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EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control

Book 1: Tuesday, May 16, 1995
Sessions 1, 2, 3

Sponsored by
Electric Power Research Institute
Generation Group
Air Quality Control Program

U.S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Combustion Research Branch

May 16–19, 1995
Hyatt Regency Crown Center
Kansas City, Missouri

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Generation Group

U.S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory

Session 1
Plenary

EPA Regulatory Update on Group 2 Phase II

P. Psirigotis
US EPA

Paper unavailable at time of printing. Please check the late paper table in the registration area for a copy or contact the speaker directly.

Status of EPA Regulatory Development Program for Revised NO_X New Source Performance Standards for Utility and Nonutility Units – Performance and Costs of Control Options

A. Miller
US EPA

Paper unavailable at time of printing. Please check the late paper table in the registration area for a copy or contact the speaker directly.

Phase II Positioning, Evaluating Phase II Alternatives Before the Regulations Are Issued

Presented at EPRI's Joint Symposium on Stationary Combustion NO_x Control, May 16-19,1995

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ABSTRACT

Analyzing air emission reduction compliance options in today's business climate requires an in-depth look at all alternatives in order to satisfy the diversity of interests of all involved parties. The need to provide low cost power to the grid while meeting emission reduction regulations, presents a wide array of financial and managerial decision scenarios. Although, the Draft Phase II NO_X regulations won't be published for some time, long term strategies can be evaluated now with a software tool like the CAT Workstation™. The CAT Workstation™ can help the long range planners/compliance teams begin to sort out and evaluate options. This paper will present some examples of evaluating some of these options, such as the impact meeting lower future limits after reaching the initial limits proposed, or a determination of the cost effectiveness of emission averaging versus the risks imposed. The CAT Workstation™ can evaluate multiple-overlapping emission averaging bubbles. Furthermore, some technologies reduce more than one pollutant and thus the need to evaluate the total environmental value that a technology offers is important.

Many of the older Phase II units may be subject to significant BOP impact costs due to the addition of SO_2 and/or NO_X Reduction Technologies. The CAT Workstation™ was designed to levelize the costs of operating technologies so that comparison of those capital cost intensive technologies can be made to those competing technologies that have higher O&M costs but low initial costs. The CAT Workstation™ can help the Compliance Team decide if these modifications or other more cost effective solutions should be implemented. Additional options may include shutdown, or over control of larger Units? By using the emission bubble feature and setting different limits, the program will develop the least-cost approach for meeting each lower limit. Therefore, one can model a given system to analyze the impact of future regulations.

INTRODUCTION

Reducing air emissions for fossil power plants, as mandated by the U.S. Environmental Protection Agency (EPA) under Title I and Title IV of the 1990 Clean Air Act Amendments (CAAA), can be accomplished by one of several selected technologies. However, the decision on how to most cost-effectively reach these new emission limits on a specific utility system involves an extensive and time consuming analysis. As an addition to the Clean Air Technology (CAT) Workstation™, cofunded by Sargent & Lundy (S&L) and the Electric Power Research Institute (EPRI), a tool has been developed which aids utilities in the analysis of system-wide NO_X and/or SO_2 air emission control strategies and cost optimization.

The CAT Workstation™ enables the user to develop least-cost emission reduction strategies for each emission reduction technology considered at every unit. In addition, input data from EPRI technology support programs can be used to provide performance and cost data to the CAT Workstation if such data is otherwise unavailable.

The application of CAT's Mixed-Integer Linear Programming (MILP) allows quick determination of the least-cost emission compliance plan while considering all possible unit/technology/fuel combinations for the time periods specified.

The user can conduct rapid sensitivity runs on such input variables as emission reduction technology performance and associated capital and operating cost, fuel cost, and several different escalation factors. In areas where targeted emission limits have not been set or when speculating on future (CAAA Phase II) reduction requirements, the program can be used to develop the estimated compliance strategies and costs to meet various emission limits under consideration by Federal or local agencies. Thus allowing the long range planning and compliance strategy development now to minimize any "surprises" due to possible future regulations..

The use of the CAT Workstation™ does not change the compliance planning process but provides a powerful software tool to compliment the utility's planning process. The elapsed time and man-hours required to identify the possible unit/technology/fuel solutions for each unit is greatly reduced. Therefore, utilities may focus their efforts on the impact of the most promising candidate technologies and investigate the pros and cons of emission banking and trading allowances, with respect to developing an overall compliance strategy.

Version 2.0 of the CAT Workstation™ was released in November 1994 by EPRI's software distribution center. Over 65 copies have been released to EPRI members and are in various stages of using the software.

