such as overfire air or flue gas recirculation
- Burner replacement with lower-NO_x models
- NO_x reburning
- Post-combustion technologies (selective catalytic and non-catalytic reduction)

Each technology is described with information on the experience base, applicability to specific boilers, NO_x reductions achieved, typical boiler upgrades required, impacts on boiler operation, and typical costs. The document includes several promising new approaches that were not sufficiently developed to be included in the original guidelines, such as ultra low-NO_x burners that target NO_x levels below 20 ppm and boiler optimization software. Guidelines are provided for development of retrofit system purchase specifications and for boiler preparation and testing prior to and following installation of retrofit systems.

The document is accompanied by two PC diskettes. One contains a data base on diskette with detailed information on 239 NO_x retrofits. The second diskette is a set of spreadsheet cost models for Lotus 123 or Microsoft EXCEL that generate quick budget estimates of capital and operating costs for the most commonly used NO_x control technologies that have significant associated costs.

EPRI Perspective

EPRI continues to evaluate new NO_x control technologies to help utilities comply with emission regulations at the lowest possible cost. Additional EPRI products applicable to NO_x control in gas- and oil-fired boilers are listed in Section 3 of this report.

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Interest Categories

Air emissions control
Environmental compliance planning

Keywords

NO_x control technologies
Burner
Boiler tuning
Post-combustion technologies

ABSTRACT

This document is designed to help utility engineers and operating staff evaluate and select appropriate NO_x control technologies for natural gas- and oil-fired boilers. The document reviews and summarizes NO_x control technology information in the public domain, or shared with EPRI by utilities, regarding reduction capabilities, controlled emission levels achieved, retrofit issues and associated costs. It is an updated version of guidelines originally produced in 1993 (TR-102413).

The following general approaches to NO_x reduction are discussed:

- Boiler tuning and optimization
- Burner modifications
- System modifications (e.g., overfire air, flue gas recirculation)
- Burner replacement with lower-NO_x models
- NO_x reburning
- Post-combustion technologies (selective catalytic and non-catalytic reduction)

Each technology is described and information presented on the experience base, factors affecting applicability to specific boilers, NO_x reductions achieved, typical boiler upgrades required, impacts on boiler operation and typical costs. Each technology is discussed on a stand-alone basis as well as in combination with other technologies. The document includes several promising new approaches that were not sufficiently developed to be included in the original guidelines, such as ultra low-NO_x burners (targeting NO_x levels below 20 ppm) and boiler optimization software.

In addition to general discussions of the various technologies, the document includes an accompanying data base on diskette with detailed information on 239 NO_x retrofits. The data base contains information on the NO_x performance, cost and problems experienced with each system on gas and/or oil fuels as well as pertinent information about the boiler involved in each case. In surveying utilities to gather this information, it was found that substantial experience has been gained during the approximate three-year period since development of the original guidelines with the more costly technologies that had not been extensively applied at that time, especially low-NO_x burners and selective catalytic reduction.

Also accompanying the document on diskette is a set of spreadsheet cost models developed by EPRI to assist utilities in quickly developing budgetary estimates (± 25%) of capital and operating costs for NO_x control retrofits to specific boilers. Models are provided for the most commonly used technologies that have significant costs associated with them--i.e., low-NO_x burners, overfire air, flue gas recirculation, and selective catalytic and non-catalytic reduction. The goal of these models is to provide reasonable estimation of cost while limiting the required input to parameters that are either readily available or easily obtained.

The document also includes guidelines for development of retrofit system purchase specifications and for boiler preparation and testing prior to and following installation of the retrofit system. Forty-seven references and 13 related EPRI products are cited, representing additional information and evolving technologies pertinent to control of NO_x on existing gas- and oil-fired utility boilers.

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We are especially grateful to utility personnel who helped by providing data on performance and costs of retrofit NO_x controls, reviewed data provided by vendors and/or served as reviewers of the draft report. Although numerous individuals contributed, the following individuals, listed alphabetically, were especially helpful:

- Ben Carmine, Houston Lighting & Power
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- Ray O'Sullivan, Orange & Rockland
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- Jim Schott, Entergy
- Kent Wanniger, Commonwealth Edison
- Phil Winegar, New York Power Authority

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We also want to acknowledge the help and cooperative attitude of Stratos Tavoulareas (EnTEC), who helped us coordinate this document with analogous information being assembled for coal-fired boilers.

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EXECUTIVE SUMMARY

This document is designed to help utility engineering and operating staff evaluate and select appropriate retrofit NO_x control technologies for natural gas- and oil-fired boilers. Specifically, this document reviews and summarizes NO_x control technology information in the public domain, or shared with EPRI by utilities, regarding reduction capabilities, controlled emission levels achieved, retrofit issues, and associated costs. The document is an updated version of guidelines originally produced in 1993 (TR-102413). Background information in the original version that has not changed since 1993 is not repeated in this document, and the reader is referred to the original version for information on those subjects. Sections not repeated in the current version include "NO_x Formation," "Regulatory Overview," and "Developing a NO_x Control Strategy."

Almost since its inception, EPRI has been at the center of NO_x control research for utility boilers. As NO_x has become a nationwide issue, a number of products have been and are being developed to assist utilities in planning and implementing cost-effective NO_x control strategies. Products, in addition to this document and its predecessor, that are applicable to gas- and oil-fired boilers are listed in Section 3. For additional information regarding their status and applicability to address a given need, it is highly recommended that the listed EPRI project manager be contacted.

Information on specific NO_x control technologies that are generally applicable to gas- and oil-fired boilers is presented in Section 4. Each technology is described and information provided on the experience base, applicability to various types of boilers on gas and oil fuel, actual NO_x reductions achieved, typical boiler upgrades required, impacts on boiler operation, and typical costs.

Technologies are presented in the order of increasing cost, as a utility will generally want to consider implementation of technologies in this order. A summary of NO_x reduction performance achieved at full scale, in conjunction with control cost, is presented in Figure 1-1. The purpose of Figure 1-1 is to orient the reader with respect to the range of NO_x reduction performance and order of magnitude cost as a function of technology. Figure 1-1 reflects the generalized cost information presented in the document for the various technologies. To assist the utility in developing more accurate (±25%) estimates for specific applications, the document is accompanied by a Cost Estimating Methodology for Retrofit NO_x Controls (developed by Black & Veatch) on diskette. Appendix D provides a description of the cost estimating methodology and instructions for its use.

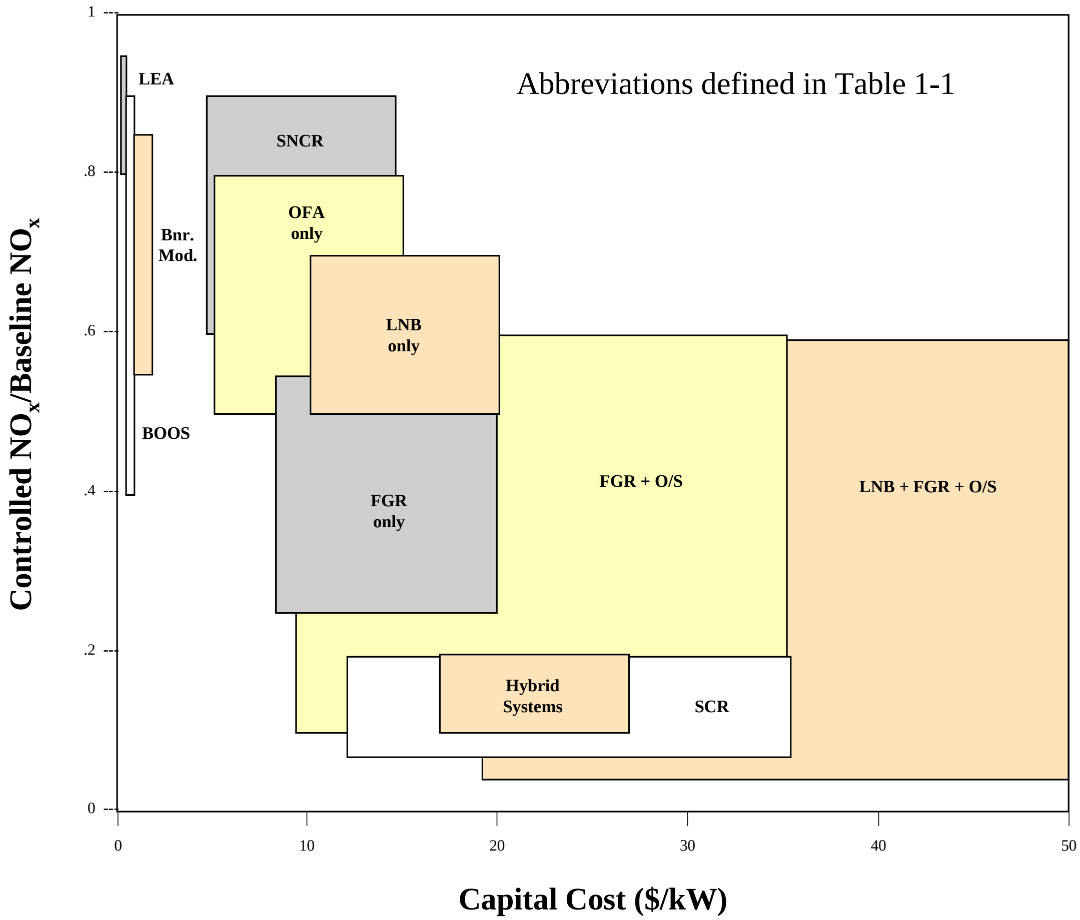

Figure 1-1
NO_x Control Technologies: Reduction Capability versus Capital Cost

Frequently, multiple NO_x control technologies are applied in combination. It is important to realize that when technologies are combined, the overall NO_x reduction capability of the combination will be less than the sum of what the technologies could each accomplish if applied alone. It is also important that in determining cost-effectiveness of a technology combination on a $/ton basis, the technologies be considered separately in the order of increasing cost so that more costly technologies are given credit only for the marginal NO_x reduction that they actually contribute. This avoids the common error of including a high-cost technology in a package in which its marginal cost-effectiveness is actually very poor.

A summary of NO_x control technology applications is presented in Table 1-1. Included for each technology are both controlled NO_x levels and percentage reductions that have been achieved on various boilers to which each technology has been applied. These figures reflect results for full-load operation of the boilers, and results may differ at reduced loads. In viewing controlled NO_x levels achieved by various technologies, as presented in this document, it should be borne in mind that these figures are dependent not only on the technology but also on boiler design and operating factors such as furnace heat release rate and, for oil, fuel nitrogen content. More detailed data, including information on these factors, can be found for specific applications in the Retrofit NO_x Control Data Base (Appendix A).

Table 1-1
Summary of Evaluation of Control Technologies

Control Technology	NO_x Reduction (%)	Controlled Emission Rate[1] lb/MBtu (g/MJ)	Applicability Factors	Typical Boiler Upgrades	Potential Impacts on Boiler Operation	Capital Costs[2]
Low Excess Air (LEA)	5-20 (typical)	Insufficient data as stand-alone technology	Not applicable to controlled units (full-load O_2 levels are already less than 1% above optimum levels) Applicability to low load may be restricted by steam temperature or NFPA requirements	O_2 and CO monitors Combustion diagnostic testing and boiler tuning	Improved boiler efficiency Effect on steam temperature control can be beneficial or detrimental May increase CO, as well as opacity or particulate levels for oil-fired applications	<<$1/kW
Burners -Out-of-Service (BOOS)	Gas: 20-60 Oil: 10-50	0.10-0.30 (.043 0.13) 0.15-0.35 (.065-0.15)	Requires ≥2 burner elevations for maximum effectiveness	O_2 and CO monitors Combustion diagnostic testing and boiler tuning Recalibration of flame scanners Modified burner management system to permit open air registers for BOOS operation Modified fuel supply system, oil atomizers, and gas spuds to support increased burner fuel flow	Potential impacts (may be avoided or minimized through site-specific design): - increased excess O_2 - increased opacity, CO, and particulate - flame impingement - flame instability and boiler rumble - steam temperature control - load restrictions Reduced operating and maintenance flexibility due to fewer in-service burners	<$1/kW
Biased Firing[3]	Gas: 20-50 (est.) Oil: 10-40 (est.)	Insufficient data. Generally expected to be comparable to but somewhat less effective than BOOS.	Generally applicable to multi-burner boilers.	Requires valving to regulate fuel supply to individual burners or headers. Existing hardware may suffice.	Similar to BOOS except that all burners remain in service.	<$1/kW
Optimization Software	10-35	Insufficient data as a stand-alone technology	Reasonably modern instrumentation and controls required; some softwares require DCS	Calibration, refurbishing and possible upgrade of instrumentation and actuators; some personnel training	Can be used to simultaneously optimize for reduced heat rate	$35,000-$50,000 (one-time optimization) $150,000-$300,000 (on-line optimizer)
Burner Modification (Oil)	15-45	0.15-0.40 (.065-0.17)	Applicable to most oil-fired boilers. Being developed by EPRI for gas.	New atomizers and impellers Potential fuel supply system modifications to accommodate pressure or flow requirements	Improved combustion efficiency Increased atomization steam requirements	$1-2/kW

Table 1-1
Summary of Evaluation of Control Technologies

Control Technology	NO_x Reduction (%)	Controlled Emission Rate[1] lb/MBtu (g/MJ)	Applicability Factors	Typical Boiler Upgrades	Potential Impacts on Boiler Operation	Capital Costs[2]
Overfire Air (OFA)	Gas: ~50 Oil: 20-50	0.08-0.30 (.034-0.13) 0.14-0.37 (.06-0.16)	Requires sufficient upper furnace volume for OFA mixing and complete combustion Physical space requirements for OFA ports and air supply ducts	Tube wall panels for OFA ports Air supply ducts OFA measurement and control for each port	Potential impacts (may be avoided or minimized through site-specific design): - increased excess O_2 - increased opacity, CO, particulate - flame impingement - flame instability and boiler rumble - steam temperature control - load restrictions	\$5-\$15/kW (see Appendix D)
Flue Gas Recirculation (FGR)	Gas: 60-75 (FGR only)[5] 70-90 (FGR + O/S)[4] Oil: 45-70 (FGR only)[5] 40-80 (FGR + O/S)[4]	0.13-0.23 (.056-.099) (FGR only)[5] .05-0.16 (.022-.069) (FGR + O/S)[4] 0.20-0.38 (.09-0.16) (FGR only)[5] 0.15-0.35 (.065-0.15) (FGR + O/S)[4]	Applicability may be limited by: - steam temperature requirements - windbox pressure limits - fan draft limitations - burner design velocity - burner stability	FGR fans, ductwork, dampers, and controls Gas mixing devices Gas measurement and control devices Potential heat transfer surface modifications FD and ID fan upgrades	Potential flame instability and boiler rumble Potential load restrictions due to furnace, FD fan, or windbox pressure limitations (can be overcome with equipment upgrades) Effect on steam temperature control can be beneficial or detrimental FGR fan power requirements	\$8-\$20/kW \$9-\$35/kW (FGR + O/S based on FGR cost range plus lowest BOOS and highest OFA cost) (See Appendix D)
Low-NO_x Burners (LNB)	Gas: 30-50 (LNB only) 70-90 (w/ O/S)[4] 70-95 (w/FGR+O/S)[4] Oil: 30-50 (LNB only) 30-60 (w/O/S)[4] 40-80 (w/FGR+O/S)[4]	0.10-0.35 (.043-0.15) (LNB only) .06-0.10 (.026-.043) (w/ O/S)[4] 0.03 -0.17 (.013-.073) (w/FGR+O/S)[4] 0.15-0.50 (.065-0.22) (LNB only) 0.15-0.25 (.065-0.11) (w/O/S)[4] 0.15-0.30 (.065-0.13) (w/FGR+O/S)[4]	Existing burner spacing must accommodate LNB Furnace dimensions to accommodate longer LNB flame without impingement Sufficient FD fan capacity and windbox pressure limits for higher pressure drop burners	Burner assemblies and related equipment (air registers, fuel elements, ignitors, scanners, etc.) Fuel and air supply system modifications Monitoring and control of fuel and air distribution to burners to achieve balanced flow Potential upgraded FD fans Potential waterwall modifications	Potential impacts (may be avoided or minimized through site-specific design): - increased excess O_2 - increased opacity, CO, particulate - flame impingement Increased fan power requirements	\$10-\$20/kW \$19-\$50/kW (LNB+FGR+O/S based on lowest cost LNB/FGR/BOOS system and highest-cost LNB/FGR/OFA system) (See Appendix D)
Ultra Low-NO_x Burners (ULNB)	Not yet demonstrated in utility environment	Gas (est.): .038-.063 (.016-.027) (w/fuel biasing) ≤.025 (.011) (w/FGR) ≤.02 (.009) (w/ advanced fuel staging [AFS]) ≤.013 (.006) (w/ AFS + FGR) Oil (est.): ≤0.195 (.084) (w/ FGR)	Wall-fired boilers Ultra-low NO_x on gas fuel only Same retrofit concerns as LNB Burner size and pressure drop likely to be more severe High FGR and/or fuel staging may be required for ultra-low NO_x	Same as for LNB	Same as for LNB except for simulated premix type ULNB, which has inherently good combustion characteristics and short flame	Significantly higher than LNB; also FGR and/or fuel staging system may be required

Table 1-1
Summary of Evaluation of Control Technologies

Control Technology	NO_x Reduction (%)	Controlled Emission Rate[1] lb/MBtu (g/MJ)	Applicability Factors	Typical Boiler Upgrades	Potential Impacts on Boiler Operation	Capital Costs[2]
Reburning	Gas over Gas: 30-75 Gas over Oil: ~45	.050-0.15 (~.022-.065) ~0.15 (~0.065)	Requires sufficient upper furnace volume for reburn zone and OFA zone OFA system required	OFA system Small (3-4%) FGR system in most cases Fuel injection ports Reburn fuel/FGR and OFA controls	More complex operation. Fuel-rich zone: potential corrosion on high-sulfur oil, explosion concern on pressurized furnaces. Potentially higher CO, particulate and opacity. Potential higher steam temperatures.	Approx. $15/kW for 500-MW unit. $/kW roughly proportional to $1/MW^{-1/2}$
Selective Non-Catalytic Reduction (SNCR)	10-40 (SNCR only) 75-85 (w/FGR+O/S [gas])[4]	 .050-0.10 (.022-.043) (w/FGR+O/S [gas])[4]	Requires sufficient flue gas residence time at critical temperature window NO_x reduction varies with boiler operating conditions Physical access for injectors at optimum locations Lower NO_x reduction potential where NO_x is already very low (i.e., <100 ppm) or with low NH_3 slip limits	Reagent unloading and storage equipment Reagent conveying and injection equipment Process control system Air heater sootblower upgrade (oil unit)	NH_3 slip, N_2O emissions Air heater pluggage (oil units) Increased opacity and particulate emissions (oil units) Reagent cost	$5-$15/kW (see Appendix D)
Selective Catalytic Reduction (SCR)	80-93 (SCR only)	<0.05 (<.022) (w/FGR+O/S [gas])[4]	Physical space requirements Fan draft limitations Furnace and ductwork pressure limits In-duct systems generally applicable only to well-controlled gas units or where moderate reduction is required	SCR reactor, ductwork, and support structure or duct expansion/ strengthening for in-duct systems Reagent unloading and storage equipment Reagent conveying and injection equipment Process control system Air heater sootblower upgrade (oil unit) Upgraded FD fans/new ID fans	Increased pressure drop and fan power requirements Potential load restrictions due to FD fan or windbox pressure limitations (can be overcome with equipment upgrades) Air heater pluggage, increased opacity and particulate emissions (oil units) NH_3 slip Reduced thermal efficiency Catalyst replacement and disposal costs Reagent cost	$12-$35/kW (See Appendix D)
Hybrid Post Combustion NO_x Control	80-90	.025-.03 (.011-.013) (gas)	Same as for SNCR and SCR; however, size and pressure drop of SCR are reduced relative to stand-alone SCR	Same as for SNCR and SCR; however, size and pressure drop of SCR are reduced relative to stand-alone SCR	Same as for SNCR and SCR; however, size and pressure drop of SCR are reduced relative to stand-alone system	$17-$27/kW (based on SNCR range and min. SCR cost)

Notes:

1. Approximate range based on full-load results from units surveyed. Included are short-term test data that may not reflect long-term emission rates. For NO_x unit conversion see Appendix E.
2. In addition to capital costs, most control technologies will result in increased operating costs. Please refer to the sections entitled Control Costs included for each control technology discussed in Section 4.
3. "Biased firing" generally denotes fuel biasing to create rich and lean zones and includes "spuds-out-of-service" (SOOS) operation on gas fuel.
4. O/S denotes BOOS (or biased firing) and/or OFA.
5. Only three data points.

Other factors that can influence NO_x performance data from technology applications are: (1) whether the controlled NO_x level represents short-term operation under test conditions or longer-term operating data and (2) whether the NO_x reduction figure is based on a "tuned" or "untuned" NO_x baseline. Short-term test data often produce a lower NO_x level than is sustainable on a long-term basis, and comparison to an untuned NO_x baseline (i.e., prior to any optimization of the boiler for lower-NO_x operation) tends to overstate the NO_x reduction achieved. Wherever possible the data presented in this document represent long-term results and comparisons to tuned baselines. However, it was not possible to verify this in every case. Here again, the data base attempts to clarify these issues for specific applications where possible.

Cost figures provided in this document are necessarily generic in nature as costs for application of each of these technologies are highly dependent on numerous site-specific factors and the scope of work elected by the utility. For the more costly NO_x control technologies—SCR, SNCR, LNB, FGR, and OFA--the cost estimating methodology in Appendix D allows a more site specific evaluation of application costs. With regard to both NO_x reduction and cost to be expected in applying a given technology to a given boiler, figures in this document are intended to provide general guidance only. Accurate figures will require a detailed evaluation in each case. Guidelines for preparing and testing the boiler are provided in Appendix B, and guidelines for preparing a purchase specification are provided in Appendix C.

The following paragraphs present a brief overview of the NO_x control technologies that are included in the document.

Tuning and Optimization. This group of technologies includes low excess air (LEA) operation, burners-out-of-service (BOOS) operation and/or biased firing and application of optimization software. Since these NO_x control approaches involve little or no hardware changes on the boiler and little or no operating cost, they are usually considered as the first step in controlling NO_x. LEA should be considered for any boiler where it is believed that significant reduction in operating excess O_2 may be possible. Many gas- and oil-fired boilers are today operating below one percent excess O_2.

BOOS operation, in which selected burners are placed on air-only operation, has been applied extensively to gas- and oil-fired boilers, particularly in areas of the country where NO_x regulations have been in effect for many years. BOOS has been most successful on boilers with four or five burner elevations, where 20 or 25% of the burners can be taken out of service without skewing the fuel/air admission pattern side-to-side. The overall experience with BOOS has been that it is highly cost effective relative to alternative controls that could achieve similar NO_x levels. However, BOOS operation is generally found to produce some operational problems, and in some cases minor efficiency degradations, particularly when combined with flue gas recirculation. Where possible, utilities practicing BOOS operation would generally prefer to return their boilers to all-burners-in-service (ABIS) operation.

Biased firing involves the redistribution of fuel among the burners to create staged combustion conditions, which can be advantageous where there are a limited number of burners or burner elevations. One way of implementing biased firing in gas-fired units having multiple element burners is to remove selected gas elements (spuds) from service to create rich and lean zones. Compared to BOOS, biased firing and spuds-out-of-service (SOOS) are not as widely demonstrated and are more complex to implement and operate. Furthermore, the NO_x reductions attainable with these firing modes are generally less than or comparable to those demonstrated with BOOS.

A number of optimization software packages have been and are being developed specifically to optimize utility boiler operation. Optimization objectives can include both NO_x and efficiency as well as other performance criteria, and the software can be instructed to prioritize objectives as well as to constrain selected performance criteria within acceptable limits. With respect to NO_x control, however, it is important for the utility to assess what operating parameters are available to effect NO_x emission reductions, and determine whether the optimization software will provide any results beyond those available through rudimentary NO_x tuning approaches (e.g., as described in TR-105109).

Burner Modifications. On oil-fired boilers, significant NO_x reductions, as well as improvements in other performance characteristics such as opacity and unburned carbon particulates, can be achieved through replacement of critical components of the burner hardware (normally the atomizer and impeller) with improved designs. This low-cost NO_x reduction technology has been applied to many oil-fired boilers, and similar technology, based on the same principles, is now being developed for gas-fired boilers.

System Modifications. The most significant technologies included in this category are overfire air (OFA) and flue gas recirculation (FGR) to the windbox. These technologies require significant modification to the boiler system, and FGR involves significant incremental operating cost in terms of fan power; however, both are highly cost effective NO_x controls and have been applied to many gas- and oil-fired boilers. They are generally applicable to all types of boilers; however, various constraints, such as space limitations, insufficient air fan capacity, or steam temperature limits, may restrain their application. OFA applicability and effectiveness depends mainly on upper furnace volume available to complete burnout reactions and space available on the boiler for ports and ductwork. In some cases similar results can be achieved at much lower cost using BOOS operation. Many installed FGR systems have been limited in their achievable NO_x reductions by constraining factors, and methods are available to mitigate these constraints in existing systems as well as in planning new installations.

FGR and off-stoichiometric (O/S) combustion (i.e., BOOS and/or OFA) are frequently combined due to the complementary NO_x reductions and excellent cost effectiveness of both technologies. However, combination of these technologies has compromised combustion performance on a number of the boilers on which it has been practiced. In many of those cases, operation has been improved through windbox modifications to more evenly balance air flows to burners and by replacing burners with low-NO_x models, which in this case mainly act to better stabilize the flames. FGR and O/S combustion have been especially effective on gas fuel, and low-cost burner modifications are being developed by EPRI to enable gas fuel operation in this mode without having to replace the burners.

EPRI is currently evaluating a low-cost method to achieve a limited degree of FGR by utilizing any excess FD fan capacity on a given boiler to pull flue gas into the combustion air. This method, known as induced flue gas recirculation (IFGR), can be extremely cost-effective since it involves very little capital or operating cost. Although quantities of flue gas that can be recirculated using IFGR are limited, NO_x reductions can be quite significant since the first few percent of FGR are the most effective in reducing NO_x.

On tangential-fired boilers, windbox FGR has often been applied to the auxiliary air only and not to the fuel air. For this type of system, further NO_x reduction can be achieved by a low-cost modification in which a portion of the FGR is ducted to the fuel air. For new FGR retrofits to tangential-fired boilers, FGR should be directed to both the fuel and auxiliary air for maximum NO_x reduction effectiveness.

Units equipped with FGR directly to the furnace and not via the windbox (i.e., older FGR systems intended for steam temperature control) can in some cases use this existing capability to reduce NO_x. Reductions of approximately 25% have been demonstrated using this technique on opposed-fired units operating on gas fuel. This type of non-windbox FGR would not, however, be expected to perform as well on tangential-fired boilers, where the flame zone is already heavily diluted with furnace gases, and may not perform as well on some single wall-fired units, i.e., those on which the FGR admission point does not cause it to pass through the flame zone.

Another system modification, which can reduce NO_x emissions on gas fuel is fuel injection recirculation (FIR). FIR involves dilution of gaseous fuel with an inert medium such as flue gas or steam prior to combustion, which lowers flame temperature and reduces NO_x. Tested on a 44 MW gas-fired utility boiler using steam as the diluent, FIR provided 50% additional NO_x reduction from a NO_x level that was already very low with approximately 15% FGR to the windbox. Use of steam or compression of flue gas to dilute the fuel represents a substantial operating cost, and thus FIR, using either of these methods, is most suitable for a unit with a low capacity factor and/or short remaining life. However, methods to induce flue gas into the fuel using a smaller amount of steam or by taking advantage of inherently high natural gas line pressures have been considered.

Two other system modification technologies that have been applied to utility boilers are water injection and reduced air preheat. Both of these technologies have severe economic penalties in terms of direct impacts on boiler efficiency and thus are not generally recommended except as trim controls to be used infrequently. Water injection has been applied on some boilers, and is effective on both gas and oil, but is more effective on gas. Water (or steam) can be sprayed into the combustion air upstream of the burners or added directly at the burners. On dual-fuel fired boilers that use oil infrequently, the oil guns can be used to inject water during gas operation. A reduced-air preheat system, consisting of a dampered air preheater by-pass duct, was demonstrated on one boiler in Southern California, but was not used in practical operation. These methods, like FGR, depend on cooling the flame to reduce NO_x formed by high-temperature reactions, and thus their effectiveness can be predicted based on the diluent flame cooling effect in each case, as shown in Figure 1-2. For example, based on a flame cooling of 1500 Btu/lb fuel, the NO_x can be reduced on average 48% with either 10% FGR, 0.50 lb/lb fuel, or 400°F reduction in air preheat temperature. For FGR, this translates to nominally -4.8% per percent FGR, which is comparable to results from Morro Bay (Figure 4-17) in which -4.4% per percent FGR were obtained between 9% and 18% FGR.

Burner Replacement. LNBs have been available for many years, and a significant number of gas- and oil-fired utility boilers currently operate with this retrofit technology in place. LNBs have been developed mainly for wall-fired (i.e., circular burner) boilers, but have also been applied on a few tangential-fired boilers. LNBs are capable of substantial NO_x reductions on both gas and oil fuels, but similar NO_x reductions can frequently be achieved using lower-cost combustion modifications (O/S combustion and FGR) discussed previously in this section. The utility should thus carefully analyze the cost-effectiveness of any proposed LNB retrofit versus that of combustion modifications. Once FGR and O/S combustion have been applied, LNB technology can generally offer little further NO_x reduction. In some cases LNBs have been successfully used to improve flame stability under high-FGR, O/S firing conditions. However, burner modification technology being developed by EPRI is intended to enable operation under these conditions on gas fuel at substantially lower cost than LNB technologies.

Several ultra low-NO_x burner (ULNB) technologies are at various stages of development. These burners are, from a retrofit point of view, virtually the same as LNBs but utilize advanced mixing and staging techniques to achieve NO_x levels well below those achievable by LNBs. ULNBs have thus far been developed using circular burner configurations (i.e., for wall-fired boilers) operating on gas fuel, but the technologies may be extendible to tangential-fired boilers and oil fuel. Based on its performance on several small industrial boilers, installation of one ULNB technology on a utility boiler is planned. The NO_x level on this boiler on gas fuel is expected to be less than 20 ppm with FGR and approximately 10 ppm with FGR and fuel staging. With the possibility of producing NO_x levels in this range, ULNB technologies may thus be highly significant for utilities facing the possibility of NO_x limits in the future that are typically associated with SCR technology for compliance.

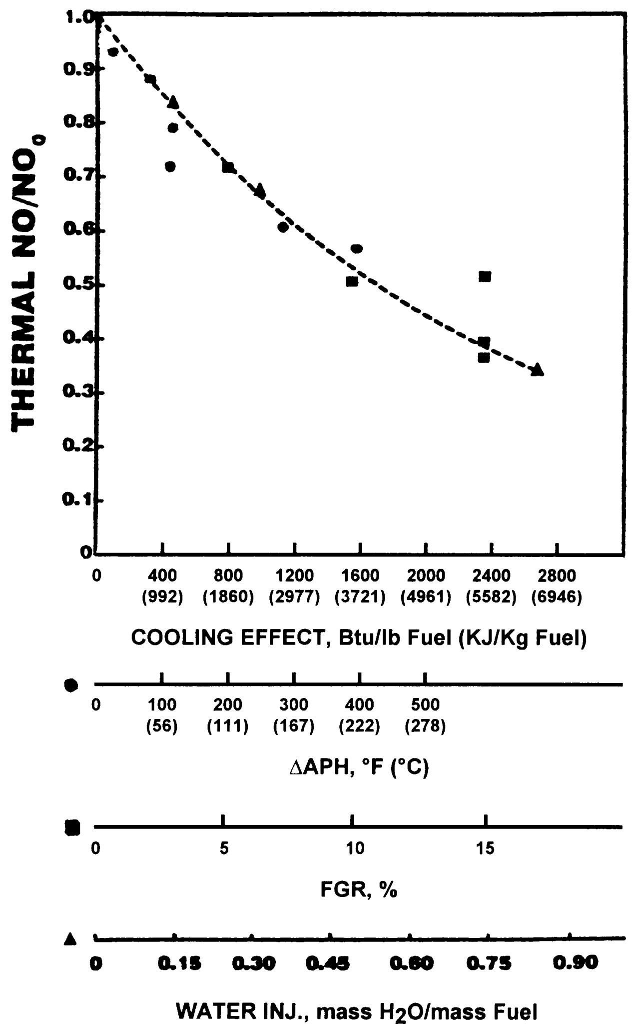

Figure 1-2
Correlation of NO_x Reduction as a Function of FGR, Reduced Air Preheat and Water Injection Levels

Reburning. Reburning involves redeployment of fuel and air admission to the boiler to create a fuel-rich zone above the main burners, which reduces NO_x, followed by overfire air zone to burn out residual combustibles. Reburning technology is commercially available but has thus far been installed on boilers in the U.S. for demonstration purposes only. Gas/gas (i.e., gas over gas) reburning has been demonstrated on three boilers, and gas/oil reburning has been demonstrated on one of these three. It is significant, however, that all three boilers were coal-design boilers, which have substantially more upper furnace volume than boilers designed for gas and/or oil firing. Utilities should proceed with caution with regard to retrofitting reburn systems to gas/oil- design units. Proposed designs that place the overfire air higher in the furnace than has been successfully demonstrated on existing OFA applications should be carefully analyzed.

On one of the demonstration systems, it was found that reburning accomplished little more NO_x reduction than operation of the overfire air system alone. Thus utilities, in evaluating this technology for specific boilers, should analyze the net benefit that reburning can be expected to produce relative to overfire air alone.

Both gas/gas and oil/oil reburning have, however, been retrofit commercially to gas- and oil-design boilers in Italy with good performance results reported. However, it is not clear in information that has been made available to what extent the relatively high (up to 80%) NO_x reductions attributed to reburning may have been partially due to other technologies applied simultaneously to the same boilers.

A variation of reburning called "controlled mixing" has undergone demonstration testing on a coal-fired boiler with NO_x reductions on the order of 30%. This approach may be a cost competitive option to low-NO_x burners, as it relies on localized reburn reactions to reduce NO_x and does not have the added cost of overfire air ports.

Advanced gas reburning, a synergistic combination of reburning with SNCR, is another variation. In this case, the reburn system is operated upstream of an SNCR system in a manner that conditions the flue gas to broaden the SNCR temperature window and improve the performance of the SNCR system. Advanced gas reburning is now undergoing testing on a coal-fired utility boiler.

Post Combustion NO_x Controls. This group of technologies includes selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR) and Hybrid Post-Combustion NO_x Control (Hybrid Systems). All of these technologies depend on the selective reaction of ammonia or amine compound with NO_x, and thus require injection of ammonia or an ammonia-base chemical into the flue gas. SNCR is applied in a relatively high-temperature zone of the boiler and does not require a catalyst whereas SCR does require a catalyst but can be applied at lower temperature, i.e., at the economizer outlet.

SNCR has normally been applied in conjunction with O/S combustion and/or FGR, and as such has typically achieved only modest NO_x reductions, in the 10 to 40% range. Utilities generally do not favor this technology because of the need to deal with chemical reagents. Also, the technology can present operational challenges for load-following units, since the NO_x reduction reactions on which it depends are sensitive to temperature and the temperature in the chosen injection zone will change as a function of boiler load. Multiple injection zones can ameliorate this problem in some cases, but add cost and increase operational complexity. Other concerns are the potential of residual ammonia emissions to foul downstream equipment and/or form a visible plume when the boiler is operated on oil fuel and possible future regulatory concerns with release to the atmosphere of unreacted ammonia, commonly termed “ammonia slip”, and/or nitrous oxide (N_2O), which is also formed. Nonetheless, SNCR has been a useful niche technology, largely in view of its low capital requirements and ability to operate on urea, which is a relatively inert chemical involving little storage and handling difficulty.

During the past several years, there has been substantial experience with SCR on gas-fired boilers (many of which have fuel oil as a back-up or secondary fuel). In general, the experience has been favorable with performance meeting or exceeding expectations and capital costs being substantially below the expected values. NO_x removals as high as 93% have been achieved. While a few conventional SCR systems have been installed, the majority of the experience has been with in-duct SCR (Figure 1-3). The design of ammonia injection and control systems has matured and the industry trend is towards aqueous ammonia rather than the anhydrous form, mainly to mitigate the permitting and safety requirements associated with handling of ammonia. Another important trend has been that catalyst life expectancy has increased. As the existing systems have been operated, it has become evident that the catalyst degradation rate, particularly with gas firing, is slower than previously predicted. Furthermore, improvements in catalyst formulations have enhanced overall life expectancy.

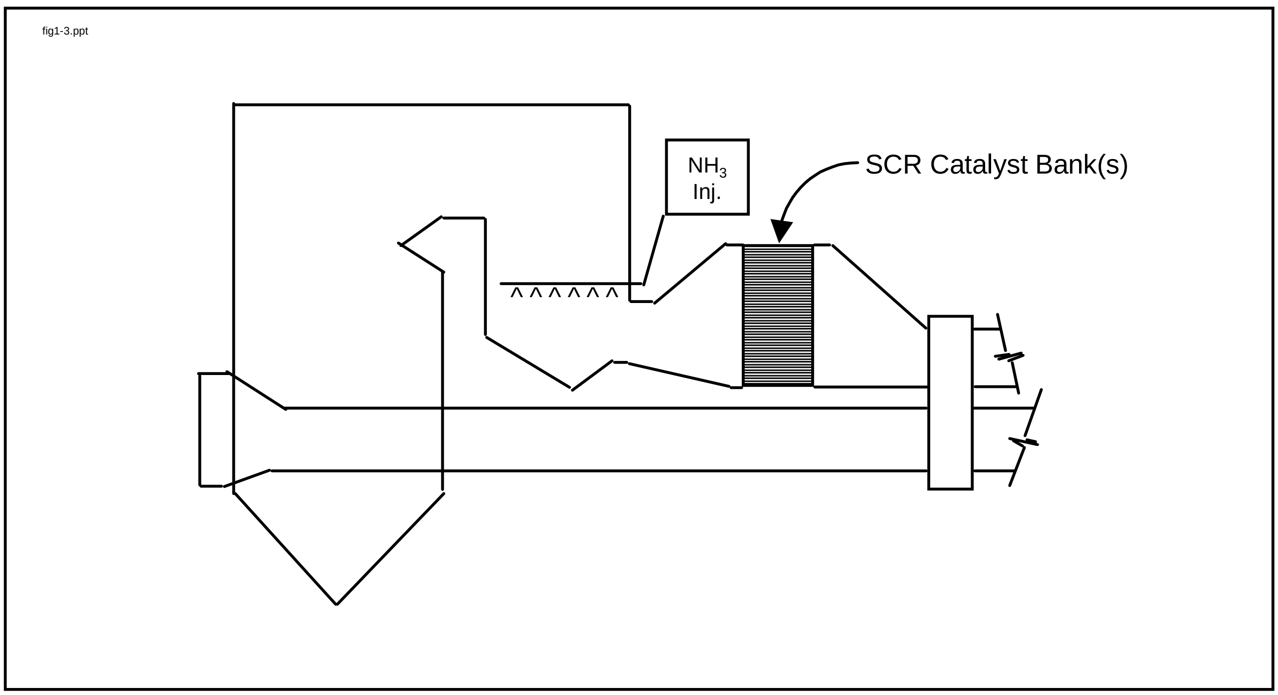

Figure 1-3
Typical Arrangement of an In-Duct Selective Catalytic Reduction System

The most significant cost-determinant factor, affecting both the capital and operating cost of an SCR system is the reactor size. Figure 1-4 shows that if the SCR design point is at a relatively high removal efficiency, SCR reactor size can be reduced substantially by lowering the inlet NO_x level, which lowers the percentage removal needed for compliance. Combustion controls (e.g., O/S combustion, FGR) utilized to minimize the NO_x concentrations entering the SCR reactor will thus permit the use of a smaller reactor which lowers the control cost. SCR operating cost consists mainly of catalyst replacement cost, and incorporating a suitable catalyst management strategy is an important aspect of planning an SCR installation.

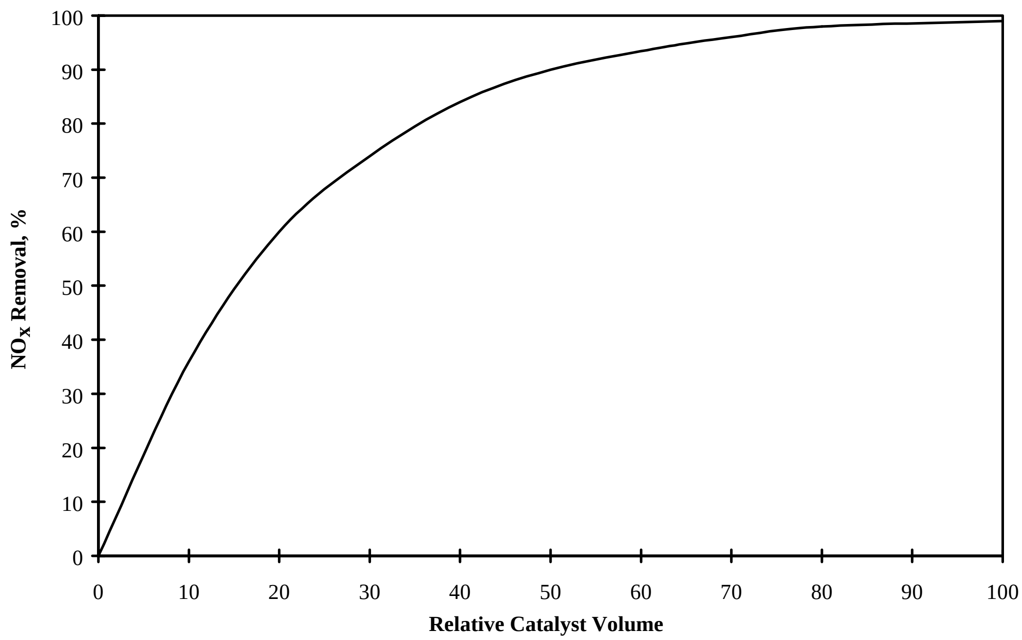

Figure 1-4
Generalized NO_x Removal Efficiency versus Catalyst Volume

All of the SCR systems installed to date on gas- and oil-fired boilers have been on gas-fired boilers with oil firing limited to back-up. Furthermore, because the systems were installed on units firing oil with very low sulfur content, the majority of the systems utilized high activity catalyst. Boilers which fire a higher sulfur fuel oil, and/or fire fuel oil more frequently, may not be able to utilize high activity catalyst due to concerns regarding the formation of sulfur trioxide. High concentrations of sulfur trioxide in the presence of ammonia will form ammonium sulfates and bisulfates, which tend to foul both the catalyst and downstream equipment.

A Hybrid System is basically a synergistic combination of SCR and SNCR in which the SNCR system is operated at a relatively high ammonia slip, which allows greater NO_x reduction, and the SCR reactor utilizes the slip ammonia to further reduce the NO_x. Hybrid Systems have been demonstrated on two utility boilers. This option should be considered whenever installation of an SCR system is being evaluated. The Hybrid System option reduces the size of the SCR reactor required for a given amount of NO_x reduction and allows the input chemical to be urea rather than ammonia. A Hybrid System also offers more operational flexibility for seasonal NO_x control requirements and/or load following and to accommodate the use of oil as a back up fuel. A methodology has been developed specifically to assess applicability of Hybrid Post-Combustion NO_x Control for specific applications, and is available in the form of an electronic spreadsheet from EPRI.

2

HOW TO USE THIS DOCUMENT

This document is designed to help utility engineering and operating staff evaluate and select appropriate retrofit NO_x control technologies for natural gas- and oil-fired boilers. Specifically, this document reviews and summarizes NO_x control technology information in the public domain, or shared with EPRI by utilities, regarding reduction capabilities, controlled emission levels achieved, retrofit issues, and associated costs. The document is an update of guidelines originally produced in 1993 (1). Background information in the original guidelines that has not changed since 1993 is not repeated in this document, and the reader is referred to the original guidelines document for information on these subjects. Sections not repeated in the current guidelines update include "NO_x Formation," "Regulatory Overview," and "Developing a NO_x Control Strategy." Table 2-1 can be used to quickly locate various types of information contained in this document, as well as the original guidelines document.

For those readers not familiar with the principles of NO_x formation, it is highly recommended that they review Section 3 in the previous guidelines document (1). As noted in subsequent discussions regarding specific NO_x control technologies, some technologies are more effective in addressing thermal NO_x versus fuel-NO_x, or vice versa, thus necessitating a cursory understanding of what operating and/or design factors (e.g., fuel oil nitrogen content, fuel/air mixing, burner zone heat release rate, etc.) are driving the total NO_x emissions.

Unit information with which the reader should be familiar prior to assessing appropriate NO_x control technologies include:

- fuel use mix and associated times of the year
- NO_x controls already in use (e.g., BOOS, OFA, FGR, LNB, etc.)
- baseline NO_x emissions over the load range
- excess air levels over the load range
- capacity factor and the percent of time of each year spent at specific load intervals

- current operating limitations that could increase retrofit costs of specific technologies (e.g., fan limitations that would derate unit with increased windbox-to-furnace pressure differential associated with low NO_x burners if not addressed)

- target NO_x limit and associated averaging times, as well as a determination of the applicability of system averaging.

With this information in mind, the reader is then ready to assess what level of NO_x reduction is required, on average, to achieve compliance. The reader can then apply Figure 1-1 to determine applicable unit-specific NO_x control technologies and order of magnitude costs. It is important to bear in mind that Figure 1-1 presents ranges of percent NO_x reductions and retrofit costs achieved at full scale as a function of control technology. Spreadsheet cost models (developed by Black & Veatch) intended to assist the utility in developing budgetary estimates (±25%) of application costs for established NO_x control technologies accompany the document on diskette and are described in Appendix D.

Once specific NO_x control technologies of interest have been identified on a cursory basis, the reader should then evaluate information in Section 4 regarding those technologies. Based on this information a preliminary assessment can then be made regarding the applicability of the experience base for a given control technology to units of interest. To assist in this effort, a retrofit NO_x controls data base accompanies this document on diskette. While the document provides generalized information (e.g., ranges of NO_x reductions and costs) for various NO_x control technologies applied to various types of boilers, the data base contains more detailed information for each retrofit for which information was obtained in preparing the guidelines. Appendix A provides a description of the data base and instructions for its use.

The information included in this document and the accompanying data base describing NO_x reduction capabilities, control costs, and retrofitability issues was largely obtained from recent utility and vendor presentations, EPRI reports and databases (both published and unpublished), and communications with utility personnel and NO_x control consultants. It is important to understand that:

- The controlled NO_x emission data represent actual values reported for specific units and NO_x control retrofits; these values should not be construed as levels that can be universally achieved for similar retrofits, but rather as indicators of the potential control level for a particular technology.

- Some of the controlled NO_x emission rate values were collected during short-term tests under controlled conditions. These values often reflect the “best-case” achieved and may not represent rates that a unit can maintain over the long term.

Therefore, the information presented in this document should be used primarily to familiarize utility personnel with NO_x control technologies for gas- and oil-fired units. In addition, the document is intended to establish a point of reference for estimating the NO_x reduction potential and associated order of magnitude retrofit costs for specific technologies so as to assist in the initial development of a NO_x compliance strategy and budget.