CAT WORKSTATION

The CAT Workstation™ is a tool used to determine the most economical and reasonable methods of system-wide SO_2 and/or NO_X emission reduction strategies. It allows both actual and theoretical technologies to be evaluated and enables users to create detailed configurations of unit/technology/fuel combinations for each unit as needed. Many power plant units and strategies can be evaluated at once while considering all necessary dependencies. Period-dependent variables are factored into all evaluations, including economic parameters, unit capacity factors, emission constraints, and projected emission allowance values. The Workstation™ then outputs a ranked list of optimal technology-fuel combinations for each unit by time period, along with the number of allowances to buy or sell in each period. The program also provides an emission bubbling (or emission averaging) capability which allows the user to evaluate the cost effectiveness of adding emission reduction technologies to older, low capacity factor units versus a greater incremental emission reduction at larger, higher capacity factor units.

The technical objectives of the CAT Workstation™ are to take maximum advantage of existing EPRI R&D results and information on SO_2 and NO_X reduction technologies and to aid the utility industry in determining the best emission reduction strategies by:

- consolidating existing, relevant information from previous EPRI R&D projects into a single computer-based source (i.e., the CAT Workstation™)

- providing a means for utility users to quickly identify the appropriate emission reduction technologies for their specific requirements through a technical screening and then to evaluate these selected technologies on an economic basis

- providing an effective means of technology transfer through an easy-to-learn, easy-to-use graphical user interface to the workstation software

After the unit/technology/fuel combinations have been identified and the emission limits established, a selected number of the lowest cost scenarios are identified by the CAT Workstation™ using the MILP process. MILP is a mathematical optimization method that uses linear programming techniques for solution variables that are restricted to integer values. This involves an iterative search algorithm that has been refined by mathematicians over the past several decades. Large problems (e.g., many units, technology, fuel options, and/or time periods), which ordinarily take hours or days to solve on the computer by explicit enumeration, can be solved in minutes.

The intended function of using an MILP formulation for the CAT economic analysis is to minimize the system-wide life-cycle cost of compliance, subject to the constraints of allowable emissions per period and other restrictions. The output of this formulation includes the optimal technology-fuel combination for each unit and period, and the number of allowances to buy or sell in each period.

The user can have the program identify up to the top 50 least-cost scenarios, which help identify a set of technologies that may be more practical to retrofit, yet within 1 or 2% of the initial least-cost scenario.

Hardware and Software Requirements

The CAT Workstation™ will operate on any PC capable of running the Microsoft Windows 3.1 operating system in the enhanced mode. The following list is considered the minimum hardware configuration:

- a minimum 486DX/33 with math co-processor, Pentium, P-5,60 or better is recommended
- at least 8 MB RAM
- a 4 MB RAM driver or greater
- a hard drive with 10 MB available
- Microsoft Windows-compatible Super-VGA color monitor
- Microsoft Windows-compatible pointing device (mouse)
- Microsoft Windows-compatible printer

COMPLIANCE PLANNING - PROJECT SETUP

The simplest method of demonstrating the setup of the CAT Workstation™ for compliance planning is to walk-through a project. The emission reduction study process begins with the collection of the data necessary to complete the analysis.
The data required for the Workstation™ is the same that compliance teams are and have been gathering in the past with regards to information on their units, fuels, system economics, and technologies being considered for each unit. Utility-specific data is entered into the Workstation™ through the following database management screens:

- Project Setup
- Utility Economic Database
- Fuel Database
- Unit Database
- Evaluation Inputs determination
- Technology Costs
- Emission Bubbles to be considered

In the Project Setup screen the users identifies the units, fuels, and technologies applicable to the proposed project. Figure 1 illustrates the project setup screen for the case study.

The utility Economic screen identifies basic financial data for the user's system such as base year, discount rate, escalation rates, allowance prices if any, and CAAA periods. Figure 2 illustrates the utility economic database input screen. Four load profile input boxes have been added for the purpose of modeling the unit operating characteristics such as seasonal peaking demands and lower load operation in the off-peak season.

Fuel information is incorporated into the database through the fuel screen, where user-defined coal, oil, or gas fuels or fuel blends can be created. The CAT Workstation™ will generate the appropriate fuel blend properties and costs by using a weighted average of the base fuel information. If the actual fuel blend properties are known, they can be entered. The fuel database input screen is shown in Figure 3.

Due to the large quantity of information, several input screens are utilized. There are three screens for the unit information entries for unit capacity factor, heat rate, and basic data such as unit size and boiler efficiency. Figures 4, 5, and 6 illustrate the input screens for a unit of the case study.

The unit load or capacity factor data, shown in Figure 5, can be entered as either a unit average for each load profile/time period combination or a plot of capacity factor versus time of day. Typically, a utility would use an average value for initial screening runs and proceed with more precise data, if available or necessary, when the field of alternatives has been narrowed and final optimization is taking place.

The same methodology may also be used for the unit heat rate data. The unit heat rate can be entered as either a yearly average type value or as a function of unit load. The new screen is shown in Figure 6.

The emission bubble screen is used to identify the emission limit constraints for the system and is based on the compliance team's review of pending regulations. This function allows a utility to identify the pollutant, units, and time period included in the emission bubble. Multiple emission bubbles can be created to properly define the utility's emissions requirements. For this example, a combined SO_2 /NO_x bubble has been created. Figures 8 and 9 illustrate the input screens and database for the emission bubbles database.

The evaluation input screen is used to establish the various unit/technology/fuel combinations to be analyzed in the proposed study. The CAT Workstation™ can accommodate any number of combinations. Figure 10 illustrates the evaluation input screen.

The final data entry involves the costs (Capital and O&M) and performance for each technology at each unit. This screen captures all the applicable technology information that is usually developed by outside studies. This data can now be gathered and consolidated in one area for analysis on a total life-cycle least-cost basis specific to the utility's system characteristics. Figure 10 illustrates the Evaluation input screen.

After the databases are input into the CAT Workstation™ and the base analysis is performed, the tool becomes quite effective in assisting a utility in determining the most prudent technology choices. This is particularly true when analyzing the banking and trading of allowances. Sensitivity runs, which help identify the boundary limits of given technologies, can be performed to bracket risk for both current and future regulatory needs. Judgments concerning the suitability of including low capacity factor units in the analysis can also be easily tested and confirmed. Examples of the types of sensitivity analyses to perform would be to change fuel cost escalation, change the discount rate, vary capital costs for technologies, and emission reduction performance.

Figures 11 and 12 show the results of one economic analysis and identify the least-cost technology/fuel combination for each unit and shows the emission rate for each unit after control. Additional data is available through using the drop-down menu for Reports and choosing the Economic Analysis Reports.

COMPLIANCE PLANNING EMISSION LIMIT EVALUATION

Although the system used in the case study consists of multiple coal fired fossil units, CAT is also capable of handling oil and gas fired units. One of the first things a compliance team should determine is the "mix" of technologies needed to achieve lower emission limits. For example, if the system meets phase I limits today how does it achieve phase II and beyond proposed limits in the most cost-effective way? The first step of the case study involved running several iterations of the CAT model with the NO_X emission target varying from 0.25 to 0.5 lb/mmBtu and place all the units in the emission bubble. In this example, six iterations of the computation were performed. The costs for the six cases are illustrated on Figure 13.

This data is important since it identifies the estimated least-cost technologies for various emission limits under consideration by the regulatory agencies. It is anticipated that this data would be used to demonstrate the cost of compliance once emission limits are established. Other features of CAT allow the user to investigate what-if scenarios with regards to banking and/or trading allowances. For this case study, obtaining system NO_X emissions below 0.25 lb/mmBtu becomes quite costly. It should be noted that for this case study the baseline unit NO_X emission rates are relatively low and therefore, the cost of emission reduction for the other utility systems may be much higher. This information is useful to the utility internally as well as externally. It may be useful in working with the regulatory bodies who will ultimately determine the NO_X permit requirements for the system.

One of the points on this chart illustrates the effect of over-control by a deep reduction technology on only one unit. This is the triangular point, and shows that the present value costs of this technology are higher than the true least-cost to obtain an emission rate of 0.5 lb/mmBtu and the system average is nowhere near the first target bubble limit.

Also shown on this chart is an overlay of some of the second, third, and fourth least-cost options at an emission limit. These are the circular points just above the optimized curve. Some of these alternatives may either be :

- more practical to install

- allow for add-on technologies for future emission reductions

- provide additional emission reduction for very little cost and also provide a slight degree of margin

- indicate that a unit with a turbine overall outage coming up to be "cost-effective"

While there is a lot shown on this chart it illustrates the type of system analysis that can be performed.

Although not demonstrated as part of this case study, the next logical step in the system-wide compliance analysis would be to evaluate the pros and cons of emission banking, trading, and purchasing options.

The case study shows that the command and control of each unit has a higher initial cost and impact on outage schedules for retrofits. On the other hand, if bubbling is allowed, then there is a reduction in initial capital cost expenditures, and the funds can be spent on the higher capacity factor units. Although bubbling initially has a lower cost, there may be an added administrative burden. Sensitivity runs should be performed to determine the impact of losing one of these larger units with emission control equipment and using banked allowances or generating higher levels of NO_X removal on other units.

While this is only one of many analyses that should be performed to develop a compliance strategy, it does illustrate the economic advantage of emission bubbling believed achievable on all systems. The bubbling concept is shown to be more cost effective since fewer units are modified. This also has an impact on outage planning so that fewer units need to be taken off-line or planned outages extended for emission reduction modifications. As shown in Figure 14, Unit 1's cost per ton of NO_X reduced is not in proportion to the other units, since Unit 1 is one of the smaller, older units in the system and is dispatched on a less arduous basis. Therefore, capital expenditures on older units, primarily used for seasonal peaking duty, could perhaps be eliminated. Furthermore, some states still require Prevention of Significant Deterioration (PSD) permits, if LNB's are added to a unit. This is over and above the CAAA provision for exemption.