Once oriented to applicable NO_x control technologies and order of magnitude costs, the reader is then prepared to move on to the next step, which is to construct and evaluate different NO_x compliance scenarios. Although not the focus of the current document, a brief introduction is provided here so that the reader can be collecting necessary information during initial technology screening and evaluation. As the number of permutations and combinations of technologies for achieving compliance can increase rapidly, EPRI has co-developed the Clean Air Technology (CAT) Workstation™ with Sargent & Lundy. A sample output screen is shown in Figure 2-1. Based on input information regarding specific units, system-wide considerations and regulatory scenarios, the CAT Workstation™ rapidly screens NO_x control technologies to identify the most cost-effective compliance strategy.

Prior to final selection of an optimum NO_x control strategy for a particular unit, a detailed, site-specific engineering and cost analysis of the most promising technology options is recommended. Appendix B presents guidelines for boiler preparation and testing, specifically for NO_x assessments on gas- and oil-fired boilers. Appendix C provides information that is useful in preparing a comprehensive purchase specification for a retrofit NO_x control system.

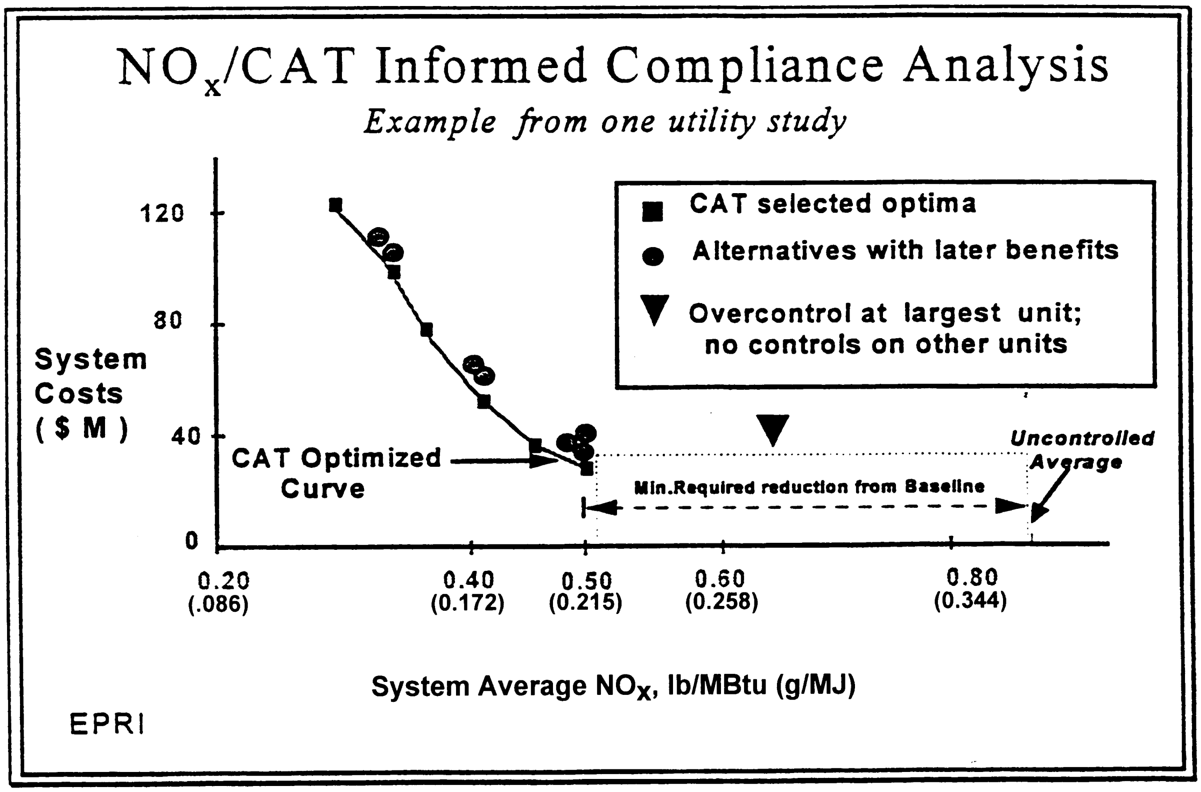

Figure 2-1
Sample CAT Workstation™ Compliance Chart

Table 2-1
Information Cross-Reference between Original and Updated Gas and Oil Retrofit Guidelines Documents

Utility Questions/Information Needs	Section in This Document	Section in Original Guidelines (TR 102413)	Diskettes Accompanying This Document	Contents
Related EPRI products	3	NI		Brief descriptions and contacts for other EPRI products that support NO_x planning
Regulatory drivers for NO_x control; boiler population characteristics	NI	2		Legislative and regulatory initiatives behind most utility NO_x control programs NO_x emission rate targets for selected states National perspective of the gas- and oil-fired boiler population
Practical background on NO_x formation	NI	3		NO_x formation in a utility boiler Plant design and operating factors influencing NO_x emissions
Available NO_x controls • **Experience base** • **Retrofit applicability factors** • **Performance (emission rates) achieved** • **Typical boiler upgrades** • **Potential operational impacts** • **Expected costs**	4	4		Technical presentations on applicable retrofit combustion and post-combustion control technologies
How to select the appropriate NO_X control technology	NI	5		Developing a compliance strategy • Time requirements • Information requirements • Decision points • Criteria for screening technologies
Supporting details • **Field tests** • **Syntheses, assessments, and analyses**	5	6		Lists recent publications especially relevant to gas- and oil-fired boilers
Unit-by-unit retrofit experience	Appendix A	Appendix A	Retrofit NO_x Controls Data Base	Tabulates information on NO_x control retrofits; data base on diskette with description and instructions in Appendix A
Boiler preparation and testing	Appendix B	NI		Equipment adjustments frequently needed; baseline and post-retrofit testing
Specifying NO_x combustion controls	Appendix C	Appendix C		Lists important elements to be included in a bid specification for selected NO_x combustion controls, using low-NO_x burners as an example
How to estimate cost for a specific application	Appendix D	NI	Cost Estimating Methodology for Retrofit NO_x Controls	Software supporting development of cost estimates for major control technologies. Description and instructions in Appendix D.
NO_x unit conversions	Appendix E	Appendix D		Provides useful formulas to convert between lb/MBtu, ppm and Btu/MWh and to SI units
Commercially available low-NO_x burners	Appendix F	Appendix B		Lists commercially available low-NO_x burners for gas- and oil-fired boilers
Glossary	Appendix G	NI		Definitions of frequently used terms and acronyms

NI = not included; if not included in this document, reader is referred to original guideline document

3

RELATED EPRI PRODUCTS

Almost since its inception, EPRI has been at the center of NO_x control research for utility boilers. As NO_x has become a nationwide issue, a number of products have been and are being developed to assist utilities in planning and implementing cost-effective NO_x control strategies. Products, in addition to this document, that are applicable to gas- and oil-fired boilers are listed below. For additional information regarding their status and applicability to address a given need, it is highly recommended that the listed EPRI project manager be contacted.

Topic	Product	Description	EPRI Involvement	Status	Contact (as of this writing)
Compliance Planning	CAT Work Station™	NO_x control selection software	Co-developer	Commercial product	Tony Facchiano/ Dick Rhudy (415-855-2494/ 415-855-2421)
Tuning and Optimization	*NO_x Emissions Testing and Optimization for Coal-Fired Utility Boilers* (TR-105109)	Guidelines Document	Authorship/ publisher	Produced in 1995	Jeff Stallings (415-855-2427)
	ULTRAMAX	Boiler optimization software	Co-developer	Commercial product	Jeff Stallings (415-855-2427)
	Generic NO_x Control Intelligent System (GNOCIS)	Boiler optimization software	Co-developer	Full-scale demonstrations in progress	Jeff Stallings (415-855-2427)
Burner Modification and Replacement	Reduced Emissions and Advanced Combustion Hardware (REACH)	NO_x control technology for oil fuel	Co-developer	Commercial product	Tony Facchiano (415-855-2494)
	Gas-REACH	NO_x control technology for gas fuel	Developer	Development and full-scale demonstration currently scheduled for 1997	Tony Facchiano (415-855-2494)
	Ultra Low-NO_x Burner	NO_x control technology for gas fuel	Demonstration and evaluation	Commercial product for industrial boilers, offered for utility boilers	Tony Facchiano (415-855-2494)

Related EPRI Products

Topic	Product	Description	EPRI Involvement	Status	Contact (as of this writing)
System Modifications	Induced Flue Gas Recirculation (IFGR)	NO_x control technology	Demonstration and evaluation	Full-scale demonstration currently scheduled for 1997	Tony Facchiano (415-855-2494)
Post Combustion NO_x Controls	*SNCR Feasibility and Economic Evaluation Guidelines* (TR-103885)	Guidelines document	Authorship/ publisher	Produced in 1994	Jeff Stallings (415-855-2427)
	State-of-the-Art Assessment of SNCR Technology (TR-102414)	Document	Authorship/ publisher	Produced in 1993	Jeff Stallings (415-855-2427)
	Technical Feasibility and Cost of Selective Catalytic Reduction (SCR) NO_x Control (GS-7266)	Guidelines document	Authorship/ publisher	Produced in 1991	Kent Zammit (415-855-2097)
	SCR Design and Operational Recommendations R&D Lessons Learned (TR-105103)	Document	Authorship/ publisher	Produced in 1995	Kent Zammit (415-855-2097)
	Hybrid Post Combustion NO_x Control Feasibility and Recommendations (TR-105693)	Guidelines document and software	Authorship/ publisher	Produced in 1996	Kent Zammit (415-855-2097)

4

NO_x CONTROL TECHNOLOGIES

This section describes the NO_x control technologies that are generally applicable to gas- and oil-fired boilers. Each technology is described and information provided on the experience base, applicability to various types of boilers on gas and oil fuel, actual NO_x reduction achieved, typical boiler upgrades required, impacts on boiler operation, and typical costs. Technologies are presented in the order of increasing cost, as a utility will generally want to consider implementation of NO_x control technologies in this order.

4.1 Tuning and Optimization

The most cost-effective NO_x reductions on utility boilers are achieved through the general approach of tuning and optimization. The reader is referred to Appendix B for specific information regarding boiler tuning. In the past, tuning and optimization was normally restricted to minor operational and/or equipment changes to redistribute air to the burners in order to achieve low excess air (LEA) operation of the boiler and, in some cases, burners-out-of-service (BOOS) operation or biased firing. With the advent of computer-based optimization methods, more comprehensive optimization, involving more of the boiler's adjustable parameters and assessing virtually all possible control settings, is now possible. This section will address these approaches.

4.1.1 Low Excess Air

Description

Operating utility boilers at low excess air (LEA) levels is an operational modification that can provide measurable NO_x reductions at low cost, and should be the first step in any NO_x control program. Minimizing the quantity of excess air supplied to the furnace reduces the amount of available oxygen during the combustion process and reduces the formation of NO_x. The objective of LEA operation is to minimize the quantity of excess combustion air while maintaining satisfactory combustion conditions at the burners, proper boiler heat absorption, and low particulate emissions, opacity, and CO emissions.

Implementation of LEA operation generally involves some modifications to improve the evenness of air (and possibly fuel) distribution to the burners. Initial steps in this process are:

- Inspection of burners, air registers or dampers and windbox internals, and correction of any equipment problems
- O_2 and CO profiling at the boiler exit to assess and characterize any air imbalance, coupled with adjustment of registers or dampers to improve air distributio

For a serious air/fuel imbalance that cannot be corrected on line, windbox and air supply system modeling may be productive to identify modifications to windbox or air duct internals that will correct the problem. Either cold flow or computational fluid dynamic (CFD) modeling can be used. Figure 4-1 shows a typical cold flow model of a windbox, and Figure 4-2 shows "before" and "after" air flow distributions for corrective windbox modifications. The fuel supply system should be assessed for its potential to maldistribute the fuel to the burners and any needed modifications identified. Following installation of system modifications, the boiler should be retested and adjustable fuel/air distribution parameters retuned.

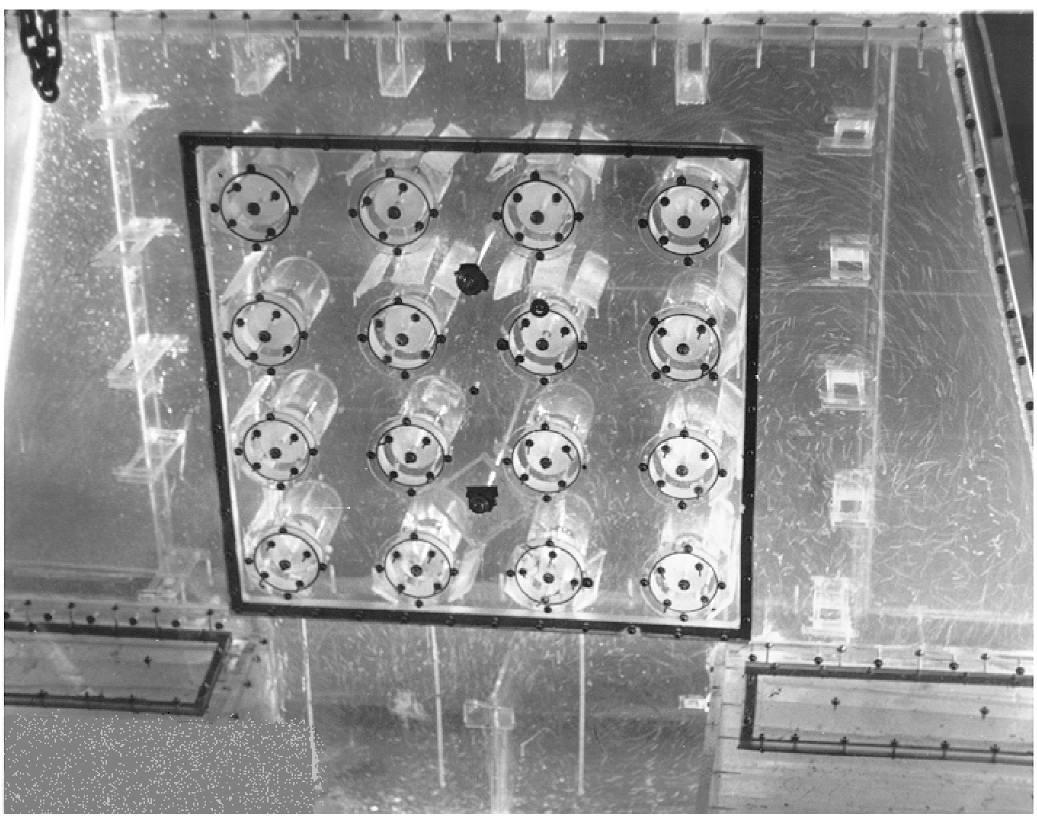

Figure 4-1
Typical Cold Flow Model
(Courtesy of Todd Combustion)

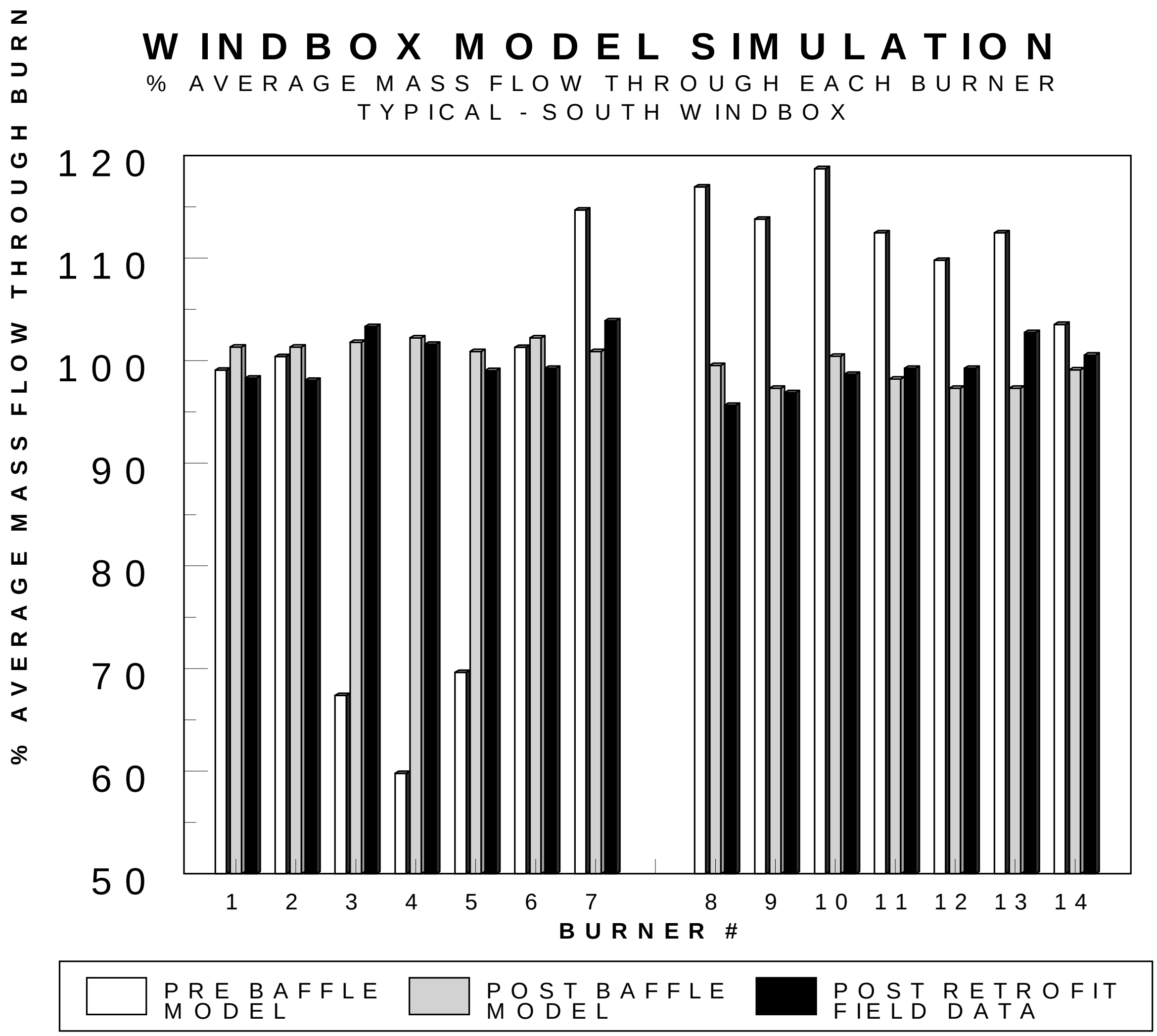

Figure 4-2
As-Found and Improved Air Flow Distributions on 28-Burner Face-Fired Boiler (Courtesy of Todd Combustion)

Experience

There is considerable experience in operating utility boilers with LEA. Most utilities currently operate their units in this mode to improve thermal efficiency and reduce NO_x emissions. However, effects on NO_x are difficult to isolate because LEA was usually implemented in conjunction with other tuning and optimization methods or other NO_x control technologies. Limited recent test data from gas- and oil-fired units in the Northeast, however, provide more current information than the 1970's Southern California data reported in the previous guideline.

Applicability

As a stand-alone technology, it is assumed that LEA is applicable to all boilers, with the following exceptions: (1) units designed to meet NSPS that likely operate with LEA already; (2) other boilers operating with low-NO_x combustion modifications (e.g., units in Southern California where operational or combustion equipment modifications have been implemented); (3) pre-NSPS boilers already operating with low excess air (i.e., less than 2% excess oxygen at full load); and (4) boilers equipped with high intensity, low excess air burners, where it is unlikely that further reductions in excess air can be made. LEA is likely to produce greatest NO_x reduction benefits on a boiler having a relatively high minimum excess O_2 threshold (e.g., 4% or higher) caused by non-uniform distribution of air to the burners. The uniformity of air distribution can be determined from an O_2 map of the flue gas exit duct(s). For more information on tuning the boiler for LEA operation, consult Reference 2. Although Reference 2 is intended for coal-fired boilers, information regarding tuning for LEA operation also applies to gas- and oil-fired boilers. LEA is generally an integral part of NO_x combustion control techniques, and is therefore likely to be incorporated into the operation of boilers that are subject to NO_x emission limits.

NO_x Performance Achieved

All boiler types, including front wall-, opposed wall-, tangential-, and turbo-fired, typically experience a reduction in NO_x, per 1% reduction in furnace O_2, of approximately 40 ppm on gas firing and 20 ppm on oil firing units. For front wall- and opposed wall-fired units, these reductions are difficult to estimate, and may, at times, be higher than the values just cited. These values, based on field test data, are for cases where no other NO_x control is applied. For the majority of gas- and oil-fired boilers, these values correspond to reductions in NO_x emissions of from 5 to 20% for a 1% reduction in excess oxygen at maximum boiler load (3). Actual reductions achieved may differ significantly from site to site. When applied in combination with other NO_x combustion controls, the effect of LEA would generally be lower.

Typical Boiler Upgrades

Typically, LEA can be implemented without significant modification to existing combustion equipment. However, to realize maximum NO_x reduction benefits, combustion instrumentation and controls may require upgrading. Such modifications may include: (1) upgrading the boiler excess oxygen monitoring system; (2) installing a carbon monoxide (CO) emissions monitor; and (3) re-calibrating the boiler's excess-air-versus-load controller. The CO monitor is used in conjunction with the excess oxygen and opacity monitors (if installed) to guide the boiler operators in adjusting excess oxygen to the lowest possible level without exceeding CO or opacity limits as fuel properties and boiler operating conditions vary. CO and opacity levels are frequently used as trim control in applications utilizing computer control of the air/fuel ratio.

Potential Impacts on Boiler Operation

LEA operation can affect boiler efficiency and steam temperature control. Improved boiler efficiency results from the reduction in flue gas flow rate and the corresponding lower stack gas heat losses. At a given furnace heat input, a reduction in excess oxygen of 1% (i.e., excess oxygen is reduced from 3 to 2%) results in an increase in boiler efficiency and improvement in unit heat rate of approximately 0.25% (3).

Reduced gas flow through the boiler due to LEA operation may positively or adversely affect control of steam temperature, depending on the heat absorption and steam temperature control characteristics of the boiler. For example, at high loads, lower excess air can reduce steam attemperation requirements with potentially beneficial effects on plant heat rate, or alternatively may lead to unacceptably low steam temperatures if design steam temperature is normally only marginally achieved. At low loads, application of LEA may be restricted by overriding excess air requirements to maintain steam temperature or to satisfy boiler minimum air flow requirements. If a boiler is equipped with flue gas recirculation (to the hopper or windbox), increasing the recirculation flow rate may offset the effects of reduced LEA on steam conditions.

Control Costs

Where hardware modifications are not required, capital costs of implementing LEA operation are minor, consisting of the cost of diagnostic testing and tuning the boiler and, in many cases, installation of O_2 and CO probes at the boiler outlet. More information on the cost of LEA tuning can be found in Reference 2. To correct a relatively severe imbalance problem, the capital cost will also include the cost of air system modeling and hardware modifications to improve the air/fuel distribution to the burners. Costs for cold flow modeling are generally on the order of $50,000, and costs for CFD modeling are usually in the $50,000 to $100,000 range, depending on the size and complexity of the windbox and the load range over which modeling is to be done. CFD modeling may have an advantage if numerous hardware approaches are to be considered and is capable of greater precision than cold flow modeling. However, in many cases cold flow modeling may suffice.

The total cost of modeling and hardware modifications to correct a flow imbalance problem should be well under $1/kW. To maintain the advantage of LEA for long-term operation, tighter tolerances on combustion equipment operation may be needed. Increased maintenance costs may be incurred to maintain high performance of air registers, fuel oil atomizers, and instrumentation essential for LEA operation (as well as other combustion controls described in this document). A reduction in fuel consumption, however, may help to offset these maintenance costs. As previously stated, every 1% reduction in excess oxygen will improve unit heat rate by approximately 0.25%.

4.1.2 Burners-Out-of-Service and Biased Firing

Description

Burners-out-of-service (BOOS) is an inexpensive and proven means of achieving staged combustion without the use of overfire air ports on boilers with multiple burner levels. Staged combustion involves generating a fuel-rich region near the burner with the remainder of the air added elsewhere in the furnace. This is accomplished with BOOS by terminating the fuel flow to selected burners while leaving their air registers open. This results in increased fuel flow to the remaining operating burners causing them to operate in a slightly fuel-rich condition. The air needed to complete combustion is supplied through the out-of-service burners.

The number and location of burners that are removed from service for BOOS operation are determined from combustion diagnostic testing conducted on the boiler. More information on tuning the boiler for BOOS operation can be found in Reference 2. Although Reference 2 is intended for coal-fired boilers, much of the information regarding implementation of BOOS operation also applies to gas- and oil-fired boilers. Typically, the most effective burners to remove from service are those located in the upper burner elevations. At full load, the maximum number of burners removed from service is typically 20 to 25% of the total burners, although up to 40% can be removed in certain gas-fired applications. In dual-fueled units, a compromise pattern is usually found that can be used on both gas and oil.

Similar to BOOS, "biased firing" involves the redistribution of fuel among the burners to create staged combustion conditions. However, biased firing differs in that the fuel continues to be supplied to all the burners that would normally be in service at a particular load. The desired distribution is accomplished by operating with unequal fuel flow among the burner elevations, and may be augmented by redistributing the air quantity to individual burner elevations by adjusting air registers or air compartment dampers.

Biased firing can be advantageous where there are a limited number of burners or burner elevations. In such applications, a more uniform air and fuel distribution may be possible as compared to removing several burners from service. This can lower excess oxygen requirements as well as minimize CO and opacity emissions. In tangential units, the air flow may be biased (maximum flow at the top and minimum at the bottom of the burner column) in conjunction with a small percentage of BOOS.

One way of implementing biased firing in gas-fired units having multiple element burners is to remove selected gas elements (spuds) from service. Spuds-out-of-service (SOOS) operation allows the burners with all spuds in operation to operate fuel-rich to reduce NO_x formation, with completion of combustion accomplished by excess air from the SOOS (fuel-lean) burners. SOOS should also be effective on an intra-burner basis, i.e., as a means of staging the combustion on individual burners.

Compared to BOOS, biased firing and SOOS are not as widely demonstrated and are more complex to implement and operate. Furthermore, the NO_x reductions attainable with these firing modes are generally less than or comparable to those demonstrated with BOOS. Therefore, the remainder of this section will focus on BOOS.

Experience

Numerous gas- and oil-fired boilers have successfully operated with BOOS for more than 20 years to achieve compliance with NO_x emission standards, e.g., Figure 4-3. While a highly cost effective NO_x control, BOOS operation has generally been found to produce some operational problems and minor efficiency degradation, and utilities practicing BOOS operation would generally prefer to return their boilers to all-burners-in-service (ABIS) operation.

Applicability

BOOS is generally applicable to tangential-fired and wall-fired boilers with multiple burner levels burning gas or oil. It is effective as a stand-alone technique or in combination with other combustion or post-combustion NO_x controls. Many of the boilers on which BOOS has been most successful are relatively large boilers with four to five burner elevations. On this type of boiler, 20 to 25 percent of the burners can be taken out of service to produce vertical fuel/air separation without skewing fuel or air distribution side-to-side. It has been found that this degree of BOOS and type of BOOS pattern produces substantial NO_x reduction while still permitting operation at reasonable levels of excess air. BOOS may be somewhat less successful on boilers equipped with cell burners in that operable patterns will probably involve both air-only and fired burners being in same cells, thus making it more difficult to achieve fuel/air separation. However, BOOS has effected significant NO_x reductions on boilers having cell burners.

BOOS is less effective in turbo-fired boilers manufactured by Riley Stoker, since the burners are arranged in a single elevation on each side of the furnace, precluding effective use of vertical combustion staging as imparted by BOOS. However, combinations of BOOS and burner air vane adjustments have been tried and have produced nominal NO_x reductions.

Since BOOS operation requires that CO and (for oil) carbon burnout take place higher in the furnace, its implementation may be most successful on boilers with relatively large furnace volumes, e.g., post-NSPS boilers and boilers originally designed for coal. In these cases, BOOS operation may not involve excess air penalties as was the case with many of the boilers on which it was implemented in California, most of which are pre-NSPS gas/oil-design boilers.

NO_x Performance Achieved

The NO_x reduction attainable on a given boiler with BOOS varies with the degree of staging (i.e., number of burners out of service), burner spacing, BOOS patterns relative to the boiler-specific fuel/air distribution, fuel type, boiler load, operating oxygen level, and burner zone heat release rate. Figure 4-3 summarizes the NO_x reduction achieved through the application of BOOS, and overfire air in some cases, on the gas- and oil-fired boilers surveyed (see also Appendix A). BOOS, either stand-alone or in combination with overfire air, has been categorized as off-stoichiometric (O/S) combustion, since it was difficult to identify the specific controls actually utilized by the units.

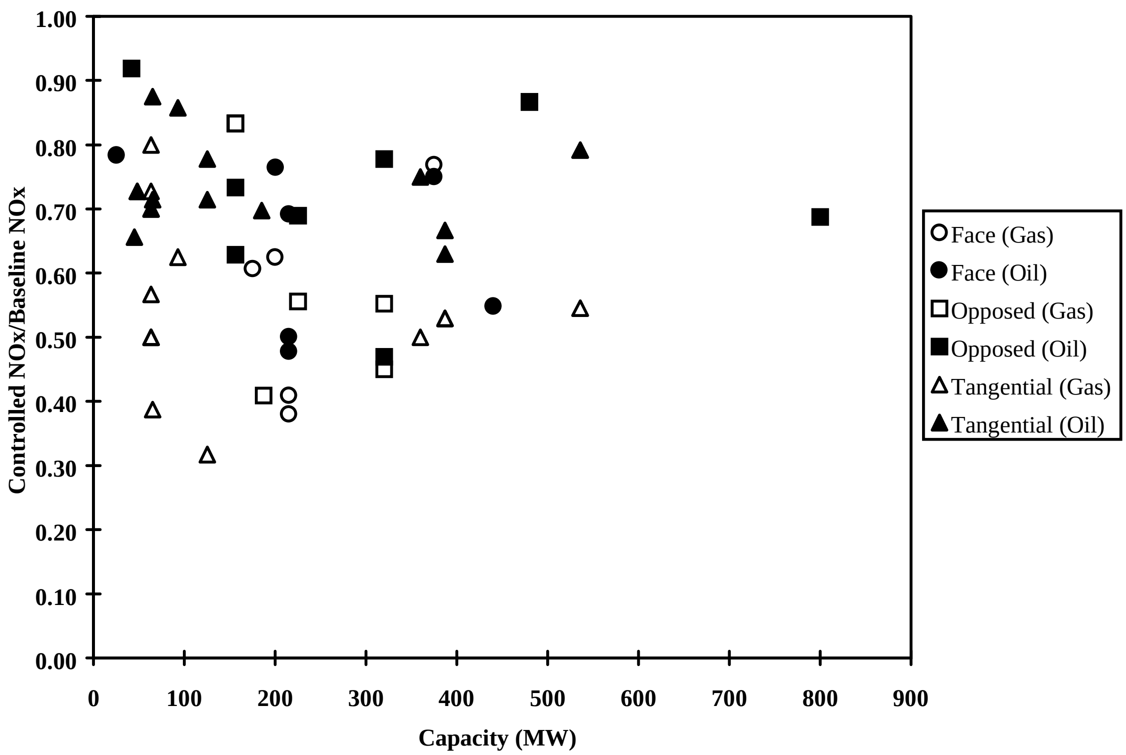

Figure 4-3
NO_x Reduction Performance of O/S Firing (No FGR or LNB)

For gas- and oil-fired units using O/S combustion, the bulk of the data indicate controlled emission rates and NO_x reductions of:

Fuel	Controlled Emission Rate lb/MBtu (g/MJ)	Percent Reduction
Gas	0.10-0.30 (.043-0.13)	20-60
Oil	0.15-0.35 (.065-0.15)	10-50

In general, combustion modifications were made to meet emission regulations at a given point in time, and not to maximize the reductions that could be achieved. As regulations became more stringent, utilities renewed testing efforts to push the limits of the combustion modification approaches. The data presented here often reflect the best results achieved for a unit, even if the reductions occurred in several steps, over a period of years, by more aggressive staging and tuning of the firing system.

It is important to note that significant NO_x reductions are achievable with O/S combustion; however, large site-to-site variations in effectiveness have been encountered. Furthermore, the percentage NO_x reduction achievable with O/S combustion diminishes when it is combined with other combustion controls. However, the overall NO_x reduction achievable with a combination of technologies is greater than with the application of O/S combustion alone. Finally, many of the reported emission values were developed from short-term test programs at controlled conditions and do not necessarily reflect reductions that can be achieved on a continuous basis over a long period of time.

Typical Boiler Upgrades

Typically, BOOS can be implemented without significant modifications to existing combustion equipment or other boiler hardware. However, capital expenditures may be required to upgrade existing combustion instrumentation and controls. In addition, utilities will need to conduct extensive stack emission and combustion diagnostic testing to implement and optimize the BOOS pattern to minimize NO_x production and operational impacts. A test program similar to that described in the discussion of LEA operation, but including BOOS pattern optimization (i.e., which burners to remove from service at different load points), should be conducted, and will typically require several weeks. More information on testing the boiler to determine the most effective BOOS pattern can be found in Reference 2.

Depending on the design of the existing fuel supply system and burners, minor equipment modifications may be required in implementing BOOS to redistribute fuel among the burners. For oil firing, replacement of existing oil atomizers with larger capacity atomizers may be required to accommodate greater fuel flow to maintain boiler load capability with fewer burners in service. Similarly, for gas firing, installation of higher capacity fuel elements (e.g., resized gas spuds) may be needed to maintain gas supply pressures within acceptable limits. In certain instances, upgraded gas meters, regulators, and header lines may be required due to the increase in fuel pressure to the burners in service.

In the case of a boiler equipped with mechanical atomizers, BOOS operation may be made more acceptable by a change to steam atomizers. One utility, in evaluating potential NO_x control strategies for two 600 MW gas- and oil-fired boilers, found the most cost effective approach to include changing from mechanical to steam atomizers to enable BOOS operation on oil (4).

Potential Impacts on Boiler Operation

Implementation of BOOS may require higher excess air levels than conventional firing to achieve complete combustion and maintain acceptable opacity, particulate matter, and CO emissions. It is not uncommon for excess oxygen requirements to increase by 0.5% for gas firing and 0.5 to 1% for oil firing. The higher air flow requirements will reduce thermal efficiency and could conceivably result in load restriction where a unit is fan-limited, furnace or windbox pressure limitations are encountered, or burner heat release ratings are exceeded. These problems will be most significant in the case of boilers with relatively less generous furnace volumes, e.g., pre-NSPS boilers designed for gas and/or oil. In these cases, CFD modeling may be useful to assess the effect of BOOS operation on CO or carbon burnout.

BOOS operation can adversely affect boiler operating flexibility. For example, the capability to remove additional burners from service for maintenance can be restricted at higher loads due to fuel supply pressure limitations. BOOS operation may also induce flame stability problems and boiler rumble—potentially leading to load restrictions if not corrected. Optimization of air register settings, flame stabilizer position, and atomizer design through a trial-and-error process may be required to improve flame stability. Flame impingement on heat transfer surfaces due to longer flames may also be experienced. To identify such problems before committing to BOOS operation, a utility should conduct a carefully monitored and well-instrumented trial with BOOS over the boiler operating range to determine the potential extent of problems and the effectiveness of corrective actions. BOOS operation may also affect boiler heat absorption patterns. Here again, CFD modeling may be useful to assess the effects of BOOS operation on flame size and shape and heat transfer distribution.

Control Costs

The capital cost for implementation of BOOS will be based on the need for upgrading combustion monitoring instrumentation and controls, as well as costs associated with combustion optimization testing. In addition, minor modifications may be required to the burner control system, fuel supply system, and burners. A capital cost estimate of $1/kW is applicable for units where major modifications are not required. The bulk of the operating costs associated with BOOS will be proportional to any required increase in excess air level, which will impact annual fuel consumption. A penalty of approximately 0.25% in unit heat rate will be experienced for every 1% increase in O_2.

4.1.3 Optimization Software

Description

In recent years, a number of optimization software tools have become available which both broaden the scope of the optimization, by including more of the boiler's adjustable variables, and expedite the optimization process through application of statistical analysis, neural network and artificial intelligence techniques. While use of software requires testing of the boiler, in most cases the testing is done under normal unit operation (not "controlled" conditions) and allows changes of more than one variable at a time.

Optimization software may be used either in an "open-loop" system (providing advice to the plant operator) or "closed-loop" (integrated into the power plant controls). Open-loop applications can be either one-time optimizations or more sustained use of the software in a continuous advisory mode. Some optimization softwares do not require digital control systems (DCS), but a DCS makes optimization easier and may be considered an essential component, especially in the case of closed-loop systems. The optimization process seeks the best settings of a number of adjustable variables to meet or most closely approach specified goals in terms of an objective parameter such as NO_x. The process can be applied to multiple objectives; for example both NO_x and heat rate can be optimized. Other performance parameters, e.g., CO, opacity, steam temperatures, etc., could also be optimized or can be constrained in the optimization process to prevent them from degrading beyond set limits.

There are many optimization software tools available. The ones used for NO_x reduction in power plants are shown in Table 4-1. While any of these softwares can be, and some have been, applied to gas- and oil-fired boilers, it is important to realize that they have been primarily developed for optimization of coal-fired boilers, where there are typically more variables influencing NO_x emissions. Application to gas- and oil-fired boilers may be harder to justify relative to conventional boiler tuning (e.g., Reference 2), particularly in cases where only a few controllable parameters influence NO_x. It may be especially difficult to justify software installations in continuous advisory or closed-loop modes on gas- or oil-fired boilers in that changing coal characteristics are probably the main driving force leading to a need for continuous optimization of coal-fired boilers whereas the relatively invariant characteristics of gas and, in most cases, oil fuels seem far less likely to engender such a need.

Table 4-1
Some Optimization Softwares Used for NO_x Reduction

Software Name	Developed by	Commercialized by	Key Features
GNOCIS	EPRI, PowerGen and Southern Company Services	Radian and Southern Company Services	Neural network-based; demonstrated in both open- & closed-loop applications
IDCOM-B™	Setpoint	Bailey Controls	Advanced model-predictive multi-variable controller
InEC™	Lockheed Martin Control Systems and New York State Electric & Gas	New York State Electric & Gas	Neural network-based; intended for both open- & closed-loop applications
NeuCOP	NeuralWare	NeuralWare	Neural network-based
NeuSIGHT	Pegasus Technologies	Pegasus Technology	Neural network-based; demonstrated in both open- & closed-loop applications
PECOS™	Praxis Engineers	Praxis Engineers	Advisory tool supporting plant-level decisions to minimize cost of electricity with environmental compliance
TOPAZ	DHR Technologies	DHR Technologies	Neural network-based; intended for both open- & closed-loop applications
ULTRAMAX	ULTRAMAX and EPRI	PowerMAX	Sequential optimization; primarily intended for open-loop advisory applications; particularly suitable for first-cut improvements

EPRI has supported the development of two of these optimization tools:

- ULTRAMAX for initial optimization and identification of set points, and
- GNOCIS for fine-tuning and sustained optimum operation

ULTRAMAX is most commonly used as a one-time optimization tool (although it can also be used in a continuous advisory mode). The expected result of a one-time optimization is a set of improved boiler control settings for each load at which optimization is done. It is the utility's responsibility to incorporate these recommendations into the boiler operating procedures, and thus a commitment at the plant management level to training of operators and implementation of new procedures is an important component of a one-time optimization. Figure 4-4 shows input and output variables that were involved in application of ULTRAMAX to a gas-fired boiler. There are virtually no training or computer hardware requirements to utilize the software in a one-time optimization mode, assuming that PowerMAX personnel will be involved. The time required to optimize a boiler, assuming a reasonably modern control system, is typically two weeks at full load and one to two weeks per additional load.

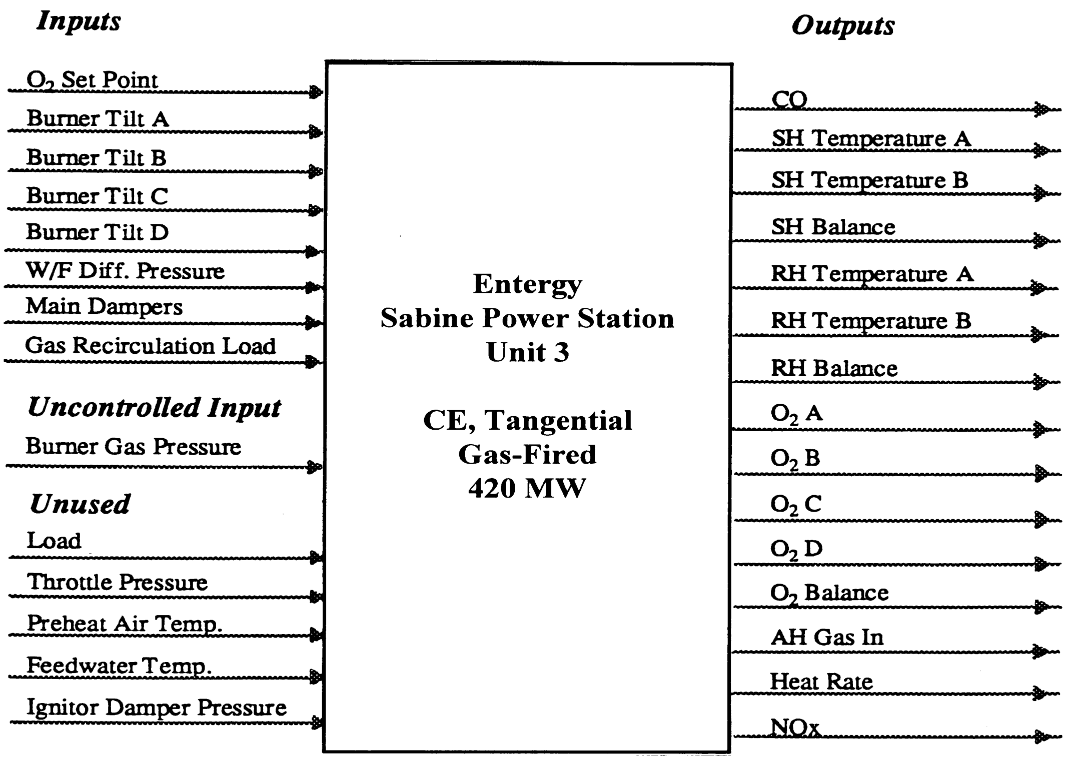

Figure 4-4
Entergy's Sabine Unit 3 - Variables Processed by ULTRAMAX

Utility personnel can easily be trained sufficiently to apply the software without PowerMAX support, and this is probably the most cost-effective course in the case of a multiple-boiler application. Following a one-time optimization, the utility may need to re-optimize at times in the future, particularly in the case of oil-firing, as changes occur in the fuel and/or equipment.

The neural network-based softwares listed in Table 4-1 are designed primarily to be closed-loop supervisory systems integrated with the plant DCS. This means that the software essentially takes control of certain set points that are normally adjusted by the operator. However, the software can be switchable between closed-loop and open-loop (advisory) modes (Figure 4-5). The softwares are designed to run on a desk-top computer or internally on some digital control systems. An application begins with extensive data acquisition during normal boiler operation (although the softwares also require varying degrees of structured tests) over a period of typically two to three months. The software then begins to continuously optimize boiler operation based on the accumulated data. The overall process of bringing a neural network-based system into full operation is estimated to require from 3 to 6 months. Once the software is functioning, in addition to its main optimizing function, it exercises quality control over plant sensors and flags any suspicious readings. Flagged readings generally indicate a plant instrumentation problem, but eventually may mean that the software needs to be "re-trained". Neural network-based softwares can thus be more tolerant of changes in related parameters, such as the calibration status of instruments, maintenance status of equipment, and fuel properties, than a one-time optimization.

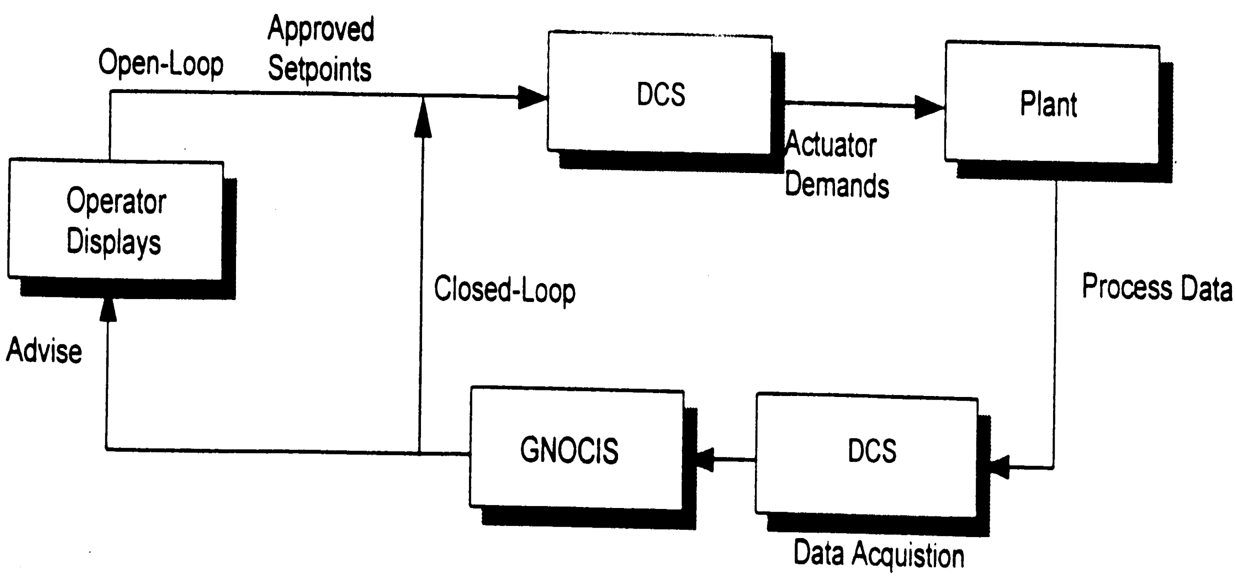

Figure 4-5
Typical GNOCIS Installation

Although the choice between the two approaches may be based primarily on whether the need is for a one-time optimization or for an on-going optimization, the differences with regard to model building and scope of optimization may also be important in many cases. It seems especially significant that the neural network-based softwares, while being able to optimize more input variables than ULTRAMAX, do not optimize beyond the range of operation represented in the data set used to build the models. Thus if only data from normal operation are used, the software will find a "local" optimum within the normal experience range of the boiler, whereas ULTRAMAX inherently conducts a "global" search that considers all possible modes of operation. However, it should also be noted that the search range of the neural network-based softwares can be made more global by including special tests, outside the boiler's normal range, in the data set used for model building.

In selecting between the neural network approach and the ULTRAMAX approach to boiler optimization, in addition to considering the objectives of the project, it is important to recognize the following fundamental differences between the two approaches:

	ULTRAMAX	Neural Network
Number of operating variables that can be optimized	Approximately 10 or fewer	Essentially unlimited
Approach to model building and optimization	Software learns as it goes, typically requiring two weeks optimization time	Model building requires typically several months of operating data; optimization is based on a fixed set of models
Scope of search for optimum settings	Software will explore beyond normal operating ranges except as constrained by user	Search is limited to range of data used in model building--i.e., to expand the envelope, the boiler must have been operated outside its normal range during the data acquisition period

IDCOM-B™ is a multi-variable non-linear controller developed by Bailey Controls through an agreement with Setpoint, Inc., the original developer of IDCOM software. The IDCOM control approach may be particularly useful for units that operate under dynamic loading conditions (i.e., on auto-dispatch). IDCOM-B™ is designed to be installed in a Bailey DCS but may be useable with other control systems. In retrofit installations, IDCOM-B™ can be in parallel with and switchable with the pre-existing control logic.

Experience

Most experience with optimization software has been on coal-fired boilers (5). Experience on gas- and oil-fired boilers consists of several one-time ULTRAMAX optimizations and two IDCOM-B™ installations. Although one GNOCIS project is underway at Entergy's Nelson Unit 4, a gas-fired B&W boiler, no results were available at the time of this writing. The ULTRAMAX applications are listed in Table 4-2. As shown in the table, ULTRAMAX has been applied to two types of boilers in Long Island Lighting Co. (LILCO) plants and to one boiler in the Entergy system. All eight LILCO boilers for which data are presented in the table were optimized on oil, and three of these boilers were also optimized on gas. The utility reported that in general NO_x was reduced by from one quarter to one third in all cases. PowerMAX personnel conducted the optimization of Port Jefferson Unit 3 on oil (6), and were involved in two other optimizations of the LILCO boilers, after which utility personnel conducted the remaining optimizations without PowerMAX involvement. Optimization of Entergy's Sabine Unit 3 was conducted primarily by PowerMAX. In addition to the substantial NO_x reduction, heat rate was improved by 0.5% (7), although operational settings producing the best heat rate improvement differed from those producing the best NO_x reduction. Both utilities found the software easy to apply with minimal preparation required in cases in which PowerMAX conducted the optimization. LILCO reported that more training, at least one week, was needed to adequately prepare utility engineers to apply the software themselves. Neither utility plans to install the software in a continuous advisory mode.

IDCOM-B™ has been installed by the Southern California Edison Company at El Segundo Units 3 and 4 (8). Both are tangential, gas-fired boilers rated at 320 MW. The primary purpose of these installations was to improve steam-temperature control, and the software was found to be highly effective for this purpose. Based on this success the utility has expanded the use of the software to include continuous optimization of heat rate and NO_x.

Applicability

ULTRAMAX can be applied to any boiler. The only general requirement is that a sufficient number of key process variables be adjustable and the boiler system include adequate capability to measure the objective and constrained performance parameters. Although both data input to the software and adjustment of boiler variables for each test can be done manually, connecting ULTRAMAX to a boiler DCS or DAS expedites optimization, as does having the key boiler variables on remote control. Manual data input and boiler adjustments would not be compatible with the neural network-based systems, which are primarily intended for use on boilers with reasonably modern control systems, i.e., a DCS or, at minimum, a DAS (for advisory mode only). Key adjustable parameters, including burner air registers/dampers, tilts, etc., should be on auto-control for closed-loop applications. Installation of an IDCOM-B™ advanced multi-variable controller is designed for a Bailey DCS.

Table 4-2
Applications of ULTRAMAX for NO_x Reduction on Gas- and Oil-Fired Boilers

	LILCO Barrett 1,2 and Port Jefferson 3,4	LILCO Northport 1-4	Entergy Sabine 3
Rated MW	188	387	473
Firing Configuration	Tangential	Tangential	Tangential
Startup Year	1956-58	1967-77	1962
Fuel(s)	Oil, Gas	Oil, Gas	Gas
NO_x Controls	CCOFA	CCOFA	None
Results	NO_x reduced 25-33%	NO_x reduced 25-33%	NO_x reduced 35%, from 0.23 to 0.15 lb/MBtu (0.10 to 0.064 g/MJ)
Reference	6		7

NO_x Performance Achieved

NO_x reductions that have been achieved using ULTRAMAX on gas- and oil-fired boilers are listed in Table 4-2 (see also Appendix A). It should be noted that some of the largest NO_x reductions have occurred on boilers that had not been recently tuned. Using ULTRAMAX on relatively untuned boilers has generally resulted in NO_x reduction greater than 25%, whereas PowerMAX predicts only 8 to 10% reduction for boilers that have been well tuned for NO_x.

Typical Boiler Upgrades

It is advisable that the utility, prior to application of the software, identify the key adjustable variables and the parameters that will be considered the objective and/or constrained performance parameters. EPRI's boiler tuning guidelines (2), although primarily intended for coal-fired boilers, may be helpful in this regard. Typically, some refurbishing or minor improvements are required to insure that needed adjustments can be made and that key performance parameters can be reliably measured. Also, it is important that the calibration status of all parameters involved in the optimization be known at the time of initial testing and maintained thereafter. In the case of the neural network-based softwares, boiler instrumentation/control system upgrades (e.g., sensors, local controllers, etc.) needed for successful use of the software, while minor, may be numerous, and these costs should be realistically assessed.

Some operator training will generally be required so that the operators will be sufficiently knowledgeable to make effective use of the software. For example, PowerMAX estimates that two days of training is sufficient in most cases for application of the ULTRAMAX software to a given boiler. This training is primarily intended for initial optimization and identification of set points. Where the utility intends to apply the software to a number of boilers, more substantial up-front training may be appropriate. LILCO, who applied the software in this manner, felt that one week of training is needed for the primary user(s) of the software. An important step in a one-time optimization project is for the plant to implement the optimized control settings in the boiler operation procedures. It is important that plant management recognize this need before applying the software and include implementation (mainly operator training) in the optimization project plan. For application of an optimization software in a closed-loop or continuous advisory mode, a gradual operator training program over a period of weeks or months can be expected, and it will be necessary for at least one utility engineer to be thoroughly trained in the software at each application site.

Impacts on Boiler Operation

Application of optimization software is not expected to negatively impact any aspect of operation. If another performance parameter together with NO_x is assigned an improvement goal, some improvement is likely to be realized in both parameters. For example, heat rate has been improved along with NO_x in some cases. While direct effects on boiler operation should all be positive, in adding any on-line optimizer to its boiler systems, the utility should anticipate a need to dedicate some engineering time to periodically tuning and occasionally upgrading each installation of the software or adapting it to system changes that will probably occur.

Control Costs

A typical cost for a two-week optimization project using ULTRAMAX is $35,000 to $50,000. The cost of a site license, which includes rights for the use of the technology on any equipment at that plant site, is dependent on the size and number of boiler units at a site. Typical costs range from $75,000 to $150,000 for a plant site. A possible extension is integration of ULTRAMAX with the unit's control system to provide operator advisory capability. For integration with a control system, $10,000 to $50,000 would be added depending on system complexity.

The costs for application of the neural network-based softwares are less well defined in view of the developmental status of these technologies. Estimated costs for installation and start-up of the software (i.e., several months of data acquisition and model building by vendor personnel on site) range from $150,000 to $300,000.

In addition to payments made to the vendor, application of optimization software will require some minor to significant investment in upgrading boiler components and training plant personnel to both set the stage for effective use of the software and to act upon its recommendations. Preparatory and follow-on items mentioned above under "Typical Boiler Upgrades" should be considered in assessing the cost of an optimization.

4.2 Burner Modifications

After tuning and optimization, the next most cost-effective approach for achieving NO_x reduction on a gas- or oil-fired boiler is usually modification of the burner hardware, specifically, the fuel injector and/or flame stabilizer design. Technologies are now available to efficiently modify these hardware elements to achieve lower-NO_x operation. Most of this technology has been developed for oil fuel. However, similar technology that is currently being developed for gas fuel will also be discussed.

Description

In oil-fired units, the design of the oil atomizer and flame stabilizer can have a significant effect on both NO_x and particulate matter emissions. However, many burner designs have primarily focused on controlling particulate matter with potentially negative effects on NO_x emissions. As an example, improvements in oil atomization quality (i.e., reducing oil droplet size) tend to decrease particulate emissions and increase NO_x emissions. Research and full-scale tests funded by EPRI and New York State utility companies provided design guidelines that integrate modification of the atomizers and flame stabilizers of existing burners in such a way that NO_x reductions are achieved with no increase in particulate or opacity emissions. This work led to development of Reduced Emissions and Advanced Combustion Hardware (REACH) (9, 10). Similar research at PowerGen in the U.K. led to development of the Advanced F-jet (AFJ) atomizer (11).

The oil atomizer and flame stabilizer are critical combustion hardware components which affect the emissions characteristics, turndown, and combustion efficiency of any oil-fired burner. As illustrated in Figure 4-6, the flame stabilizer affects the aerodynamic mixing pattern of the flame, and is designed to promote mixing of air and oil immediately downstream of the burner exit plane and to ensure stable flames over a range of firing rates. The oil atomizer produces oil droplets of a specified size distribution and spray geometry that must match the aerodynamic pattern created by the flame stabilizer. REACH technology and AFJ atomizers both act to modify these critical components for lower-NO_x operation of the burner.

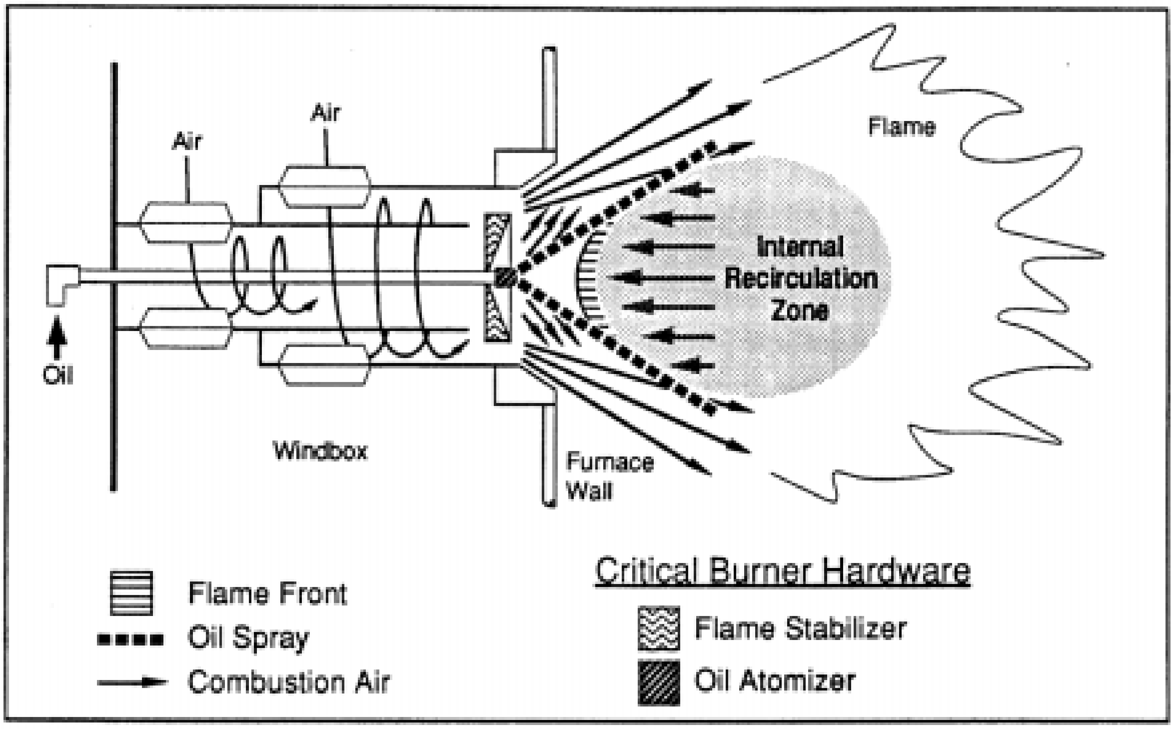

Figure 4-6
Critical Combustion Components of an Oil-Fired Burner

REACH consists of new flame stabilizers, oil atomizers, and auxiliary equipment such as installation hardware, pressure gauges for atomizer steam (if present) and oil, and maintenance tools. The new atomizers and swirlers can be retrofit during an outage of less than a week. REACH adapts to the major existing components of a burner. In the majority of retrofit applications, REACH flame stabilizers and oil atomizers replace the existing stabilizers and atomizers, while other burner components, including air registers, oil guns, flame detection equipment, ignitors, and control systems are left intact. One-time adjustments are made in the field to optimize REACH performance. Such adjustments may include: swirler axial position (oil gun guide tube position), air swirl, partitioning between air zones, orientation of gas fuel injectors, oil and atomizing steam differential pressure settings (if applicable), and the position and air supply for ignitors. The capability to adjust these parameters is normally incorporated into the design of existing burners or, if necessary, can be added during retrofit of REACH.

Two versions of REACH have been defined on the basis of combustion improvement and emissions reduction objectives:

- CP-REACH - Combustion Performance REACH (CP-REACH) solves a variety of site-specific boiler performance, maintenance, and operating problems related to poor combustion conditions.

- LN-REACH - Low-NO_x REACH (LN-REACH) provides simultaneous reductions in NO_x and particulate emissions, while retaining the advantages of CP-REACH.

CP-REACH is designed to reduce particulate emissions and opacity, whereas LN-REACH is specifically aimed at retrofit projects where NO_x reduction is a goal. The major difference between CP-REACH and LN-REACH is the design of the oil atomizer. The LN-REACH atomizer found to produce the lowest NO_x emissions is an internal-mix, steam atomizer referred to as the Segmented V-Jet atomizer (patent applied for). A low-NO_x mechanical-atomizer, which produces similar flame conditions to the Segmented V-Jet, has also been developed. CP-REACH and LN-REACH hardware are custom-designed according to the performance, operational, and emissions requirements of each specific application. Boilers equipped with CP-REACH can be easily converted to LN-REACH. For more information on REACH technology, contact Tony Facchiano at EPRI (415-855-2494).

The AFJ technology is based on an internal-mix, multi-port steam assisted atomizer designed to produce a more finely atomized oil spray than conventional steam assisted atomizers. The objective of the design is to reduce unburned carbon particulates, while also reducing NO_x through placement of the fuel by the multi-port design to produce fuel-rich and fuel-lean flame zones. Installation of the atomizers can normally be accomplished with the boiler on line. Experience has shown that a fixed blade flame stabilizer is required to achieve full benefit of the AFJ atomizer. If existing burners have bluff body flame stabilizers (i.e., the impeller or diffuser used on many oil guns), these would have to be replaced with fixed blade stabilizers.

While development of burner modification technologies has in the past focused exclusively on oil fuel, work is now underway to develop similar technology for gas fuel. The goals and near-term objectives of this program are summarized in Box 4-1.

Experience

Applications of burner modification technologies for NO_x reductions on utility and industrial boilers are summarized in Table 4-3. Many of the cases have been industrial or utility steam send-out boilers, which are not coupled to generator sets, but sizes of these boilers are nonetheless expressed as equivalent electrical power for greater ease in interpreting the data. Twelve applications are listed in the table; however several are multiple applications to sets of identical boilers, and a total of 21 boilers have been retrofitted with these technologies specifically for NO_x reductions. While most applications have been to wall-fired boilers equipped with steam atomizers, the LN-REACH applications include two tangential-fired boilers and three boilers equipped with mechanical atomizers.

Box 4-1
EPRI Program to Develop Gas REACH

EPRI member utilities have a need for retrofittable gas-burning technology that achieves moderate NO_x reductions at a fraction of the cost and complexity of new burners, fans, or post-combustion processes. This technology must: (1) be physically compatible with existing burner hardware, (2) have a capital cost that is significantly less than new burners, (3) produce NO_x reductions of 20 to 40% (without FGR) when operated with all burners in service, (4) produce NO_x levels at or below 0.1 lb/MBtu (80 ppmc) when applied in conjunction with moderate amounts of FGR, and (5) achieve NO_x levels in the .0375 lb/MBtu (30 ppmc) range when used in combination with maximum FGR and overfire air (OFA).

In this project, gas-burning technology will be developed and demonstrated which can be readily retrofit to existing oil and gas/oil burners without major modification. The work will focus on designs for adjustable gas spuds and flame stabilizers. The gas burner development will build upon REACH know-how developed previously.

Goals

- LNB performance on gas firing via replacement of nozzles and swirlers (critical components) with advanced components.
- Projected cost of $2/kW (vs. $10-15/kW for LNBs)

Phase 1 Development and Test Program (Tentative)

- Con Edison 59th St. Station

— Multi-burner, ≤100 MBtu/hr-burners, air preheat, high SHRR

— With and without FGR

- Schedule

— 2nd Q 97: Boiler modifications, baseline testing with and without FGR, conceptual design of critical components

— 4th Q 97: Testing, redesign, and retesting as required, final design.

Phase 2 Demonstration

- Wall and tangential units will be sought for demonstrations in large scale utility boilers.

Application of LN-REACH to Commonwealth Edison’s Collins units is an example of using the technology to correct problems with existing low-NO_x burners. This was also the case in an application of the technology to Hawaiian Electric's Kahe Unit 6, where deleterious effects of low-NO_x burners on opacity performance of the boiler were corrected using LN-REACH while maintaining constant NO_x performance.

Applicability

The REACH technology was developed using steam-assisted atomizers, and is applicable to most wall-fired and tangential-fired boilers equipped with steam-atomized oil guns. Further development and demonstration of the technology has extended the applicability to wall-fired and tangential-fired boilers equipped with mechanically atomized oil guns. REACH technology is compatible with conventional NO_x controls such as overfire air, flue gas recirculation to the windbox, and burners-out-of-service, and can be combined with these techniques to further reduce NO_x emissions. REACH technology may also be incorporated into the design of new low-NO_x burners for additional NO_x reduction.

The AFJ atomizer technology is applicable to steam-atomized burners, and the technology has so far been installed only in single wall-fired boilers. Like REACH, AFJ atomizers should be compatible with other types of NO_x control.

NO_x Performance Achieved

As shown in Table 4-3, the LN-REACH technology has demonstrated NO_x reductions of from 17% to 43% in 8 applications (see also Appendix A). The baseline NO_x levels shown for the Con-Edison boilers reflected CP-REACH technology which had been installed on these boilers prior to the LN-REACH. In all of these cases, opacity with the LN-REACH technology in place remained low, in the 2-7% range. Particulate was measured following the LN-REACH installation only on 74th Street #3, and was found to be .03 lb/MBtu (.013 g/MJ). The application to Bowline Point Unit 2 included addition of air balancing sleeves to burner registers and improvements in OFA and FGR control systems (12).

The LN-REACH retrofits on Collins Units 1-3 were done to correct problems with newly installed low-NO_x burners. These units are equipped with OFA and FGR, and prior to the LN-REACH installations the plant had to use FGR on these units to meet permitted NO_x levels. This represented added cost and led to problems with opacity. LN-REACH enabled the plant to meet the NO_x limit without use of FGR. LN-REACH was also installed on Hawaiian Electric's Kahe Unit 6 to correct problems encountered with low-NO_x burners. In this case the plant was using high levels of FGR and OFA to meet its NO_x limit, which led to opacity problems. LN-REACH enabled the NO_x limit to be met with substantially less OFA and FGR, which provided more margin on opacity. Specific results for Kahe Unit 6 are as follows:

	As-Found Initial Atomizer	LN-REACH
NO_x, lb/MBtu (g/MJ)	0.19 (.082)	0.19 (.082)
Opacity, %	18	10
OFA, %	26	20
FGR, %	20	11
Atomizer steam consumption (mass steam/mass oil)	0.20	0.14

Table 4-3
Summary of NO_x Reductions Achieved on Oil-Fired Boilers by Modification of Burner Hardware

Technology	Owner/ Operator	Boiler	Firing Type	Size (MWe)	Type of Atomizer	NO_x, lb/MBtu (g/MJ) Baseline	Reduced	NO_x Reduction, %		Ref.
LN-REACH	Con-Edison	74th Street #3	Single Wall	15	Steam	0.397 (0.171)	0.225 (.0968)	43	Baseline was CP-REACH	9
LN-REACH	Con-Edison	Hudson Ave. #71	Single Wall	43	Steam	0.420 (0.181)	0.256 (0.110)	39	Baseline was CP-REACH	9
LN-REACH	Con-Edison	74th Street #122	Tangential	54	Steam	0.195 (.0839)	0.151 (.0649)	23	Baseline was CP-REACH	9
LN-REACH	Con-Edison	Hudson Ave. #100	Single Wall	150	Steam	0.492 (0.212)	0.375 (0.161)	24	Baseline was CP-REACH	9
LN-REACH	Commonwealth Edison	Collins 1, 2, 3	Opposed	550-572	Steam	0.47 (0.20) 0.37 (0.16)	0.32 (0.14) 0.28 (0.12)	32 24	OFA ports closed OFA ports open	9
LN-REACH	Orange & Rockland	Bowline Pt. 1	Tangential	600	Mech.	0.29 (0.12)	0.24 (0.10)	17		13
LN-REACH	Orange & Rockland	Bowline Point 2	Opposed	600	Mech.	0.38 (0.16)	0.24 (0.10)	37		14
LN-REACH	Hawaiian Electric	Kahe 1	Single Wall	90	Mech.	0.71 (0.31)	0.41 (0.18)	42	Test program, not a permanent installation	15
AFJ	BP Chemical	Baglan Bay 2, 4	Single Wall	68	Steam	0.464 (0.200)	0.375 (0.161)	19	Boiler derated 12%	11
AFJ	British Petroleum	Grangemouth 9-13	Single Wall	40	Steam	0.409 (0.176)	0.335 (0.144)	18	Boiler derated 18%	11
AFJ	British Sugar	Newark 1	Single Wall	14	Steam	0.858 (0.369)	0.748 (0.322)	13	Untuned baseline	11
AFJ	Glaxochem	Olverston 4	Single Wall	22	Steam	0.345 (0.148)	0.266 (0.114)	23	Untuned baseline	11

As also shown in Table 4-3, the AFJ technology has demonstrated NO_x reductions of from 13% to 23% in 4 applications. The application to Newark 1 did not represent maximum NO_x reduction capability of the technology for that unit in that the atomizer was optimized to also reduce particulate from 0.116 to .06 lb/MBtu (.0500 to .026 g/MJ).

Typical Boiler Upgrades

Implementation of this technology may require minor boiler upgrades in addition to installation of the new atomizers and swirlers. Modifications may be required to the fuel oil supply system or atomization steam supply in order to improve fuel atomization. For a boiler equipped with mechanical oil atomizers, a change to steam atomization may be an appropriate part of a burner modification program for NO_x reduction. Steam atomization, while involving some incremental cost, may improve the boiler's compatibility with low-cost combustion staging NO_x controls (including O/S combustion as well as low-NO_x atomizers being discussed here) and may be especially appropriate if the boiler is marginal on particulate emissions and/or opacity relative to current or anticipated regulations. Balancing the fuel and air flow to each burner may also be required to achieve the full NO_x reduction capability of this technology.

Potential Impacts on Boiler Operation

In applications where the existing equipment provides poor oil atomization and requires high excess oxygen levels to maintain acceptable particulate emissions and opacity, optimized atomizers and swirlers can reduce boiler excess oxygen requirements and result in improved boiler efficiency. Both REACH technology and AFJ atomizers can be designed to optimize between NO_x and particulate emissions or opacity as needed in each case. Various possible combinations of NO_x and particulate (or opacity) objectives are shown in Figure 4-7. If current levels of particulate emissions are satisfactory, the technology may enable a reduction in excess O_2, which will improve boiler efficiency.

Control Costs

The overall cost for installing and optimization testing of LN-REACH technology is approximately $1-2/kW. If improved atomization allows a decrease in excess air level, then an operating credit (of approximately 0.25% improvement in unit heat rate per 1% decrease in O_2) should be taken. A general cost estimate for installation of AFJ atomizers, provided by PowerGen, is $12,500-$25,000 for engineering and testing plus $800-$1,000 per atomizer, plus any additional cost for modification of oil guns or flame stabilizers should this be necessary.

4.3 System Modifications

To achieve further or larger NO_x reductions than those achievable through relatively minor modifications to the burner hardware, the utility must consider more substantial changes to the overall boiler system. While, for coal-fired boilers replacement of the burners with low-NO_x designs is generally considered the next most cost-effective NO_x reduction method after tuning and optimization, less costly system modifications are generally more cost-effective for gas- and oil-fired boilers. These consist of overfire air and flue gas recirculation and in the case of peaking, low capacity factor units, water injection or reduced air preheat. Overfire air is a relatively minor boiler modification involving little operational cost and should be given particular attention if air staging of the boiler cannot readily be achieved using BOOS. Flue gas recirculation is also a relatively minor modification if an FGR fan is already present, but involves a significant operating cost in terms of added fan power. However, this method is highly effective on gas and also achieves substantial NO_x reductions on oil. Water injection or reduced air preheat are similar to FGR in that they reduce peak flame temperatures and thermal NO_x. Due to their impacts on unit efficiency, however, they are only mentioned as low capital cost niche technologies for low capacity factor units used for peak power production and which do not have FGR fans.

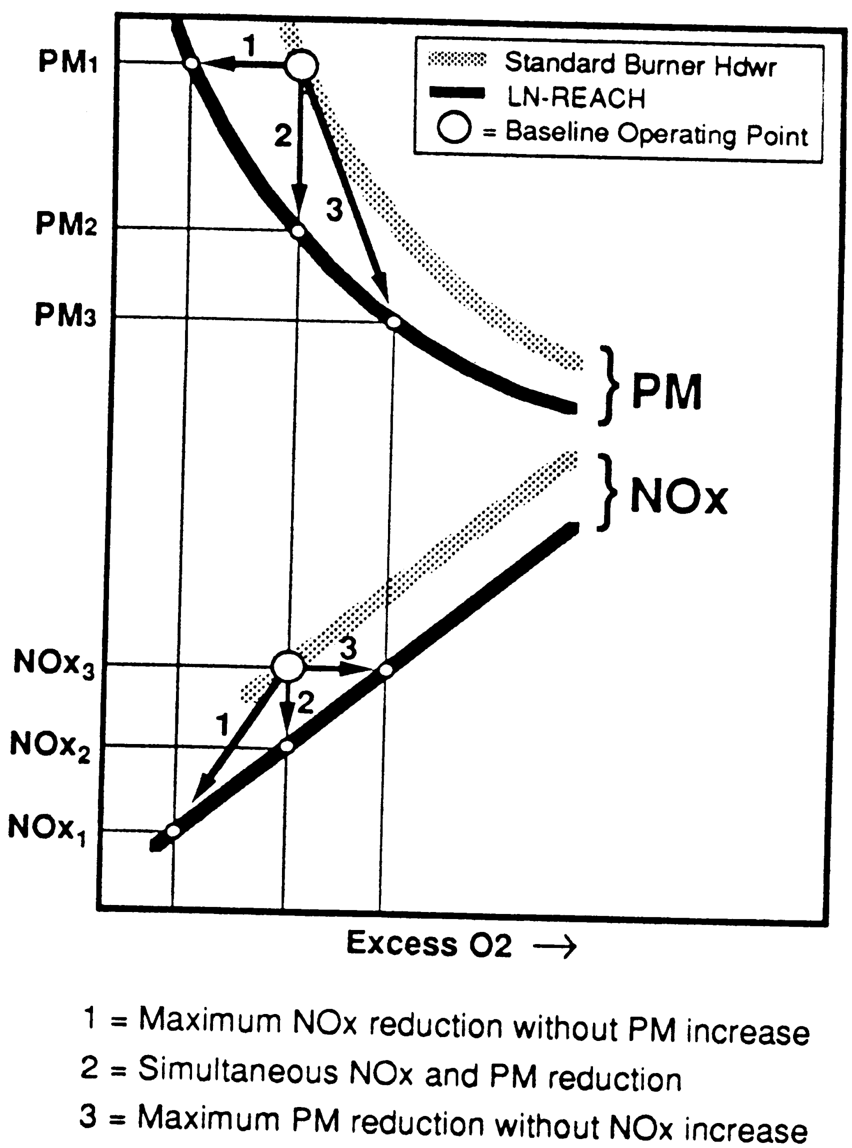

Figure 4-7
Tradeoffs between NO_x, Particulate, and Excess O_2 with LN-REACH

4.3.1 Overfire Air

Description

Overfire air (OFA) involves the use of air injection ports in the upper furnace above the burner zone to divert a portion of the combustion air away from the burners. The quantity of air diverted to the ports typically varies from 10 to 15% up to rates as high as 20 or 30%. Limitations to the degree of OFA that can be achieved include:

- WB pressure and FD fan limitations
- CO emissions, and
- opacity (oil-fired boilers)

For wall-fired boilers, the overfire air ports are usually located on each firing wall of an opposed wall-fired unit, and on the firing wall and/or the opposite wall of a single wall-fired unit. Side wall ports may also be offered by vendors as a means of improving overfire air mixing with the bulk furnace gases. For tangential-fired boilers, the overfire air may be supplied by: (1) a separate windbox at the corners of the furnace above the main burner windbox (termed "separate overfire air" [SOFA]; or (2) separate air nozzles at the top of the main burner windbox (termed "close-coupled overfire air" [CCOFA]).

The primary objective of OFA is to reduce oxygen availability to the fuel at the point of the most intense combustion. This reduces the NO_x formation from both the thermal reaction and the reaction of fuel bound nitrogen (in oil-fired units). Also, the lack of oxygen tends to slow the combustion process, reducing peak temperatures. The introduction of the air later in the combustion process allows for complete burnout of the fuel in a second, less intense, lower temperature combustion zone. The name "two-stage combustion" is often used in referring to OFA systems.

OFA technology has been applied in the power industry for over 25 years to control NO_x emissions. Originally, OFA ports on wall-fired boilers were designed as tube wall openings above the top row of burners, typically within the boundaries of the burner windbox. One problem with this arrangement is the lack of control over air distribution among the ports and over the subsequent mixing of the air with the furnace gases. To overcome these limitations, manufacturers have developed "advanced" OFA systems that involve separate windboxes and more sophisticated air control systems. In addition, advanced OFA systems may include independent control of overfire air jet velocities, directional control of the air, and optimization of port location through CFD or physical flow modeling, enabling larger quantities of OFA injection than historically used without encountering adverse CO or opacity emissions. As a result, greater NO_x reductions may be possible compared to conventional OFA systems fed from the main burner windbox. Figure 4-8 provides an illustration of an advanced OFA system.

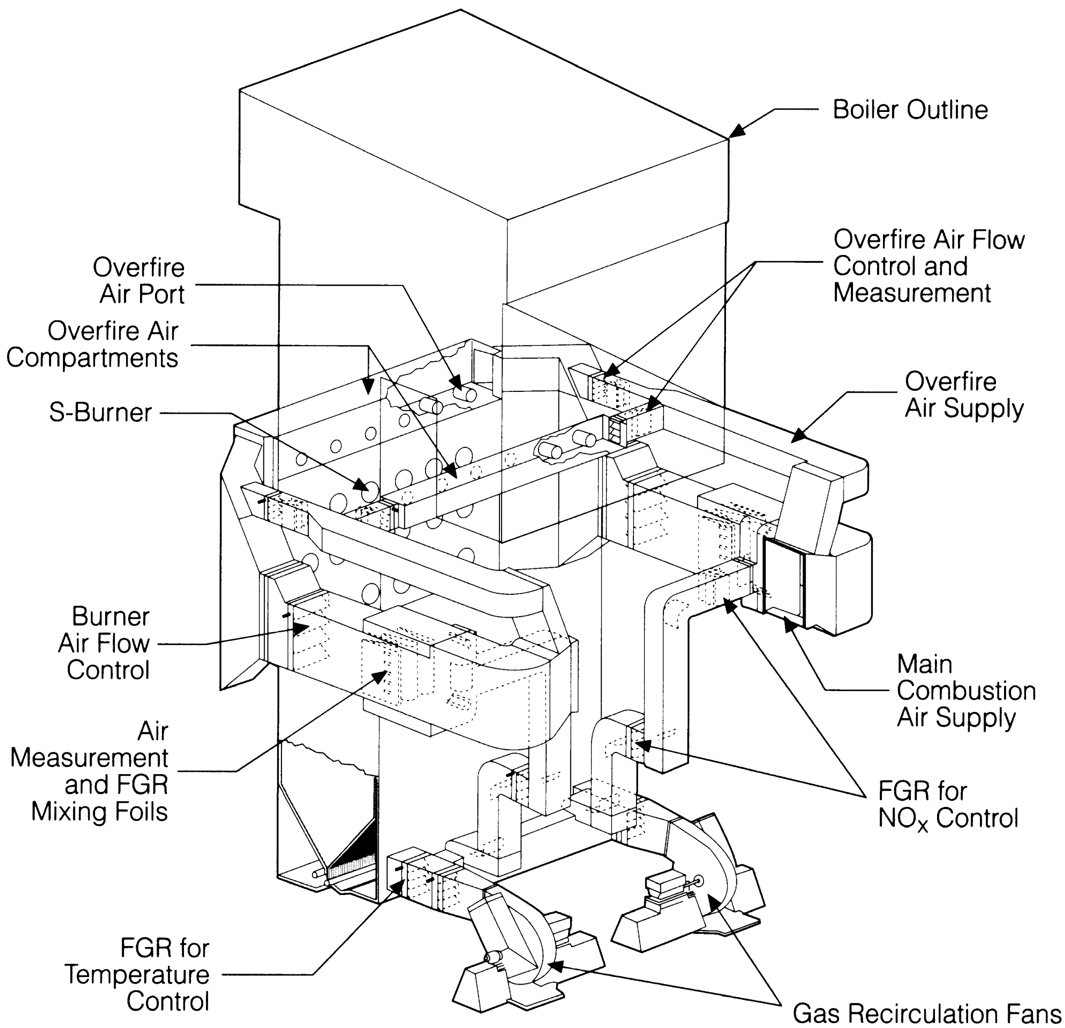

Figure 4-8
Arrangement of an Advanced Overfire Air System and Flue Gas Recirculation System on a Single Wall-Fired Unit

Experience

There are a number of gas- and oil-fired units equipped with conventional OFA systems, although it is in many cases uncertain which of these systems were part of the original boiler design and which were retrofitted. Advanced OFA systems have been installed in conjunction with other NO_x reduction technologies (e.g., low-NO_x burners and/or flue gas recirculation) on several units including Southern California Edison's Mandalay Unit 1, Hawaiian Electric's Kahe Unit 6, Los Angeles Department of Water and Power's Haynes Unit 3, and Pacific Gas & Electric's Morro Bay Unit 3 and 4. SOFA systems have recently been installed on two gas/oil-fired tangential boilers as part of NO_x reburning retrofits. These are Illinois Power Hennepin Unit 1 and Long Island

Lighting (LILCO) Barrett Unit 2, both coal-design boilers. CCOFA systems have been installed on a number of tangential coal-design boilers in the LILCO system.

Applicability

Several factors must be considered in terms of the current unit design relative to its operation under staged combustion. These factors include:

- Adequate forced draft fan capacity and level-by-level or individual burner combustion air control with flow indicators to enable uniform air flow to burners and OFA ports at the prescribed burner zone stoichiometry.

- Adequate furnace volume and convective section design to permit OFA while meeting steam temperature requirements and without unacceptable CO or carbon carryover under oil-fired conditions.

- Proper design of OFA ports with appropriate spacing relative to burners and injection velocity to complete secondary combustion (i.e., acceptable CO and opacity) but without significant NO formation (numerical modeling recommended as a tool to optimize OFA design and/or confirm expected NO_x reductions).

- Proper windbox and furnace design to avoid acoustic resonant vibration and "rumble."

OFA can be applied to wall- and tangential-fired gas and oil units. Two site-specific factors that determine the retrofit feasibility of overfire air include the residence time and mixing characteristics available above the upper burner elevation for mixing and burnout, and the physical space for the ports and associated windbox and ducting. An assessment of required residence time within the burnout zone between OFA ports and furnace exit can be made from extensive gas reburn testing. Based on data from these programs, burnout zone residence times greater than 200 msec should be available for optimal applications of OFA. It is important to note that off-stoichiometric combustion conditions created by OFA can on many boilers be realized at much lower cost using BOOS operation. A numerical modeling effort may be useful to assess the relative merits of OFA vs. BOOS.

NO_x Performance Achieved

As evident in Table 4-4 (see also Appendix A), NO_x reduction data from OFA systems by themselves is limited. Although there is considerable operating experience with conventional OFA systems on gas- and oil-fired utility boilers, NO_x reduction levels attributable solely to OFA are not well-documented as these systems are installed in conjunction with other NO_x reduction technologies (e.g., low-NO_x burners, and/or flue gas recirculation). Many first-generation OFA systems were limited in terms of the quantity of air that could be injected, and were not effective in distributing the air through the cross section of the boiler. Consequently, these systems were often ineffective in reducing NO_x, or NO_x reductions were achieved at the expense of higher excess air and opacity levels. For gas-fired OFA applications, NO_x reductions of 18%-64% were found. However, the 18% reduction on the 70 MW tangential unit was presented as part of a gas reburn demonstration, and was not well characterized with respect to test conditions and possible limiting factors to further NO_x reductions through deeper staging. An approximate 50% reduction, which is well supported by the remaining two gas-fuel data is probably more realistic and is consistent with earlier OFA developmental data.

Table 4-4
Gas and Oil-Fired Utility Experience with Stand-Alone OFA Systems

Unit Design	Capacity, MW	Fuel	NO_x Emissions Baseline lb/MBtu (g/MJ)	NO_x Emissions Controlled lb/MBtu (g/MJ)	Reduction, %
Opposed	560	Gas	0.64 (0.28)	0.30 (0.13)	53
		Oil	0.47 (0.20)	0.37 (0.16)	21
Tangential	70	Gas	0.135 (.0581)	0.11 (.047)	18
Tangential	185	Gas	0.225 (.0968)	0.08 (.034)	64
		Oil	0.24 (0.10)	0.14 (.060)	42
Tangential	387	Oil	0.37 (0.16)	0.19 (.082)	49

In implementing OFA together with other combustion modification technologies, the incremental effectiveness of OFA has exhibited a wide range. Implementation of OFA at Morro Bay, a 330 MW opposed design gas-fired unit, in combination with low-NO_x burners and 17% FGR demonstrated a NO_x sensitivity of nominally -2% NO_x per percent OFA. Thus, even with FGR and LNB, 25% OFA (82% burner zone stoichiometry at 10% excess air) would provide a nominal 50% reduction in NO_x emissions (16). On Los Angeles Department of Water and Power's gas-fired Haynes Unit 3, the OFA system had only a marginal impact on NO_x emissions at maximum flue gas recirculation rates (17).

Limited OFA data from oil-fired boilers exhibited NO_x reductions of approximately 20%-50%. As an example, the OFA system installed on oil-fired Hawaiian Electric's Kahe Unit 6 demonstrated a 40% reduction in NO_x when other operating parameters were held constant (18). Limitations to additional NO_x reduction were increases in the windbox to furnace differential pressure from 4.5 to 6 inches water, as well as CO and opacity.

Typical Boiler Upgrades

Retrofitting OFA requires new tube wall panels for the overfire air port openings and a register assembly for each port to control air flow and in-furnace mixing. New ductwork to deliver the air to the overfire air ports from the secondary air duct will also be required.

In tangential-fired units, replacement or extension of the corner windbox to accommodate OFA compartments may be necessary. If the existing windbox is retained, modifications to fuel and air compartments may be required to maintain combustion efficiency, flame stability, and proper distribution of air to OFA nozzles. Likewise, minor modifications to burner components on wall-fired units may be required.

Effective application of an OFA system requires that the flow of air to the OFA ports be measured and controlled. This gives plant operators the flexibility to adjust the stoichiometry of the operating burners through control of the air flow to the OFA ports, a primary system variable affecting both NO_x reduction and combustion system operation. Flow meters to indicate total OFA flow and port-to-port distribution will be required, as well as damper assemblies and related controls to regulate OFA quantity and velocity. The complexity of the instrumentation and control requirements differ, depending on the specific application.

Potential Impacts on Boiler Operation

A trade-off among reducing NO_x, minimizing combustion air levels, and minimizing CO emissions and stack opacity in the case of oil-fired boilers can be expected, even with a well-designed OFA system. Maintaining opacity, and/or particulate matter emissions below allowable levels may be the primary factor limiting the quantity of OFA that can be injected. Assessments of OFA system design and potential impacts to the combustion process can be made through the use of numerical models.

Another consideration is the performance of the existing burners with reduced air flows. Burners are designed for a specified range of air flow. The reduction in air flow through the burner accompanying OFA results in reduced mixing in the main combustion zone, potentially resulting in degradation in flame stability or combustion efficiency, especially when high rates of OFA are used. Boiler rumble due to burner instability may also be experienced under these conditions. To determine whether these operational problems will be encountered with OFA, a utility can simulate OFA conditions with BOOS and observe flame stability.

OFA can change the furnace outlet temperature. The magnitude of the change (typically 50 to 100°F [28 to 56°C]) is generally within the range of variation experienced during normal boiler operation. As a result, OFA usually will not pose a problem for steam temperature control unless the unit currently experiences high or marginally high steam temperatures. The boiler heat absorption characteristics, steam temperature conditions, and capability of existing steam temperature control devices need to be assessed on a case-by-case basis for OFA retrofit projects. These parameters can be evaluated through heat transfer modeling by boiler manufacturers, engineering and consulting firms, and by utility engineers. An alternative approach is to assess potential impacts during a NO_x reduction test program, since boiler performance parameters (e.g., steam temperature, firing rate, attemperation, etc.) are all evaluated by the test engineer.

Control Costs

OFA systems are frequently retrofit only on units in combination with flue gas recirculation and low-NO_x burners. As a result, stand-alone cost estimates for this technology are limited. However, the capital cost for installation of OFA ports, associated ducting, dampers, and controls would be expected to be $5 to $15/kW. The range in costs is contingent upon the use of a common or separated windbox as well as site specific factors. Site specific costs for OFA are discussed in greater detail in Appendix D. As in the case of BOOS, operating costs associated with OFA are a function of increased fuel consumption resulting from any required increase in excess air levels. A 0.25% penalty in unit heat rate will be experienced for every 1% increase in O_2.

4.3.2 Flue Gas Recirculation and Other Thermal Diluent Techniques

Description

Recirculating flue gas back to the combustion zone is an effective method of reducing NO_x emissions from gas- and oil-fired units. Flue gas recirculation (FGR) acts to reduce NO_x formation by reducing peak flame temperatures and by lowering the oxygen concentration in the combustion zone. For oil firing, where conversion of fuel-bound nitrogen contributes to NO_x, the reduced oxygen availability due to FGR also reduces the fraction of fuel nitrogen converted to NO_x. However, FGR is typically much more effective in reducing NO_x for gas-fired applications than on oil-fired applications. For both gas and oil, in order to ensure that sufficient oxygen is available for combustion, the oxygen concentration in the combustion air/flue gas mixture should be maintained above a safe minimum, typically 16 to 17% O_2 (for 500ºF [260°C] or higher air preheat applications).

In conventional applications, the recirculated flue gas is typically extracted from the boiler outlet duct upstream of the air heater. The flue gas is then returned through a separate duct and fan to the combustion air duct that feeds the windbox. The recirculated flue gas is mixed with the combustion air with air foils or other mixing devices in the duct. This technology is known as "windbox FGR." Figure 4-8 illustrates a typical windbox FGR arrangement as well as the advanced OFA system already described. Some existing FGR systems, installed for purposes of steam temperature control, circulate flue gas to the furnace hopper or through tempering ports in the furnace wall; since the flue gas is not introduced into the high-temperature region of the flame where NO_x formation occurs, these systems do not reduce NO_x as effectively as windbox FGR. Throughout this document unless stated otherwise, the term "FGR" normally indicates windbox FGR.

Box 4-2
Induced Flue Gas Recirculation

For a boiler that is not already equipped with windbox FGR, induced flue gas recirculation (IFGR) may be a low-cost method to achieve a limited degree of NO_x reduction.

Conventional windbox FGR systems require installation of a separate FGR fan to move flue gas from the boiler exit to the air supply ducting at the windbox inlet, where the flue gas must be uniformly mixed with the combustion air. Typically, 15% or more of the boiler flue gas is recirculated, and substantial NO_x reductions are achieved. A far less costly method to implement a limited amount of windbox FGR may be possible on a unit having some excess FD fan capacity. This method, known as induced flue gas recirculation (IFGR), utilizes the FD fan to pull flue gas from the air preheater exit into the combustion air at the fan inlet. The fan thus also serves as a mixing device. Amounts of FGR that can be achieved using IFGR will be limited to probably 5% or less at full load. However, NO_x reductions achievable can still be quite significant. FGR, like most NO_x controls, has a "diminishing-returns" characteristic, and a disproportionately large fraction of the NO_x reduction is achieved by the first few percent FGR.

IFGR is thus a very low-cost method to achieve incremental NO_x reduction, requiring only a minor boiler modification and having relatively little impact on boiler operation. The key question for a given boiler would be the applicability of IFGR. If the boiler has excess FD fan capacity at full load, IFGR should probably be considered. However, IFGR may be possible even if the boiler is believed to have marginal excess fan capacity. For these units, the following methods might be considered to enable IFGR:

- *Reduce the amount of excess air used at full load.* This applies only if low-excess air (LEA) operation has not already been implemented. Implementation of LEA is discussed above in the section entitiled "Tuning and Optimization".
- *Reduce pressure drop across high-loss components.* Evaluate pressure drops across the air preheater and dampers/registers in the air flow path versus design, or new-boiler, conditions. Examine the air preheater condition and damper/register settings.
- *Modify the fan and/or motor to increase capacity.* Rewinding the motor and/or adding vane extenders can be low-cost methods to increase fan capacity.

As the IFGR approach impacts FD fan capacity from both the perspective of higher flow rates and differential pressures, the applicability needs to be carefully evaluated. A demonstration of IFGR on a small utility boiler is planned for mid-1997. For more information, contact Tony Facchiano at EPRI (415-855-2494).

EPRI is currently evaluating a low-cost method to achieve a limited degree of windbox FGR by utilizing any excess FD fan capacity on a given boiler to pull flue gas into the combustion air. Information on this variation of windbox FGR, known as induced flue gas recirculation (IFGR), is provided in Box 4-2.

Another system modification, which can reduce NO_x emissions on gas fuel is "fuel injection recirculation" (FIR). FIR involves dilution of gaseous fuel with an inert medium such as flue gas or steam prior to combustion, which lowers flame temperature and reduces NO_x. Tests have shown that, per pound of diluent, FIR is more effective than windbox FGR in reducing NO_x and, significantly, the effects of FIR and FGR are additive, enabling very low levels of NO_x to be achieved when the two technologies are combined. FIR has been demonstrated on a utility boiler but is not yet commercially available. FIR results on a 44 MW gas-fired boiler using steam as the diluent are presented in Figure 4-9. As shown for equivalent diluent injection rates, FIR provided 50% additional NO_x reduction from a NO_x level that was already very low with approximately 15% FGR to the windbox (19). Use of steam or compression of flue gas to dilute the fuel represents a substantial operating cost, and thus FIR, using either of these methods, is most suitable for a unit with a low capacity factor and/or short remaining life. However, methods to induce flue gas into the fuel using a smaller amount of steam or by taking advantage of inherently high natural gas line pressures have been considered. While no work is presently in progress, methods such as these could make FIR, when combined with FGR, an attractive method to achieve very low NO_x levels.