COMPLIANCE PLANNING OTHER ISSUES

There is a wide range of questions and concerns facing the Compliance Planning Teams, some of which are geographically unique to just a few systems, others which are more universal. This section lists some of these issues that have been addressed by having used the Workstation™ on compliance studies and/or answered questions from users on how to setup the Workstation™ to handle a specific case.

1. What technologies need to be installed to achieve one emission limit for five months of the year (i.e. ; ozone season) and then meet another limit for the remaining seven months. What if the largest unit has a forced outage during this "ozone" season, how do the rest of the units need to be operated to maintain the seasonal emission limit.

2. If the use of a technology on one unit to control one pollutant increases the other pollutant slightly, what's the more cost-effective strategy? Should the utility control another unit's emission rate, or install an additional technology at the first unit?

3. If future emission reductions are required, will the technologies installed today be effective are need to be replaced? Thus from a system standpoint, is there a more appropriate technology to install now to position the utility for the future?

4. Many older units will most likely incurred significant BOP costs associated with adding certain technologies. In these cases, some low capital cost modifications may be more appropriate for these older units. One then needs to consider what happens when these units are brought on line in an emergency or to sell power on a spot basis.

5. Is seasonal fuel switching to a cheaper fuel, which causes some load restrictions, but lowers emissions for that seasonal period, a cost effective approach?

6. Emission averaging may present significant cost savings but are they enough to offset the administration requirements and other risks?

These are just some of the many questions/issues facing Compliance Planning Teams in system evaluation. All of these can and have been evaluated by using the CAT Workstation™ in concert with the other compliance planning tools. In essence the Workstation™ is a multi-dimensional "spreadsheet" which was specifically developed to assist in selecting the right unit/technology/fuel combination to meet a specified emission target literally from millions of alternatives.

SUMMARY

This paper demonstrates only some of the many capabilities of the Workstation™ Used now, the utility planner can develop a model of the system which will compliment other resources used. The Workstation™ can will assist in developing such plans as:

- Emission Compliance

  Title I and "Beyond" (NO_X)

  Title IV Phase 2 (SO_X and NO_X)

- Title V Operating Permit preparation and submittal
- Impact of system expansion plans on air emissions
- Outage scheduling to implement emission reduction technologies

Incorporating such features as an economic optimization engine, unique-unit operating characteristics, emission evaluation, and simulating banking and trading, can help the utility planner evaluate options, even though some emission limits have not yet been established. The current schedule for issuing these limits may not allow sufficient time for evaluating options before an emission reduction technology is required.

While the purpose of this paper is to demonstrate the NO_X enhancement to CAT, another valuable aspect of CAT is the simultaneous SO_2/NO_X evaluation capability. When reducing a pollutant, implementing one technology may have a positive or negative impact on the emission of another pollutant and the corresponding compliance plan. This valuable capability will be demonstrated in future case studies.

EPRI and S&L have entered into a strategic alliance to provide the CAT Workstation™ to EPRI member utilities for the planning and implementation of emission reduction strategies. The Workstation™ also incorporates an integrated, interactive set of software tools that educates the users on selected emission technologies while assisting in the development of a compliance strategy. The usefulness of the CAT Workstation™ exceeds the initial identification and evaluation of compliance strategies. The CAT Workstation™ allows rapid, inexpensive, and flexible reevaluations of compliance strategies in the face of changing economic factors and system planning considerations.

ACKNOWLEDGMENTS

The authors wish to acknowledge Tony Maurer, John Kalanik, Dale Sopocy, and Thomas Tokarski for their contributions to the Workstation™ design and development. The authors also wish to acknowledge Dennis Ward for his original concept for the economic analysis function and for his expertise regarding CAAA implementation considerations. The economic analysis function was developed and tested with the assistance of Raj Gaikwad, Walter Rymarczyk, Dan Reuben, and a special thanks to the following host utilities who have participated in Beta testing:

Beta-tested the Version 1.0 software and provided valuable insight into the practical uses of the CAT Workstation™: The Cincinnati Gas & Electric Company, Duke Power Company, New York State Electric & Gas Corporation, Rochester Gas & Electric Corporation, and Wisconsin Electric Power Company. Also, a special thanks is extended to the six host utilities who beta-tested the NO_X Enhanced Version 1.5 leading to Version 2.0: Cincinnati Gas & Electric, Centerior Energy, Northern Indiana Public Service Company, Sierra Pacific Power Corporation, South Carolina Electric & Gas Company, and Wisconsin Electric Power Company.

FIGURES

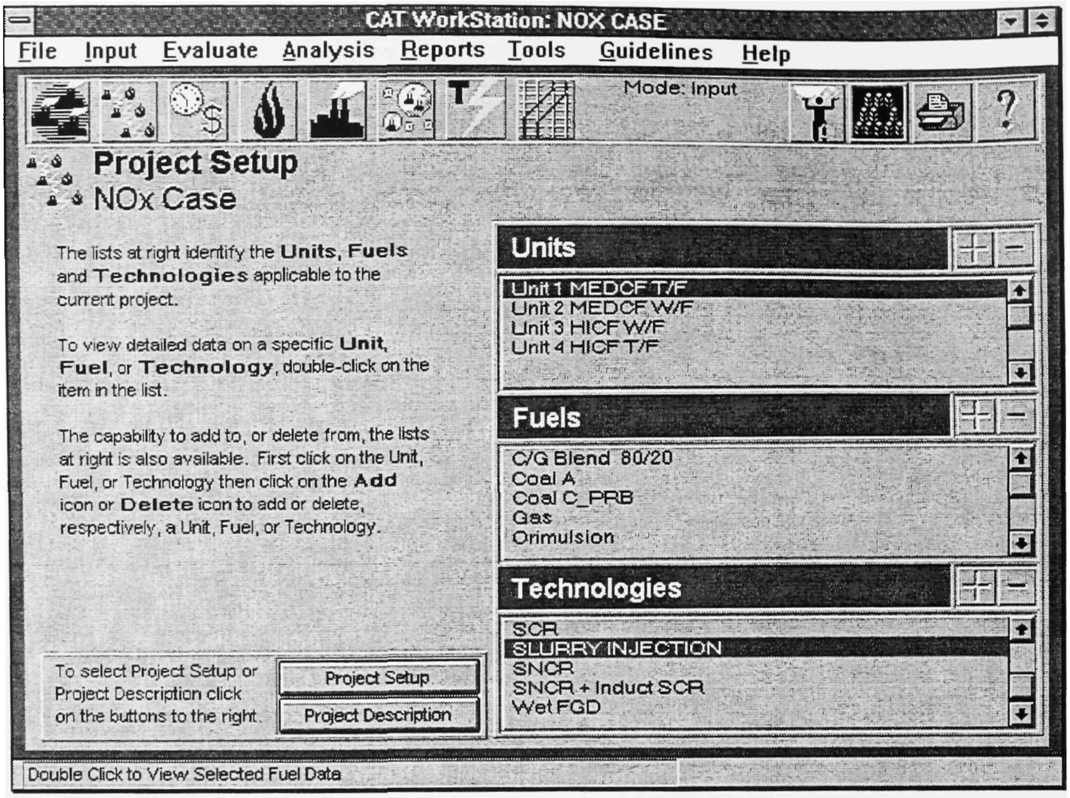

Figure # 1 Project Setup screen

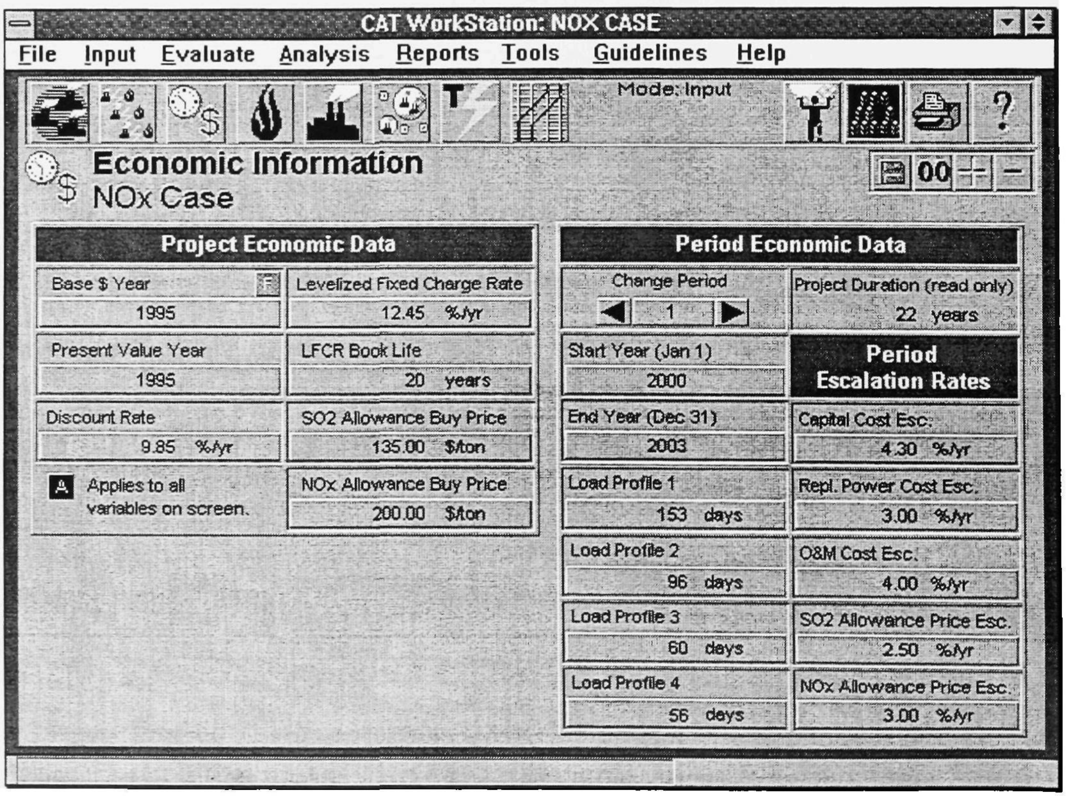

Figure # 2 Economic data