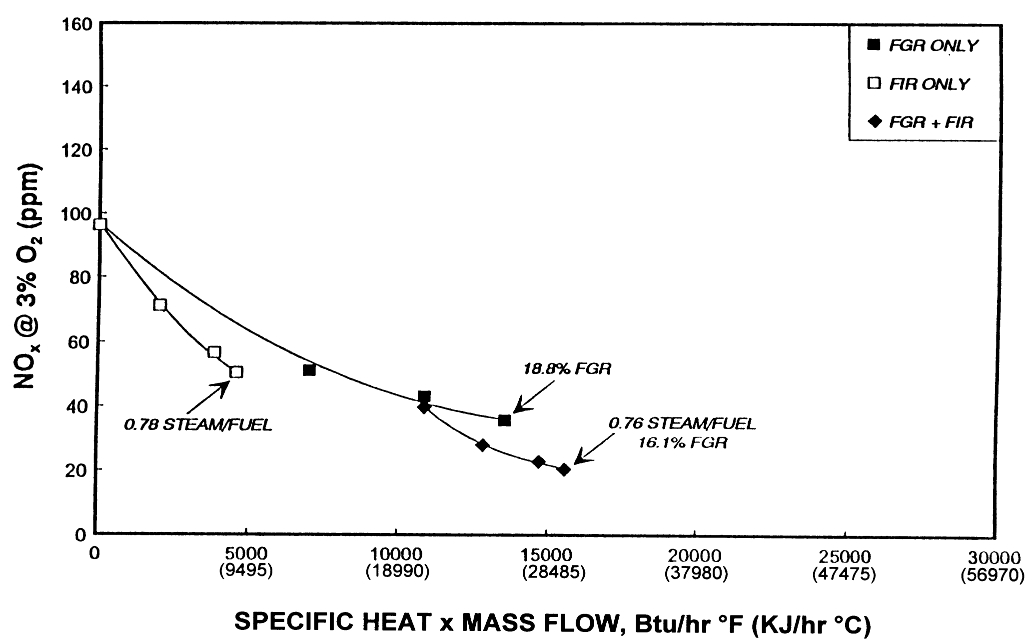

Figure 4-9
FIR Results on 44 MW Utility Boiler

Reduced air preheat and water injection are additional techniques comparable to FGR, albeit with higher associated efficiency penalties. Water injection introduces water or steam into the combustion air through a network of nozzles in the windbox or directly to the burners (for example, by using the oil guns to inject water during gas firing). When using water, sufficient time must be allowed for its vaporization, otherwise fouling of the burner and boiler surfaces can occur. Reduced air preheat is usually accomplished through the use of a duct bypassing part of the combustion air around the air preheater.

As with FGR, reduced air preheat and water injection are most effective in lowering thermal NO with their primary application being on gas- and oil-fired units. Both techniques reduce flame temperatures. Water injection provides an inert diluent, similar to FGR, to absorb heat and lower the combustion temperature. Reduced air preheat lowers the temperature of the reactants which results in lowering peak temperature. Reduced air preheat and water injection have adverse effects on unit heat rate and are not popular for this reason. Approximate effects on heat rate are: 2% increase per 100°F decrease in air preheat and 4.75% increase on gas fuel or 6% increase on oil fuel for one pound of water per pound of fuel.

Experience

Windbox FGR has been in use for over 20 years for reduction of NO_x emissions on boilers firing natural gas and fuel oil, frequently in combination with BOOS or OFA. Beginning in the early 1970s, numerous units have operated with windbox FGR, notably boilers subject to NSPS or strict local environmental regulations. FGR integral to the burner has been demonstrated in the retrofit to Hawaiian Electric's Kahe Unit 6, SCE's Mandalay, and PG&E's Morro Bay Unit 3 and 4.

A reduced-air preheat system, consisting of a dampered air preheater by-pass duct, was demonstrated on one boiler in Southern California, but was not used in practical operation.

Applicability

Windbox FGR can be retrofit to most wall- and tangential-fired boilers, although its compatibility with burner and boiler design characteristics needs to be evaluated in determining retrofit feasibility. Key applicability factors include burner flow requirements, existing fan (draft) capacity, and furnace pressure limits.

All burners are designed for a specified range of combustion air quantity and velocity through the burner air zones. The velocity of the air leaving the burner affects the mixing of the fuel and air, establishes the aerodynamic structure of the flame, and can impact flame stability. When the volume of flow through the burner increases due to the addition of FGR, the velocity at the burner exit increases proportionally. The impact of FGR can be detrimental to combustion performance if the velocity limits of the burner are exceeded, resulting in poor flame stability and poor fuel/air mixing. This is compounded by the fact that the concentration of the O_2 in the air stream is now reduced. On the other hand, if FGR can be utilized within the constraints of the burner design, its presence may improve mixing (i.e., create a more uniform low-oxygen, high-diluent combustion zone) due to increased velocity and turbulence. EPRI is exploring methods to enable high-FGR operation on gas fuel without having to replace the burners as has often been required (Box 4-1). When combined with OFA, increased levels of FGR can be achieved while maintaining constant burner velocities by virtue of the diversion of some of the combustion air to the OFA ports.

Another criterion for evaluating FGR applicability is existing fan capacity. The forced-draft (FD) fan(s) must be able to provide necessary air flow for combustion at an increased pressure, since the burner windbox pressure will increase due to the increased flow through the windbox and boiler with FGR. Also, the furnace and burner windbox structures are designed with static pressure limits that must be considered prior to retrofitting FGR. Additional considerations are the availability of space for locating an FGR fan(s), running ducts from the boiler outlet to the FGR fan and from the FGR fan to the gas mixing section, and installing a mixing grid in the secondary air duct. It should be noted, however, that the greatest NO_x reduction per quantity of FGR are achieved over the first 5%. Although additional NO_x reductions are achieved at higher FGR levels, diminishing NO_x benefits are realized.

NO_x Performance Achieved

The NO_x reduction from FGR is primarily dependent on: (1) FGR flow rate; (2) proximity between its point of introduction and the near-burner flame zone; (3) fuel type (gas versus oil) and nitrogen content (oil only); (4) excess oxygen level; (5) burner stoichiometry; and (6) furnace heat release rate.

The effect of FGR on NO_x emissions, in terms of percentage NO_x reduction, is generally greater with gas firing than it is with oil firing, because FGR is not as effective in reducing fuel NO_x as thermal NO_x.

By convention, FGR flow rate percentage is generally based on mass flow of FGR as a percentage of total furnace mass flow without FGR. In very general terms, for natural gas firing, windbox FGR can provide a reduction in NO_x emissions of about 2.5% for every 1% FGR flow to the burner zone at full load. This rule of thumb is suitable for FGR flow rates of 5 to 20%. The incremental effectiveness of FGR diminishes as the amount of FGR is increased and is generally small for FGR flows greater than approximately 20%. For oil firing, FGR can provide a reduction in NO_x emissions of about 1.5% for every 1% FGR flow to the burner zone at full load. This estimate is suitable for FGR flow from 5 to 20% also, but is dependent on fuel nitrogen content. Fuel oils with low nitrogen content (e.g., less than 0.20%) may experience higher percentage reductions; fuels with higher nitrogen content (greater than 0.40%) will probably exhibit less reduction (20).

As stated, these are very general rules that provide an estimate of the potential NO_x reduction due to FGR alone. It should be noted that the use of FGR in combination with other NO_x control technologies may provide reductions significantly different from those predicted above, due to the interactions between the combined technologies. Similarly, combined technologies will likely yield greater NO_x reduction than the application of FGR alone. In view of the lower cost of off-stoichiometric (O/S) firing techniques (i.e., BOOS and OFA), FGR will most frequently be applied together with O/S combustion. For units surveyed, neglecting a few installations that appear to be statistical outliers, a combination of windbox FGR and O/S combustion yielded NO_x reductions ranging from approximately 70 to 90% on gas-fired units and 40 to 80% on oil-fired units. Controlled NO_x emission rates for these units generally ranged from 0.05 to 0.16 lb/MBtu (.022 to .069 g/MJ) for gas firing and 0.15 to 0.35 lb/MBtu (.065 to 0.15 g/MJ) for oil firing. Figures 4-10 and 4-11 summarize the NO_x reduction capability of FGR alone and FGR with O/S firing on the gas- and oil-fired boilers surveyed. (See also Appendix A.)

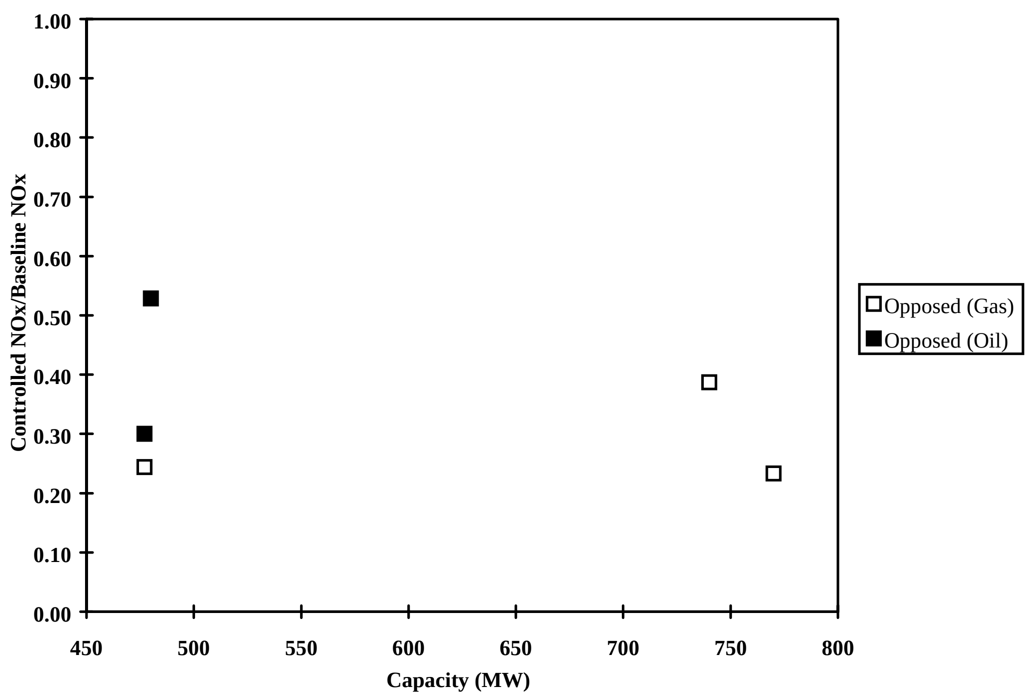

Figure 4-10
NO_x Reduction Performance of FGR Retrofits (No O/S firing or LNB)

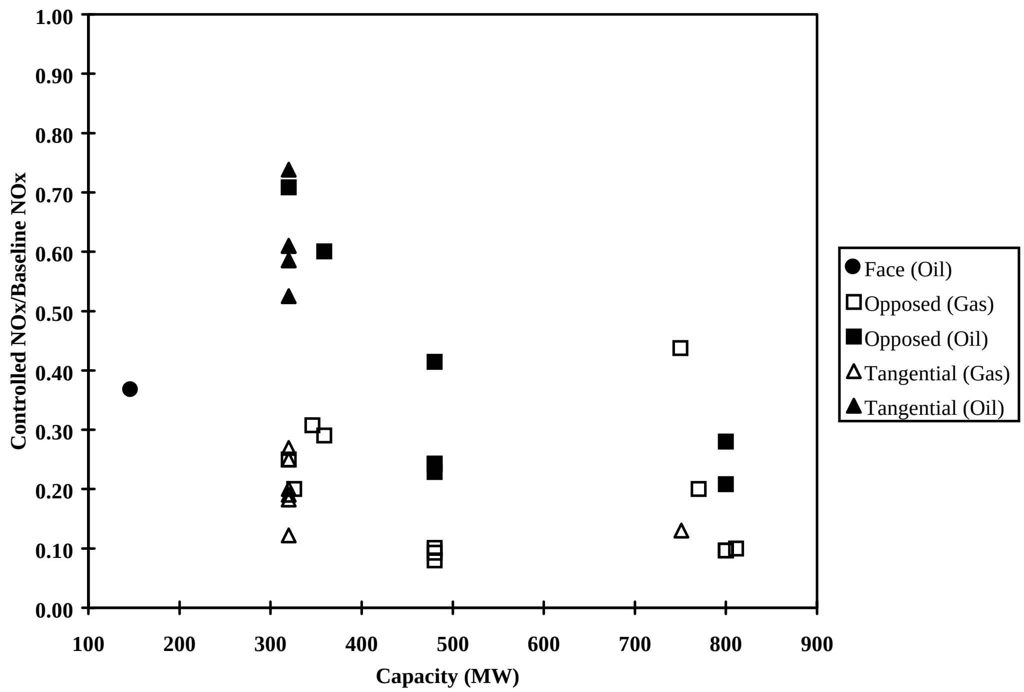

Figure 4-11
NO_x Reduction Performance of FGR with O/S Firing on Surveyed Units (No LNB)

A general assessment of reduced air preheat and water injection relative to FGR is shown in Figure 4-12. As all of these approaches are directed toward controlling thermal NO_x through lowering of flame temperature, their effectiveness can be correlated in terms of flame cooling effect. As presented, a 185ºF (103°C) reduction in air preheat temperature or 0.225 mass water per mass fuel are equivalent to approximately 5% FGR in terms of flame cooling effect. It should be noted, however, that the stack energy losses associated with reduced air preheat or water injection are significant, which limits their economic attractiveness to small capacity peaking units.

NO_x reductions using windbox FGR have generally been limited by factors restricting the amount of FGR that can be applied. These restrictions have included FGR fan capability, flame stability, FD fan capability, furnace pressure and steam temperatures. Significant further NO_x reductions could be achieved in many cases, particularly on gas-fired units, if restrictions could be removed by adequately sizing the FGR system and/or upgrading limiting factors on the boiler. In planning a new FGR retrofit, knowledge of the NO_x-versus-windbox O_2 characteristic of the unit would be a valuable guide, enabling the utility to evaluate the cost-effectiveness of incremental degrees of FGR. This information may be available from similar units already having FGR capability.

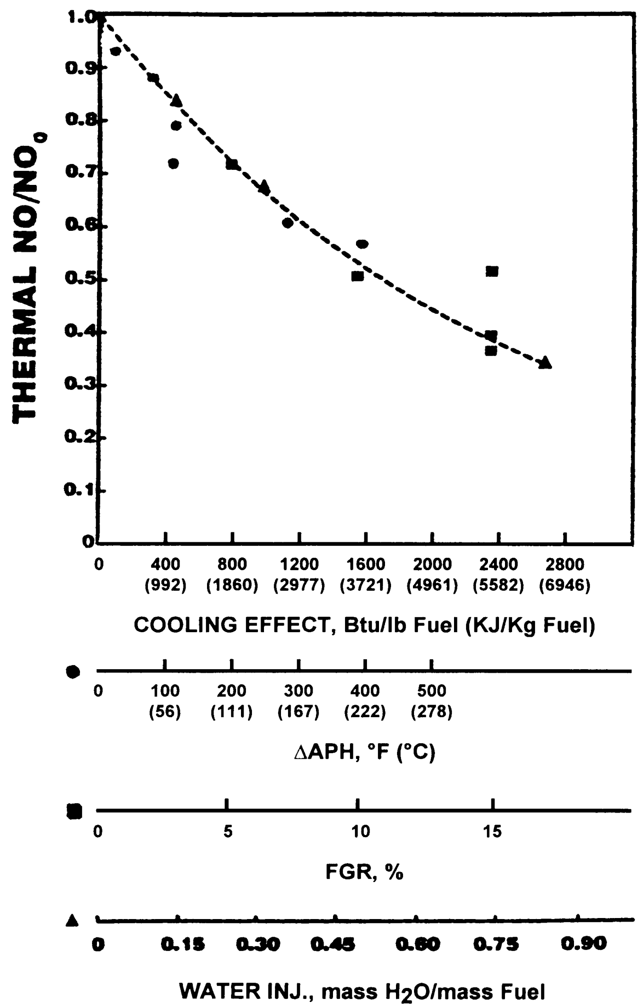

Figure 4-12
Correlation of NO_x Reduction as a Function of FGR, Reduced Air Preheat and Water Injection Levels

On tangential-fired boilers, windbox FGR has often been applied to the auxiliary air only and not to the fuel air. For this type of system, further NO_x reduction can be achieved by a low-cost modification in which a portion of the FGR is ducted to the fuel air. This modification has been demonstrated on Southern California Edison Company's Etiwanda Unit 3, where it reduced NO_x by 15% to levels below .05 lb/MBtu (in conjunction with BOOS operation) (21). For new FGR retrofits to tangential-fired boilers, FGR should be directed to both the fuel and auxiliary air for maximum NO_x reduction effectiveness.

Units equipped with FGR to the furnace (i.e., older FGR systems intended for steam temperature control) can in some cases use this existing capability to reduce NO_x. Reductions of approximately 25% have been demonstrated using FGR to the furnace hopper on opposed-fired units operating on gas fuel. This type of non-windbox FGR would not, however, be expected to perform as well on tangential-fired boilers, where the flame zone is already heavily diluted with furnace gases, and may not perform as well on some wall-fired units, i.e., those on which the FGR admission point does not cause it to pass through the flame zone.

Demonstration of FIR in which a diluent was added directly to the fuel occurred on Southern California Edison's Highgrove Unit 3, a 44 MW single wall-fired boiler equipped with FGR (19). In this case steam was used as the fuel diluent, and tests were run at 25 MW to accommodate the added mass passing through the burners, without having to modify burner hardware. Key results of these tests were discussed above (Figure 4-9).

Typical Boiler Upgrades

The equipment and modifications necessary for the addition of FGR to a boiler are dependent on the existing equipment and configuration. Three possible configurations must be considered: (1) no existing FGR or OFA system; (2) an existing FGR system for steam temperature control; and (3) existing OFA ports.

If there is *no existing FGR system*, the retrofit of an FGR system requires the following equipment:

- FD and ID fan upgrades, or booster fan to handle higher differential pressures
- Possible burner modifications for compatibility with FGR (e.g. gas REACH)
- FGR fan(s) to provide a driving pressure to mix the gas with the combustion air, and associated electrical equipment (e.g., new or upgraded switchgear, transformer, etc.).
- FGR ducts: (1) from the FGR extraction point in the boiler (i.e., economizer outlet) to the FGR fan inlet; and (2) from the FGR fan discharge to the FGR gas mixing section upstream of the burner windbox.
- A mixing device may be required to disperse the recirculated flue gas into the combustion air or existing hardware may be modified to achieve adequate mixing. For any chosen method, sufficient analysis should be applied to insure that adequate mixing is achieved.
- Provisions to measure flue gas flow. In most cases, there will be more than one FGR duct (due to secondary air duct arrangements), and each duct should be controlled separately. Dampers with drives and associated controls will be required to integrate FGR operation with the boiler control system.

For *conversion of an existing FGR steam temperature control system* to windbox FGR, the capability of the existing FGR fan must be evaluated to determine if it can provide the necessary flow and pressure. Modest improvements in fan pressure and performance can be achieved by extending fan vanes and rewinding motors with a higher class of insulation. However, a new fan (or fans) will be required for many applications. New ducts that deliver flue gas to the combustion air duct will also be required, as will a mixing grid and flow control system. Depending on the application, the existing FGR duct for temperature control may no longer be required. Generally, a detailed analysis will be required to determine whether the major components of an existing steam temperature control system (i.e., fans, ducts, dampers, etc.) can be re-used in a windbox FGR conversion.

For the *retrofit or conversion of an FGR system on a boiler that has an existing OFA system*, the air supply to the OFA ports should be separated from the main windbox, thereby eliminating recirculated flue gas from the overfire air. The recirculated flue gas provides no reduction in NO_x generation when introduced through the OFA ports, and reduces the amount available for NO_x control in the burner zone. Installation of a separate duct to the OFA ports, originating from the secondary air duct prior to the FGR mixing point, is required, including control dampers and flow measuring devices.

For any of the above three cases, the FGR retrofit should include installation of windbox O_2 sensors downstream of the flue gas mixing point. Since maintaining a minimum value of windbox O_2 is critical to combustion stability, this parameter should be evident to the operator and tied to an alarm, and may be used as the FGR flow control criterion. Other potential modifications include FD fan upgrading to overcome increased furnace pressure drop, and modified burner flame stabilizers or gas spuds to adapt to higher burner velocities. Flame scanners may need to be modified or replaced if the flame shape or characteristics are significantly different with FGR. Strengthening of the windbox and furnace structure, where possible, to accommodate increased static pressure may also be required. The addition of windbox FGR may also necessitate boiler heat transfer surface modifications or other means to improve steam temperature control.

Potential Impacts on Boiler Operation

The introduction of flue gas in the lower furnace increases the volumetric flow and reduces furnace residence time and heat transfer, allowing for a greater percentage of heat transfer to occur in the convection pass. Under some conditions, such as operation at reduced loads, this may be beneficial for maintaining steam temperatures. Under other conditions, such as full-load operation, the addition of FGR would tend to increase steam temperatures and reduce furnace absorption. Again, this could be a detriment or benefit, depending on the existing steam temperatures and control. If necessary, other methods of steam temperature control, such as attemperation, or modification of convection heat transfer surfaces, can in principle be used to compensate for any adverse affect on heat absorption. If large amounts of attemperation are to be used, anticipated tube metal temperatures at locations upstream of the attemperation point should be evaluated.

As mentioned previously, the increased volumetric flow through the burner air registers, the furnace, and convection passes leads to higher windbox and furnace pressures. For units with only marginal FD fan capability, or windbox or furnace pressure limitations, load restriction may be experienced unless modifications are made. High FGR rates have also been reported to cause burner flame instability leading to unacceptable furnace rumble and, potentially, load restrictions to avoid boiler casing, support, and insulation failures. While such conditions are difficult to predict and may prove difficult to solve, air register adjustments and re-designed fuel elements may mitigate the underlying flame stability problems. Again, a detailed analysis will likely be required to determine the feasibility of retrofitting FGR on an existing unit, the effect on a boiler's thermal characteristics, and the overall NO_x reduction capability.

Control Costs

Recent FGR system retrofits have been installed in combination with other NO_x reduction technologies (low-NO_x burners and OFA). As a result, limited stand-alone cost estimates for this technology are available. However, the capital cost of an FGR system, with associated ducting, dampers and controls, would be expected to be $8-$20/kW. If extensive upgrades to existing equipment are required (e.g., modification of heat transfer surfaces, FD fan replacement, or boiler structural enhancements), capital costs can be significantly higher. Appendix D provides an FGR cost estimating methodology.

The cost of power required to run FGR fans is the largest single expense in operating an FGR system, and can vary widely from plant to plant. For a given $/kWh electricity cost, expenses for running FGR fans may vary substantially depending on the required volumetric flow rate and differential pressure through the fans. FGR volumetric flow rate will be proportional to excess air level and flue gas (absolute) temperature at the FGR fan inlet as well as to unit capacity and percentage of flue gas recirculated. Fan differential pressure will be the pressure difference between the windbox and the boiler outlet duct upstream of the air heater. Note that following the addition of an FGR system, this differential pressure will rise by a factor of approximately $(1+\%FGR/100)^2$.

Adding an FGR fan will further increase power cost as it increases flue gas volumetric flow rate through the furnace which, in turn, increases windbox pressure and combustion air fan pressure. Again, differential pressure can be approximated by a factor of $(1+\%FGR/100)^2$ times the original (pre-FGR) windbox pressure. It has been estimated (22) that a 500-MW base-loaded unit might experience an increase of approximately $75,000/yr in combustion air fan operating cost for every 1-inch H_2O increase in required fan differential pressure. This cost factor will vary widely from unit to unit as a function of electricity cost, unit size, capacity factor, fan efficiency, excess air level, etc.

In addition to power expenditures, other operating costs associated with FGR systems may include increased maintenance (for FGR fans, dampers, and controls), heat rate penalties associated with any increase in steam attemperation (if required), and increases in air heater leakage that might result from the required increase in combustion air pressure.

4.4 Burner Replacement

Replacement of existing burners with models producing lower NO_x emissions is a NO_x control approach generally considered by a utility once all operational modifications have been explored to their fullest potential. Replacement burners designed for reduced NO_x emissions will be discussed in two major categories: low-NO_x burners (LNBs) and ultra low-NO_x burners (ULNBs).

LNBs accomplish low-NO_x operation by internally staging the air, and in some cases the fuel, to produce more gradual, lower-temperature combustion, generally with the primary, higher-temperature, combustion zone operated fuel-rich to further restrict NO_x formation. LNBs have been developed mainly for wall-fired (i.e., circular burner) boilers, but have also been applied on a few tangential-fired boilers. LNBs are capable of substantial NO_x reductions on both gas and oil fuels, but similar NO_x reductions can frequently be achieved using lower-cost combustion modifications (O/S combustion and FGR) discussed previously in this section. The utility should thus carefully analyze the cost-effectiveness of any proposed LNB retrofit versus that of combustion modifications. In many cases, the LNB vendor will suggest a system that includes FGR and possibly overfire air. In this case, the utility should evaluate the net NO_x benefit attributable to the LNBs. Generally, in this case, the LNBs will be found to contribute only a small incremental NO_x reduction while accounting for a major portion of the cost. However, experience indicates that in some cases the LNB, by improving flame stability relative to what the original burner can provide under high-FGR, O/S firing conditions may be an important factor in the overall retrofit. EPRI is exploring methods to enable high-FGR operation on gas at substantially lower cost than LNB technologies (Box 4-1).

Several ULNBs are at various stages of development. These burners are, from a retrofit point of view, virtually the same as LNBs but utilize advanced mixing and staging techniques to achieve NO_x levels well below those achievable by LNBs. ULNBs have thus far been developed using circular burner configurations (i.e., for wall-fired boilers) operating on gas fuel, but the technologies may be extendible to tangential-fired boilers and oil fuel. Based on their performance on several small industrial boilers, NO_x levels on utility boilers operated on gas fuel are expected to be in the 15-20 ppm range, and levels as low as 10 ppm will be sought using fuel staging and maximum FGR. With the possibility of producing NO_x levels in this range, ULNB technologies may thus be highly significant for utilities facing the possibility of NO_x limits in the future that are typically associated with SCR technology for compliance.

4.4.1 Low-NO_x Burners

Description

Low-NO_x burners (LNBs) reduce NO_x formation by controlling the mixing of fuel and air in the primary stages of the combustion process. There are numerous burner equipment arrangements that can achieve such control, resulting in distinctly different burner designs offered commercially for retrofit.

The concept underlying most LNBs suitable for utility applications is to delay the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. Mixing can be delayed by introducing the air through zones in the burner that are physically separated from the fuel zones, and/or by providing aerodynamic separation of fuel and air streams after they are injected into the flame. In most designs, combustion staging is accomplished by staging the air admission to the burner. Combustion initially occurs using a portion of the air in a fuel-rich zone, and the balance of the air mixes with the partial combustion products downstream in the flame zone. NO_x formation is reduced because the peak flame temperatures, and availability of oxygen for conversion of fuel-bound nitrogen, are reduced in the initial stages of combustion. Figure 4-13 illustrates an air-staged LNB design.

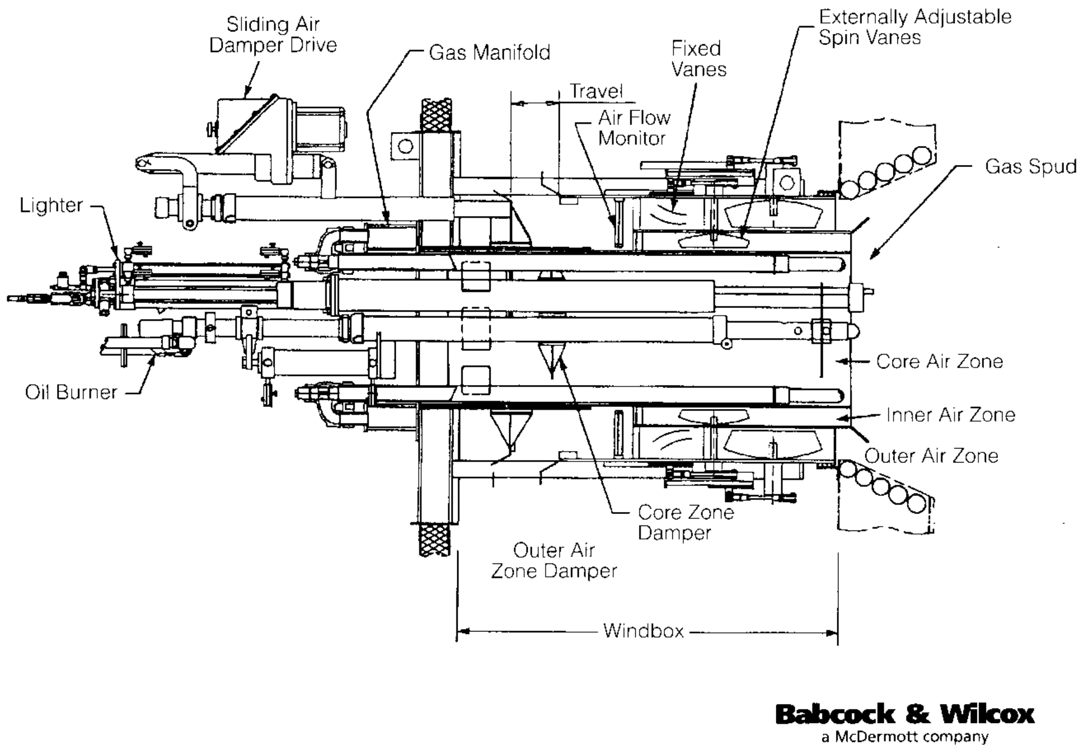

Figure 4-13
Air-Staged LNB Design

Other LNB designs utilize a combination of air staging and fuel staging, creating rich and lean combustion zones. Reduced availability of oxygen in the rich zone produces lower NO_x, and the lean zone produces lower NO_x due to the cooling effect of high excess air. The combustion products from the two zones combine to complete combustion downstream in the combustion process. As is the case for simple air-staged designs, this type of design lowers peak flame temperatures. An LNB design incorporating both air and fuel staging is shown in Figure 4-14. Another design feature that is incorporated in some LNBs is internal flue gas recirculation. Although all practical burners inherently recirculate some combustion products into the primary flame zone, these burners are designed to exaggerate this effect to accomplish a higher degree of flame cooling than conventional burners. For oil firing, some LNBs utilize a segmented oil spray as a fuel staging technique. This produces fuel-rich flame fingers, with the overall effect being much the same as a simple air-staged burner.

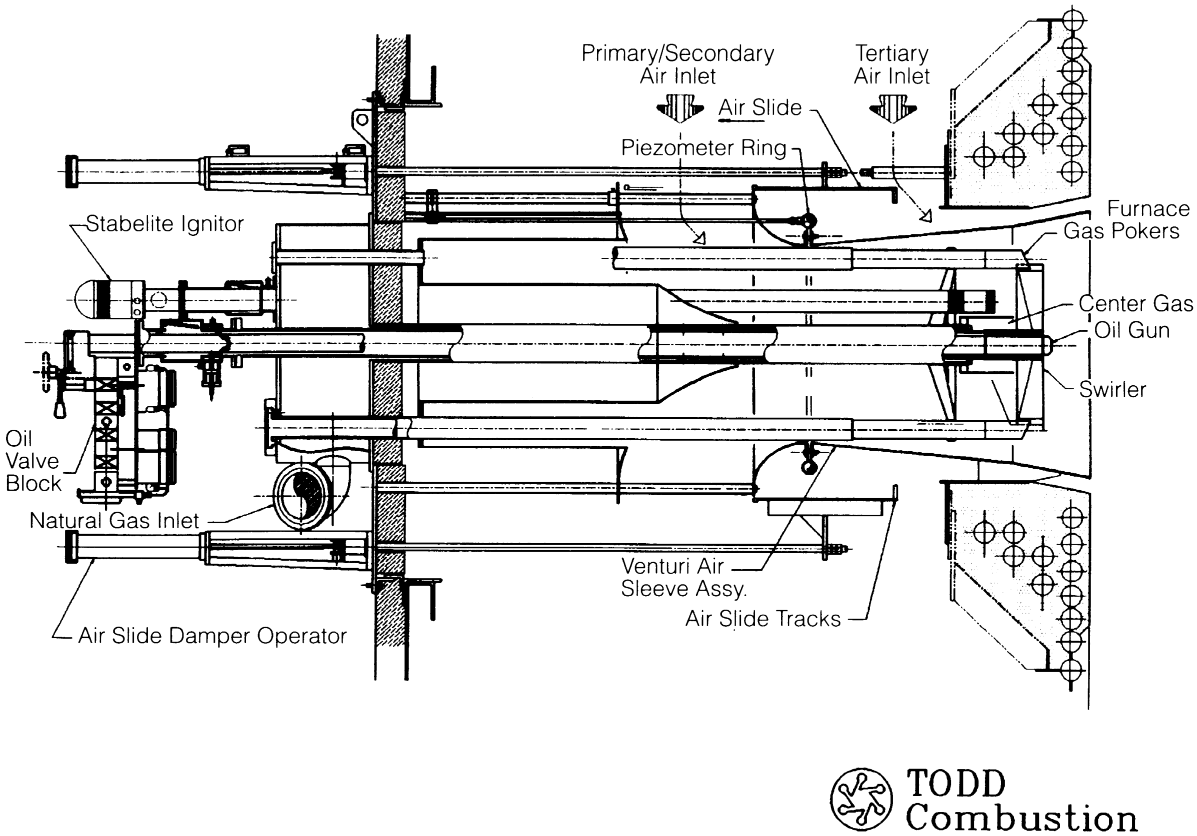

Figure 4-14
LNB Design with Both Air and Fuel Staging

Several low-NO_x burner systems integrate externally recirculated flue gas in the burner design. With these designs, flue gas is injected in discrete streams through the burner throat to create a mixing barrier between adjacent fuel and air streams. While this feature should maximize staging, results from one publicly documented installation indicate modest additional NO_x reductions (7%) from levels achieved without FGR flow through the burner (18).

Important elements to be included in a retrofit LNB specification are discussed in Appendix C.

Experience

There is a growing experience base with the retrofit of state-of-the-art LNB systems on gas- and oil-fired units in the United States. The known applications and the respective LNB suppliers are listed in Table 4-5.

Table 4-5
Retrofit Low-NO_x Burner Installation on Utility Boilers in the U.S.

Utility	Unit	Size (MW)	Boiler Manufacturer/Type	Fuel(s)	Other NO_x Controls	Supplier	Year
City of Burbank	Magnolia 3, 4	20, 30	B&W/Single-Wall	Gas	None	AUS, Inc.	1994
City of Burbank	Olive 1	44	Riley Stoker/Single-Wall	Gas	None	AUS, Inc.	1994
City of Glendale	Grayson 3	20	B&W/Single-Wall	Gas	None	AUS, Inc.	1994
City of Glendale	Grayson 4	44	Riley Stoker/Single-Wall	Gas	None	AUS, Inc.	1994
City of Pasadena	Broadway 2	45	ABB-CE/Single-Wall	Gas	None	Todd Combustion	1993
Com Electric	Canal 1	560	B&W/Opposed-Wall	Oil	O/S, FGR	DB Riley	1995
Com Electric	Canal 2	560	B&W/Opposed-Wall	Gas, Oil	O/S, FGR	DB Riley	1996
Commonwealth Edison	Collins 1, 2	572	B&W/Opposed-Wall	Gas, Oil	OFA, FGR	AUS, Inc.	1993
Commonwealth Edison	Collins 3	550	B&W/Opposed-Wall	Gas, Oil	OFA, FGR	AUS, Inc.	1993
Commonwealth Edison	Collins 4	550	B&W/Opposed-Wall	Gas, Oil	OFA, FGR	Ansaldo	1996
Con Edison Co. of New York	Astoria 30	380	B&W/Single-Wall	Gas, Oil	FGR	Todd Combustion	1993
Con Edison Co. of New York	Hudson Avenue 100	150	B&W/Single-Wall	Oil	None	Todd Combustion	1993
Consumers Power Company	Karn 4	630	Riley Stoker/Single-Wall	Gas, Oil	None	DB Riley	1993
Delmarva Power & Light	Edge Moor 5	440	B&W/Opposed-Wall	Oil	OFA	Todd Combustion	1994
Florida Power & Light	Martin County 1, 2	800	Foster Wheeler/Single-Wall	Oil	O/S, FGR	NEI - ICL	1986
Florida Power & Light	Port Everglades 1, 2	240	Foster Wheeler/Single-Wall	Gas, Oil	None	Todd Combustion	1994
Florida Power & Light	Port Everglades 3, 4	400	Foster Wheeler/Single-Wall	Gas, Oil	None	Todd Combustion	1992
Florida Power & Light	Riviera Beach 3, 4	310	Foster Wheeler/Single-Wall	Gas, Oil	None	Todd Combustion	1995
Florida Power & Light	Turkey Point 1, 2	400	Foster Wheeler/Single-Wall	Gas, Oil	None	Todd Combustion	1995
Hawaiian Electric Company	Kahe 6	150	B&W/Single-Wall	Oil	OFA, FGR	B&W (oil-only)	1988
Jacksonville Electric Authority	Northside 3	500	Riley Stoker/Single-Wall	Gas, Oil	None	NEI - ICL	1990
Long Island Lighting Co.	Port Jefferson 4	185	ABB-CE/Tangential	Oil	CCOFA	International Combustion Ltd.	--
New England Power	Brayton Point 4	440	Riley Stoker/Single-Wall	Oil	O/S, FGR	Rodenhuis & Verloop	1991
New England Power	Salem Harbor 4	440	Riley Stoker/Single-Wall			Rodenhuis & Verloop	1992
Pacific Gas & Electric	Morro Bay 3, 4	359	B&W/Single-Wall	Gas	OFA, FGR	B&W	1995
Pacific Gas & Electric	Moss Landing 6, 7	812	B&W/Opposed-Wall	Gas		B&W	1996
PacifiCorp	Gadsby 1, 2	62, 75	Riley Stoker/Single-Wall	Gas	None	Todd Combustion	1994
Southern California Edison	Alamitos 5	480	B&W/Opposed-Wall	Gas	O/S, FGR	AUS, Inc.	1993
Southern California Edison	Alamitos 6	480	B&W/Opposed-Wall	Gas	O/S, FGR	Todd Combustion	1988
Southern California Edison	Mandalay 1	215	B&W/Single-Wall	Gas, Oil	O/S, FGR	B & W	1992
Southern California Edison	Ormond Beach 1, 2	800	Foster Wheeler/Opposed-Wall	Gas, Oil	O/S, FGR	Todd Combustion	1991,1988

Most of these projects involve wall-fired boilers manufactured by B&W, Foster Wheeler, and Riley Stoker. Only one retrofit of a tangential-fired boiler with a state-of-the-art LNB system was identified in the United States, although numerous retrofits to tangential-fired boilers have been performed in Japan and Europe. Appendix F summarizes current suppliers of LNBs for gas- and oil-fired units, burner features, and relevant experience. Table 4-6 lists LNB system vendors. By comparison with Table 4-5 and Appendix F, it can be seen that several LNB vendors listed in Table 4-6 have not actually had any utility boiler installations.

Table 4-6
Low-NO_x Burner System Vendors

Circular Burners for Wall-Fired Boilers:
AUS Combustion Systems, Inc., Santa Ana, California
Babcock & Wilcox Company, Barberton, Ohio
Coen Company, Inc., Burlingame, California
DB Riley Corporation, Worcester, Massachusetts
Forney International, Inc., Addison, Texas
International Combustion Ltd., Derby, England
John Zink Company, Tulsa, Oklahoma
Pillard, Montreal, Canada
Rodenhuis & Verloop B.V., The Netherlands
Todd Combustion, Inc., Stamford, Connecticut

Corner Windbox/Burner Assemblies for Tangential-Fired Boilers:
ABB-Combustion Engineering, Inc., Windsor, Connecticut
International Combustion Ltd., Derby, England

Applicability

Virtually all wall- and tangential-fired boilers burning gas or oil can be retrofit with LNB technology. However, options for tangential-fired boilers are limited, with only one vendor, International Combustion Ltd., offering LNB technology for this type of boiler. The primary criteria that must be reviewed to determine whether an LNB application is economically feasible are the existing burner spacing, burner and throat size, furnace dimensions, and fan capabilities.

Manufacturers have endeavored to design retrofit burners that can fit into furnace openings used for existing burners. However, on older wall-fired units, many burners were designed with high velocities (small burner throats) to provide very intense mixing near the burner exit. Low-NO_x burners tend to have lower design velocities, and may also have multiple annular air zones, which tend to increase the burner diameter. For the same heat input, an LNB may require a larger throat diameter (wall opening) than does the existing burner. This could require modifications to the furnace tube walls to enlarge the openings, creating an additional expense associated with the retrofit. The space available between adjacent burners also needs to be considered when retrofitting LNB systems due to the potentially larger burner throat and air register dimensions of an LNB design. Overlap with an adjacent flame zone can reduce the effectiveness of the LNB by restricting the degree to which cooled combustion products can be entrained into the outer combustion air.

LNB flame lengths tend to be longer than the flame lengths of a high intensity burner. By delaying the fuel and air mixing, the combustion process is extended and the flame length will increase. For wall-fired boilers, the existing furnace must be able to accommodate any increase in flame length without experiencing flame impingement on the water walls. Offset distance of wing burners from side walls should also be addressed with regard to the expected flame size and shape. Impingement of flames on the cool water walls will quench the flame, potentially contributing to high opacity and CO levels, and reduced combustion efficiency. Flame impingement can also cause water-wall tubes to exceed temperature limits, resulting in long-term reliability problems. For ash-bearing fuel oil, flame impingement will also create ash deposits on the walls. The potential for accelerated tube wall corrosion due to "hot spots" in the boiler circulation system (i.e., localized film boiling) is also a concern.

Some LNB designs may have higher pressure drops than original burners. For some applications, the difference in pressure drop can be substantial enough to exceed the capabilities of existing fans or windbox static pressure limits.

NO_x Performance Achieved

The reduction in NO_x emissions achievable solely by replacing conventional burners with low-NO_x burners is difficult to determine due to the limited range of actual retrofit applications with regard to fuel properties and boiler design. For those retrofit LNB projects reviewed, the bulk of the data showed NO_x reductions due solely to the new burners ranged from approximately 30 to 50% for both gas- and oil-fired units, as summarized in Figure 4-15 (see also Appendix A). However, these reductions generally include the effect of air balancing to the burners, which could have been accomplished without the LNBs (see above 4.1.1). Controlled emission rates ranged from 0.10 to 0.35 lb/MBtu (.043 to 0.15 g/MJ) for gas firing and 0.15 to 0.50 lb/MBtu (.065 to 0.22 g/MJ) for oil firing.

Available data suggest that the NO_x reduction achievable on gas- and oil-fired boilers by retrofitting low-NO_x burners alone is roughly equivalent to the NO_x reduction that would result utilizing off-stoichiometric firing (BOOS and/or OFA). Therefore, it is unlikely that a decision to retrofit low-NO_x burners would be made solely on the basis of NO_x control. Often, the objective of LNB retrofits is to improve the operation of existing burners or to avoid the potential operating problems associated with O/S and/or FGR operation.

LNB systems incorporating FGR and O/S firing provide the maximum proven NO_x reduction via modification to the combustion process. Overall reductions of up to 95% on gas fuel, and 80% on oil, have been demonstrated. The actual reduction achieved on a given unit depends on factors such as the burner zone heat release rate, flue gas recirculation rate, fuel nitrogen, and the specific burner system selected. A burner with proven compatibility with the maximum anticipated level of FGR and type/degree of O/S firing should be selected.

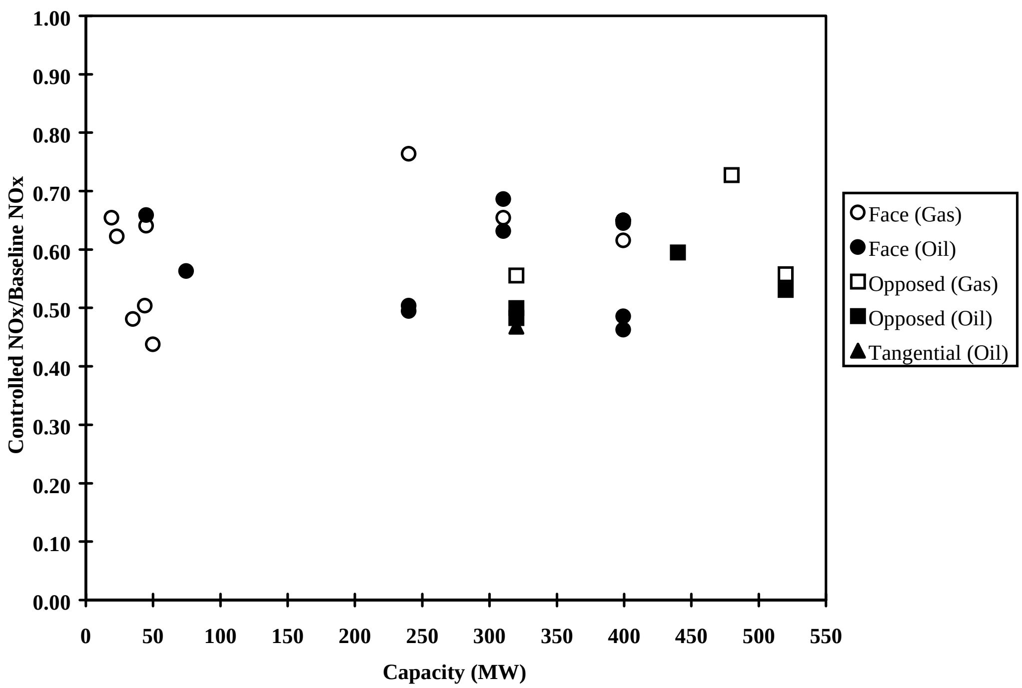

Figure 4-15
NO_x Reduction Performance of LNB Retrofits (No FGR or O/S Firing)

Controlled emission levels with LNB, FGR and/or O/S firing for the units surveyed ranged from .03 to 0.23 lb/MBtu (.013 to .099 g/MJ) for gas firing and 0.15 to 0.30 lb/MBtu (.065 to 0.13 g/MJ) for oil firing. Figure 4-16 summarizes the NO_x reductions achieved using this combination of technologies (see also Appendix A). A breakdown of the general ranges of NO_x performances of LNB with either FGR or O/S firing or both is as follows:

	Controlled NO_x, lb/MBtu (g/MJ)	Controlled NO_x/Baseline NO_x, %	No. of Boilers Surveyed
LNB+FGR+O/S			
Gas	.03-0.17 (.013-.073)	5-30	14
Oil	0.15-0.30 (.065-0.13)	20-60	11
LNB+FGR			
Gas	0.12-0.23 (.052-.099)	~10	2
Oil	0.17-0.22 (.073-0.10)	25-40	2
LNB+O/S			
Gas	.06-0.10 (.026-.043)	10-30	5
Oil	0.15-0.25 (.065-0.11)	40-70	5

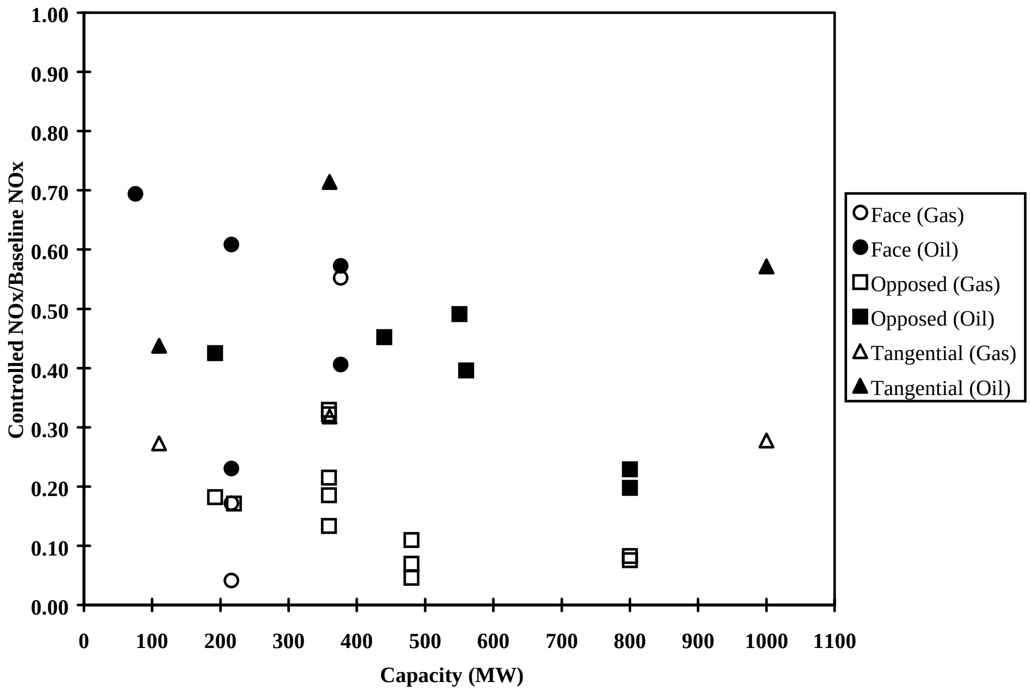

Figure 4-16
NO_x Reduction Capabilities of LNB with FGR and/or O/S Firing

The fraction of the NO_x reduction due to the LNB in these cases is not known, and is probably in most cases small in view of the excellent NO_x reduction capabilities of FGR and O/S combustion. For example in a recent LNB installation on PG&E Morro Bay Unit 3 (Reference 16), the NO_x level on gas fuel was reduced from a baseline of approximately 225 ppmc to a controlled NO_x level of 30 ppmc by the LNB in combination with 27% FGR and 29% OFA, an 87% reduction. The 225 ppmc baseline was based on previous operation of the boiler without OFA or FGR (Reference 23). However, extrapolation of the data to zero FGR based on Figure 4-17 and zero OFA based on sensitivity coefficients developed through field test data indicated a controlled NO_x level for the burners alone of nominally 172 ppmc. When compared to the 225 ppmc baseline data, this would represent a NO_x reduction attributable to the burners on the order of 25%. The majority of the NO_x reduction achieved was thus through the use of FGR and OFA.

Typical Boiler Upgrades

For an LNB retrofit on a wall-fired unit, the major new equipment items will be the burner assemblies, which would typically include new air registers, fuel elements, and interfacing hardware. New furnace wall openings may be required to accommodate a larger burner throat. Significant portions of the original burner support structures and auxiliary equipment (spark systems, drives, burner management system, etc.) can potentially be reutilized, depending on their performance history and compatibility with new burner equipment.

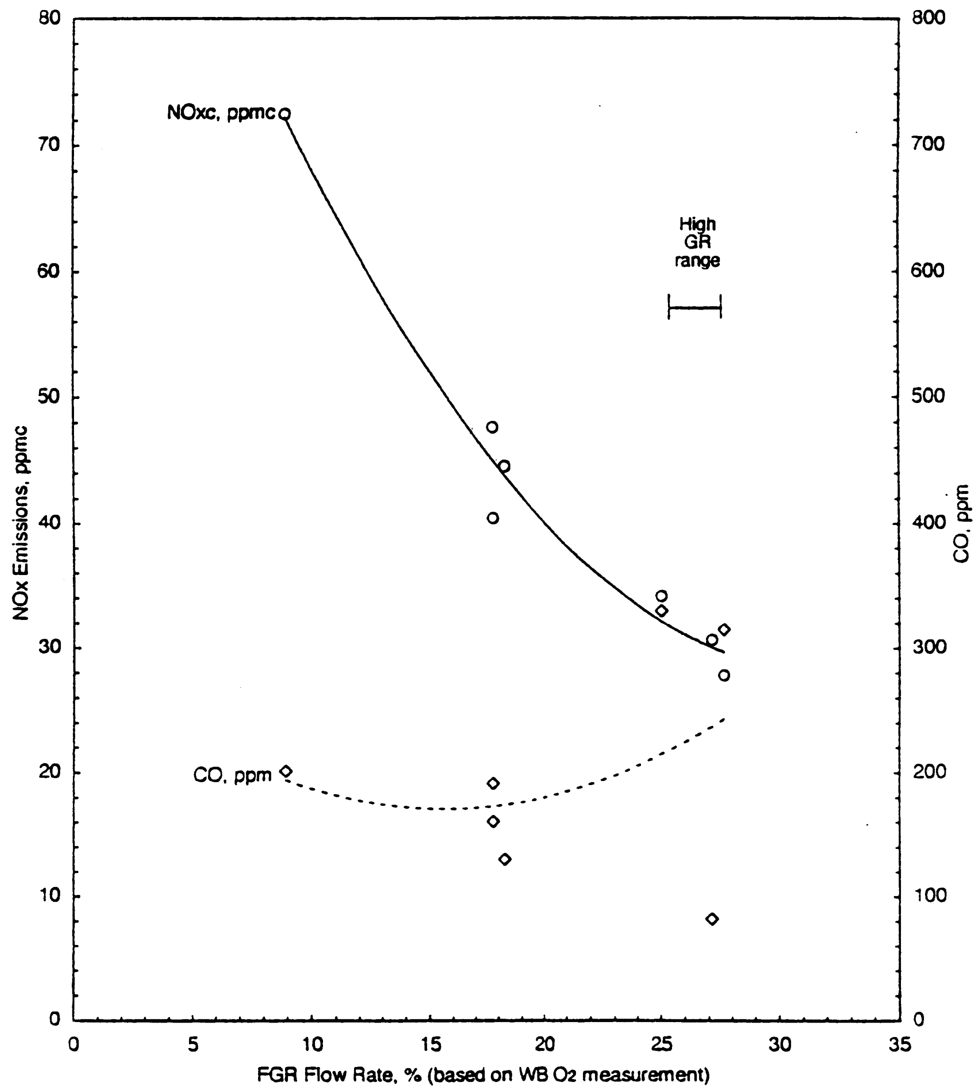

Figure 4-17
Morro Bay 3, Effect of FGR Flow Rate on NO_x and CO Emissions at 345 MWg

Balancing the air and fuel flow to all burners within an LNB system is critical to achieving high NO_x reduction. Ideally, the air and fuel flow to each burner should be within approximately $\pm$ 5% of the average for all burners. Best performance of the LNB also generally requires that air flow approaching the burner be in an axial orientation with respect to the burner, and windbox modifications should also consider this where it is a requirement. Scaled flow modeling of the air supply system and windbox can be performed to assess windbox air flow distribution. If adequate control of air flow distribution among the burners is not provided in the burner design or cannot be achieved without excessive pressure loss, modifications may be required to the windbox and secondary air ducts such that balanced flow can be achieved. This may include (in order of increasing complexity and cost) baffles and turning vanes to redistribute the air flow, or additional plating for windbox partitions and control dampers to compartmentalize the windbox. Individual burners should be instrumented with flow measurement devices for control purposes. In some cases, the most beneficial aspect of an LNB retrofit may be balancing of air flows to burners as part of the retrofit and/or the inherent capability of some LNB designs to measure and control flows to individual burners. If this is suspected to be the case, it is suggested that the utility first consider lower-cost methods of balancing the air flows (e.g., tuning for LEA operation, as described in 4.1.1), followed by an evaluation of the incremental cost and NO_x reduction associated with installation of the LNB.

Depending on the age and performance of a boiler's existing combustion control system, an upgrade or replacement of the system may be included as part of an LNB retrofit project. The conversion of a unit's analog control system to a new digital distributed-control system (DCS) will improve control over combustion parameters (e.g., excess oxygen levels, fuel/air settings, burner tilts, and damper positions). The quicker, more accurate control provided by a DCS system can lower the variability in NO_x emissions and enhance the NO_x reduction potential of LNB systems or other combustion-based NO_x controls.

Other potentially significant modifications associated with LNB retrofits include:

- Fuel supply system modifications, which may include new burner front piping, valves, and conversion to another type of oil atomization.
- Upgraded forced-draft fans to overcome higher windbox-to-furnace pressure drop that may occur with some burner designs.
- Replacement or extension of the corner windbox of tangential-fired boilers to accommodate new fuel and air admission assemblies.
- Flame safety system and burner management system upgrades to accommodate new flame scanning and ignition equipment.

Potential Impacts on Boiler Operation

It is anticipated that low-NO_x burners can be retrofit in most instances, without incurring boiler efficiency penalties or increasing emissions of other pollutants, by proper specification and optimization of the burners and related combustion equipment. In fact, the goal of some LNB retrofits is to eliminate operational difficulties sometimes encountered with BOOS or FGR operation (i.e., flame instability, furnace rumble, reduced maintenance flexibility, load limitations, etc.). Furthermore, air flow balancing, which almost invariably accompanies an LNB retrofit, works in the direction of lowering minimum excess air and generally improves boiler operation and performance.

However, the potential does exist for increased excess air levels, and increased opacity levels, carbon monoxide, and unburned carbon particulate emissions (for oil firing) if burners are not properly matched to the fuel, boiler design, and boiler operating conditions of a specific unit. As mentioned above, LNB's tend to alter the sizes and shapes of the flames, which may potentially impact heat transfer distribution in the furnace. This can result in changes in steam temperature, which can affect boiler efficiency, and local increases in furnace tube metal temperatures. In one LNB retrofit project, it was estimated that a 50°F (28°C) increase in metal temperature would reduce expected tube life from 32 to 4 years (24).

In general, every retrofit requires a period of equipment tuning by the vendor to ensure proper operation. Physical modifications to the fuel elements or other burner components may be required during this period. The extent of post-retrofit problems can be minimized through adequate pre-retrofit analysis and preparation (see Appendices B and C). In some cases, utilities may consider sub-scale testing of burners. While sub-scale tests of fluid dynamic or combustion characteristics of burners may be helpful if properly interpreted, several LNB retrofit projects have initially failed to achieve their performance goals despite extensive evaluation and testing of candidate burners (25).

Control Costs

Based on published reports and EPRI in-house data, the total installed cost of LNB retrofits can range from approximately $10 to $20/kW, depending on the size of the unit, number of burners, ease of retrofit, and scope of modifications. Costs as high as $45/kW have been reported; however, exceptionally high costs per kW have involved small (e.g., 20 MW) boilers and extended scope of supply, for example, including a new burner management system. A more detailed assessment to determine where a particular unit's retrofit costs may fall with respect to this range is provided in Appendix D.

Burners designed to operate with flue gas recirculation or overfire air will involve additional costs for these components, depending on whether they are already installed and the degree of upgrading or modification required to make them compatible with the new burners. Available information on the total installed cost of combinations of combustion technologies suggests a range of $25 to $50/kW for an integrated LNB/FGR/OFA system (26, 27, 28).

Operating costs associated with LNBs may result from an increase in excess air level (approximately 0.25% penalty in unit heat rate per 1% increase in O_2). Use of LNBs that require an increase in windbox static pressure will result in increased combustion air fan energy costs as well. As stated before, a 500-MW base-loaded unit might experience an operating cost increase of approximately $75,000/yr per 1-inch H_2O rise in windbox static pressure.

4.4.2 Ultra Low-NO_x Burners

Description

As explained above, ULNBs are, for practical purposes, similar to LNBs, but are designed to achieve significantly lower NO_x levels. While LNBs may be justified mainly in their abilities to improve operation with FGR and O/S firing, ULNBs add to and enhance the effectiveness of these techniques. ULNB technologies fall into three major categories:

- *Simulated Premix*. This approach is based on the long-standing observation in the laboratory that NO_x formation in premix burners (fuel and air premixed upstream of the burner) can be sharply and predictably reduced by flame dilution using either excess air or FGR. Although premixing fuel and air is not practical in large boiler installations, simulated premix ULNBs approach premixed conditions as closely as possible by rapidly mixing the fuel and air at the burner exit plane. These burners achieve low NO_x operation through the use of high excess air or FGR, with the latter method being more practical for utility boilers. Figure 4-18 shows a simulated premix burner design.

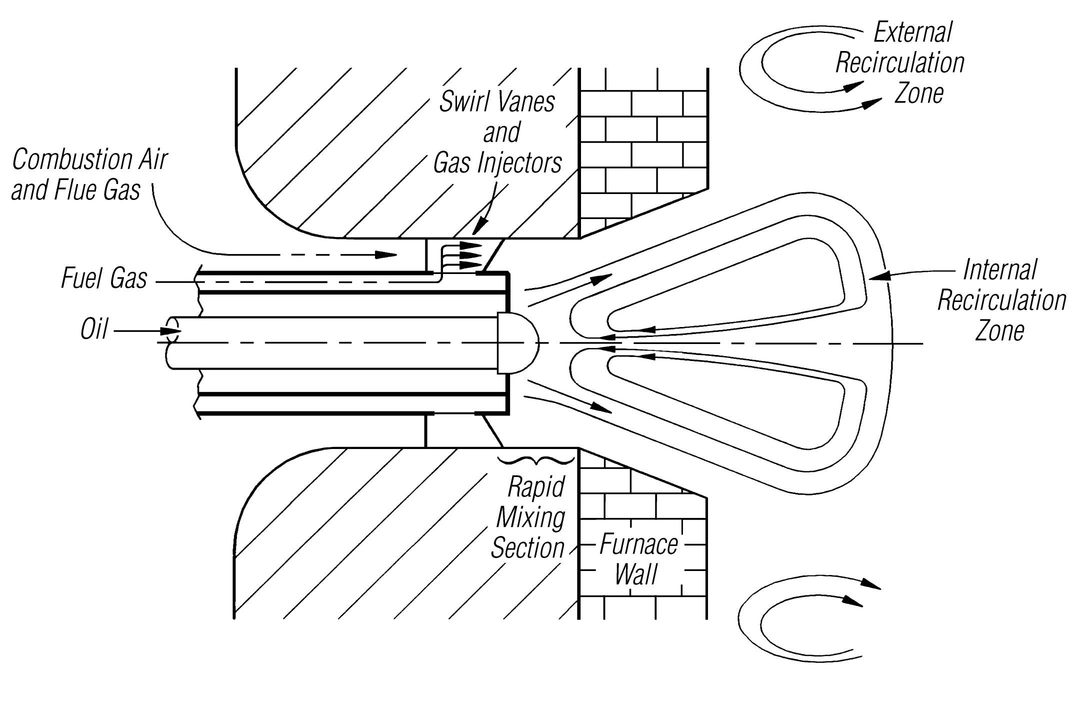

Figure 4-18
Simulated Premix Burner
(Courtesy of Radian/Todd RMB)

- *Simulated Premix with Advanced Fuel Staging*. This approach is based on the simulated premix approach described above, but part of the fuel is diverted to the periphery of the primary flame. This creates a simulated premix flame operating with high excess air, which is inherently low in NO_x, followed by burnout of the staged fuel farther out in the furnace where temperatures are lower and the products of primary combustion further cool the flame. Addition of FGR can produce an additional reduction in the flame temperature and further restrict NO_x formation.

- *Advanced Air Staging*. This approach uses aerodynamic design to create rich and lean combustion zones, similar to some LNB technologies, and is designed to tolerate very high levels of FGR.

Table 4-7 lists the most significant advantages and disadvantages of these ULNB technology approaches and also lists burners that are being developed in each category.

Table 4-7
Categories of Ultra Low-NO_x Burners

NO_x Reduction Mechanism	Advantages	Potential Disadvantages	Burners
Simulated Premix	NO_x levels <10 ppm achievable on gas firing on industrial applications (including some with preheated air)	High Baseline NO_x High levels of FGR or O_2 required for ultra-low NO_x No real advantage on heavy oil	Radian/Todd, Rapid-Mix Burner (RMB)
Simulated Premix with Advanced Fuel Staging	Low baseline on gas Lower FGR required for ultra-low NO_x levels	Lowest NO_x level may not match levels achieved on above designs	Pillard - Advanced GRC Coen QLN Radian/Todd RMB with external gas nozzles
Advanced Air Staged	Low baseline Low NO_x with heavy oil	FGR not used; ultra-low NO_x levels not achievable on gas	ABB/CE - Radially Stratified Flame Core (RSFC)

Experience

Field experience with ULNBs has thus far occurred only on industrial boilers. These retrofits are listed in Table 4-8. Thirteen industrial boilers have been retrofit with ULNBs in the U.S. As seen in the table, experience has been mainly with gas firing.

Table 4-8
Summary of Ultra Low-NO_x Burner Technology Status

ULNB Type	Type of Retrofit and No. of Boilers	Boiler Type and Size	No. of Burners per Boiler	FGR, %	Controlled NO_x, ppm @ 3% O_2	
					Gas	Oil
Simulated Premix	Commercial, 10 Boilers	Industrial 5,000-150,000 lb/hr (2,300-68,000 kg/hr)	1-2	23-35	7-9	--
				0	<20	--
	Proposal	Utility-scale	24	30	<20 (guar.)	--
	EPRI Test Program (2nd Q 97))	Package 150,000 lb/hr (68,000 kg/hr) (has air preheat and FGR)	2	20-25	≤20*	≤150
				20-25	≤15**	
				0	30-50*	
Simulated Premix with Advanced Fuel Staging	Commercial, 2 Boilers	Industrial 200,000-300,000 lb/hr (91,000-136,000 kg/hr)	4	0	42-47	--
	Commercial, 1 Boiler	Industrial 250,000 lb/hr (113,000 kg/hr)	1	yes	<20	--
	Commercial	Industrial	--	yes	9 (guar.)	--
	Proposal (controlled NO_x predicted)	Utility-scale	24	17	10 (est.)	--
	EPRI Test Program (2nd Q 97)	Package 150,000 lb/hr (68,000 kg/hr) (has air preheat and FGR)	2	Minimal	≤10 (est.)	--
				0	≤15 (est.)	--
Advanced Air Staged	Commercial, 1 Boiler	Industrial 110,000 lb/hr (50,000 kg/hr)	4	0	62	185

*Fuel biased between burners
**Fuel and FGR biased between burners

Of the three ULNB technology approaches, the simulated premix approach is clearly the most advanced. Following testing at 4, 30, and 100 MBtu/hr (4, 32 and 105 GJ/hr) scales in the laboratory (29), retrofits of this technology as of mid-1996 had occurred on 10 boilers (30). Nine of these are single-burner installations, and one is a 2-burner installation. These installations replaced progressively larger burners, enabling a stepwise scale-up of the ULNB size from 5 MBtu/hr to 185 MBtu/hr (5 to 195 GJ/hr). Simulated premix burners have since been installed on 12 additional boilers, up to a maximum burner size of 280 MBtu/hr (294 GJ/hr). ULNBs using simulated premix combined with advanced fuel staging have been retrofit to two somewhat larger industrial boilers, both of which are 4-burner installations. ULNBs based on the advanced air staging approach have been retrofit to only one industrial boiler in the U.S., although there have been several installations overseas.

Applicability

ULNB technologies have thus far been applied almost exclusively on wall-fired (circular burner) boilers, although the technologies can, in principle, be applied to tangential-fired boilers as well. Also, although the technology principles apply to both gas and oil fuels, almost all of the work, with the exception of the advanced air staged RSFC design, has been on gas. The simulated premix approach may, in fact, be impractical to achieve on oil fuel, although internal staging may be incorporated into the design to reduce NO_x when firing fuel oil. In view of the need for further development for tangential-fired boilers and for oil fuel, ULNBs must as of this writing be considered as being available only for wall-fired boilers operating on gas fuel. For applications to boilers that operate on both gas and oil, it is probably realistic to expect ULNB oil-fuel NO_x levels to be similar to those produced by conventional LNBs. However, the NO_x level and other operation and performance criteria should be verified on oil prior to installation of the burners.

Comments above under "Low-NO_x Burners, Applicability" apply equally to ULNBs. Issues that may be more severe in the case of ULNBs than for conventional LNBs include: (1) amount of FGR required to achieve required NO_x performance, (2) burner size and (3) windbox/furnace pressure differential.

NO_x Performance Achieved

NO_x performance figures for the three types of ULNBs on industrial boilers are summarized in Table 4-8. The simulated premix type ULNBs, when operated with relatively high levels of FGR as intended, have consistently achieved NO_x levels in the 7 to 9 ppm range (corrected to 3% O_2) on gas fuel. It is important to note however that these installations represent small, one- or two-burner boilers, mostly, with no air preheat or need to control superheat temperatures. Other operating and performance parameters of the burners in these industrial applications have been within reasonable ranges, i.e., excess O_2 levels 3-4% and CO levels <30 ppm, although windbox/furnace differentials have been somewhat high (5.5-8.0 iwg [14-20 cm H_2O]). The <20 ppm result achieved without FGR on an industrial boiler with no preheat must be interpreted with caution for utility applications. This type of burner, operated without FGR or staged fuel, is highly susceptible to factors that increase the flame temperature and thus may exhibit substantially higher NO_x, especially if operated in this mode on a boiler having air preheat. As shown in the table, retrofits of ULNBs of the simulated premix type to two additional boilers are in the proposal stage (30). One of these boilers is a large power production boiler, and the other is a package boiler operated by a utility. The expected NO_x levels for these installations are 15-20 ppm with FGR. These figures are based on laboratory tests coupled with the experience gained in scaling the technology over a wide range of burner sizes. However, it should be noted that the experience base has not included large, multi-burner boilers.

As also shown in the table, simulated premix burners with advanced fuel staging have been retrofit to two somewhat larger, 4-burner industrial boilers. These retrofits have resulted in NO_x levels of 42-47 ppm on gas fuel for operation without FGR. This NO_x range is higher than expected relative to the results achieved without FGR using simulated premix burners without fuel staging (second row in the table). This may reflect the influence of the larger, multi-burner furnaces on the NO_x results. This would not portend well for further extrapolation to utility boiler conditions. However, this trend will be much less significant with the burners operating with FGR as would probably be the case in utility applications. As noted in the table, the proposed retrofits of simulated premix burners to a large power production boiler and a package boiler operated by a utility include, in each case, a test of advanced external fuel staging of the burners. The estimated NO_x levels to be achieved in these tests with FGR are 10-15 ppm. These estimates appear to be based on laboratory data only; thus the ability to achieve these projected NO_x levels at full scale must await the actual demonstrations in the field.

The NO_x performance of advanced air staged ULNB technology on one industrial boiler, shown in the table, is little better than levels that can be achieved using conventional LNBs. While substantially lower NO_x levels may be achievable on both gas and oil fuels with this burner using FGR and staging, the developer presently has no specific plans to do so.

In interpreting ULNB results achieved on or predicted for industrial boilers, it is important to consider the fact that these results and predictions are for boilers that are not equipped with air preheat. To achieve similar NO_x levels on large utility boilers, where air preheat levels are typically 500 to 600°F (260 to 316°C), FGR rates will have to be nearly twice those used on non-preheat boilers. To achieve 10-20 ppmc NO_x levels on non-preheat boilers FGR rates have been in the 15-25% range. To achieve these same NO_x levels on a large utility boiler would thus require FGR rates in the 25-45% range. For example, the proposed retrofit to a utility boiler requires 30% FGR for a guarantee NO_x level of 20 ppmc. For many utility boilers, FGR rates in this range will be difficult to achieve with existing equipment due to excessive impacts on steam temperatures and fan limitations.

Typical Boiler Upgrades

Comments above in 4.4.1 under "Low-NO_x Burners, Typical Boiler Upgrades" generally apply to ULNBs. ULNBs will tend to be larger than conventional LNBs due to the usage of larger amounts of FGR and, for advanced staging burners, the need for a larger burner diameter to accommodate outer air or fuel injection. Thus it is more likely that pressure part modifications will be required for installation of ULNBs than for conventional LNBs. Air balancing to the burners will be critical for ULNBs as it is for conventional LNBs. Upgrading combustion controls should be considered in planning a ULNB retrofit as it would be considered in retrofitting conventional LNBs, and this decision will usually depend mainly on the sophistication of the existing control system.

Since FGR fans are typically sized for 15-20% FGR at full load, ULNBs that depend on high FGR rates are likely to require installation of a larger FGR fan (or a new one if one is not already present) or upgrading the existing fan. High-FGR burners are also likely to require upgrading of air fans to operate against a higher pressure loss through the system. Since operation at high FGR elevates steam temperatures, provision for more steam attemperation may have to be added. However, if this is the case, the utility should carefully assess the impact that redistribution of heat absorption from the furnace to the tube sections may have on boiler efficiency and maximum load capability.

Methods that have been suggested by ULNB vendors to reduce FGR requirements for ultra low NO_x levels and avoid the need for fuel staging the burner, include biasing of air, fuel and/or FGR between burners. If provisions for these methods are to be included in a ULNB retrofit, they obviously imply added flow regulating hardware and associated measurements and controls. One vendor is suggesting fuel staging external to the burner. This would require fuel injector penetrations through the water wall (similar to that employed in a gas reburn system) as well as added fuel piping and fuel flow controls.

Potential Impacts on Boiler Operation

Comments above in 4.4.1 under "Low-NO_x Burners, Potential Impacts on Boiler Operation" generally apply to ULNBs. Two areas of concern with conventional LNBs is the potential need for increased excess air to maintain good combustion performance and the potential for flame impingement problems due to elongated flames. For simulated premix type ULNBs, these problems are unlikely to be the case. The good mixing characteristics of this type of burner favors complete combustion at normal excess air levels and also tends to produce a relatively short flame. Advanced air or fuel staged burners, like conventional LNBs, may tend to require somewhat higher excess air and may operate with longer flames than conventional burners. ULNBs that require high FGR rates to achieve ultra low NO_x levels will impact boiler efficiency in terms of increased auxiliary power requirements to operate FGR and air fans. Operation with high FGR may also impact efficiency in terms of higher attemperation rates and/or above-design steam temperatures.

Control Costs

Costs of ULNB systems are expected to be significantly higher than costs for conventional LNB systems. Costs for burner hardware will tend to be higher due to larger burner sizes required. For ULNBs requiring high FGR rates, additional capital costs are likely for upgrading FGR and air fans, and operating costs will increase due to increased fan power requirements. If the ULNB retrofit includes capability to bias air, fuel or FGR between burners, capital cost will be increased significantly relative to a conventional LNB retrofit to provide for needed hardware and controls to accomplish such biasing. If fuel staging external to the burner is involved, water wall penetrations, piping and controls will represent a substantial incremental capital cost.

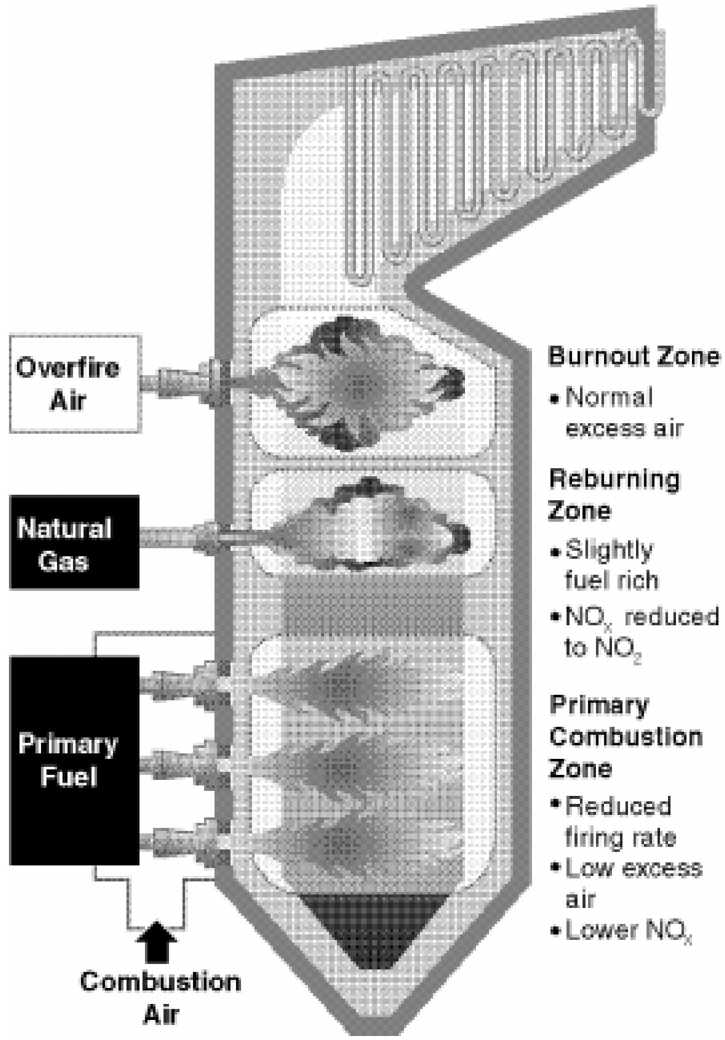

Figure 4-19
Gas Reburning
(Courtesy of Gas Research Institute)

4.5 Reburning

Description

Reburning is a method of in-furnace NO_x reduction in which a portion of the fuel supplied to the furnace is injected separately from the main burner zone in order to create a fuel-rich reburning zone in which NO_x is partially converted to molecular nitrogen. This is followed by a final fuel-lean stage for burnout of remaining combustibles. In reburning demonstrations conducted thus far in the U.S., the reburn fuel has been gas regardless of the main boiler fuel, and the technology is frequently referred to as "gas reburning". However, in the case of a boiler firing oil, oil can be used as the reburn fuel, as has been demonstrated by ENEL in Italy. The overall reburning process using gas as the reburn fuel is shown in Figure 4-19. The reburning process basically divides the furnace into the following three zones:

- *Primary Combustion Zone.* In the primary combustion zone, existing burners are turned down by 10 to 20 percent. The burners may be operated at the lowest excess air consistent with normal commercial operation to minimize NO_x formation and to provide appropriate conditions for reburning.

- *Reburning Zone*. Reburn fuel (between 10 and 20 percent of boiler heat input) is injected above the primary combustion zone. This creates a fuel-rich region where hydrocarbon radicals react with NO_x to form molecular nitrogen. The reburn fuel may be mixed with recirculated flue gas prior to injection to promote better mixing within the furnace.

- *Burnout Zone*. A separate overfire air system redirects air from the primary combustion zone to a location downstream of the reburning zone to ensure complete combustion of unreacted fuel and combustible gases.

Three variations of basic reburning are "close-coupled reburning," "controlled mixing," and "advanced gas reburning." Distinguishing features of these variations are as follows:

- *Close-coupled reburning* has been demonstrated on one tangential-fired boiler. Its main attractive feature is that the reburn fuel is injected at the top of the original main windbox, thus obviating the need for waterwall penetrations above the windbox to accommodate the reburn fuel injectors. However, in the demonstration case, the project included total windbox redesign and replacement, and the reburn fuel injectors, while being included in the main windbox, were separated from the main burners by close-coupled overfire air. Thus it is still unclear to what extent close-coupled reburning can be accomplished on an existing windbox without major modifications.

- *Controlled mixing* is an economic variation of the reburn process in which localized fuel rich zones are created by gas injectors located above the burner zone. As the burner zone is fired at normal excess air levels, the separate overfire air system is eliminated, and burnout is controlled by bulk furnace turbulent mixing. For maximum effectiveness, the unit should be normally operated at low excess oxygen levels (e.g., <1.5%).

- In *advanced gas reburning*, gas reburning is combined with SNCR to broaden the temperature window within which the SNCR process is effective. This is accomplished by regulating the burnout zone stoichiometry to maintain CO within a critical range for lowering the temperature threshold of the SNCR reactions. Final combustion air is used as a carrier for the SNCR reagent to provide momentum for mixing and air to complete the oxidation of the CO. In principle, this could also be achieved with oil as the reburning fuel; however, increased levels of unburned carbon particulate and opacity would be concerns. Advanced gas reburning is a developing technology, and the only demonstration to date is occurring on a coal-fired boiler. A brief summary of the process is depicted in Figure 4-20. It should be noted, however, that any synergies to be realized by combining gas reburn and SNCR are yet to be demonstrated at full scale. More information is also available in Reference 5.

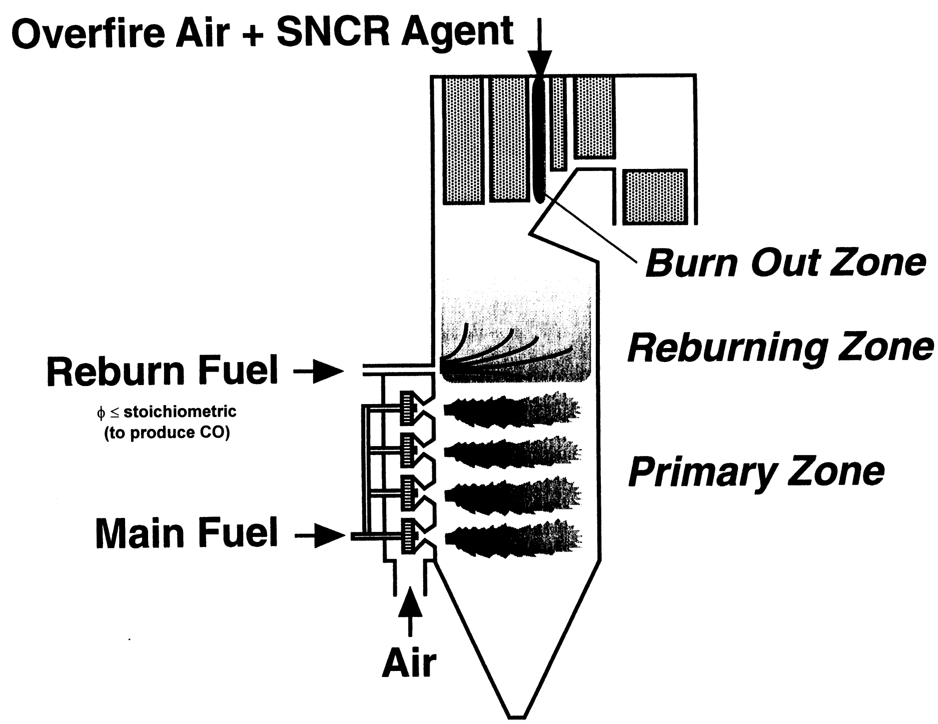

Figure 4-20
Advanced Gas Reburning

Experience

Gas reburning with gas or oil as the main fuel has been tested on three boilers in the U.S.: Illinois Power Hennepin Unit 1, Public Service Colorado Cherokee Unit 3 and Long Island Lighting Co. Barrett Unit 2. As summarized in Table 4-9, the Hennepin and Barrett units are tangentially fired and the Cherokee unit is wall fired. On both the Hennepin and Cherokee units, gas reburning was basically installed for use with coal as the main fuel, but short tests were performed with gas as the main fuel. The Barrett unit, while currently operating on gas and oil, was originally designed for coal. Thus, all demonstrations of gas reburning in the U.S. have been on coal-design boilers. Barrett Unit 2 represents the first U.S. installation and test of close-coupled gas reburning. The gas reburning system on that unit has not been used since testing, but may be used in the future as a NO_x trim when the boiler fires oil.

Table 4-9
NO_x Reduction Results for Reburning Systems on Gas- and Oil-Fired Boilers

	Hennepin 1 (Ref. 31)	Cherokee 3 (Ref. 32)	Barrett 2		S. Gilla 2 (ENEL)		Torrevaldaliga 2 (ENEL)		Fusina 5 (ENEL)	Cassano (ENEL)
Size, MW	70	171	185		35		320		160	75
Firing Configuration	Tang.	Wall	Tang.		Tang.		Tang.		Tang.	Wall
Main Fuel	Gas	Gas	Gas	Oil	Oil		Oil		Oil	Gas
Reburn Fuel	Gas	Gas	Gas[b]	Gas[b]	Gas	Oil	Gas[b]	Oil[b]	Oil	Gas
Baseline NO_x, lb/MBtu (g/MJ)	0.135 (.0581)	0.270 (0.116)	0.255 (0.110)	0.241 (0.104)	0.280 (0.120)	0.280 (0.120)	0.480 (0.206)	0.480 (0.206)	0.480 (0.206)	0.141[e] (.0606)
Controlled NO_x, lb/MBtu (g/MJ)	0.054 (.023)	0.158 (.0679)	.062-.099 (.027-.043)	0.130 (.0559)	0.102[d] (.0439)	0.126[d] (.0542)	0.096[d] (.041)	0.102[d] (.0439)	0.108[d] (.0464)	0.102[f] (.0439)
% Reduction	60	41[a]	61-76[c]	46[c]	64	55	80	79	78	28

a Limited extent of reburning (7% of heat input).

b Close-coupled reburning.

c Overfire air system without reburning achieved 61-76% reduction on gas and 40% reduction on oil.

d NO_x reduction may include other combustion modifications.

e Unit previously equipped with low-NO_x burners.

f NO_x was further reduced to .051 lb/MBtu (.022 g/MJ) using windbox FGR.

ENEL, the principal utility of Italy, operates a large number of oil-fired units, some of which also fire gas. The utility has done extensive testing of both gas/oil (i.e., gas over oil) and oil/oil reburning (33) and has selected oil/oil reburning as the primary NO_x control for all tangential oil- and gas-fired boilers and some wall-fired boilers. Reburning was not generally selected for wall-fired boilers because BOOS and low-NO_x burners were found to be more cost-effective in most cases. Following exploratory testing on bench and pilot scale units, ENEL first tested reburning on a 35 MW tangential boiler, S. Gilla 2, and has since installed and verified the technology on two larger boilers and is in the process of installation on additional boilers. Installations for which performance data are available are included in Table 4-9 (see also Appendix A). The retrofit to Torrevaldaliga Unit 2 is another example of close-coupled reburning on a tangential-fired boiler. Overall, ENEL reported that oil/oil reburning performed very well, with no deleterious effects on boiler performance, CO, or particulate emissions. In view of the large NO_x reductions stated for the Torrevaldaliga and Fusina retrofits, it appears that the reported NO_x reductions may have included effects of other NO_x controls. For example, it was mentioned that Torrevaldaliga Unit 2 was previously equipped with windbox FGR, but not clear in the data whether the baseline NO_x level was with FGR in use.

Controlled mixing has only been demonstrated on a 110 MW coal-fired boiler at Duquesne Power & Light Elrama Station. With gas as the localized reburn fuel, providing 5% of the total heat input, nominal 30% NO_x reductions were achieved. Although less than full reburn systems, the approach is competitive to low-NO_x burners, especially with no fuel cost differential.

Advanced gas reburn is also being demonstrated on NYSEG's Greenidge Unit 4, a coal-fired unit of 105 MW. Testing is scheduled for spring 1997 with a target NO_x level of 0.15 lb/MBtu (.065 g/MJ) from a baseline of 0.62 lb/MBtu (0.27 g/MJ).

Applicability

The critical factor in applying reburning is the availability of sufficient furnace volume above the existing burner zone. As noted above, all demonstrations in the U.S. with gas or oil as the main fuel have occurred on coal-design boilers, which have substantially larger upper furnace volumes than boilers designed for gas and/or oil. For gas reburning, some suppliers believe that from 0.3 to 0.5 seconds mean residence time in the Reburning Zone is required for the process to be effective. However, ENEL feels that 0.2 to 0.3 seconds is sufficient for gas reburning, while reburning with oil requires at least 0.45 to 0.5 seconds (34). Additional volume is required to accommodate the Burnout Zone, and ENEL suggests 0.3 to 0.4 seconds residence time for this zone. For a typical furnace gas average velocity of 20 ft/sec (6.1 m/sec) at full load, each 0.1 second residence time translates to 2 ft (0.61 m) of furnace height.

NO_x Performance Achieved

Results of reburning tests are summarized in Table 4-9 (see also Appendix A). These results all represent short-term tests, as there has not as yet been long-term experience on any boiler. However, as noted above, ENEL has a number of permanent oil/oil reburning installations in Italy. In summary, tests to date have shown NO_x reductions in the following ranges:

Main Fuel	Reburn Fuel	Range of NO_x Reductions, %
Gas	Gas	28 - 76
Oil	Gas	46 - 80
Oil	Oil	55 - 79

The range given for gas/gas reburning includes the 41% reduction on Cherokee Unit 3; however, that test used an unusually low degree of reburning (7% of the total heat input to the boiler). The ranges for gas/oil and oil/oil reburning include the full reductions reported by ENEL; however, it should be noted that those figures may not be highly accurate in that the stated NO_x reductions may have been in part due to other combustion modifications.

It should also be noted that for close-coupled gas reburning (the tests on Barrett Unit 2) it was not clear that reburning produced significantly better results than use of the overfire air alone. The reburning and overfire air-alone results were essentially identical with gas as the main fuel, and reburning was only slightly better with oil as the main fuel (46% reduction versus 40% reduction with overfire air only). This suggests that a utility should analyze the net benefit that reburning will produce relative to installation of overfire air alone.

Typical Boiler Upgrades

Primary retrofit components include fuel injectors above the main combustion zone, overfire air above the reburn fuel injectors, and reburn system controls integrated with the base firing system controls. No modifications are required in the main firing system as the burners are simply turned down to accommodate the reburn fuel. In some cases, a relatively small flue gas recirculation system (typically 3-4% of the boiler flue gas) is added to help mixing and penetration of the reburn fuel into the furnace. Design of the reburn fuel and overfire air injection systems is critical to the success of the process, and well proven modeling techniques should be used to insure that these systems are adequately designed to accomplish rapid and complete involvement of a high percentage of furnace gas entering each zone. Depending on the furnace size and geometry, installation of the reburn fuel injectors and overfire air ports may require as many as thirty bent tube openings in the furnace water walls. Each water wall opening may require from four to eight bent tubes to be installed. In considering application of reburning, the utility should investigate the impact of the bent tube openings on circulation, heat flux pattern and steam generation in the lower furnace water walls.

Potential Impacts on Boiler Operation

The potential impacts of a reburning system on boiler operation are similar to those of an overfire air system in the absence of reburning, which are discussed above under “System Modifications”. In summary, the reburning system, by attempting to complete combustion higher in the furnace, may lead to problems with incomplete combustion and/or higher steam temperatures. Incomplete combustion generally manifests itself in the form of higher CO emissions on gas fuel and higher opacity and/or unburned carbon particulate on oil. In designing reburning systems, the desirability of having sufficient residence time in the reburning zone will tend to force the burnout zone higher in the furnace, perhaps higher than has been done successfully with simple overfire air systems. The utility should be mindful of this tendency and make comparisons to known overfire air systems where possible. The extent to which steam temperatures can be expected to increase on a given boiler with any proposed reburn arrangement can be assessed using a reliable heat-transfer model, and the extent of efficiency degradation resulting from higher steam temperatures will depend on the baseline status of the boiler's steam temperatures relative to design and remaining margins in steam temperature control systems. In the case of a pressurized furnace, unless an adequate safety system can be devised, there may be a concern with regard to the potential for fuel-rich furnace gases creating an explosive mixture in the overfire air supply plenum under some conditions.

Control Costs

Very little information has been made available on the cost of installing a reburn system. However, capital costs for gas- and oil-fired boilers are expected to be similar to those for coal-fired boilers, excluding any cost for bringing gas into the plant. Information based on experience with a demonstration system installed on a 125-MW coal-fired cyclone boiler already equipped with gas indicated a cost of approximately \$26/kW. It was further estimated that the cost per kW would vary approximately in proportion to the inverse square root of the unit size, i.e., $MW^{-1/2}$. Thus, an estimated cost for a more typical unit size of 500 MW would \$13/kW, or, conservatively, \$15/kW.

For the case in which oil is the main fuel and gas is used as the reburn fuel, the cost differential for the gas used would be the primary operating cost, although part of this cost may be recoverable as SO_2 emission credits in that sulfur-containing oil is being replaced by sulfur-free natural gas. Other operating costs consist of incremental fan power for the overfire air system and, possibly, additional power to operate a flue gas recirculation fan.

4.6 Post Combustion NO_x Controls

This group of technologies includes selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR) and hybrid post combustion NO_x control (hybrid systems). Hybrid systems include various synergistic combinations of SNCR and SCR. These technologies all rely on injection of a reagent into the flue gas downstream of the boiler furnace to chemically decompose NO_x. Of the retrofit NO_x control technologies available today, utilities generally consider post combustion technologies to be the least desirable in view of their high capital and operating costs and the fact that they all require addition of a chemical storage and handling system to the plant. However, in recent years, technology advances and competition have acted to lower catalyst costs; and SCR is now viewed by many utilities as having a potential role in a NO_x control strategy if appropriately applied in coordination with other technologies. Maximizing

NO_x reduction using the tuning and combustion modification technologies described in the preceding parts of Section 4 will minimize the size and operating cost of the post-combustion system.

4.6.1 Selective Non-Catalytic Reduction

Description

Selective non-catalytic reduction (SNCR) of NO_x involves the injection of a nitrogen containing chemical (reducing agent) into the combustion products where the temperature is in the range of 1600-2100°F (871-1149°C). In this temperature range the reducing agent reacts selectively with NO_x in the presence of oxygen, forming primarily molecular nitrogen (N_2) and water (H_2O). A number of reducing agents have been investigated and implemented for SNCR, the most widely used including urea ($OC(NH_3)_2$) and anhydrous or aqueous ammonia. The injection ratio of reducing agent is frequently presented in terms of the normalized stoichiometric ratio (NSR), which represents the moles of nitrogen in the reducing agent injected per mole of NO in the flue gas. Figure 4-21 illustrates the arrangement of a typical low-energy urea-based SNCR system.