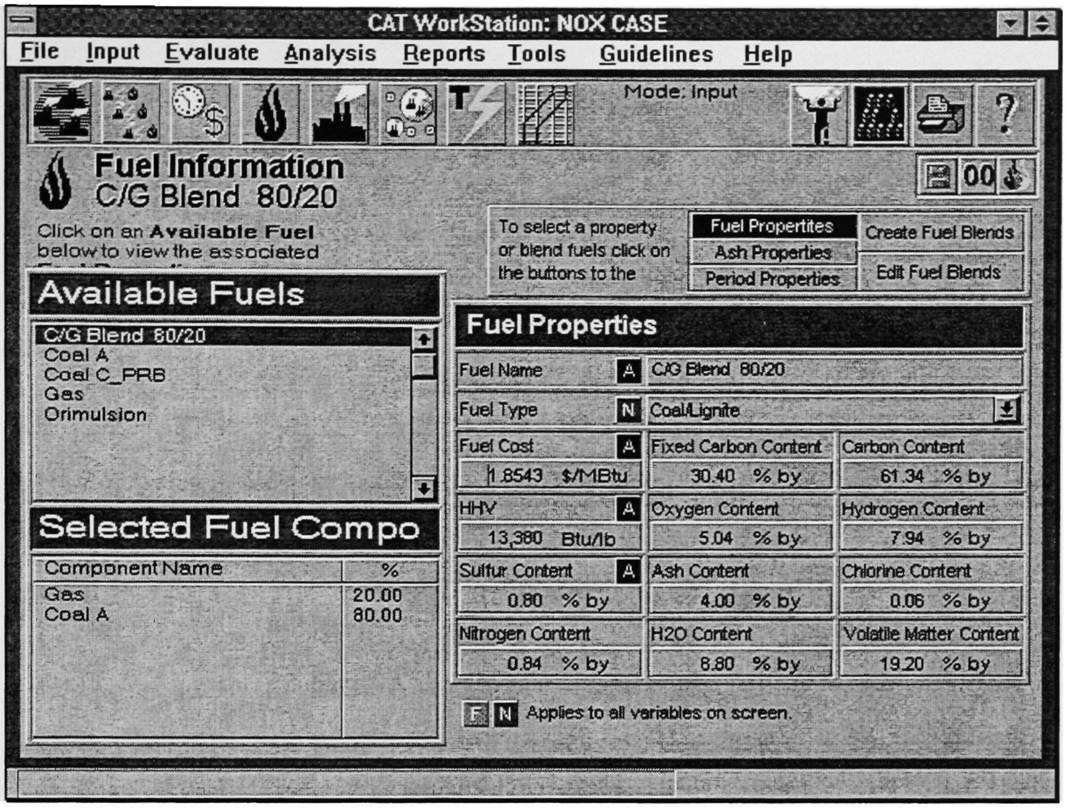

Figure # 3 **Fuel Information**

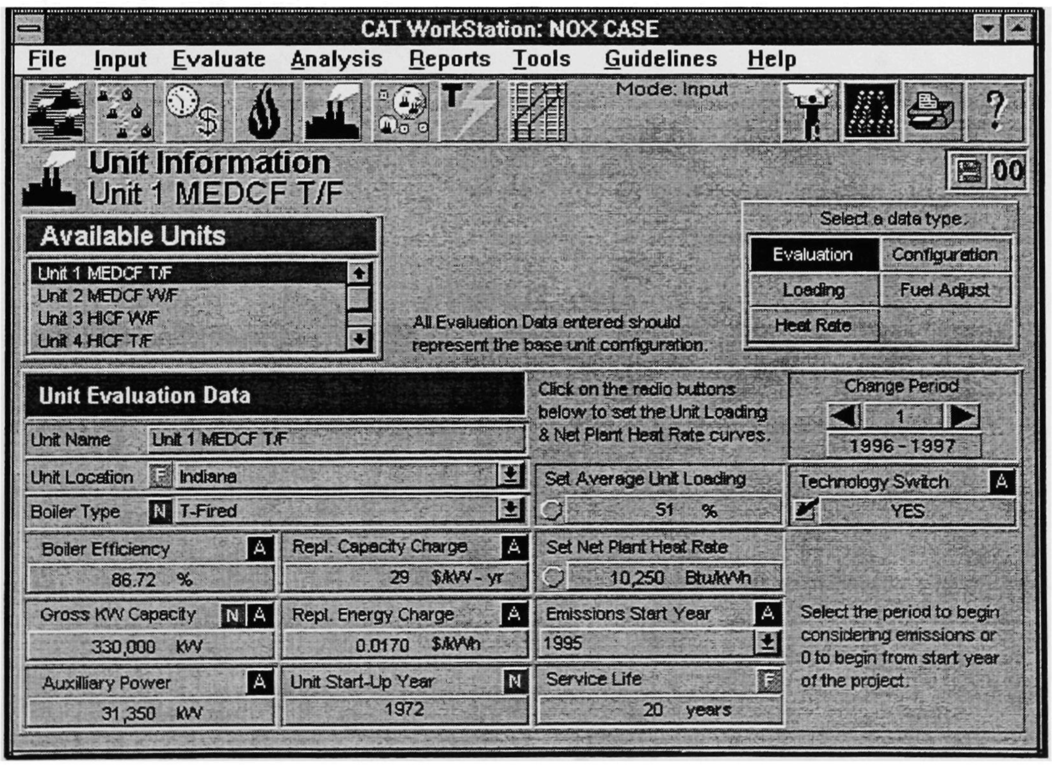

Figure # 4 **Basic Unit Information**