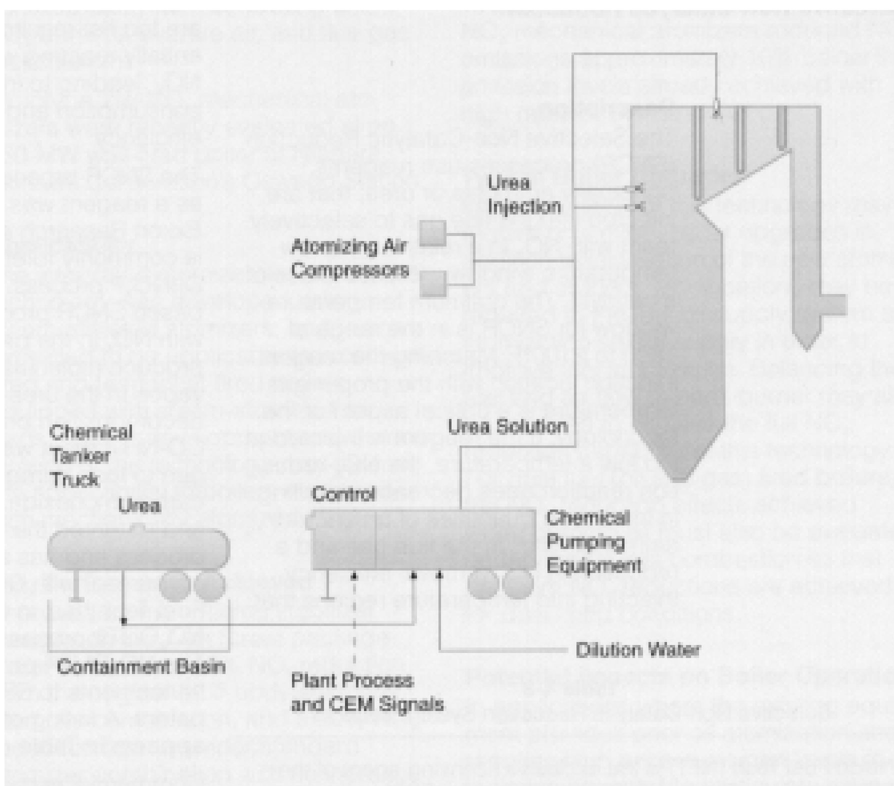

Figure 4-21
Typical Arrangement of a Urea-Based Selective Non-Catalytic Reduction System

A number of facts may enter into the decision to choose a particular SNCR reducing agent. These may include cost and availability, storage and handling requirements, site permitting issues, SNCR vendor preference, furnace dimensions, and process chemistry. Many of these factors are site-specific and cannot be generalized; although it can be generally stated that permitting, storage and handling will be easier with urea than with ammonia-based reducing agents. On the other hand, the cost of urea will be greater than ammonia. Generally speaking, low energy injection systems utilize urea in the upper furnace and rely on bulk turbulence to provide mixing. high energy injection systems in the convective section generally utilize ammonia, taking advantage of a favorable tradeoff between cheaper reagent cost and increased operating expense for the injection system.

It is also important to recognize that SNCR performance is not just a function of the process chemistry, but also of process and furnace parameters, which frequently present tradeoffs between acceptable ammonia emissions and achievable levels of NO_x reduction. A brief synopsis of pertinent operating constraints imposed by ammonia emission limitations, either operational or regulatory, include:

- Temperature
  - accessibility for injection systems on utility boilers in the proper temperature zone is frequently constrained or occurs in convective passages with limited residence time
  - increased NH_3 slip is associated with the lower end of the process temperature window
  - decreased reducing agent utilization and ΔNO_x is associated with upper end of the process temperature window
  - ammonia: 1600-1900ºF (871-1038°C) range; peak removal at 1750ºF (954°C)
  - urea: 1700-2000ºF (927-1093°C) range; peak removal at 1850ºF (1010°C)
  - location of optimal temperature zone shifts with operating load
- Initial NO_x Level
  - optimum temperature increases 50ºF to 100ºF (28 to 56°C) at high initial NO_x levels (>1.5 lb/MBtu [0.65 g/MJ])
  - process performance degradation observed at initial NO_x levels less than 100 ppm

- Residence Time
  - performance degradation demonstrated at reduced residence times (lower NO_x removal and higher NH_3 slip if residence time at typical reaction temperature is less than 200 msec)
- Amount of Chemical
  - acceptable NH_3 emission levels can restrict the maximum achievable molar N/NO injection ratio
- Fuel Effects
  - NH_3 slip reactions with trace species in the combustion products (e.g., SO_3, HCl) can limit achievable NO_x reductions
  - formation of ammonium salts can result in air heater pluggage which can cause increased unit outages and plant maintenance costs
- Injection/Mixing System
  - higher levels of mixing enhance NO_x removal and reduce NH_3 slip, but can increase operating costs

Because of the broad range of factors affecting the performance of SNCR, a correspondingly broad range of NO_x reductions has been reported (20%-50%), with a similarly high range of exhibited NH_3 emissions. Consequently, any imposed NH_3 slip limitation, either operationally or through the operating permit, will restrict the NO_x reduction effectiveness that the SNCR process can achieve.

Requirements for a successful SNCR application then become an ability to:

- achieve less than the regulatory prescribed level of NO_x emissions
- maintain the NH_3 slip sufficiently low so as to not result in fouling or corrosion of the air heater under oil-fired conditions, and not create a visible plume
- result in no operational impacts
  - back-end corrosion
  - air heater fouling
- provide injection system reliability and load following capability, and
- yield competitive process economics (levelized cost per ton NO_x removed)

In order to achieve the above targeted goals, optimization testing must take into account the following factors:

- temperature non-uniformities across the boiler and with load changes
- burner fuel/air distributions
- NO_x emission sensitivities to load and excess oxygen
- SNCR performance to quantified changes in droplet size distribution, droplet trajectory, droplet evaporation time, and solution dilution ratio, and
- ammonium salt deposit rates at different NH_3/SO_3 ratios for units firing sulfur bearing fuels

The SNCR process that uses ammonia as a reagent was initially developed by Exxon Research and Engineering and is commonly referred to as the Thermal DeNOx® process. EPRI has developed and patented the urea-based SNCR process and has an exclusive licensing agreement with Nalco Fuel Tech. Nalco Fuel Tech has, in turn, sublicensed their NO_xOUT® process to other vendors. The NO_xOUT® process includes enhancements to EPRI's urea injection patent. A listing of SNCR vendors appears in Table 4-10.

Table 4-10
Selective Non-Catalytic Reduction System Vendors

Nalco Fuel Tech (NFT) is the exclusive licensing agent of the EPRI urea injection technology, the base patent for which expires June 17, 1997. Licenses for EPRI technology are available from NFT to qualified vendors. Licensed implementors of NFT's further developments under the NOxOUT® trademark include:

- *ABB Flakt Ltd.,* Ottawa, Ontario, Canada
- *Foster Wheeler Energy Corp.,* Livingston, New Jersey
- *Petrokraft AB*, Gothenberg, Sweden
- *Research-Cottrell, Inc.*, Branchburg, New Jersey
- *RJM Corporation,* Ridgefield, Connecticut
- *Todd Combustion, Inc.,* Stamford, Connecticut
- *Vitkovice,* Ostrava, Czechoslovakia
- *Wheelabrator Air Pollution Control,* Pittsburgh, Pennsylvania

Exxon Research and Engineering (ERE) is the owner and developer of the ammonia-based THERMAL DeNO$_x$® process; however, the base patent expired August 19, 1992. A THERMAL DeNO$_x$® system is provided through either ERE or one of its licensed technology implementors. These implementors include:

- *Deutsche Babcock Anlagen,* Krefeld, Germany
- *ESA Engineering Corp.*, Laguna Hills, California
- *International Utility Services, Inc.*, Fairfield, Connecticut
- *Sulzer Brothers Limited*, Winterthur, Switzerland

The utility SNCR experience in the United States has almost exclusively been with urea-based systems. Figure 4-21 illustrates the arrangement of a typical low energy urea-based SNCR system. The equipment requirements for aqueous ammonia and urea-based SNCR systems are similar, so the following discussion is applicable to both reagents. The use of anhydrous ammonia, however, presents a number of unique delivery, storage, conveyance, and injection equipment issues which will be described in 4.6.2.

Experience

SNCR technology is commercially available with full scale operating experience on many utility boiler applications. SNCR technology was initially demonstrated on a gas- and oil-fired unit in Southern California in late 1985. In the early 1990's, the technology was commercially applied to 18 gas-fired units in the Southern California air basin as an interim means to comply with the area's strict NO_x limits. Once SCR systems were installed, however, sufficient compliance margins relative to system averages were created to allow the SNCR systems to be shut down. Currently, none of the installations in Southern California are presently operating.

It should be noted that the Southern California SNCR systems were designed as a low cost intermediate solution for NO_x control, and as such were not intended to achieve maximum NO_x reduction levels. As noted in Table 4-11, the SNCR systems were used in combination with combustion controls to achieve additional NO_x reductions of 9%-38% from application of SNCR, with an average of 21%. Recent SNCR applications on oil-fired units in the Northeast by Nalco FuelTech were designed to provide nominal 20% NO_x reductions as a trimming approach to achieve 0.20 lb/MMBtu (.086 g/MJ) (0.25 lb/MBtu [0.11 g/MJ] baseline) in anticipation of the proposed NESCAUM Phase II NO_x limits. These NO_x reductions are significantly less than the 30% NO_x reduction demonstrated at PG&E's Morro Bay under gas-fired conditions and the 50% NO_x reductions demonstrated at LILCO's Port Jefferson under oil-fired conditions. SNCR system performance results should thus be viewed in context of the application goals. Multiple injection levels may not be warranted under use as a trimming technology at full load, which certainly contributed to reduced performance, albeit at a lower overall cost.

Ammonia emissions have been typically maintained under 20 ppm, with the abbreviated residence time within the SNCR temperature window contributing to ammonia emissions of 30-50 ppm at an NSR of 1.0 at Morro Bay. With recent concerns raised regarding $PM_{2.5}$, ammonia emissions may receive greater attention during the permitting process, as studies indicate $PM_{2.5}$ is primarily comprised of ammonium salts, nitrates, and sulfates.

Applicability

SNCR systems can be retrofit to most gas- and oil-fired utility boilers, but the NO_x reductions achieved are highly site-specific, and, as noted above, are related to the application objectives. The NO_x reduction reactions are strongly dependent on flue gas temperature and residence time available at the proper process reaction temperature. As a result, the performance of an SNCR system is affected by the boiler design (e.g., flue gas residence time in the critical temperature window; ease of access to that window; and ability to achieve rapid, complete mixing of the injected reagent with the flue gas within the temperature window), as well as operational parameters that can alter the furnace gas temperatures such as changes in unit load, fuel, burner firing pattern, and FGR flow rate. It is important to note that gas-fired boilers typically exhibit the proper temperature window for the SNCR process within the convective cavities where limited residence time exists for mixing and reaction. Furnace exit gas temperatures under oil-fired conditions are typically lower due to increased radiant heat transfer within the furnace. Upper furnace injection can become applicable under these scenarios with the added benefit of the bulk furnace turbulence assisting in the mixing process between the reagent and flue gas.

NO_x Performance Achieved

Application of SNCR technology is addressed in the SNCR guideline document (TR-103885) which also has a diskette to assist the user in identifying and costing a SNCR system. A broad range of sometimes uncontrollable factors affect the performance of commercial SNCR applications. These factors result in widely varying NO_x reductions from unit to unit and can even lead to large variations in the NO_x reduction performance on a single unit when the combustion conditions are changed. As an example, the influence of the CO concentration at the point of injection is shown in Figure 4-22. Morro Bay Unit 3 NO_x reduction levels under gas-fired conditions were found to either increase or decrease as the CO levels were increased from 10 ppm to 1,000 ppm, depending upon the injection location temperature.

On carefully tuned gas- and oil-fired boilers with initial NO_x concentrations of 250 to 350 ppm, full load NO_x reductions of 50 to 60% have been achieved with acceptable ammonia emissions (35, 36, 37). The SNCR program at SDG&E Encina Unit 2 demonstrated NO_x reductions in excess of 60% with ammonia slip levels below 10 ppm. However, subsequent tests during operation with low-NO_x combustion modifications resulted in reductions of the SNCR system performance to 39% and 27% during air bias and BOOS operation, respectively. These reductions in performance illustrate the sensitivity of SNCR to process parameters, such as temperature and CO at the point of injection of the reducing agent. Although use of multiple injection locations can reduce these reductions in performance, optimal temperature windows are frequently shifted to locations in the convective pass where sub-optimal residence time for mixing and reaction exist.

Although the SNCR process is sensitive to process parameters, significant reductions from uncontrolled conditions may be achieved when the process is combined with low-NO_x combustion modifications such as O/S firing and FGR. For example, commercial SNCR systems applied to gas-fired units in Southern California achieved overall NO_x reductions of 76 to 86% when used in conjunction with combustion modifications. However, the SNCR contribution to the overall reduction was small (38). As previously noted, these systems were designed to be low cost and had limited injection controls. Recent oil-fired applications in the Northeast were also designed primarily as a trim technology with 20% normal NO_x reduction achieved. Overall performance has thus been demonstrated from 20%-60%, with results dependent upon system design, boiler operating conditions, and time-temperature profile.

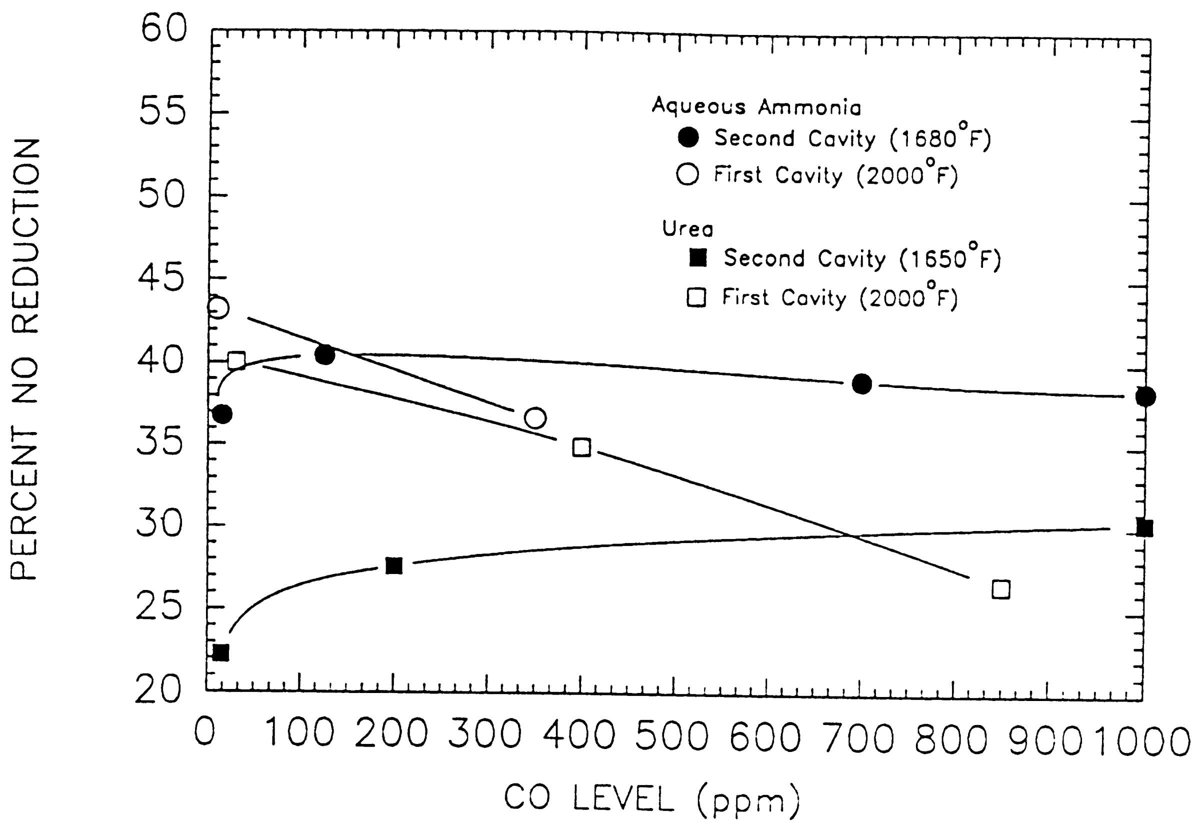

Figure 4-22
Influence of CO Concentration on SNCR NO_x Reduction, Morro Bay Unit 3

A major, controllable variable affecting NO_x reduction is the amount of reagent injected. The term normalized stoichiometric ratio (NSR) is generally used to represent the ratio between the amount of reagent injected and that theoretically required to reduce all of the NO_x present in the flue gas. An NSR greater than 1.0 indicates that excess reagent has been injected. Because of imperfect mixing and temperature gradients which often exist, excess reagent is required to provide incremental increases in NO_x reduction. However, injection rates well in excess of an NSR of 1.0 are not practical because of subsequent decreases in the chemical utilization and corresponding increases in the ammonia slip. Figure 4-23 illustrates the relationship between NSR, NO_x reduction, and ammonia slip in a field evaluation of SNCR on Pacific Gas and Electric's Morro Bay Unit 3 (a difficult application due to the limited convective pass residence time (<100 msec) available for chemical reactions).

Additional information on the surveyed units appears in Table 4-11 (see also Appendix A).

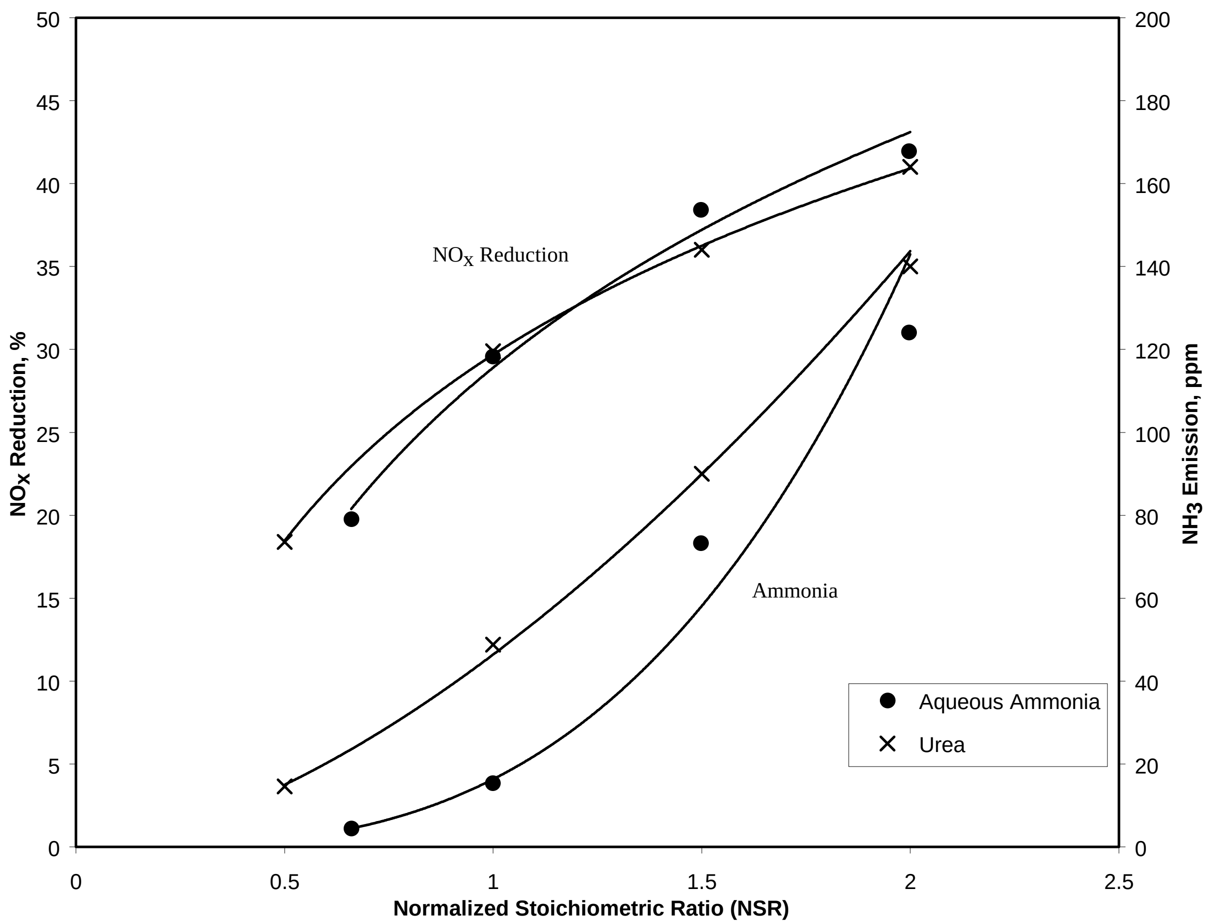

Figure 4-23
Tradeoff between Achievable NO_x Reduction and NH_3 Slip at Full Load

Table 4-11
Summary of NO_x Reductions Achieved by SNCR Systems Separately and in Combination with Combustion Modifications (O/S Firing and FGR)

Fuel	Firing Type[1]	Unit Size (MW)	Uncontrolled NO_x (ppm @ 3% O_2)	SNCR Reducing Agent	Controlled NO_x[2] Level (ppm @ 3% O_2): Combustion Controls (ppm @ 3% O_2)	Controlled NO_x[2] Level (ppm @ 3% O_2): SNCR	Percent Reduction[3]: SNCR (%)	Percent Reduction[3]: Overall (%)	NSR[4]	NH_3 Emissions (ppm)
Gas	T	320	330	Urea	80	50	38	85	2.1	<2.0
Gas	T	320	330	Urea	60	45	25	86	1.6	<2.0
Gas	T	320	330	Urea	67	53	21	84	2.2	<2.0
Gas	T	320	330	Urea	63	51	19	85	2.3	<2.0
Gas	T	320	350	Urea	70	64	9	82	1.4	<2.0
Gas	T	320	350	Urea	61	52	15	85	1.0	<2.0
Gas	SW	175	500	Urea	78	68	13	86	1.7	<2.0
Gas	SW	175	500	Urea	97	73	25	85	1.5	<2.0
Gas	SW	110	225	Urea	76	55	28	76		<2.0
Gas	T	180	87	Urea		56	36		3.0	20
Gas	O	345	260	Aq. NH_3		180	30		1.0	30
				Urea		180	30		1.0	50
Oil	T	185	250	Urea		130±30	~50		1.5-1.75	10-20
Oil	T	171	189	Urea		155[6]	18		1.0	<2
Oil	T	176	200	Urea		155[6]	22		1.0	<2
Oil	T	168	195	Urea		155[6]	21		1.0	<10

1. O = Opposed
   SW = Single Wall
   T = Tangential
2. Based on full load results. Included are short-term test data that may not reflect long-term emission rates.
3. Percent reduction is derived from test data for uncontrolled and controlled emissions.
4. NSR is normalized stoichiometric ratio and represents moles nitrogen injected per mole NO in the flue gas.

It is important to note that NO_x reductions achievable with SNCR will be limited if strict emission standards are placed on ammonia slip. An analysis of the Morro Bay test data indicates the achievable NO_x reductions for this particular site under gas-fired conditions as a function of allowable ammonia slip (39):

Allowable NH_3 (ppm)	Percent NO_x Reduction Over the Boiler Load Range	
	Aqueous NH_3	Urea
10	15-21	13-18
30	19-31	19-27
50	24-36	21-32

Typical Boiler Upgrades

The equipment required for retrofitting SNCR includes:

- Reagent unloading and storage equipment to transfer the reagent from the transport vessel to the storage vessel. Containment basins may be required for reagent spill control.
- Reagent conveying equipment including pumps, mixers, heaters to prevent freezing, and air pumps or compressors for injection into the boiler.
- Reagent injection hardware including wall injectors and retractable lances. Multiple furnace penetrations will also be required in the upper furnace wall and convective pass. Existing penetrations may be utilized if suitably located.
- Process control system to control reagent flow and injection location as a function of boiler load and outlet NO_x.

Potential Impacts on Boiler Operation

SNCR system performance is affected significantly by changes in flue gas temperature and CO within the reagent injection area. Therefore, boiler operating flexibility (i.e., load following, fuel changes, burner firing pattern, and FGR flow rate) can be impacted if maximum NO_x reduction is to be achieved, unless the system design accounts for these variations with enough injectors, appropriate real-time feed-back control loops, and/or the use of additives.

For both the ammonia-based and urea-based processes, unreacted ammonia slip is a by-product that is present in the treated flue gas and which may represent a permit compliance limitation to achievable NO_x reductions. Current regulations affecting California utilities using SNCR require NH3 emissions to be limited to between 5-20 ppm as measured at the stack. In addition to regulatory constraints, the reaction of ammonia with sulfur trioxides (SO_3) when burning fuel oil will result in the formation and deposition of ammonium bisulfate on the air heater (40). Over an extended period of time, these deposits can cause air heater plugging, necessitating increased soot blowing or air heater washing. Modifications may then be required to a plant's existing wastewater management system to treat ammonia wastes in the air heater wash. The ammonium bisulfate plugging reduces air heater performance and can accelerate corrosion of air heater surfaces.

Another concern with SNCR on oil-fired units is the potential increase in particulate emissions and opacity. Higher particulate emissions and opacity can result from the formation of ammonium bisulfate, although insufficient test data exist to determine the magnitude of an increase, if any. The reaction between hydrogen chloride in the flue gas (resulting from salt water contamination in fuel oil) and ammonia forms solid ammonium chloride. This reaction, which typically occurs after the flue gas leaves the stack and cools below 250°F (121°C), can potentially lead to detached plumes and visibility issues (38). To the extent that ammonium salts form, they will tend to be mainly in the sub-10 micron range and thus are potential concerns with regard to PM_{10} and $PM_{2.5}$ regulations.

In view of air pollutant and operational impacts of ammonia emissions from SNCR systems, a continuous ammonia monitor and integration of the ammonia slip measurement into the SNCR control scheme would be a useful addition in most cases, i.e., to enable better control of this parameter. Utilities that have implemented ammonia monitoring systems have had limited success, with the most successful systems being those applied to gas-fired systems. For flue gases produced by sulfur-containing oil systems, formation of ammonium sulfate/bisulfate compounds in the sampling system has proven a difficult problem to overcome. EPRI is currently evaluating advanced systems that may be capable of accurate continuous ammonia measurements in flue gases containing sulfur compounds and particulate. The results of that study are expected to be available in 1998.

Nitrous oxide (N_2O) is also a by-product of SNCR chemistry, with higher levels associated with the urea-based systems. Test data from full-scale installations suggests that N_2O levels are generally on the order of 10 to 20% of the NO_x reduced with urea injection and less than 5% of the NO_x reduced with ammonia injection (38). N_2O has been identified as a possible contributor to global warming. While it is currently not subject to regulation in the United States, some states do require utilities to consider the environmental externalities of N_2O production as an added cost penalty when selecting technologies for new generating capacity.

In addition to back-end impacts on the boiler operation, implementation of SNCR can also result in a decrease in the boiler efficiency. High energy SNCR systems can increase the gas flow rate through the boiler by up to 2%, increasing the dry gas losses. If steam is used as the transport fluid, additional efficiency penalties will be incurred. In addition, the energy lost to vaporization of the aqueous solution for both high and low energy systems will result in further reductions in the NO_x efficiency. The combination of the above penalties could result in an overall reduction in the boiler efficiency of up to 1%.

Control Costs

The total capital costs for SNCR systems typically range from approximately $5 to $15/kW and depend primarily upon the number of injection locations, and whether a low or high energy reagent injection approach is implemented. The cost of reagents and chemical additives can also represent a major operating expense. Reagent costs typically result in levelized control costs that range from $500 to $1500 per ton of NO_x removed, depending on the type of reagent used, its delivered cost, and utilization rate. Reagent utilization is very site specific, but based on results from Port Jefferson (oil-fired 250 ppm initial NO_x and nominal 50% reduction) with a delivered cost of $0.93 per gallon for NO_xOUT-A, the reagent cost was equated to $814 per ton of NO_x removed. To minimize reagent costs, combustion modifications are often applied to lower initial NO_x levels and reduce reagent injection requirements. Energy consumption for the reagent transport fluid is also an important cost item, although it is substantially less costly than the reagent. Energy costs are very dependent on the injection system design and host unit. (See Reference 41 and Appendix D for more detailed cost guidelines.)

4.6.2 Selective Catalytic Reduction

During the past several years, there has been substantial experience in selective catalytic reduction (SCR) on gas-fired boilers (many of which have fuel oil as a back-up or secondary fuel). While a few conventional SCR systems have been installed, the majority of the experience has been with in-duct SCR. The design of ammonia injection and control systems has matured and the industry trend is towards aqueous ammonia rather than anhydrous. Another important trend has been that catalyst life expectancy has increased. As the existing systems have been operated, it has become evident that the catalyst degradation rate, particularly with gas firing, is slower than previously predicted. Furthermore, improvements in catalyst formulations have enhanced overall life expectancy. All of the issues will be addressed in the sections that follow.

Description

In an SCR system, NO_x emissions are reduced to molecular nitrogen and water in chemical reactions with ammonia in the presence of a catalyst. The ammonia is supplied by direct injection into the flue gas upstream of the catalyst reactor. The flue gas then passes through the catalyst on which the reactions occur. There are numerous reduction reactions associated with both nitric oxide and nitrogen dioxide. The most prevalent are presented below:

1. $4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
2. $4NH_3 + 6NO \rightarrow 5N_2 + 6H_2O$
3. $4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$
4. $8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

Due to the O_2 concentration typically associated with flue gas (e.g., nominally 1%-3%), reactions 1 and 3 predominate. NO_2 is typically 5% or less of the total NO_x, although it should be noted that the LNB retrofit in combination with FGR and OFA at Morro Bay exhibited 13-30% NO_2 under some operating conditions. When the NO_x is mostly comprised of NO, however, only one mole of ammonia is required for each mole of NO_x removed.

SCR catalysts generally consist of a base material, such as an oxide of titanium, or a zeolite that is combined with active elements. The primary active element is typically vanadium pentoxide, but other non-noble metals are usually added to increase activity, decrease SO_2 to SO_3 oxidation, reduce poisoning, and match the flue gas temperatures at a particular site. These metals are molybdenum, tungsten, iron, nickel, cobalt, copper, and chromium.

The majority of existing gas- and oil-fired applications have utilized honeycomb type catalysts; however, a few boiler applications and many combustion turbine applications have used plate type catalysts. In conventional SCR designs, the catalyst is installed in layers within the SCR reactor. The reactor is typically retrofit in the flue gas stream downstream of the economizer and upstream of the air heater(s).

Two important considerations for catalyst selection are the pitch of the catalyst and space velocity. Honeycomb catalysts are manufactured in various cell sizes. The measure of the cell size is the pitch (equal to the width of one cell opening plus the thickness of the cell wall). In general, a pitch of 3.5 to 5 mm is specified for clean flue gas applications, while a larger pitch (6 to 7 mm) is required for high-ash fuel oil applications. It is important to select a catalyst with the smallest practical pitch because of its effect on the catalyst volume requirement (i.e., a smaller pitch increases the catalyst surface area per unit volume) and, hence, on the size and cost of the SCR system.

The term "space velocity," which is used in determining the quantity of catalyst required for a particular installation, relates to the volume of gas (at 32°F [0°C]) treated per hour by a unit volume (cubic feet) of catalyst. Space velocity is measured as $(ft^3/hr)/ft^3$, or hr^{-1}, with smaller values indicating a larger catalyst volume. Generally, space velocities of 6,000-10,000 hr^{-1} are utilized for conventional SCR systems on gas- or oil-fired units. The space velocity required for a particular application is determined by process conditions, catalyst properties, and catalyst surface area per unit volume. Typical process conditions that affect space velocity requirements are the initial NO_x concentration, NO_x reduction requirement, operating temperature, flue gas SO_2 concentration, ash concentration and chemical properties, and ammonia slip requirements. For boilers that are high in uncontrolled NO_x, or require a high NO_x reduction rate and/or low ammonia slip, an SCR system with a low space velocity (high unit volume) is specified. Figure 4-24 shows that if the SCR design point is at a relatively high removal efficiency, SCR reactor size can be reduced substantially by lowering the inlet NO_x level. Combustion controls (e.g., O/S combustion, FGR) utilized to minimize the NO_x concentration entering the SCR reactor will permit the use of a higher space velocity reactor which lowers the system cost.

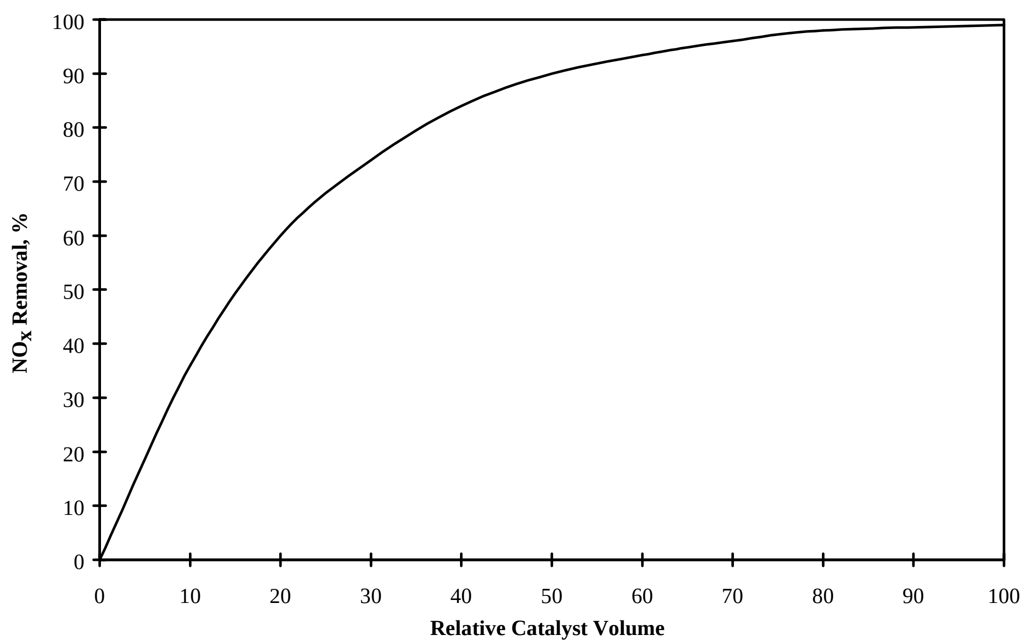

Figure 4-24
Generalized NO_x Removal Efficiency versus Catalyst Volume

Two variations of the conventional SCR reactor design are the “in-duct” SCR and catalytic air heater (CAT-AH) designs. Both of these variations permit retrofit of the technology without major modification to existing duct work. Figure 4-25 depicts an in-duct SCR arrangement in which the duct has been expanded to accommodate the reactor. In the CAT-AH design, the existing hot-end air heater elements are replaced with homogeneous or coated catalyst elements. The CAT-AH design has the advantage of adding catalyst surface without a significant increase in pressure loss and without ductwork modifications. A drawback to this approach, however, is that only one-half of the catalyst is exposed to the flue gas at a time as the regenerative air heater wheel rotates between the flue gas and air ductwork.

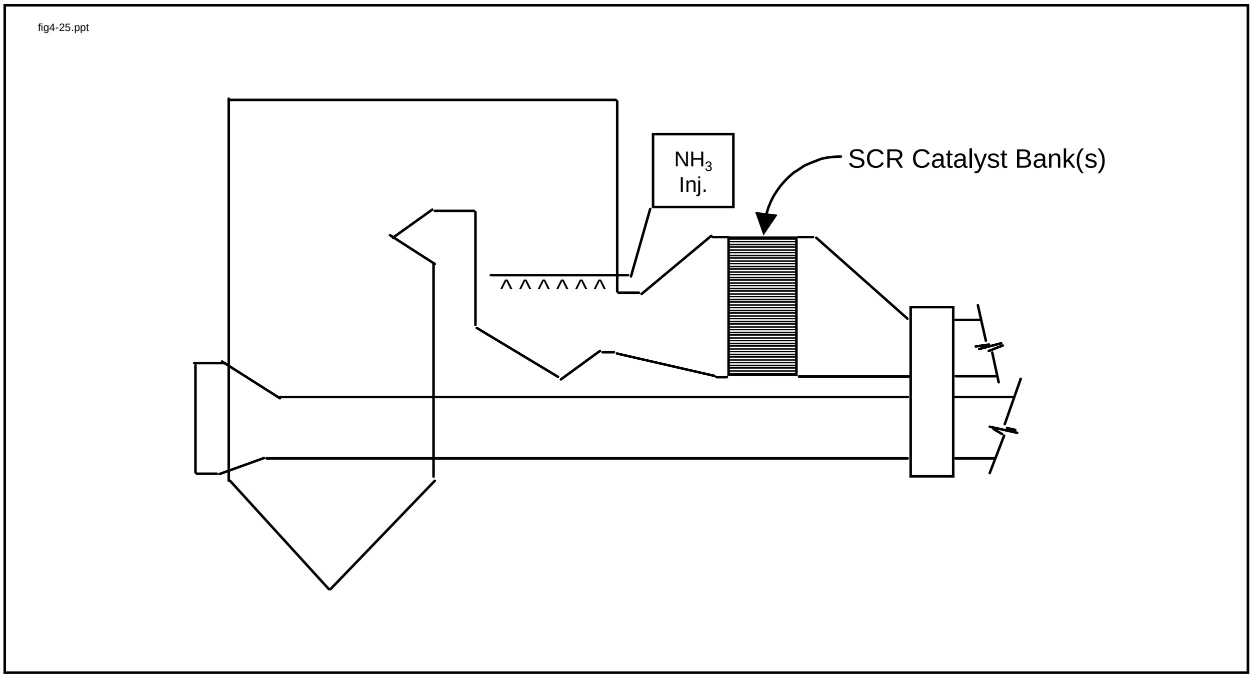

Figure 4-25
Typical Arrangement of an In-Duct Selective Catalytic Reduction System

The typical operating temperature range for SCR systems is 550 to 750°F (288 to 399°C), with greater NO_x reduction efficiency occurring at higher temperatures. However, flue gas temperatures exceeding 750°F (399°C) can degrade catalyst performance and life due to thermal sintering of the catalyst causing loss of catalyst activity.

In oil-fired boiler applications, a portion of the sulfur dioxide in the flue gas will be oxidized to sulfur trioxide on the catalyst surface. The rate of sulfur dioxide conversion is typically proportional to the catalyst activity. Depending on the concentration of ammonia in the flue gas, the sulfur trioxide will react with the ammonia reagent to form either ammonium sulfate or bisulfate. This reaction will take place in the bulk flue gas at temperatures below approximately 500°F. Within the catalyst "pores" (for high-sulfur and ammonia conditions) ammonium sulfate can form at temperatures approaching 600°F (316°C). Precipitation of ammonium bisulfate on the catalyst reduces available surface area and degrades the NO_x reduction capability of the catalyst. Precipitation in APH causes performance degradation or unit outages for cleaning and may increase corrosion.

For most gas- and oil-fired applications, the negligible particulate matter content of the flue gas eliminates the need for soot-blowers. However, for heavier fuel oils, soot-blowers may be required, at least at the first layer, to clean the catalyst surfaces.

References 42 and 43 provide additional information on the design and cost of conventional SCR technology for heavy oil-fired applications.

Table 4-12 presents a list of catalyst and SCR system vendors with the approximate number of installed SCR systems on gas- and oil-fired utility boilers.

Table 4-12
Catalyst and SCR System Vendors

Catalyst Vendors	**Approx. No. U.S. Gas/Oil-Fired Utility Boiler Retrofits[1]**
Cormetech	10
Englehard	0
Haldor Topsoe	0
Hitachi	4
Norton	0
Siemens	0
SCR Vendors	
ABB/Combustion Engineering	0
Babcock and Wilcox	4
Joy Environmental	2
Mitsubishi Heavy Industry America	2
Noel, Inc.	6
Wahlco Environmental Systems	0

Notes:

1. Experience data based on vendor's response to survey. When no response was received the quantity was estimated based on industry knowledge.

Experience

The first application of SCR in the U.S. was a demonstration project at Southern California Edison's (SCE) gas- and oil-fired Huntington Beach Unit 2 in the early 1980s. Since that time, 14 commercial systems (and four demonstration systems) have been installed on gas- and oil-fired boilers in the U.S. and two in Canada. The experience represents over 5,000 MW of installed capacity with the oldest systems having approximately three years of operating experience. Details on each of the commercial SCR systems as well as several demonstrations are included in the Retrofit NO_x Controls Database (Appendix A).

In general, the experience has been favorable with performance meeting or exceeding the expectations and capital costs being substantially below the expected values. As stated previously the vast majority of installed systems have been in-duct SCRs. To date, the only CAT-AH systems installed on gas- and oil-fired boilers are the demonstration projects at SCE Mandalay Unit 2 and San Diego Gas & Electric (SDG&E) Encina Unit 2. Neither of these CAT-AH systems are currently in service.

One caveat to the experience summarized above and in the database is that all of the gas- and oil-fired boilers retrofit to date are gas-fired boilers with oil-firing limited to back-up. Due to the favorable gas prices as well as the local regulations regarding oil firing, many of the units with SCR have not fired fuel oil since the SCRs were installed. Furthermore the design basis for the majority of the SCRs was for less than 200 hours per year of fuel oil firing and a very low sulfur fuel oil (<0.25 percent sulfur). Therefore, many of the designs utilized high activity catalyst formulated for natural gas firing. Thus, the U.S. SCR experience on oil firing is extremely limited and the only experience with moderate or high sulfur oils is pilot scale or international. Many of the lessons learned on SCR systems serving coal-fired boilers will be applicable to higher sulfur and higher ash heavy fuel oils.

Outside the United States, there is extensive experience with conventional SCR systems. Currently, this technology has been installed on more than 50,000 MW of coal-, oil-, and gas-fired capacity world-wide.

Applicability

SCR technology is applicable to most gas- and oil-fired utility boilers. However, the feasibility and cost of the retrofit on a particular unit depends on the existing equipment arrangement, boiler operating conditions, NO_x reduction requirements, and fuel type. For retrofit of an SCR system, major considerations include availability of space, and arrangement of existing ductwork and heat exchange surfaces, which affect feasibility and cost. The availability of sufficient fan capacity, and margins on furnace and ductwork pressure limits, improve SCR retrofit feasibility.

As stated previously, the majority of the systems installed to date utilize a high activity catalyst. Because a consequence of high activity for NO_x is also a high sulfur dioxide conversion rate, boilers which fire a higher sulfur fuel oil, and/or fire fuel oil more frequently, may not be able to utilize high activity catalyst due to concerns regarding the formation of sulfur trioxide. Box 4-3 discusses options to allow for the use of oil as a back-up fuel.

Box 4-3
Design Issues Related to Oil Firing as a Back-Up Fuel

To minimize the formation of sulfur trioxide, a utility which fires higher sulfur fuel oil and/or fires fuel oil more frequently may specify a catalyst with a lower sulfur dioxide conversion rate and a larger pitch to minimize pluggage with fly ash. Catalyst with lower conversion rates may have lower activity and therefore require a greater volume of catalyst to achieve the same NO_x reduction. The larger pitch also increases the volume requirement. The greater volume may make it impractical to install the catalyst in-duct and may increase the system pressure drop to a point beyond the capabilities of the existing draft system. In this case, the additional cost to accommodate oil firing will be a substantial portion of the total control costs. Depending on the frequency of oil firing this may be the only option; however, to minimize the overall cost of compliance, it may be prudent to consider other options on units with infrequent oil firing.

The first option would be to eliminate oil firing as the back-up fuel. While this may not be practical for all of the boilers within a utility or even all the boilers at a given site, it may be possible for several of the boilers to be designated as natural gas only boilers. This approach will be more practical if the utility has more than one source of natural gas.

The second option is to change the fuel oil specification to reduce the allowable sulfur content. This will minimize the sulfur dioxide concentration and thus the sulfur trioxide formation. The higher cost of the lower sulfur fuel oil may make this impractical; however, if the annual consumption is low the cost may be small compared to the higher cost of utilizing oil-specific catalyst. A utility with a large stockpile of moderate or high sulfur fuel must consider the cost of replacing or blending that fuel when evaluating this option.

The third option is dependent on the NO_x reduction requirements for oil firing and may require modifications to local regulations. If the SCR system is operated with a low ammonia injection rate, no ammonia slip will be created. (The maximum allowable injection rate will be a function of the initial NO_x concentration and the space velocity.) The lower injection rate will provide a lower NO_x reduction from the SCR. Typically this will not meet the regulatory limits for fuel-oil firing. However, if the frequency of fuel-oil firing is low and the utility agrees to fire oil only when natural gas is not available, the regulators may agree to modify the rules. The relief would be based on the very high cost of designing the SCR for the full fuel-oil capability versus the incremental reduction of NO_x during the infrequent use of fuel oil. One consideration that must be kept in mind if this option is selected, is that the catalyst will convert the sulfur dioxide to sulfur trioxide regardless of the ammonia injection rate. Although the formation of ammonium sulfate and bisulfate are eliminated by limiting ammonia slip, the potential problems of high sulfur trioxide levels (corrosion of cold end air heater elements and downstream ducts and equipment as well as the formation of a visible plume) may still be present. The level of sulfur trioxide should be assessed and a determination made as to the impact.

NO_x Performance Achieved

The SCR systems installed on gas- and oil-fired boilers have achieved design NO_x reductions of up to 95 percent (SCE Mandalay Unit 2) based on initial catalyst performance. The performance of any system is primarily dependent on the inlet NO_x, the space available for catalyst and the allowable ammonia slip. Typically, SCR performance on gas- and oil- fired boilers will be in the range of 80 to 95 percent (e.g., see Appendix A); however, on some units the modifications necessary to install sufficient catalyst to achieve that level of reduction may not be practical or cost effective.

The differentiation between in-duct and conventional SCR regarding performance has been minimized by the performance achieved on recently installed in-duct SCRs. As stated previously, the majority of systems installed have been in-duct and NO_x reductions as high as 93 percent have been achieved. It should be noted that the potential of in-duct SCR is very unit specific and the high reductions achieved to date will not be possible on all units.

The CAT-AH system at Mandalay Unit 2 has demonstrated 50 to 70% NO_x reduction at full-load equivalent conditions, with ammonia slip less than 10 ppm (43). At 50% load, a NO_x reduction of 85% was achieved with lower initial NO_x levels and reduced flue gas flow. It is important to recognize that the small catalyst quantity and limited flue gas residence time inherent with CAT-AH systems generally limit high NO_x removal rates to applications with low inlet NO_x levels, or to those that can tolerate high NH_3 slip. When the CAT-AH system was operated in combination with a urea-based SNCR system, full-load NO_x reductions reached 79%, but ammonia slip increased to nearly 25 ppm. With a combination of off stoichiometric firing, SNCR and CAT-AH, overall NO_x reductions exceeded 90%. The above results were all achieved while firing natural gas.

Typical Boiler Upgrades

Retrofitting a conventional or in-duct SCR system to an existing unit requires modifications to the boiler. On a conventional SCR, the flue gas must be diverted to the SCR reactor at or near the boiler's economizer outlet and then routed from the outlet of the reactor back to the air heaters. In-duct SCR requires duct modifications and in some cases the relocation of the air heater.

Foundations and structural modifications are required to support the SCR reactor. In addition, upgrading existing fan capacity or retrofitting new fans may be required to accommodate the pressure drop due to the SCR reactor, additional ductwork, and increased pressure drop across the air heater resulting from ammonium bisulfate deposition (when firing oil). Turning vanes may be required in the SCR inlet ductwork to distribute flue gas evenly across the catalyst. Air heater soot-blower modifications may also be required to control plugging on oil-fired units.

The following systems are generally an integral part of an SCR installation:

- An ammonia handling and injection system including unloading stations, storage, vaporization, distribution, and injection (see details below).

- Access and handling provisions for catalyst replacements. This can include a dedicated crane but must at minimum provide access and clearance to remove catalyst.

- An SCR control system must be provided to match the ammonia injection rate to the flue gas flow rate and inlet NO_x concentration. A feed forward control scheme, based on inlet flow rate and NO_x concentration, is commonly utilized, with trim by a feedback control loop based on NO_x concentration at the reactor outlet. A value for flue gas flow is supplied by the boiler combustion controls based on boiler load, flue gas temperature, and excess oxygen levels. Reactor inlet and outlet NO_x concentrations are provided by continuous NO_x monitors. Controls will also be required to shut off ammonia flow in the event the SCR operating temperature drops below minimum recommended levels.