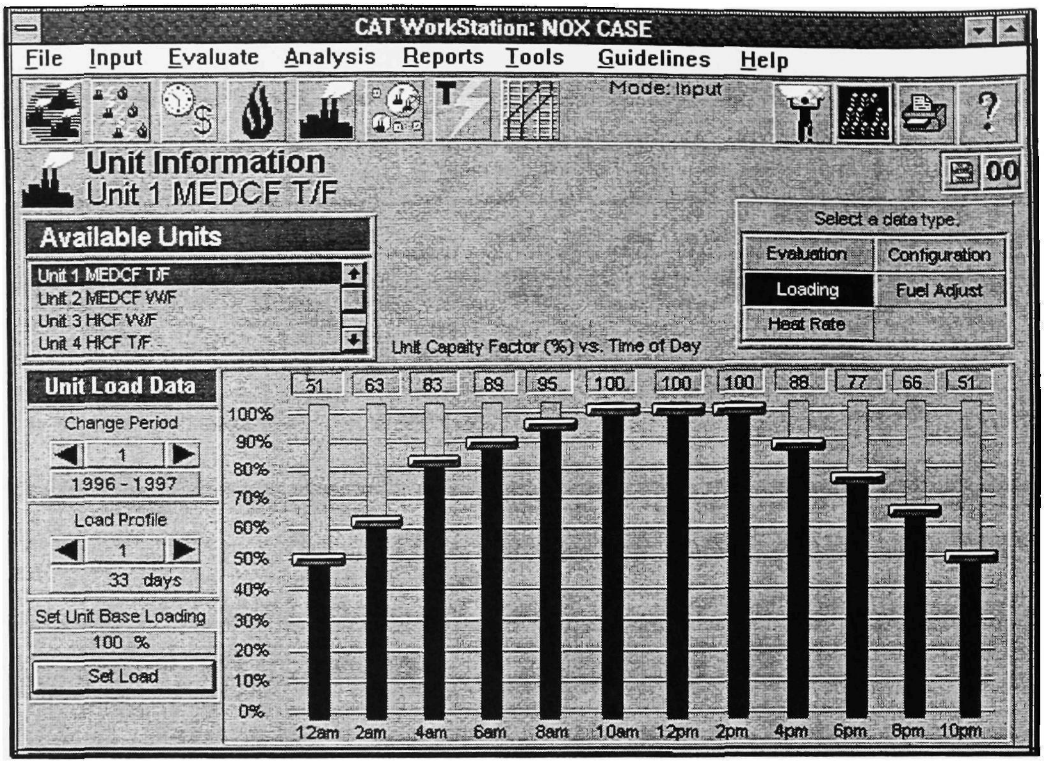

Figure # 5 **Daily Unit Loading Profile**

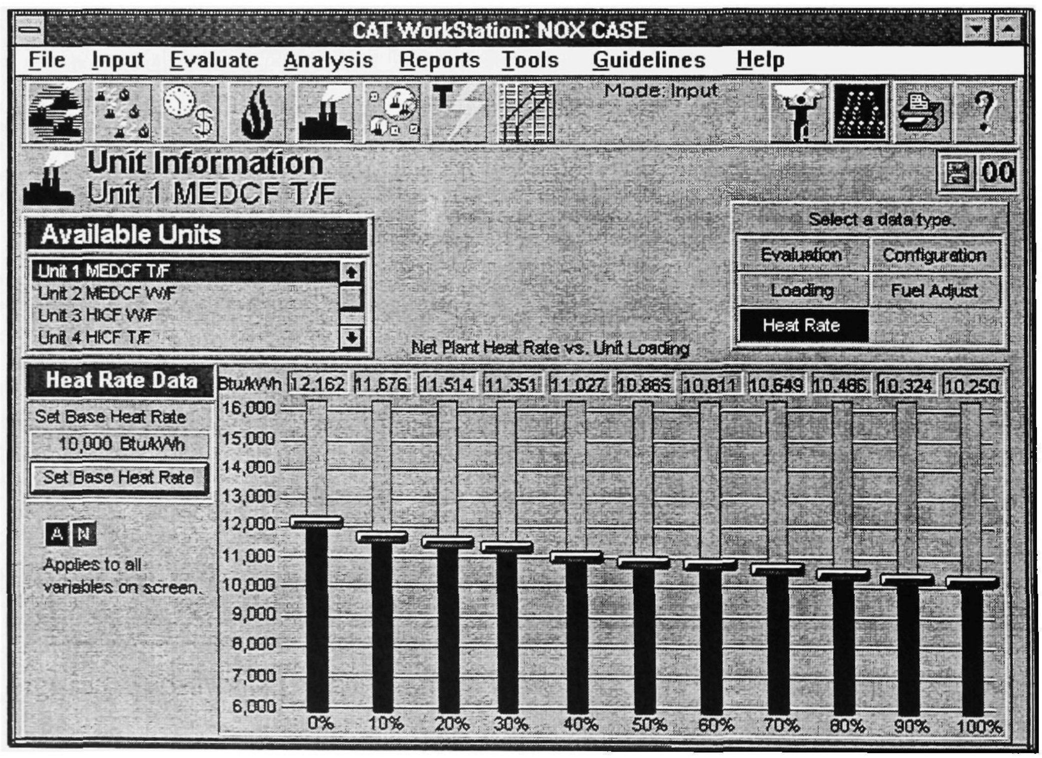