Ammonia Handling and Injection Systems

Two options are available for the ammonia supply, anhydrous or aqueous. The early SCR pilot plants and demonstrations, as well as the majority of the combustion turbine applications, utilized anhydrous ammonia. However, due to safety concerns and permitting issues, all of the SCR systems installed on gas- and oil-fired utilities have incorporated aqueous ammonia. Table 4-13 summarizes the advantages and disadvantages of anhydrous and aqueous ammonia.

Due to the prevalence of aqueous ammonia for utility applications, the following system requirements are based on an aqueous ammonia system. System requirements for an anhydrous system can be found in Reference 1.

Unloading Station - An unloading station is required with a liquid fill and a vapor return line to route the vapors displaced by the incoming liquid back to the tank. The fittings are usually cam lock fittings; but the local ammonia vendor(s) should be consulted prior to specifying. The unloading station should be located in an area with good truck access and should include provisions for unloading the storage tank back to trucks. This may be necessary in the event of a system leak or other problem.

Storage - The quantity of storage necessary is dependent on the injection rate and the frequency of deliveries. The tank should be sized to allow full truck loads to be delivered (approximately 6,000 gallons [2,271 m^3] per truck load). This reduces the reagent cost as well as freight costs. The storage tank can be designed for atmospheric pressure but will then require a vent with a scrubber to avoid pressurization on warm days. A more practical alternative is to design the tank for a pressure of approximately 50 psig (345 kPa). The tank will hold any pressure build-up caused by changes in ambient temperature.

Table 4-13
Comparison of Anhydrous and Aqueous Ammonia

Anhydrous		Aqueous	
Advantages	Disadvantages	Advantages	Disadvantages
•Lower storage volume requirements •Lower energy requirements for vaporization •Simplified handling/ vaporization requirements •Lower reagent and transportation costs	•ASME coded pressure vessel requirements •Greater risk from accidental release •EPA risk management program (RMP) and OSHA process safety management required	•Atmospheric or low pressure storage tank can be used •Reduced risk from release •No risk management program (RMP) or process safety management (PSM) requirements if concentration is <20% by weight •Simplified permitting	•Greater storage volume required (3.5 to 5 times anhydrous) •Requires more complicated vaporization system •Higher energy consumption for vaporization •Higher reagent and transportation costs •Demineralized or other high purity water must be used to make aqueous ammonia

The critical design features of an ammonia handling and injection system primarily involve safety and the ability to provide sufficient ammonia distribution and mixing. As described above, safety features are a function of the type of ammonia to be used (anhydrous or aqueous). Safety bulletins are available from most ammonia vendors, who will usually assist the end user or designer by reviewing design drawings and/or giving safety seminars.

The distribution and mixing of ammonia with the flue gas is essential to provide uniform mole ratio of ammonia to NO_x at the catalyst inlet. Two critical parameters are the number of individually controllable injection headers and the number of planes of adjustment (i.e., a series of parallel injectors provides one plane of adjustment and two sets of injectors at a 90 degree angle provide two planes of adjustment).

The end user can utilize the features of an advanced injection grid to adjust the grid to match ammonia injection to the inlet NO_x and flow stratification. This will require the installation of test ports and/or permanent sampling grid(s). The optimum design would have sampling grids at the inlet and outlet, both of which match the injection grid. This will provide the maximum information when adjusting the ammonia injection. It will always be more expensive to install a sophisticated injection and sampling system. When the catalyst is new, the advanced features may not be required. However, as the catalyst ages and performance deteriorates, the ability to adjust the ammonia flow more accurately will be important to maintaining overall system performance. Without the ability to adequately adjust the ammonia injection, it may be necessary to replace the catalyst sooner, especially if SCR performance is constrained by a NO_x and NH_3 emission permit limit. If the advanced features delay the catalyst replacement by just one year, the savings will often more than pay for the additional cost.

Potential Impacts on Boiler Operation

The retrofit of an SCR system can impact plant operations and performance in the following manner:

- The addition of an SCR system may add from 3 to 6 inches (7.6 to 15 cm) H_2O to the flue gas pressure drop due to the catalyst beds, longer duct runs, mixing and straightening devices, the ammonia injection grid, and additional air heater sootblowers and water wash nozzles (if needed). For in-duct systems, the expected pressure drop can be lower, typically in the 2.5 to 4 inch (6.4 to 10 cm) H_2O range. The catalytic air heater elements in a CAT-AH system would not be expected to appreciably increase pressure drop but may affect thermal performance of the unit. To overcome the increased pressure loss from an SCR system, the forced-draft and/or induced-draft (ID) fans will require additional auxiliary power from the plant.

- Further incremental increases in pressure drop (and plant heat rate) may be experienced if the volumetric flow rate downstream of the SCR increases due to: (1) the addition of dilution air utilized for ammonia injection; (2) an increase in air heater leakage resulting from the increased pressure differential between the flue gas and air sides of the air heater; (3) lower static pressures in equipment upstream of the ID fan; and (4) higher air heater outlet temperatures, if necessary to prevent the formation of sulfur trioxide in the reactor.

- If required, methods to establish a minimum SCR operating temperature at low load, such as bypassing or removing some of the heat transfer surface in the economizer, will adversely affect plant heat rate.

- Previous comments in the section titled "Selective Non-Catalytic NO_x Reduction, Potential Impacts on Boiler Operation" with regard to impacts of ammonia slip on boiler operation also apply to SCR systems. However, slip levels are generally lower and more predictable on SCR systems than on SNCR systems.

Catalyst replacement will be the greatest operating cost for the vast majority of SCR systems. The frequency of catalyst replacement will be a function of the system design, the catalyst formulation, and the flue gas conditions (temperature, ash loading, and presence of poisons). To minimize the total operating cost of the system, the end user should develop and implement a catalyst management strategy. A complete description of the requirements of a catalyst management strategy is beyond the scope of this document; however, the primary functions of a management strategy are listed in Box 4-4. Refer to Reference 43 for additional recommendations on O&M.

Box 4-4
Catalyst Management

Minimize degradation rate - Many operating practices will impact the catalyst degradation rate either positively or negatively. Strict operating procedures should be maintained, including start-up and shut-down procedures, procedures to avoid catalyst exposure to moisture during long-term outages, and periodic catalyst cleaning procedures.

Assess the catalyst condition - Periodic catalyst assessment will identify problems early and allow the end user to take corrective action and/or budget and plan for catalyst replacements. Assessments should include catalyst sampling for activity tests and analysis for poisons.

Evaluate replacement options - Replacement options include reactivating the catalyst (currently only offered for some catalysts) and partial replacement.

Partial catalyst replacement - Partial replacement of the SCR catalyst can offer substantial savings in life-cycle catalyst costs. This option requires that the original design include multiple catalyst layers; however, if space is available, the additional up-front cost will be more than offset by the long-term savings. If the catalyst degradation is due to poisoning or masking, the first layer of catalyst will typically degrade more rapidly than subsequent layers. If practical, an arrangement which removes the first layer of catalyst, cycles each subsequent layer forward and adds new catalyst as the last layer would be optimum. However, the added cost and downtime may be prohibitive, and a simple direct replacement may be more cost-effective. Another option is to leave an empty layer in the original design and add catalyst to that layer at a later date. The additional layer will provide a greater performance improvement than a layer replacement; however, it will also increase system pressure drop.

Address disposal issues - Spent SCR catalyst is considered a hazardous waste and therefore can only be disposed in a hazardous waste landfill. To avoid this cost, a strategy should consider reactivating or recycling if possible. If the end user has more than one facility with different NO_x reduction requirements, he or she may consider cycling the catalyst from the facility with the most stringent requirements to facilities with lower requirements. This procedure could also be applied to a utility with a NO_x averaging rule by cycling the catalyst from high capacity factor units to lower capacity factor units.

Control Costs

Capital costs for installed SCR systems on gas- and oil-fired boilers have ranged from \$15 to \$30 per kW for unit capacity of 70 to 750 MW depending on the complexity of the installation. These costs reflect lower catalyst costs and the use of in-duct SCR designs compared to conventional designs. The units in question operated with very limited oil firing and with a very low sulfur fuel oil. The cost for units with more frequent fuel oil firing or higher sulfur levels will be higher. These prices do not include any draft system upgrades which may be required on some units. In general, costs for SCR systems are expected to be in the \$12 to \$35 per kW range. Appendix D provides an SCR cost estimating methodology.

Operating costs for SCR systems will include expenditures for reagents, catalyst replacement, incremental power costs (for the increased combustion air fan pressure requirement and added reagent feed system), and incremental O&M expenses (labor and materials). Reagent costs (in \$/gallon) for SCR systems are similar to those outlined in the SNCR section, and will depend on the type of reagent used, delivered cost, and utilization rate; however, reagent utilization is much better than for SNCR (typically close to 100% for SCR). Catalyst replacement costs will be a function of fuel(s) burned, catalyst volume and the expected catalyst life. Expected catalyst life is a function of the original design volume, the reduction requirement and the ammonia slip limit. While guarantee life is typically four to six years for natural gas, catalyst vendors have indicated an expected life as long as 10 years. The increase in combustion air fan energy costs will be proportional to the added flue gas pressure drop which, as previously stated, may consume from 4 to 8 inches (10 to 20 cm) H_2O for conventional SCR systems, from 2.5 to 4 inches (6.4 to 10 cm) H_2O for in-duct systems, and less than 1 inch (2.5 cm) H_2O for most CAT-AH systems. Reagent feed system energy costs will depend on the fan power requirements of the injection blowers and, for aqueous ammonia-based systems, the thermal loading requirements of the evaporators.

For example, the following operating costs are associated with the addition of a conventional ammonia-based SCR system to a 400-MW, oil-fired unit, where a 90% NO_x removal rate is targeted (42):

Operating Parameter	Levelized Value (mills/kWh)
O&M Expenditures	0.24
Reagent	0.19
Catalyst Replacement	0.55
Increased Power Requirements	0.52

Note that for either an in-duct or CAT-AH system, the above estimated value (of 0.52 mills/kWh) for increased power requirements could be substantially reduced. The estimated values for O&M expenditures, reagents, and catalyst replacement would depend on installed catalyst volume, NO_x removal rates, etc.

4.6.3 Hybrid Post Combustion NO_x Control

Selective catalytic reduction (SCR) is capable of achieving desired NO_x reductions in many cases; however, high costs and/or technical limitations caused by unique boiler configurations often make stand-alone SCR a less than optimum solution. Hybrid Post Combustion NO_x Control Systems (Hybrid Systems) offer the high levels of NO_x reduction necessary for compliance and can often overcome the limitations caused by unique boiler configurations (44).

Description

There are four post combustion NO_x control configurations which fall under the general heading "Hybrid Systems." Each configuration has its own individual benefits and applicability.

1. Combination of selective noncatalytic reduction (SNCR) with in-duct SCR. This configuration utilizes the ammonia slip from the SNCR process as part or all of the ammonia for the SCR reaction. This configuration can be further categorized according to the type of reagent used, urea or ammonia, and by whether or not supplemental ammonia is injected upstream of the SCR.

   A subset of this option, as well as of option 3 below, is an SNCR system with a small amount of catalyst to act as an ammonia slip eliminator. The catalyst would not provide significant NO_x reduction itself; however, it would improve performance of the SNCR system by allowing higher ammonia slip from that system.

2. Combination of an in-duct SCR with a CAT-AH system. Typically a single ammonia injection grid is installed upstream of the in-duct SCR. Ammonia slip from the in-duct SCR provides the inlet ammonia for the CAT-AH system, thus allowing the in-duct SCR to operate at a higher ammonia slip than would be possible without the CAT-AH system. Although the NO_x reduction in the CAT-AH system may be moderate, operating the in-duct SCR at a higher ammonia slip will dramatically increase in-duct SCR performance.

3. Combination of SNCR with a CAT-AH system. As with the first option this configuration can utilize either an ammonia or urea based reagent for the SNCR and supplemental ammonia injection at the SCR inlet. The utilization of an CAT-AH system differentiates this option from option 1 due to the unique characteristics of the CAT-AH system.

4. Combination of SNCR with both in-duct SCR and CAT-AH system. This configuration combines the benefits of all three systems.

Experience

Two Hybrid Systems have been installed on gas- and oil-fired boilers as demonstration projects on gas fuel. These installations were on San Diego Gas & Electric (SDG&E) Encina Unit 2 (45) and Southern California Edison Mandalay Unit 2 (46). The Encina Unit 2 installation included a urea-based SNCR system and both in-duct and CAT-AH SCR reactors. The Mandalay Unit 2 installation included a urea-based SNCR system and a CAT-AH SCR reactor.

Similar systems have been demonstrated successfully on two full-scale utility boilers in Japan. The systems were installed on two 850 MW oil-fired boilers in the late 1970s (47). Each of these systems consisted of an ammonia based SNCR system and an in-duct SCR. The SNCR system utilized lance type injectors located in the convective pass section of the boiler. The in-duct catalyst was located in the existing duct upstream of the air heater. An ammonia injection grid was installed upstream of the catalyst to supplement the ammonia slip from the SNCR system. Although the systems are no longer in operation, they achieved the design goal of 60 percent NO_x reduction while maintaining ammonia slip at 10 ppm or less.

Applicability

Hybrid Post Combustion NO_x Control should be considered as an option whenever installation of an SCR system is being evaluated. The Hybrid System option basically reduces the size of the SCR reactor required for a given amount of NO_x reduction, creates a two-part system in place of a one-part system, and allows the chemical reagent to be either urea or ammonia. The principal advantages of a Hybrid System relative to a stand-alone SCR system are as follows:

- Higher overall NO_x reduction without extensive unit modifications (i.e., reactor will weigh less and require less space)
- Lower system pressure drop
- Safer and less costly chemical storage (if SNCR system uses urea and SCR system does not utilize supplemental ammonia injection)
- Operational flexibility for seasonal NO_x control requirements and/or load following
- Can be more cost-effectively designed to permit use of oil as a back up fuel

Implementation of these advantages is discussed in detail in EPRI's assessment report on this technology (44).

Disadvantages relative to a stand-alone SCR are mainly increased complexity and higher chemical costs. Increased complexity is inherent in the use of two technologies in place of one and will tend to increase both engineering costs to install the system and O&M costs once the system is on line. Higher chemical costs result from higher stoichiometric feed ratios required for SNCR than for SCR and, assuming that urea will be chosen, the higher cost of urea than ammonia per pound of reactive nitrogen.

If an SNCR system is already in place and additional NO_x reduction is required, conversion to a Hybrid System should obviously be considered. Although this scenario is not now common (few SNCR systems in place), it could be utilized as a contingency feature in a long-term NO_x control strategy, i.e., installation of SNCR in the near term with the option to convert to a Hybrid System for incremental NO_x control in the future.

A methodology has been developed specifically to assess applicability of Hybrid Post-Combustion NO_x Control for specific applications, and is available in the form of an electronic spreadsheet from EPRI (44).

NO_x Performance Achieved

Table 4-14 shows NO_x performance results from the Hybrid System demonstration on SDG&E Encina Unit 2. Substantial NO_x reductions were achieved over the unit's load range without major unit modifications. Results for the Mandalay Unit 2 demonstration are shown in Table 4-15, where performance of the Hybrid System is compared to performance of the SNCR and SCR as stand-alone systems. In both cases, the Hybrid System, by permitting operation of the SNCR system at a higher slip level, achieved substantially better performance than the sum of performances of the two systems operated separately. Full-load NO_x reductions demonstrated were in the 70-80% range; however, Hybrid Systems can readily be designed to achieve NO_x reductions in the 80-90% range. A demonstration Hybrid System on Public Service Electric & Gas Mercer Unit 2, a coal-fired boiler, achieved greater than 90% NO_x reduction in a short-term test on gas fuel.

Table 4-14
SDG&E Encina Power Plant Unit 2 Hybrid System Demonstration - Individual and Combined Performance - Phase III Results (Gas Fuel)

	SNCR (NSR=3.0)		In-Duct SCR (NH_3/NO_x=1.0)		CAT-AH System (NH_3/NO_x=1.0)		Hybrid SCR	
Unit Load (MW)	%Red	Outlet NO_x ppm	% Red	Outlet NO_x ppm	% Red	Outlet NO_x ppm	% Red	Outlet NO_x ppm
22	38	56	66	19	57	8	91	8
70	50	45	48	23	26	17	81	17
108	41	53	36	34	26	25	72	25

Note: Baseline NO_x emissions approximately 90 ppm for all loads.

Table 4-15
SCE Mandalay Generation Station Unit 2 Hybrid System Demonstration, Independent SNCR/SCR versus Hybrid Performance, Full Load Natural Gas Firing

	NO_x Reduction (%)[1]	
Technology	Independent Performance	Hybrid Performance
Urea Based SNCR	10-15	30
CAT-AH	70	74
Total System	73-75[2]	82

Notes:
1. NO_x reductions are from a baseline of approximately 115 ppm (8 BOOS) and in all cases ammonia emissions were less than 10 ppm.
2. Theoretical system performance based on combined independent performance.

Typical Boiler Upgrades

Comments above under "Selective Non-Catalytic Reduction, Typical Boiler Upgrades" and "Selective Catalytic Reduction, Typical Boiler Upgrades" generally apply to Hybrid Systems. However, comments regarding SCR ammonia handling and injection may not apply if the Hybrid System does not utilize supplemental ammonia injection.

Potential Impacts on Boiler Operation

Comments above under “Selective Non-Catalytic Reduction, Potential Impacts on Boiler Operation” and “Selective Catalytic Reduction, Potential Impacts on Boiler Operation” also apply to Hybrid systems.

Control Costs

Cost guidelines given above under “Selective Non-Catalytic Reduction, Control Costs” and "Selective Catalytic Reduction, Control Costs" also apply to Hybrid Systems. However, costs related to an SCR ammonia handling and injection system may not apply if the Hybrid System does not utilize supplemental ammonia injection.

5

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A

RETROFIT NO_x CONTROL DATA BASE

An important aspect of preparing these guidelines has been the gathering of information on NO_x control retrofits that have occurred on gas- and oil-fired boilers. For greatest usefulness to utility personnel, this information has been assembled into two EXCEL spreadsheet data files, which are contained on a diskette accompanying this document. One data file, RETRONOX.XLS, contains information on all NO_x control technologies except SCR, and the other data file, RETROSCR.XLS, contains information on SCR systems. Data fields for which information was requested, and a brief explanation of each where necessary, are listed in Tables A-1 and A-2. The combined data base contains information on 239 NO_x control retrofits, many of which were applied to both gas and oil (total of 312 NO_x reduction data entries). Although it was not possible to obtain complete information in all cases, a substantial array of information is contained, and the data base represents an important new tool for utilities in planning NO_x control strategies for their units. Table A-3 shows the number of entries in the data base for various control technologies by major boiler/fuel categories.

The following are some suggestions for most effective use of the data base in EXCEL.

1. In extracting information to answer a given question, you may find it useful to rearrange the order of rows to place the data fields of greatest interest near the top of the spreadsheet.

   Note: It is advisable to keep a backup copy on a diskette in case you accidentally “save” a modified version over the original.

2. To extract a given type of information, you will be using the “data/sort” command to sort the data by columns.

   For example, using RETRONOX.XLS, to extract information on FGR retrofits to tangential boilers of 150 to 250 MW rated capacity built prior to 1971:

- Sort the entire data base by “Firing Configuration”, “Startup Year”, and “Rated Net MW” to group tangential boilers built before 1971 and rated between 150 and 250 MW,

- Eliminate data sets not in this group,
- Then sort by “Retrofit NO_x Control(s)” to group FGR retrofits, and eliminate data sets not in this group. The surviving group of data sets meets the extraction criteria.

Table A-1
Data Fields in RETRONOX.XLS (continued)

Data Field	Comments
Retrofit NO_x Control(s)	NO_x control(s) to which this data set pertains (i.e., the boiler may have had pre-existing controls)
Supplier	Vendor(s) that provided the NO_x control(s) to the utility
Year	Year in which the retrofit occurred
Pre-Existing NO_x Control(s)	NO_x control(s) in place prior to this retrofit
Controlled NO_x at MCR (lb/MBtu) Gas (Long- or Short-Term) Oil (Long- or Short-Term)	Post-retrofit NO_x emissions at maximum continuous rating (MCR) on gas and/or oil fuel. Long-term data represents significant operational experience, short-term data indicates test data (e.g., acceptance test)
NO_x Limits (lb/MBtu) Gas Oil	Regulatory limits in effect. In some cases the controlled NO_x may reflect what was needed to meet the limit rather than the full control capability of the retrofit.
Baseline NO_x at MCR (lb/MBtu) Gas (Tuned or Untuned) Oil (Tuned or Untuned)	Pre-retrofit NO_x emissions at maximum continuous rating (MCR) expressed as ppmc or lb/MBtu. "Tuned or untuned" refers to whether the boiler had been tuned for low-NO_x operation prior to recording its baseline NO_x.
NO_x Control System Impacts on Boiler Operation/Performance	Any impacts on heat rate, minimum O_2, particulate emissions, opacity, CO emissions, steam temperatures, turndown, etc.
Problems with NO_x Control System	Any problems in terms of reliability, operability, maintenance requirements, performance at reduced loads, etc.
WBFGR, % Gas Oil	FGR to the windbox at the time of post-retrofit NO_x measurements
FGR other than WBFGR On Gas? On Oil?	Shows whether the boiler is equipped with FGR to the furnace (not via the windbox) and, if so, whether it is used on gas, on oil or on both fuels.
SNCR System: Inlet NO_x, ppm Urea or NH_3 High- or Low-Energy? NH_3 slip, ppm	Applies only if an SNCR system is involved; "high- or low-energy" refers to method of injection of reagent (steam or air assisted or simply pressure atomized)
Installed Capital Cost Operating Cost	

Table A-1
Data Fields in RETRONOX.XLS (continued)

Data Field	Comments
Boiler:	All fields below are information regarding the boiler design and operation
Rated Net MW	Rated MCR
Full Load Net MW	Actual MCR
Manufacturer	
Startup Year	
Firing Config.	
Design Fuel(s)	Fuel(s) for which the boiler was originally designed
Base or Cycling	Whether the unit is base loaded or is used to respond to load demand
Excess O_2 at MCR	
On Gas	
On Oil	
Oil Atomiz (Stm or Mech)	Type of oil atomizers (steam or mechanical)
Oil Sulfur, %	
Oil Nitrogen, % (Typ.)	Typical nitrogen content of oil, if known
No. Burners	
No. Burner Elev's	Number of burner elevations (rows)
Spacing betw Elev's	Spacing between burner elevations (rows)
Furnace Dimensions:	
Height	Overall height of furnace open space
Width	
Depth	
Height above burners	
Division Walls:	
Number	
Height	
Depth	
Notes	
Questionable Data	Indicated NO_x reduction considered uncertain due to uncertainty in baseline or statistical improbability of NO_x reduction relative to similar cases. "Gas" indicates gas-fuel data are questionable; "Oil" indicates oil-fuel data are questionable; "Gas, Oil" indicates both gas-fuel and oil-fuel data are questionable.
Date/Name	Date and operator's initials for original entry and updates/revisions.
Source of Data	

Table A-2
Data Fields in RETROSCR.XLS

Data Field	Comment
Capacity (MW)	Rated capacity of unit to which SCR was retrofit
Fuel	Fuel(s) on which unit operates
SCR system supplier	
Installation year	
SCR type	Conventional, in-duct, air heater, or hybrid
Design temperature (ºF)	At catalyst inlet
Design flow rate (SCFM)	Expected flue gas flow rate at full load
Design inlet NO_x (ppm)	ppm (dry, corrected to 3% O_2)
Design NO_x reduction at end of guarantee life (%)	
Design outlet NO_x (ppm)	ppm (dry, corrected to 3% O_2)
Design NH_3 slip at end of guarantee life (ppm)	
Catalyst manufacturer	
Catalyst type	
Catalyst pitch (mm)	Spacing of cells, transverse to direction of flow
Catalyst volume (ft^3)	Superficial volume, i.e., space occupied
Catalyst guarantee life (years or hrs. of operation)	
Catalyst expected life (years or hrs. of operation)	
Design catalyst pressure drop (in. w.c.)	
Design system pressure drop (in. w.c.)	Including injection grid, any baffles, etc.
Ammonia supply (anhydrous or aqueous)	Whether ammonia is supplied as a water solution or as essentially pure ammonia
Number of injection nozzles or orifices	
Number of flow biasing valves (for grid adjustment)	Ammonia flow control valves
Adjustments in one plane or two?	Whether ammonia distribution can be biased in only one dimension or in two dimensions

Table A-3
Data Base Contents (Number of Data Sets by Category)

	Wall-Fired Boilers		Tangential-Fired Boilers	
NO_x Control Technology	Gas	Oil	Gas	Oil
LEA	1	4	0	0
Optimization Software	0	0	3	6
Burner Modification	1	10	1	3
OFA	1	2	2	2
O/S Combustion (BOOS and/or OFA)	27	22	13	14
FGR	8	5	1	0
FGR + O/S Combustion	15	10	8	6
LNB	25	23	0	3
LNB + FGR	2	2	0	0
LNB + O/S Combustion	2	3	3	3
LNB + FGR + O/S Combustion	14	12	0	0
Reburning	2	0	2	7
SNCR	5	0	2	0
SNCR + O/S Combustion	5	1		1
SNCR + FGR + O/S Combustion	--	1	6	1
SCR	19	0	1	0
Water Injection	1	1	--	--

B

BOILER PREPARATION AND TESTING GUIDELINES FOR NOX ASSESSMENTS ON GAS-AND OIL-FIRES BOILERS

Overview

In general, utilities should conduct detailed stack emission measurements and combustion diagnostic tests to identify and implement retrofit NO_x controls on a boiler and to verify the effectiveness of controls after implementation. The following parameters should be measured as guidance in selecting the control technologies and to ensure that acceptable combustion conditions, proper steam temperature control, and low emissions of other pollutants are maintained under low-NO_x conditions:

- Flue gas composition at the boiler outlet (NO_x, CO, and O_2) including composition profiles
- Steam temperatures, pressures, and flow rates
- Steam temperature control factors (attemperation flow rates, superheat/reheat proportioning damper position, flue gas recirculation rates, burner tilts, etc.)
- Air heater leakage and inlet/outlet temperatures
- Flame impingement and stability
- Tube metal temperatures in any high-heat-flux zones in the furnace that are a concern
- Fuel composition
- Opacity and particulate emissions (oil firing)

Modifications and equipment adjustments that may be required to achieve good emissions and thermal performance with most NO_x control technologies include:

- Modifications to the fuel supply and distribution piping to ensure uniform distribution of fuel to the burners
- Air register position adjustments to maintain acceptable flame shape and stability
- Recalibration of flame scanners
- Superheat/reheat proportioning damper position, flue gas recirculation rate, attemperation and burner tilt position adjustments for steam temperature control
- Recalibration of combustion controls for low excess air operation

In general, with every major modification or installation of new technology, the utility should plan on a period of tuning, and in some cases design iterations, to attain proper operation, followed by training of the boiler operators.

NO_x Emissions Testing

Baseline NO_x emissions test programs measure NO_x emissions for typical boiler operating conditions and define the sensitivities of these emissions to variations in operating parameters. This information can be essential for NO_x compliance planning, preparing engineering procurement specifications, performing bid evaluations, and negotiating supplier performance guarantees. The results will clarify whether compliance can be achieved through operations modifications or, alternatively, the degree of NO_x reduction required with new combustion equipment.

A baseline test program can also be expanded to include investigation of combustion tuning techniques for reducing NO_x. As discussed in Section 4, combustion tuning generally involves redistributing fuel and air to the boiler to reduce overall excess O_2, or intentionally biasing boiler operation to achieve staged combustion.

Post-retrofit NO_x emission test programs are usually performed to determine the effectiveness of the retrofit NO_x control. Often this is a performance test to confirm that the retrofit system performs in accordance with the purchase specification. Although the vendor may pay for this test, the utility will want to be closely involved in all aspects of planning and execution of the test program to insure that all performance criteria and potential impacts on boiler operation are correctly measured and assessed.

Test programs vary in scope from limited investigations conducted at a single load point over a period of less than a week to detailed parametric evaluations conducted over the load range of the boiler for weeks in duration. Testing typically involves extraction of representative flue gas samples, conditioning of these samples to remove particulate matter and moisture, and an analysis for gaseous NO_x concentration with electronic instrumentation. Simultaneously, measurements are taken of corresponding excess O_2 levels and combustible levels. Values of influential operating parameters (e.g., unit load, steam conditions, burner tilt, and pulverizer loading/performance) are also recorded. More information on NO_x emission testing of boilers can be found in Reference 2.

Types and Elements of NO_x Emissions Test Programs

Table B-1 summarizes three types of NO_x emissions test programs. Table B-2 describes the measurements and information collected for each of these programs. Each program comprises several similar elements as shown in Table B-3. Baseline test programs can be Type 1, 2 or 3, depending on the program purpose. Combustion tuning typically requires conducting a Type 3 test program as a first step. Post-retrofit testing is usually Type 3, with the extent of parametric testing limited to what is required to assess performance over a range of operating conditions stipulated in the purchase specification.

Type 1 programs can usually be implemented using in-house resources at a utility company. Type 2 and Type 3 programs, which are considerably greater in scope, may require an outside contractor to plan and implement the test.

Table B-1
Types of Test Programs

	Type 1	Type 2	Type 3
Scope	Quick NO_x emissions assessment with minimal unit performance data Potentially inadequate for NO_x retrofit assessment	Gaseous and (if oil) particulate emissions characterization with appropriate combustion diagnostics Sufficient operating and support data to identify emissions range and dominant parameters, and conduct retrofit assessment	Detailed emissions, combustion diagnostics, and performance testing Detailed parametric testing with design and operating data suitable for detailed retrofit study
Emissions Measurement Precision	±25%	±10-15%	±5-10%
Relative Cost	Lowest	Moderate	Highest
Duration: Gas	1 week	1-2 weeks	2-3 weeks
Oil	1 week	2-3 weeks	3-4 weeks

Source: EPRI, EPT, FERCO

Table B-2 (continued)
Measurements and Information Collected for Each Type of Test Program

	Type 1	Type 2	Type 3
Flue Gas Sample	Single point (probe), located in ductwork at or near the stack where gas is well-mixed; point selected based on manual traverse.	Multiple-point sample extraction system located at the economizer exit ductwork. Typical system consists of multiple probes with filters, pump, condenser, and means for isolating the sample from individual probes.	Similar to that for Type 2. May include gas sampling at furnace exit and air heater outlet to measure air in-leakage.
Gaseous Emissions[1]	NO_x - Method 7 or 7E O_2 - Method 10	NO_x - Method 7E O_2 - Method 10 CO - Method 3A CO_2 - Method 3A	NO_x - Method 7E O_2 - Method 10 CO - Method 3A CO_2 - Method 3A
Ash (Oil Only)			
- Particulate Emissions	Optional	Method 5 or 17 at boiler outlet	Method 5 or 17 at boiler outlet Particle size - optional
- Ash Analysis	Carbon analysis of flyash or samples from economizer hopper	Carbon analysis of fly ash gathered in situ from flue gas at economizer exit	Same as Type 2
Fuel			
- Gas	Heating value	Heating value	Heating value
- Oil	Ultimate, proximate, viscosity		
Boiler Design Data			
- Original Equipment Design Specifications	Unit type, furnace geometry, burner type, burner arrangement, design gas and steam temperatures	Type 1 plus fuel and air supply system design specifications	All major boiler island equipment specifications available in boiler manufacturer's operating manual
- Boiler Design Modifications	Record of major boiler design modifications (if available)	Type 1 plus any available data on impact of design modifications on boiler performance	Type 2 plus assembly drawings of major boiler design modifications
- Generic Design	Optional	Identify major design constraints that would affect retrofit potential for NO_x control.	Type 2 plus estimates of potential improvement in boiler performance

Table B-2 (continued)
Measurements and Information Collected for Each Type of Test Program

	Type 1	Type 2	Type 3
Boiler Operating Data			
- Current Operating Performance	Obtain historical boiler efficiency and unit net heat test reports. Document major parameters during test. Use existing plant instrumentation only.	Obtain boiler efficiency, heat rate, and recent component performance test reports and data. Measure key boiler performance parameters at selected test conditions. Supplement plant instruments as necessary.	Type 2 tests at several points across load range and maximum load.
- Plant Maintenance Data	Optional	Acquire and review recent outage records and component failure history/ maintenance	Analyze recent O&M data and repair records by comparison with similar units in system.
- Identification of Operating Limitations	Optional	Review all components/controls performance that limits unit operations	Same as Type 2, plus actual gas temperature, tube temperature data, etc.
- Fuel Property Information	Obtain typical fuel analysis.	Obtain fuel sample for analysis, establish typical seasonal fuel use patterns plus records of fuel property variation.	Type 2 plus data on coal source, contract commitments, long-term annual fuel use projections
- Annual Operating Data	Optional	Identify typical daily unit load profile by season and quarterly capacity factors.	Actual daily operating history, maximum and minimum load, heat rate and O_2 across load range, forced outage history
- Unit Economics/ Utilization Plans	Current boiler efficiency, unit heat rate, long-term retirement plans.	Identify current ranking of unit on economic dispatch basis.	Type 2 plus sensitivity of unit economics to capacity factor and benefits of life extension under consideration
Other Boiler Data			
- Site-Specific Constraints	Optional	Identify major constraints unique to this site (i.e., one of a kind, retrofit access, asbestos removal requirements, etc.)	Same as Type 2
Fireside Measurements			
- Observations Slagging/Fouling	Optional	Recommended	Required
- Furnace Exit Gas Temperature	Optional	Optional	Recommended

[1]Conducted in accordance with U.S. EPA Reference Test Methods, as described in the U.S. Code of Federal Regulations, Title 40, Part 60.

Table B-3
Elements of NOx Emissions Test Program

Element	Type 1	Type 2	Type 3	Objectives	Typical Actions
Planning and Organization	✓	✓	✓	Test matrix Distribution of responsibilities Schedule Budget	Visit sites Meetings with all parties Draft, plan, and approve
As-Found Measurements	✓	✓	✓	Quantify emissions at minimum expense.	Survey and rank emission rates among generating units in a system.
Diagnostic		✓	✓	Verify combustion equipment is functioning properly.	Evaluate combustion uniformity and test combustion control sensitivities.
Baseline Parametrics		✓	✓	Quantify NO_x sensitivity to primary operating variables.	Take data on: - NO_x vs. load - NO_x vs. excess O_2
Detailed Parametrics			✓	Quantify NO_x sensitivity to multiple operating variables and operating transients. Determine NO_x reduction potential through operational modifications only.	Take data on: - NO_x vs. load - NO_x vs. excess O_2 - NO_x vs. WB-F/ΔP - NO_x vs. air staging - NO_x vs. burner tilt - NO_x vs. burner settings
Interpretation and Reporting	✓	✓	✓	Document emissions and boiler thermal performance as a reference. Identify areas for upgrading/ modification.	Present data tabularly and graphically. Test report for inclusion in engineering bid specification

Test Program Planning

Developing an effective NO_x emissions test program requires consideration of project objectives, information needs, operating constraints, available resources, and timing. This assessment will help determine the type of test program needed. Successful programs generally involve participation of several utility departments: plant operations and maintenance, central engineering, load dispatch control, and environmental affairs. Establishing early cooperation among these groups helps avoid delays and budget problems. Contingencies should be included to ensure that available resources are adequate, budgets are not exceeded, and deadlines are met.

Developing a Test Matrix

The fundamental component of the planning effort is development of a test matrix that defines

- Test conditions to be investigated
- Sequence of tests to be performed
- Measurements to be taken at each test condition

The test matrix can be used for planning discussions among participants, to estimate labor and test equipment requirements, to develop load dispatch requests, and for scheduling. A lead test engineer is generally designated responsibility for drafting and editing the test matrix during the planning work element. The experience and judgement of the test engineer is critical in prioritizing test conditions to be investigated, particularly for Type 3 test programs. In developing the test plan, the engineer may want to hold informal discussions with combustion equipment suppliers to confirm the information needs for preparing proposals with warranties. Prioritization is essential because schedule and budget limitations usually prevent parametric testing of all desirable combinations of the test variables, and operating demands often cut short a test program or require adjustment to operating conditions for nontesting purposes. Experienced test engineers also recognize the value of analyzing initial field results to verify NO_x parameter dependence and to guide test matrix changes during the testing.

A typical sequence of activities is to

- Define the purpose/type of test program
- Develop a list of questions to be answered using data gathered during the program
- Define the data and results needed (e.g., emissions, boiler performance, and auxiliary equipment operating characteristics)
- Define how the data will be used and by whom
- Define the precision required by data type and use
- Define the fuels to be tested, if more than one
- Identify resource, schedule, and budget constraints

Key Operational Parameters Affecting NO_x Emissions

Type 2 and Type 3 baseline test programs are designed to investigate the influences of key operating parameters that directly or indirectly affect NO_x emissions. These include

- Load (firing rate)

- Excess O_2 level
- Burner tilt position (tangential-fired units only)
- Oil viscosity and firing temperature
- Air damper positions
- Combustion uniformity
- Windbox-to-furnace differential pressure
- OFA flow rate (NSPS units only)
- Furnace cleanliness (Box B-1)

Box B-1
Effect of Furnace Cleanliness on NO_x

For boilers that fire both gas and oil, a significant factor affecting the level of NO_x produced is the cleanliness of the furnace walls. This effect was most apparent in the early days of NO_x testing, when NO_x levels were substantially higher than those encountered today. Based on testing many gas- and oil-fired boilers, it was gradually learned that deposits accumulating on furnace walls during oil firing increased NO_x levels (presumably by increasing flame temperatures). It was learned that a boiler became well "seasoned", i.e., progressed to an equilibrium state of dirtiness, after two weeks to a month of oil firing. It was also learned that after a switch from oil to gas, furnace wall cleanliness would gradually be restored, with two weeks to a month of gas firing being sufficient to return the furnace to clean conditions. The table below shows the effect of furnace cleanliness on NO_x observed on three large utility boilers operating on gas fuel. Cleanliness effects were in the range of 21 - 48% of "dirty" NO_x and 26-91% of "clean" NO_x. Although NO_x levels today are generally lower, on a percentage basis, the effect of cleanliness can be expected to be about the same. On oil fuel, the effect would be less since NO_x formed from fuel-bound nitrogen is relatively unaffected by flame temperature.

	NO_x, ppmc			Cleanliness Effect	
Unit	**Clean**	**Dirty**	**Difference**	**Percent of Clean NO_x**	**Percent of Dirty NO_x**
A	190	240	50	26	21
B	210	360	150	71	42
C	230	440	210	91	48

It will also be necessary to measure other factors affecting low-NO_x equipment design and performance, including FD and induced draft (ID) fan operating margins; primary air fan performance; load-limiting factors; furnace exit gas temperature; and steam temperature controls.

Typical Scope and Duration of NO_x Test Programs

Table B-4 summarizes test program activities and typical labor requirements for the three types of NO_x test programs.

The principal factors that affect test program cost and duration are the number of test conditions to be investigated and the number of individual measurements to be conducted at each test condition. Single-point measurements at one or a few loads can usually be acquired in two days. Installation of a multiple-point sampling grid and continuous emissions instrumentation adds to the test preparation time but permits faster data acquisition. Baseline parametric NO_x characterization at a variety of loads and air levels generally takes two weeks. Detailed parametrics and combustion tuning on large boilers can take four weeks or more.

Table B-4
Test Program Activities and Typical Schedule Requirements
(First Single-Unit Test)

Activities		Type 1 Elapsed Time (days)	Type 2 Elapsed Time (days)	Type 3 Elapsed Time (days)
1. Planning and organization				
- Preliminary scoping, budgets, schedule		<1	<1	<1
- Test plan development		<1	<1	1
- Definition of resource requirements		<1	<1	<1
- Preparation of unit implementation plan		<1	<1	<1
2. Diagnostics/As-Found Measurements	Gas	1	1-2	2-3
- Coordinate, set up, and conduct field test program	Oil	2	2-4	3-4
3. Baseline parametrics	Gas	N/A	1-3	2-3
- Coordinate, set up, and conduct field test program	Oil	N/A	2-5	3-5
4 Detailed parametrics	Gas	N/A	N/A	2-3
- Coordinate, set up, and conduct field test program	Oil	N/A	N/A	3-5
5. Interpretation and reporting	Gas	2	3	4
- Data analysis report presentation	Oil	2	4	6
Total Time[1]	Gas	4	7-9	12-15
	Oil	5	9-14	17-22

[1]This estimate assumes that the field test program is conducted by engineers and technicians meeting the qualifications specified in Table B-5. The experience level of test personnel and differences in labor practices can affect these estimates.

Source: EPRI

Project Management/Personnel Qualifications

The recommended qualifications of test personnel are shown in Table B-5. As can be seen, recommended experience levels vary with the type of test program being conducted.

Table B-5
Project Management and Personnel Qualifications
(Approximate Years of Experience)

Responsibility	Type 1	Type 2	Type 3
1. **Department or Section Leader** (Supervisor to Project Manager)	5 years emissions compliance/control; 2 years NO_x control	Type 1 plus knowledge of emissions/cost/ performance strategies/ trade-offs, retrofit costs, and economic ranking	Type 2 plus extensive interface experience with plant engineers/operators in implementation of emissions control operating mode
2. **Project Manager**	3 years emissions measurement; 2 years NO_x measurement	Type 1 plus 5 years of boiler performance test experience on all boiler types; specialist in combustion	Type 2 with 8-10 years total NO_x test experience in implementing combustion modifications
3. **Test Engineer**	3 years power plant test experience; 1 year NO_x measurement	3-5 years experience in emissions measurements with continuous analyzers and complex sample systems	Same as above; minimum 5 years on large multi-burner boilers
4 **Technician**	3 years power plant test experience; 1 year NO_x measurement/ instrumentation	Type 1 plus experience with continuous analyzers and leak-checking complex sample systems	Minimum 10 years total test experience in gaseous/particulate emissions; 5 years on NO_x measurements

Source: EPRI, EPT, FERCO

More experienced personnel are required for detailed parametric testing and combustion tuning. The boiler operating conditions encountered under such test programs may deviate from normal practice and, therefore, may reduce boiler flexibility for handling upsets.

Flue Gas Sample Extraction, Processing, and Analysis

To measure various gaseous species (e.g., NO_x, O_2), a flue gas sample is continuously extracted from a location in the boiler where the chemical reactions are completed and gaseous concentrations are relatively uniform[1]. The best sampling location is the ductwork leaving the economizer, immediately upstream of the air heater.

When sampling at the economizer exit, a multiple-point sampling system is recommended. Depending on the size of the ductwork, samples are extracted from 12

[1] Dilution-probe sampling systems common to continuous emissions monitors (CEMs) are not used for temporary, multipoint sample extraction systems in test programs. Thus, dilution-probe systems are not addressed herein.

to 24 points. This matrix of probes produces a sample that is representative of the average emissions from the boiler. Moreover, analysis of samples from individual probes provides valuable diagnostic information relating to combustion uniformity and any atypical firing conditions.

A fixed, stainless steel probe of 3/8″ to 1/2″ (0.95 to 1.27 cm) diameter is dedicated to each sample point. Ideally, the ends of the probes are positioned at varying depths and spacing to obtain a geometrically representative sample. Gas samples are drawn through the probes using a sample pump. Inert plastic tubing is typically used to connect the sample probes and the pump. In some instances, the sample lines are heat traced to (1) prevent flue gas moisture condensation, or (2) prevent freezing and breaking. Sometimes the gas samples from the probes are combined immediately outside of the duct. In other cases individual sample lines are maintained and connected to a manifold system that allows selection and combination of one or more sample streams. This latter approach is necessary for a Type 3 test program.

Prior to analysis, an extractive gas sample is conditioned to eliminate moisture and debris that might plug the analytical equipment or interfere with the analytical measurement. Having been extracted, combined, dried, and filtered, the flue gas is then pumped through electronic analyzers for analysis.

For Type 1 test programs, it may be desirable to reduce the complexity and cost of the sample extraction system. In the extreme, a single-point sample extraction system may be employed. The approach is similar to that described above, except for the location of the sample probe.

For a single-point sampling system, extraction of a sample from the flue gas ductwork entering or, preferably, in the stack is recommended because the flue gas will most likely be more thoroughly mixed farther downstream in the flow path, and the single-point sample will be more representative of the average conditions at this location compared with the economizer exit. The insertion depth of the sampling probe is based on a manual traverse of the excess O_2 concentration at the selected port/compartment location. As described above, the extracted flue gas sample is dried and filtered prior to analysis.

Flue gas is typically analyzed for the following constituents by the use of electronic instrumentation described by U.S. EPA Reference Methods. The U.S. Code of Federal Regulations, Title 40, Part 60.

- NO_x Method 7E, Chemiluminescent Analyzer
- O_2 Method 3A, Fuel Cell or Paramagnetic Analyzer
- CO Method 10, Non-Dispersive Infrared Analyzer

- CO_2 Method 3A, Non-Dispersive Infrared Analyzer

Certified calibration gases with zero, midrange, and high concentrations of each gas species are used to initially and periodically calibrate the analyzers. Analyzer output is recorded continuously on an analog strip chart. Gaseous analyses are performed on a dry gas basis. The amount of moisture removed by the sampling system must be taken into account when reporting emissions. This can be done mathematically based on a fuel analysis (see Appendix E).

For a given steady-state test condition, about one hour is required to calibrate, sample, analyze, and document the representative gaseous emissions. During this period other pertinent boiler operating data are recorded. Moreover, for Type 2 and Type 3 test programs, other related measurements include ash sampling for carbon analysis, fuel analyses, furnace exit gas temperature, and furnace exit excess oxygen[2]

NO_x concentration is typically measured in ppm. Appendix E discusses conversion of these data to a reference excess O_2 concentration and to lb/MBtu.

[2] EPRI Report CS-5552, *Guidelines for Fireside Testing in Coal-Fired Power Plants*, provides additional detail on performing these types of measurements.

C

SPECIFYING NO_x COMBUSTION CONTROLS

The following focuses on specification of a low-NO_x burner system as an example. However, many of the same considerations apply to specification of other NO_x combustion controls.

Overall Approach

The specification should address all project requirements while avoiding items that are beyond the vendor's control. Requesting warranty requirements that are too broad tends to result in high bids, bids with many exceptions or vendors refusing to bid, and may lead to unenforceable guarantees.

General Requirements

- **Modeling**

  Utilities should usually require a physical or analytical scale model of the existing boiler furnace, windbox and inlet ducting system. This modeling would serve as a basis for any modifications required to provide uniform air flow distribution to all burners. It should include flow distribution tests both with and without the required flue gas recirculation (if applicable).

- **Experience**

  The burner manufacturer should be asked to identify locations (with contacts) where the proposed low-NO_x burner assembly has been successfully installed on boilers of similar design and size to the boiler being modified. (Some utilities may wish to specify a minimum level of experience.) Qualifying systems should have fired successfully on the required fuels and complied with the emission requirements stated. The burner manufacturer should also be asked to submit tabulated data indicating actual burner performance (NO_x, CO, O_2, particulate, and opacity) for the installations sited.

- **Load Change Capability**

The specifications should require that burner equipment be designed for the following conditions:

— Daily load changes from a minimum firing rate of xx MBtu/hr to a maximum of yy MBtu/hr and then back to minimum

— Load cycling rate of up to xx MW per minute (yy percent per minute)

— xx startups and shutdowns per year

Any limitations in the design of the burners, FGR equipment and its assemblies, that would adversely affect its safe operation, should be explicitly defined in the operating instruction manual to be submitted for engineering review prior to fabrication.

Some utilities may wish to specify that the new LNBs replace the existing burners with no boiler pressure parts modifications.

- **Firing Range and Excess Air Requirement**

Minimum thermal output capacity (rating) per burner:

Gas firing, Btu/hr

Oil firing, Btu/hr

Minimum turndown (without tip change):

Gas firing	xx	(10:1 is frequently required if the boiler must operate with all burners in service [ABIS] over the whole load range)
Oil firing (steam atom.)	xx	(8:1 typically required for ABIS)
Oil firing (mech. atom.)	xx	(2.5:1 typically required for ABIS)

The supplier should be asked to submit all required burner firing characteristic data, including fuel flow versus fuel pressure curves for the burners (may be supplied following startup).

Desired maximum required excess oxygen at full load:

Gas firing 0.5-1%

Oil firing 1-2%

The lower levels represent ideal goals that may not be achievable in all cases due to resulting high CO and particulates. Low excess oxygen levels are also desired over the remaining operating load range, and bidders should be asked to provide performance curves. The location and method of O_2 measurement to be used in performance testing should be included.

- **Pressure Drop**

  Maximum pressure drop across the burners at full load with required flue gas recirculation (if applicable), normally expressed in inches of water.

- **Materials of Construction and Parts Warranty**

  Minimum alloy to be used in all burner parts and specific alloys to be used for parts exposed to high heat flux. Burner throat refractory should have a minimum service limit of 3,000ºF. Warranty on failure of burner parts due to workmanship, overheating, or corrosion.

- **Combustion Air Flow Distribution**

  Maximum allowable variation of mass flow rate through each of the burners at full load: ± 5.0% of the mean through all of the burners. (Some utilities may elect to specify air flow measurement devices on each burner, especially if the NO_x control system will be required to operate optimally at all times to meet the emission limit.)

Performance Requirements

- **Boiler Efficiency**

  The LNB system should be capable of maintaining design steam conditions and boiler efficiency as determined by ASME PTC 4.1 testing. (Baseline testing prior to installation may be required to document warranty conditions.)

- **Firing Stability**

  All burners should be expected to produce a stable flame pattern over the entire load range, without exceeding the emission limits specified, irrespective of whether firing singly or collectively.

  The combustion systems should not be allowed to cause flame impingement on any of the furnace wall tubes over the entire load range.

- **Burner Vibration**

  The burner assembly should be required to operate without evidence of excessive burner induced vibration. Vibration amplitudes should not exceed 0.3 inch (0.76 cm) (peak to peak) as measured on the furnace burner wall buckstay members by means of an accelerometer, or equivalent method.

- **Maximum Emission Limits (ppm limits are by volume, dry basis, corrected to 3% O_2)**

Nitrogen oxides (NO_x), ppm	
Gas firing	xx
Oil firing	xx
Carbon monoxide (CO), ppm	xx
Stack opacity, % (or Ringelman)	xx
Particulates, lb/MBtu or grains/scf flue gas	xx
Hydrocarbons, ppm	xx

Utilities can specify a single limit applicable over all load ranges or limits at several loads (e.g., maximum continuous rating [MCR], 75% MCR, 50% MCR, and minimum load), depending on their compliance requirements. Further, utilities may wish to require that these limits be met, for operational reasons, with: all burners in service (except below xx MW); flue gas recirculation flow rate not to exceed xx% of combustion air flow rate; and no injection of chemical additives. Some utilities have also specified that the limits be met without the use of OFA (very site-specific).

For combustion firing of both gas and oil fuels simultaneously, the limits for NO_x should be apportioned in accordance with the thermal input contribution by each of the respective fuels.

Utilities should indicate the maximum air preheat temperature at which these limits must be met. For oil, utilities should specify the fuel analysis for which a boiler must meet these limits (at least, they need to specify maximum nitrogen, fixed carbon, ash, sulfur, and viscosity at a minimum of 2 temperatures; asphaltene limits are desirable).

These limits should be guaranteed to apply collectively and concurrently over the entire specified load range between minimum load and full load, and during startups using gas fuel.

- **Performance Tests**

  The supplier should be required to hire an independent third party to perform compliance testing at least 30 days after unit operation is turned over to the utility. The tests should include all permit conditions (specified pollutants as a function of permitted loads, fuel types, fuel specifications), and should be conducted under normal dispatch settings by boiler operators, at both constant load and during load swings to document unit ramp rate requirements. The supplier should be asked to perform enough replicate tests to ensure compliance with the averaging time in the permit.

  The specification should stipulate exact methods to be used for emission measurements, including location of sampling, number of sampling points, method of flue gas analysis, number of repetitions, duration of testing, etc. A baseline performance test report including measurement methodology applied can be a useful appendix to the LNB specification.

  For oil capable boilers, performance tests for NO_x should be done when the boiler is "seasoned" - i.e., after two weeks to one month of oil firing. NO_x levels on both oil and gas can be substantially higher on a seasoned versus clean (recently washed or following a significant period on gas) boiler. For more information on the effect of boiler cleanliness on NO_x, see Appendix B (Box B-1).

  In cases where the LNB retrofit may aggravate high-heat flux and/or flame impingement problems, it may be advisable to include quantitative measures of these problems, such as chordal thermocouples in high flux zones and videotaping of flames, in both baseline and performance testing.

System Requirements

- **Burner Management System (BMS)**

  The BMS should be auto/semi-automatic and comply with applicable insurance code requirements.

- **Flame Scanners/Provers**

  Two flame scanners/provers should be provided for each burner. One scanner/prover would be used for the ignitor and as a redundancy for the main scanner/prover. The main scanner/prover should be designed to detect flame intensity and flicker frequency to allow discrimination among different flames and glowing refractory. Scanners/provers should also be designed to monitor all fuels used in the burner with and without required flue gas recirculation, and comply with insurance codes.

- **Service Life**

  Utilities may wish to require that the burner assembly be designed for a minimum service life (e.g., 25 years).

  The supplier should be asked to provide: a list of recommended spare parts; special tools, devices, and handling gear necessary for installation, adjustment or maintenance of all burner equipment.

- **Engineering Support and Manuals**

The supplier should be expected to provide: the services of qualified engineers to help direct acceptance testing; instruction manual, and operation and maintenance (O&M) manuals.

Codes and Standards

The specifications should require that all work comply with the applicable sections of the following codes and standards:

American Society of Mechanical Engineers (ASME)
Section I, Power Boilers
Section VIII, Division 1 Pressure Vessels
Section IX, Welding and Brazing Qualifications

American National Standards Institute (ANSI)
B1.1, Unified Screw Threads
B2.1, Pipe Threads
B16.11, Forged Steel Fittings, Socket Welding
B16.5, Steel Pipe Flanges and Flanged Fittings
B16.21, Non-Metallic Gaskets and Flanges
B16.25, Butt Welding Ends
B31.1, Power Piping

National Fire Protection Association (NFPA)

American Institute of Steel Construction (AISC)

American Society of Testing and Materials (ASTM)

American Welding Society (AWS)

National Electric Code (NEC)

Underwriters Laboratories (UL)

Steel Structure Painting Council (SSPC)

For a system including FGR or potential future FGR, it is suggested that Factory Mutual Loss Prevention Data Sheet No. 6-5/12-70, “Oil- or Gas-Fired Multiple Burner Boilers,” be consulted.

D

COST ESTIMATING METHODOLOGY

Purpose and Goals

The purpose of these spreadsheet formatted models is to provide the utility user with a cost estimate for NO_x control equipment that narrows the range of expected capital cost to within ±25 percent of the expected value and operating costs for SCR and SNCR to ±10 percent of the expected value. Technologies modeled include:

- Low NO_x Burners
- Overfire Air
- Flue Gas Recirculation
- Selective Non-Catalytic Reduction
- Selective Catalytic Reduction

Section 4 defines a range for the installation of each technology. The capital cost of each alternative is expressed in "dollars per kilowatt" ($/kW). By including all significant boiler types, sizes, and parameters, the resultant wide range of capital cost presented in Section 4, while accurate, may be of limited use for application to a specific unit. Therefore, models which employ site-specific information to narrow the capital cost estimate range will be of greater benefit in determining the cost of complying with NO_x emission limits for a specific system.

These cost estimating models are meant to be used within the context of the NO_x technology performance guidelines for which this is an appendix. These models are for estimating cost only: issues such as appropriateness for specific applications, ability to meet performance requirements, and impact on plant performance are addressed in Section 4.

The goal of these models is to provide reasonable estimation of cost while limiting the required input to values that are either readily available or easily obtained. Although each technology alternative has numerous components, these components do not all have the same impact on system cost. User input was minimized by selecting those components which have the greatest impact on system cost.

I. General Unit Information

Figure D-1 shows the screen for the input of information that is used for all technologies. The model is valid for units 200 MW to 800 MW, and applies to boilers that are fueled by natural gas, fuel oil, or a combination of both. For all technologies other than SCR, fuel oil is assumed to be No. 6. The SCR model requests specific input regarding ash and sulfur content of the fuel oil. By supplying unit size (MW-net) and net plant heat rate (Btu/kWh), a heat input value expressed in millions of Btu's per hour (MBtu/h) can be determined.

The default value used for labor cost to install the equipment is based on the state in which the unit is located. The labor rate represents a composite construction crew heavily weighted towards boilermakers. The default value is based on fully loaded union labor and is state-specific, based on a state-wide averages determined by a recent wage rate study conducted by Black & Veatch. If the user knows that this rate does not accurately reflect the local construction costs, then the default can be overridden and the accurate value can be used.

II. Low NO_x Burners

The algorithm used to develop the cost estimate for the installation of LNB is based on heat input, type of firing system, fuel type, existing control system, and installation difficulty.

The model is capable of estimating the capital cost of burner replacement for the following types of firing systems:

- Tangential
- Twin-tangential
- Single wall
- Opposed wall
- Cell fired

The scope of this model includes new burners, replacement of the burner management system, limited tube wall modifications, and installation of the new equipment.

The cost estimate is developed around the cost of a replacement LNB sized to supply the existing heat rate to the boiler. Using a unit cost per burner and replacing the like number of burners, the base price is determined. This base price is then modified using other input supplied by the user. For example, if both oil and gas are burned, then dual-fuel burners must be used, which have a higher cost. Also, for oil fired units, the model includes replacement of mechanical and air atomizers with a new steam system.

A retrofit difficulty factor is incorporated into the model to account for various levels of construction access and balance of plant modifications. The difficulty levels are applied to the installation portion of the project, and are defined as follows:

Nominal:	Clear access for construction, limited windbox and steel modifications, limited electrical modifications.
Moderate:	Clear access for construction, moderate windbox and steel modifications, moderate electrical modifications.
Moderately Difficult:	Construction access impeded, moderate windbox and steel modifications, extensive electrical modifications.
Difficult:	Construction access significantly impeded, extensive windbox and steel modifications, extensive electrical modifications.

Figure D-2 illustrates the screen associated with the LNB model. The results of the capital cost estimate are presented as a range expressed in $/kW.

III. Overfire Air

The algorithm used to develop the cost estimate for the installation of OFA is based on combustion air requirements (calculated from heat input and fuel type), number of burner columns, and certain boiler dimensions. Another important factor in determining the capital cost is whether the addition of OFA is in conjunction with the installation of LNB.

This model does not apply to tangential and twin-tangential units because OFA is an integral part of an LNB installation and is not a stand-alone alternative.

The suggested number of OFA ports is determined by the type of boiler. For cell or single wall fired units, two ports per burner column are suggested. Opposed wall fired units typically have four ports per burner column.

The scope of the OFA system includes new ports with associated water wall tube bends, ductwork, all plate and stiffeners, and installation. Modification to the existing combustion control system is assumed to be included if the OFA system is installed in conjunction with LNB, otherwise, control modification is required and included in the cost estimate.

Figure D-3 illustrates the input and results screen of the OFA model. The difficulty factors required as input are the same as for the LNB model described above.

IV. Flue Gas Recirculation

Figure D-4 illustrates the input and results screen of the FGR model. The scope for this model includes new fan and motor, ductwork, stiffeners, dampers, control, and installation. One of the most significant factors in determining the capital cost is the presence of an existing FGR system. Numerous gas and oil units were originally equipped with the capability for flue gas recirculation. These systems are generally used for steam temperature control and inject the flue gas below the combustion zone. For the FGR system to reduce NO_x emissions, the flue gas must be injected into the windbox to reduce flame temperature and NO_x formation. Since the windbox operates at a higher pressure than the bottom of the boiler, additional energy is required to overcome the windbox pressure. If the unit presently has an FGR system, the model includes a booster fan to increase the pressure and assumes the recirculation ductwork is already in place. On units without FGR systems, the model adds the entire ductwork in addition to a fan sized to handle the entire recirculation flow requirement.

The retrofit difficulty factors used for this model are the same as that described for LNB above.

V. Selective Catalytic Reduction

The SCR model estimates the capital and operating cost for a system capable of removing 70 to 90 percent of the inlet NO_x emissions. Figure D-5 illustrates the input and results screen of the SCR model. As evidenced by the increased number of required inputs, the SCR has numerous factors which have significant impact on the capital cost. The scope of the SCR model includes ammonia storage, catalyst, reactor and ductwork, structural steel, foundations, control, and installation.

The model can accept either anhydrous or aqueous ammonia as the reagent. Flue gas flow is one of the most important factors in determining system cost. The flue gas volumetric flow is estimated using the EPA's fuel specific "f-factors".

The design and associated cost of an SCR system is sensitive to various components of the fuel. Ash concentrations and sulfur content of the fuel oil impact the catalyst pitch and activity of the catalyst formulation. For dual-fuel units, the time the unit spends burning fuel oil defines the design basis. For this model, it is assumed that if the unit fires fuel oil for less than 500 hours per year, then the use of catalyst formulated for natural gas can be used. However, if fuel oil is burned greater than 500 hours per year, then the SCR must be designed with fuel oil as the primary fuel. The SCR system of oil fired units include sootblowers, catalyst with a larger pitch (requiring greater volume to achieve the same reduction), and possibly less active formulation based on sulfur content of the fuel.

Another important input factor is the location of the reactor. The model can accommodate the SCR reactor in three locations: in-duct, stand-alone above the air heater, and stand-alone in some other location. The in-duct reactor is a design in which the catalyst is installed within the ductwork between the economizer outlet and air heater inlet. The stand-alone above the air heater is the traditional location for the SCR reactor and requires ductwork modifications and additions allowing the flue gas to be diverted from the economizer outlet into the reactor then back into the air heater. This location can be used for any catalyst volume as long as space is available for construction. The third location is included to allow the user to specify the location of the SCR reactor. If no space is available due to site constraints (such as the presence of a horizontal air heater), then the distance between the boiler and a potential reactor location can be input by the user.

The catalyst volume requirement is estimated based on flue gas flow, NO_x reduction required, sulfur and ash content of the fuel, and flue gas temperature.

Pressure drop across the SCR system is designed to be 3 inches (wg). While pressure drop is often a design variable, by "fixing" this value, the reactor size and catalyst volume can be estimated with fewer inputs required by the owner. The assumption was made that by using this relatively low increase in pressure drop, that no modifications to the existing I.D. or F.D. fans are required. If this margin is not available, then fan modifications must be added to the cost estimate by the user.

This model includes an algorithm for estimating the annual operating expenses (fixed and variable) of the SCR system. Ammonia, replacement catalyst, and energy are the variable costs that are estimated. Fixed costs of grid tuning (to ensure good distribution of ammonia within the flue gas) and maintenance materials are also included. The energy cost includes the fan motor horsepower required to overcome the additional pressure drop due to the SCR system.

A retrofit difficulty factor is incorporated into the model to account for various levels of construction access and balance of plant modifications. The difficulty levels are applied to the installation portion of the project, and are defined as follows:

Nominal:	Clear access for construction, unimpeded reactor and ductwork arrangement possible, adequate ID fan capabilities, no electrical system modifications.

Moderate:	Clear access for construction, difficult ductwork transition, moderate electrical system modifications.
Moderately Difficult:	Construction access impeded, some equipment relocations, extensive electrical modifications.
Difficult:	Construction access significantly impeded, extensive relocations, difficult ductwork transitions, extensive electrical modifications.

VI. Selective Non-Catalytic Reduction

The model used to estimate the capital and operating cost of SNCR systems was originally developed and described in *SNCR Feasibility & Economic Evaluation Guidelines for Fossil Fired Utility Boilers, EPRI TR-103885, Final Report*, May 1994. The model presented in the SNCR guideline was slightly modified for use in the similar hybrid guideline: *Hybrid Post-Combustion NO_x Control, Feasibility & Recommendations*, EPRI TR-105693, December, 1996.

The model is based on the type of reagent, with "high energy" defined as an ammonia-based system and "low-energy" as a urea-based system. Another significant factor is the use of wall-mounted injectors or lance-type injectors. The use of lance-type injectors can be a significant adder to the system price.

The scope of the model (see Figure D-6) includes injectors, reagent storage, compressors, and installation.

VII. Use of Spreadsheet Models

The models developed for estimating the capital cost of NO_x control technologies were developed using Lotus 123. The disk also contains an equivalent version of the file in Microsoft EXCEL format. These programs allow the use of "sheets" which are used to separate the technology alternatives and ease the use of the model. The use of this spreadsheet model assumes rudimentary knowledge in the use of Lotus 123 or EXCEL.

Two types of information are required to obtain a cost estimate: general and technology-specific. This spreadsheet is arranged such that the general information that is applicable to all technology alternatives is entered only once. Each technology has a separate sheet which defines the required input and presents the results of the cost estimate.

These inputs are sensitive to the units, so care must be taken to input the values in the units requested (lb/MBtu, °F, MW, etc.). In some cases, the required input is selected from a multiple choice format. For example, the General Input Sheet requires an input for fuel type: using the choices supplied, the user should enter "1" for gas, "2" for fuel oil, or "3" for units capable of both gas and oil.

Step 1: Open Spreadsheet. Users of Lotus 123 should open "EPRINOX.WK4" while users of EXCEL should open "EPRINOX.XLS." These files are protected with user entries allowed only in the input portion of the sheets.

Step 2: Go to the General Input sheet by clicking on the sheet tab labeled "General Input." Figure D-1 is a printout of this General Input sheet. Information regarding boiler size, fuel type, baseline NO_x emissions, desired NO_x emissions, and local construction wage rate is requested. The input for location of boiler (input as the two letter state abbreviation in capital letters) is to determine the default wage rate used for the installation portion of the cost estimate. This default value is based on recent state-wide averages of union labor. The user can input a different value if a more accurate wage rate is available.

Step 3: Go to the technology-specific sheet by clicking on the sheet tab labeled with the desired technology. Each sheet requests input that applies specifically to that technology. Figures D-2 through D-6 are printouts of the technology specific sheets. Each sheet has two parts: input and results. The results of the cost estimate are located directly below the input portion of the sheet. This cost estimate is in the form of a range of costs presented in dollars per kilowatt ($/kW) based on the unit size provided in the General Input sheet.

Note that the cost estimate changes immediately upon changes made to the inputs. This allows easy "what-if" analysis, so if specific information is not readily available, various input values can be entered to determine the impact on the cost estimate upon a wide range of possible values. However, care must be taken to ensure that the final cost estimate value reflect the desired input values. The SCR and SNCR sheets also include a third section for determining the operations and maintenance (O&M) costs of each technology. The user must supply the additional information regarding the cost of consumables (values are suggested if not known by user).

Step 4: Printing Results Table. Printing the results of each technology-specific sheet can be accomplished by clicking on the "PRINT" button located above the input portion of the table.

VIII. Assumptions

The following assumptions were used in the development of the cost estimate models.

A. Assumptions Applicable to All Models

1. Pressure correction will not be used in flue gas and overfire air flow rates due to small influence.

2. Flue gas flow rates will be based on EPA f-factors from 40 CFR 60 App. A Method 19 for gas & oil corrected to 3% O_2.

   Fw (gas) = 12,308 wscf/MBtu @ 68°F 1 atm
   Fw (oil) = 11,971 wscf/MBtu

   Temperature correction at full load will be used.

3. Density of flue gas: Gas: 30.03 mole/MBtu of fuel
   Oil: 31.78 mole/MBtu of fuel

   These values are based on combustion calculations

4. All metal plating shall be 1/4" carbon steel. All insulation shall be 4" mineral wool with aluminum lagging.

5. The wage rate tables included in the cost estimates are based on a Wage Rate Study performed by Black & Veatch which included composite union wage rates for various cities in the United States. The wage rates used in these cost estimates are weighted to primarily consist of Boilermakers.

B. Assumptions Applicable to Low NO_x Burner Model.

1. The existing FD fans have the static pressure capacity to accommodate the additional 2 to 5 in wg pressure drop through the new LNB.

2. The generator unit and all of the related auxiliaries are in good and safe operating condition.

3. The Low NO_x Burner cost estimate for tangential fired units is based on the installation of ABB-CE's LNCFS II type burner system.

4. The base LNB cost is based on typical wall fired gas burning natural gas. The cost includes the cost of limited support steel, flame scanners, wall tube panels, refractory, and other miscellaneous equipment associated with the burners.

Multipliers based on several factors affecting burner and burner related material costs are used to estimate the final LNB related material cost.

C. Assumptions Applicable to Overfire Air Model

1. Overfire air is included in the cost of the LNB conversion for all tangential fired units. This section is not to be used in conjunction with the LNB cost for tangential units.

2. Combustion air flow rates are based on the following ratio of lb air/lb fuel with 10% excess air.

   Ca(gas) = 810 lb air/MBtu
   Ca(oil) = 830 lb air/MBtu

3. Overfire air velocity through ductwork and OFA ports is 4000 ft/min (67 ft/s).

4. The mechanical costs calculated for the OFA include the costs of the ductwork, OFA ports, wall tube bends, dampers, and control (if not installed with LNB).

D. Assumptions Applicable to Flue Gas Recirculation Model

1. Flue gas volumetric flow rates are calculated using an economizer gas outlet temperature of 700 F. Variation from this temperature will not have a significant impact on system cost.

2. Flue gas velocity through FGR ductwork is 4000 ft/min (67 ft/s).

3. The mechanical costs include the cost of a new FGR booster fan, which takes suction off either and existing FGR (underbed) duct or from the economizer outlet, and discharges into the windbox(s). The mechanical cost also includes the cost of the FGR booster fan drive motor, ductwork and dampers, and a small allowance for foundation work.

E. Assumptions Applicable to SCR

1. Ammonia Purity: Anhydrous = 100%
   Aqueous = 29%

2. Stoichiometric Ratio = 1.0 mole NH_3 per mole NO_x remover
   (NH_3 slip will be calculated separately)

3. Allowable NH_3 Slip: Gas = 10 ppm @ 3% O_2
   Oil = 5 ppm @ 3% O_2

4. To simplify calculations, NH_3 slip will be converted to mass flow assuming % O_2 is close enough to 3% to not require specific correction to 3% O_2.

5. Ammonia storage system includes potential for delivery by either truck or rail. No additional rail system costs are included. Barge delivery system is not included.

6. Storage tank void volume:

   Anhydrous = 20% (15% required + 5% vaporizer protection)
   Aqueous = 10% (5% expansion + 5% vaporizer protection)

7. The O_2 correction basis for calculating inlet NO_x is 3%. Conversion from lb/MBtu to ppm @ 3% O_2 is done using the EPA method defined in 40 CFR 60 Appendix A Method 19.

8. Maximum allowable face velocity at catalyst is 26 ft/s (8 m/s). All "in-duct" reactors shall be considered "modified" duct reactors with only one layer and no room available for a spare.

9. Reactor housing will be rectangular, with the long walls being 1/2 the length of the short walls.

10. Sootblowers (when required) will be spaced at 10 foot intervals along the long side of the reactor. Sootblowers will use steam.

11. The ammonia injection grid will be installed upstream of the reactor (i.e. transition ductwork) and will not require space within the reactor.

12. Flue gas velocity through existing ductwork is 3600 ft/min (60 ft/s).

13. Transition to in-line reactors will be in both axis, with a transition angle of 45°.

14. Air Heaters: A minimum distance between the air heater inlet and boiler outlet will be identified for horizontal flow air heaters. If this distance is not available, the air heater will probably have to be moved. It may be possible to keep the air heater in place, but the ductwork layout, additional pressure drop, and retrofit difficulty are beyond the scope of this model. If moving the air heater is indicated, the cost of moving it is beyond the scope of this model. The model will still provide a cost, but the out-of-scope items will not be included.

OWNER INPUTS FOR UNIT INFORMATION					
Input Number	Item		Value	Options	Option Number
1	Unit Rating, MW (net)	Input =	350		
2	Unit Heat Rate (Btu/kWhr)	Input =	9,800		
	Heat Input to Steam Generator, MBtu/hr	Calc =	3,430		
3	Fuel Types	Input =	3	Gas Oil Gas/Oil	1 2 3
4	Existing NOx Emission, lb/MBtu	Input =	0.9		
5	Desired NOx Emission, lb/MBtu	Input =	0.2		
6	State (two letter abbreviation) Default Wage Rate	Input = Calc =	CA 54.6		
7a	Use Default Wage Rate	Input =	1	Yes No	1 2
7b	Optional Owner Input Wage Rate	Input =	50		
	Wage Rate Used for Cost Estimate	Calc =	54.6		

Figure D-1

OWNER INPUTS FOR LOW NOx BURNERS					
Input Number	Item		Input	Options	Option Number
1	Type of Firing System	Input =	3	Tangential Twin-Tangential Single Wall Opposed Wall Cell Fired	1 2 3 4 5
2	Number of Burners	Input =	12		
3	Type of Atomization, (if oil fired)	Input =	2	Steam Air Mechanical	1 2 3
4	Type of Existing Combustion Control System	Input =	2	Digital Analog Pneumatic	1 2 3
5	Does the existing control system have room for expansion *	Input =	1	Yes No	1 2
6	Type of Existing Burner Management System	Input =	1	Digital Analog	1 2
7	LNB Installation Difficulty	Input =	4	Nomimal Moderate Moderately Difficult Difficult	1 2 3 4

* Wall fired units typically require an additional 5 to 8 inputs and outputs to the combustion control system per burner. In addition to the I/O, 4 to 8 manual-auto stations will be required.
Tangential units typically require an additional 30 to 50 inputs and outputs to the combustion control system and 8 to 12 manual-auto stations.

LNB SYSTEM CAPITAL COST ESTIMATE ($/kW): 13.3 to 17.9

CONTROL SYSTEM MODIFICATION COSTS ($/kW): 1.2 to 1.5

Figure D-2

OWNER INPUTS FOR OVERFIRE AIR					
Input Number	Item		Input	Options	Option Number
1	Is OFA part of a LNB retrofit?	Input =	1	Yes No	1 2
2	Total Number of Burner columns	Input =	8		
3	OFA Installation Difficulty	Input =	4	Nomimal Moderate Moderately Difficult Difficult	1 2 3 4
4	Number of OFA ports, #	Input =	10	Suggested	10

OFA SYSTEM CAPITAL COST ESTIMATE ($/kW):	**6.0**	**to**	**8.0**

Figure D-3

OWNER INPUTS FOR FLUE GAS RECIRCULATION					
Input Number	Item		Input	Options	Option Number
1	Is FGR part of a LNB retrofit?	Input =	1	Yes No	1 2
2	Does the unit have underbed FGR	Input =	2	Yes No	1 2
3	Distance from existing FGR duct to location of new FGR booster fan, ft	Input =	100		
4	Distance from new FGR booster fan location to windbox, ft	Input =	100		
5	FGR Installation Difficulty	Input =	3	Nomimal Moderate Moderately Difficult Difficult	1 2 3 4

FGR SYSTEM CAPITAL COST ESTIMATE ($/kW):	**8.7 to 11.6**

Figure D-4

OWNER INPUTS FOR SCR					
Input Number	Item		Input	Options	Option Number
1	Type of Fuel Hours of Oil Firing (for SCR purposes, firing more than 500 h/yr of oil defines the unit as an oil fired unit.)	Input =	Gas/Oil 1	0 - 500 Over 500	1 2
2	Type of Ammonia	Input =	2	Anhydrous Aqueous (29%)	1 2
3	Number of Days Of Ammonia Storage	Input =	30		
4	Economizer Outlet Temperature at Full Load, °F	Input =	700		
5	Percent Ash in Oil, %	Input =	0.5		
6	Percent Sulfur in Oil	Input =	0.2		
7	Type of Reactor Calculated Number of Required Layers=	Input= 1	1	Stand Alone In-Line	1 2
8	Reactor Location (Stand-Alone Reactor Only) The value in the Input column does not apply to this reactor location.	Input =	1 100	Above Air Heater All Other Locations	1 2
9	SCR Installation Difficulty	Input =	3	Nomimal Moderate Moderately Difficult Difficult	1 2 3 4

SCR SYSTEM CAPITAL COST ESTIMATE ($/kW): 12.3 to 16.5

SCR Operating Cost.

If the operating cost for the SCR system is desired, please input the following information:

Item		Input	Suggested Value
Capacity Factor, %	Input =	70	
Ammonia Cost, $/ton delivered (If unknown, use suggested values)	Input =	400	Anhydrous = 210-275 $/ton Aqueous* = 300-425 $/ton
Energy Cost, $/kWh (If unknown, use suggested value)	Input =	0.06	Energy cost = 0.06 $/kWh

ANNUAL COSTS	
OPERATIONS AND MAINTENANCE COST	
Ammonia	1,110,000
Grid Tuning & Ammonia SlipTesting	30,000
Catalyst	78,000
Energy**	2,542,000
Maintenance Material	41,000
ANNUAL O&M COST (1997 Dollars)	3,801,000

* : Aqueous ammonia price based on "contained" ammonia (1 ton ammonia requires 3.45 tons of solution)

**: Energy cost includes ammonia vaporization and differential fan energy.

Figure D-5

OWNER INPUTS FOR SNCR

Input Number	Item		Input	Options	Option Number
1	Select Reagent for SNCR System Low Energy = Urea-based system High Energy = Ammonia Based System	Input =	1	Urea Anhydrous Aqueous (29%)	1 2 3
2	Stoichiometric Ratio Note: Stoichiometric ratio is defined as the moles of nitrogen injected per mole of NOx at SNCR inlet.	Input =	1.75	Suggested Value: Ammonia-based Systems: 1.4 Urea-based Systems: 1.75 NOTE: enter a value between 0.5 and 4.0	
3	Number of Wall Injector Levels	Input =	2	Suggested Value: Baseload Units = 2 layers Load Following = 3 or 4 layers NOTE: enter a whole number between 0 and 5	
4	Number of Lance-Type Injector Levels	Input =	1	Suggested Value: Units > 100 MW and NOx reduction > 25% should have at least one layer of lance-type injectors. NOTE: enter a whole number between 0 and 5	

SNCR CAPITAL COST ESTIMATE ($/kW): 12.0 to 16.0

SNCR Operating Cost.
If the operating cost for the SNCR system is desired, please input the following information:

Item		Input	Suggested Value
Capacity Factor, %	Input =	70	
Reagent Purchase Price, $/dry ton reagent (If unknown, use suggested values)	Input =	315	Urea = 280-360 $/ton Anhydrous = 210-275 $/ton Aqueous = 300-425 $/ton
Water Price, $/1000 gal	Input =	0.6	0.6 $/1000 gallons
Fuel Cost, $/MBtu (If unknown, use suggested value)	Input =	2.50	Gas Cost = 2.50 $/MBtu Oil Cost = 1.80 $/MBtu

ANNUAL COSTS	
OPERATIONS AND MAINTENANCE COST	
Urea (Low Energy)	3,443,500
Compressor Energy (Low Energy)	9,400
Vaporization of Aqueous Urea Solution	315,800
Dilution Water for Aqueous Urea Solution	14,000
Maintenance Labor & Material	104,600
ANNUAL O&M COST (1997 Dollars)	3,887,300

*: Energy cost includes ammonia vaporization and differential fan energy.

Figure D-6

E

NO_x UNITS OF MEASUREMENT AND CONVERSION FACTORS

Common units of measurement used in expressing NO_x concentrations in flue gas and NO_x emission rates from boilers are:

- Volumetric parts per million (ppm) in flue gas on a dry basis, corrected to standard excess air (3% O_2) dilution, commonly **"ppm (dry, corrected to 3% O_2)"** or **"ppmc"**[3]
- Mass of NO_x, expressed as NO_2, emitted per million Btu input to the unit (based on higher heating value of fuel), **lb/MBtu**
- Mass of NO_x, expressed as NO_2, emitted per net megaWatt-hour produced, **lb/MWh$_{net}$**

Equivalent Standard International (SI) units and conversion factors are:

Common Units	SI Units	Conversion Factor (multiply common units by)
ppmc	mmol/kmol	1.0000
lb/MBtu	g/MJ	0.4299
lb/MWh$_{net}$	kg/MWh$_{net}$	0.4536

The following are useful formulas to convert units between the three methods of expressing NO_x:

- lb/MBtu = ppmc/F_e
- lb/MWh$_{net}$ = lb/MBtu x HR_{net}/1000

[3] The practice of correcting to 3% O_2 excess air dilution has become so common that the term "ppm" used alone sometimes indicates corrected NO_x.

Where F_e = Emission Factor (typical values are: 832 for natural gas and 759 for residual or No. 6 fuel oil)[4]

HR_{net} = Net heat rate, Btu/kWh

Since NO_x and/or O_2 may be measured on a wet basis and in flue gas having an O_2 concentration different than 3%, the following formulas are useful to convert to a dry basis at 3% O_2:

- NO_x ppm (dry) = NO_x ppm (wet) / (1 - F_m)
- O_2 % (dry) = O_2 % (wet) / (1 - F_m)
- ppmc = ppm (dry) x (20.9 - 3.0) / (20.9 - % O_2 [dry])

Where F_m = volumetric fraction moisture (H_2O) in flue gas

[4] The exact value depends on the fuel composition and heating value and can be calculated using formulas available in "U.S. EPA Reference Methods", *The U.S. Code of Federal Regulations*, Title 40, Part 60.

F

COMMERCIALLY AVAILABLE LOW-NO$_X$ BURNERS

Table F-1
Summary of Commercially Available Low-NO$_x$ Burners for Gas- and Oil-Fired Units (continued)

Vendor	Burner Name	Burner Type	Primary Retrofit Purpose	Air Register Type	Oil Atomizers Supplied	Gas Injector Design	Other Design Features	Utility Retrofit Experience
ABB-Combustion Engineering	LNBFS	Tangential	Low-NO$_x$	Close-Coupled Overfire Air	Steam or Mechanical	Gas Nozzles	Separated Overfire Air, Integral FGR Optional	Four 185-MW and four 387-MW boilers at Long Island Lighting Company
	RSFC	Wall	Low-NO$_x$	Triple Air Zone	Steam	Central Gas Gun	Total and Zone air flow adjustment	None to date
AUS Combustion	AUS-5000	Circular	Low-NO$_x$	Single Venturi with Slide-Type Shut Off Damper	Steam or Mechanical	Removable Poker/Spuds and/or Center Gun	Air Flow Measurement	480-MW boilers at Southern California Edison; 2x572- and 1x550-MW boilers at Commonwealth Edison Company; 20-MW and 44-MW boilers at City of Glendale CA, 20-MW, 30-MW, and 44-MW boilers at City of Burbank CA
	AUS-DFL	Circular	Low-NO$_x$	Dual Air Zones with Slide-Type Shut Off Damper	Steam	Removable Poker/Spuds or Center Gun		1276-MW industrial and utility applications overseas
Babcock & Wilcox	XCL-S	Circular	Low-NO$_x$	Axial Flow with Slide-Type Damper	Steam (Preferred)	Removable, Adjustable Spuds	Air Flow Measurement	215-MW boiler at Southern California Edison, two 359-MW and two 812-MW boilers at Pacific Gas & Electric, two 380-MW boilers at Boston Edison(all were older "type S" burners)
Coen Company	DAF	Circular	Low-NO$_x$	Dual Air Zone with Adjustable Spin Louvers, Air Ratio Controller, and Sliding Shut Off Damper	Steam	Removable Cane/Spuds or Fixed Spuds on Internal Manifold	Integral FGR Option	No utility applications to date; industrial boiler installations
	CPF-LN	Circular	Low Excess Air and Low-NO$_x$	Dual Zone Axial Flow with Shut Off Damper	Steam	Removable Cane/Spuds or Fixed Spuds on Internal Manifold	Air Flow Measurement	No utility applications to date; industrial boiler installations
	CPF-HTE	Circular	Low-NO$_x$, Low Excess Air, and Low Pressure Drop	Venturi Shaped Parallel Flow Design	Steam	Adjustable, Removable Spuds	Air Flow Measurement, Slide Damper for Air Balancing	One utility retrofit in progress overseas

Table F-1
Summary of Commercially Available Low-NO_x Burners for Gas- and Oil-Fired Units (continued)

Vendor	Burner Name	Burner Type	Primary Retrofit Purpose	Air Register Type	Oil Atomizers Supplied	Gas Injector Design	Other Design Features	Utility Retrofit Experience
	QLN	Circular	Low NO_x without FGR Ultra Low-NO_x on Gas with FGR	Segmented Axial Flow	Steam	Adjustable, Removable Spuds	Air Flow Measurement, Slide Damper for Air Balancing	Two retrofits on large industrial boilers
Damper Design		Circular	Mechanical Upgrade; Performance Improvement	Tangential Inlet Air-Distribution Scroll with Fixed Internal Vanes	Existing or Supplied by Others	Existing or Supplied by Others; Center Injector for Low-NO_x Applications		No utility applications to date; industrial boiler installations
DB Riley	STS	Circular	Low-NO_x	Dual Zone, with Separate Louver-Type Vanes and Sliding Dampers for Zonal Biasing and Total Shut Off	Steam	Gas Lances	Relative Air Flow Measurement Device	638-MW boiler at Consumers Power Company, two 560-MW boilers at Com Electric
Forney International	IFGR	Circular	Low-NO_x	Axial Flow with Slide-Type Shut Off Damper	Steam or Mechanical	Removable Cane/Spuds	Total Burner Air Flow Adjustment	No utility applications to date, industrial boiler installations
International Combustion Ltd.	RoBTAS	Circular	Low-NO_x	Dual Air Zone with Outer Air Directed Off-Axis and Slide-Type Shut Off Dampers	Steam or Mechanical	Inner and Outer Gas, with Outer Gas Directed Off-Axis		2x800-MW boilers at Florida Power & Light; 500-MW boiler at Jacksonville Electric Authority
	TAS	Tangential	Low-NO_x	Air Nozzle Tilt Drives Altered to Tier Air Away from Fuel				185-MW boiler at Long Island Lighting Company
John Zink Company	AVC	Circular	Low-NO_x	Dual Air Register Assembly with Slide-Type Shut Off Damper	Steam (Preferred)	Externally Removable Lances or Fixed Injectors; Internal Manifold	Burner Air Ports for Combustion Staging Optional	No utility applications to date; industrial boiler installations
Pillard	GRC LNO/LNG	Circular	Low-NO_x on Oil and Gas; Ultra Low-NO_x on Gas with FGR	Perforated Sleeve	Steam or Air	Tubes and Spuds	Pressure Sensors To Balance Flows to Burners	No utility applications to date, industrial boiler installations
Rodenhuis & Verloop	Verloop	Circular	Low Excess Air, Low-NO_x	Axial Flow with Slide-Type Shut Off Damper	Externally Air Atomized, Low Pressure Oil Injector	Center Gun, Integral with Oil Injector	Atomizing Air Supplied by Dedicated Fan	2x440-MW boilers at New England Power; 60-MW to 250-MW overseas
Todd Combustion	Dynaswirl-LN	Circular	Low-NO_x	Dual Air Zone Venturi with Slide-Type Shut Off Damper	Steam (Preferred)	Removable Poker/Spuds and/or Center Gun	Air Flow Measurement	45-MW, 480-MW, and 2x750-MW boilers at Southern California Edison; 4x400-MW and 2x310-MW and 2x240-MW boilers at Florida Power & Light; 150-MW and 380-MW boilers at Con-Edison of NY; 440-MW boiler at Delmarva Power & Light; 62-MW and 75-MW boilers at PacifiCorp

Table F-1
Summary of Commercially Available Low-NO_x Burners for Gas- and Oil-Fired Units (continued)

Vendor	Burner Name	Burner Type	Primary Retrofit Purpose	Air Register Type	Oil Atomizers Supplied	Gas Injector Design	Other Design Features	Utility Retrofit Experience
	RMB	Circular	Ultra Low-NO_x on Gas with FGR	Dual, Parallel Flow Registers; On/Off Air Slide	Steam or Mechanical	Via Drilled Radial Vanes in Throat	Relatively Short Flame; Stable at Very High FGR	No utility applications to date, industrial boiler installations

G

GLOSSARY

This glossary defines many terms that are frequently used in discussing NO_x control technologies that may not be familiar to some readers. It does not, however, attempt to define all technical terms used in the document.

All-Burners-in-Service (ABIS)	Normal operation of the boiler with fuel and air to all burners.
Ammonia (NH_3)	Chemical reagent used in SNCR and SCR systems.
Ammonia Slip	Unreacted ammonia exiting an SNCR or SCR reaction zone.
Anhydrous Ammonia	Essentially pure ammonia (i.e., not as a water solution).
Aqueous Ammonia	Ammonia dissolved in water, typically supplied at approximately 30 % (wt.) ammonia in water.
Atomizers	Oil fuel injectors, designed to atomize oil into fine droplets.
Baseline	Refers to boiler conditions and performance prior to retrofit of NO_x control technology.
BMS	Burner management system.
Burners-Out-of-Service (BOOS)	Operation with some burners on air-only. Lowest-cost method of implementing off-stoichiometric combustion.
Carbon Monoxide (CO)	Gaseous pollutant.
CAT-AH System	See “Catalytic Air Heater”.
Catalytic Air Heater	Version of SCR in which air heater elements are replaced with elements coated with SCR catalyst. Also called CAT-AH system.
CFD	Computational fluid dynamics

Close-Coupled Overfire Air (CCOFA)	Version of OFA used on tangential-fired boilers in which OFA ports are incorporated at the top of the main windbox.
Combustion Modifications	NO_x control technologies that affect the combustion zone of the boiler.
Controlled Emission Rate	Post-retrofit NO_x performance of boiler.
Conventional SCR System	SCR system supplied as a separate reactor requiring new duct work to connect to boiler system.
Excess Air	Amount of air supplied to furnace in excess of that theoretically required for combustion. Often monitored as excess O_2 in flue gas. Not necessarily equal to boiler-exit or stack O_2, either of which may include effects of air in-leakage downstream of furnace.
Excess O_2	See "Excess Air".
Flue Gas Recirculation (FGR)	Recirculation of flue gas from the boiler exit to the windbox or directly to the furnace. In this document, "FGR" indicates recirculation to the windbox (also called WBFGR) unless stated otherwise.
Hybrid Post Combustion NO_x Control	Combination of SNCR and SCR in which unreacted ammonia and NO_x exiting SNCR reaction zone further react in SCR reactor located downstream. May include supplemental ammonia injection to SCR reactor.
In-Duct SCR System	SCR system designed to be installed in existing duct work, typically requiring enlargement of existing duct.
Induced Flue Gas Recirculation (IFGR)	Low-cost version of FGR in which a limited amount of FGR can be achieved by using excess FD fan capability to induce flue gas into combustion air.
lb/MBtu	Units used to express NO_x level at which boiler operates (see Appendix E).
lb/MWh$_{net}$	Units used to express NO_x level at which boiler operates (see Appendix E).
LN-REACH	See REACH

Low Excess Air (LEA)	Reduction of excess air required to fire the boiler to minimum level consistent with good operation. Reduces NO_x formation. May involve minor adjustments/modifications to equipment and or operation.
Low-NO_x Burner (LNB)	Replacement burner designed for lower NO_x emission performance than older burners.
MCR	Maximum continuous rating--nameplate power production capability of a generating unit.
New Source Performance Standards (NSPS)	Air pollution regulations taking effect in 1971, affecting only new boilers. Boilers commissioned after the NSPS effective date frequently have more generous furnace sizes for lower NO_x.
Nitrous Oxide (N_2O)	Gaseous pollutant.
Normalized Stoichiometric Ratio (NSR)	Ratio of reactive nitrogen (NH_x) added to SNCR or SCR system to amount theoretically required to react with NO in flue gas.
Off-Stoichiometric (O/S) Combustion	Creation of fuel-rich and fuel-lean combustion zones by modified placement of air and/or fuel, i.e., BOOS (or fuel biasing) and/or OFA.
Opacity	Extent to which flue gas exiting boiler is visible. Related to particulate matter in flue gas; usually associated with oil firing.
Opposed Fired Boilers	Wall-fired boilers with burners on two opposite walls.
Overfire Air (OFA)	Diversion of a portion of the combustion air to ports above the burners. Method of off-stoichiometric combustion.
Particulate Emissions	Ash and unburned carbon in flue gas from oil firing.
Parts Per Million (ppm)	Units used to express concentration of trace species, including NO_x, in flue gas. Frequently corrected to 3% flue gas O_2 (see Appendix E).
REACH	Reduced Emissions and Advanced Combustion Hardware. Burner modification technology to reduce opacity and particulate emissions on oil (CP-REACH) and/or NO_x emissions (LN-REACH, Gas-REACH)

Reburning	Method of NO_x reduction in which fuel and air are diverted from main burner zone to create fuel-rich zone above burners followed by air-rich burnout zone at top of furnace.
Selective Catalytic Reduction (SCR)	Method of NO_x reduction in which ammonia is mixed with flue gas and mixture is passed through catalyst bed, where ammonia converts NO_x to N_2.
Selective Non-Catalytic Reduction (SNCR)	Method of NO_x reduction in which a reagent, usually ammonia or urea, is mixed with flue gas within a critical temperature window in which the reagent converts NO_x to N_2.
Separated Overfire Air (SOFA)	Version of OFA used on tangential-fired boilers in which OFA ports utilize a separate windbox located above the main windbox.
Single Wall-Fired Boilers	Wall-fired boilers with burners arranged on one wall. Also called face fired, front fired, rear fired, etc.
Space Velocity	Volumetric rate of flue gas processed divided by superficial reactor volume (i.e., inverse residence time).
Staged Combustion	More gradual combustion, achieved by delaying mixing of fuel and air.
Tangential-Fired Boilers	Boilers equipped with columns of burners on four walls or in corners, with fuel and air injection oriented tangential to furnace center axis to create swirling fire ball.
Tuning	Minor adjustments/modifications of equipment and/or operating procedures to reduce NO_x emissions without significant capital cost.
Ultra Low-NO_x Burner (ULNB)	Replacement burner designed to achieve extremely low NO_x, in the 10-20 ppm range.
Urea ($CO[NH_2]_2$)	Chemical reagent used in SNCR systems (decomposes to ammonia in reaction zone).
Wall-Fired Boilers	Boilers equipped with circular burners arranged on one or more firing walls.