Figure # 6 **Unit Heat Rate versus Load**

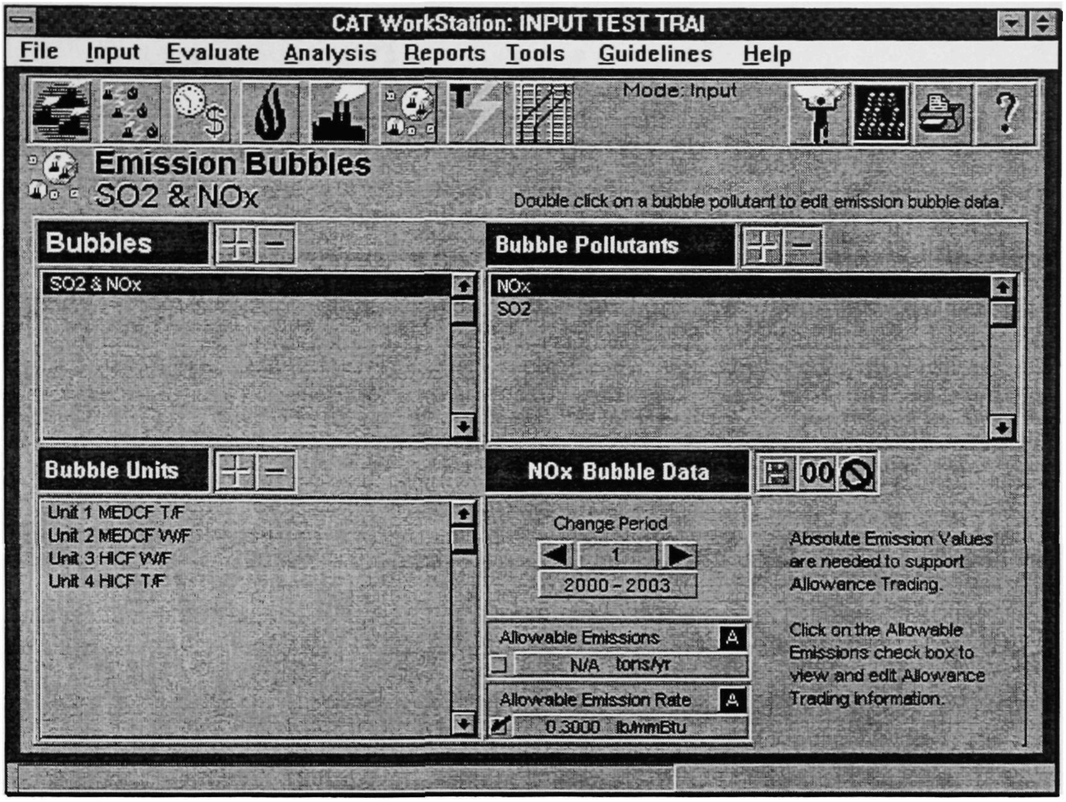

Figure # 7 Creating Emission "BUBBLES" for NOx Emission Rates

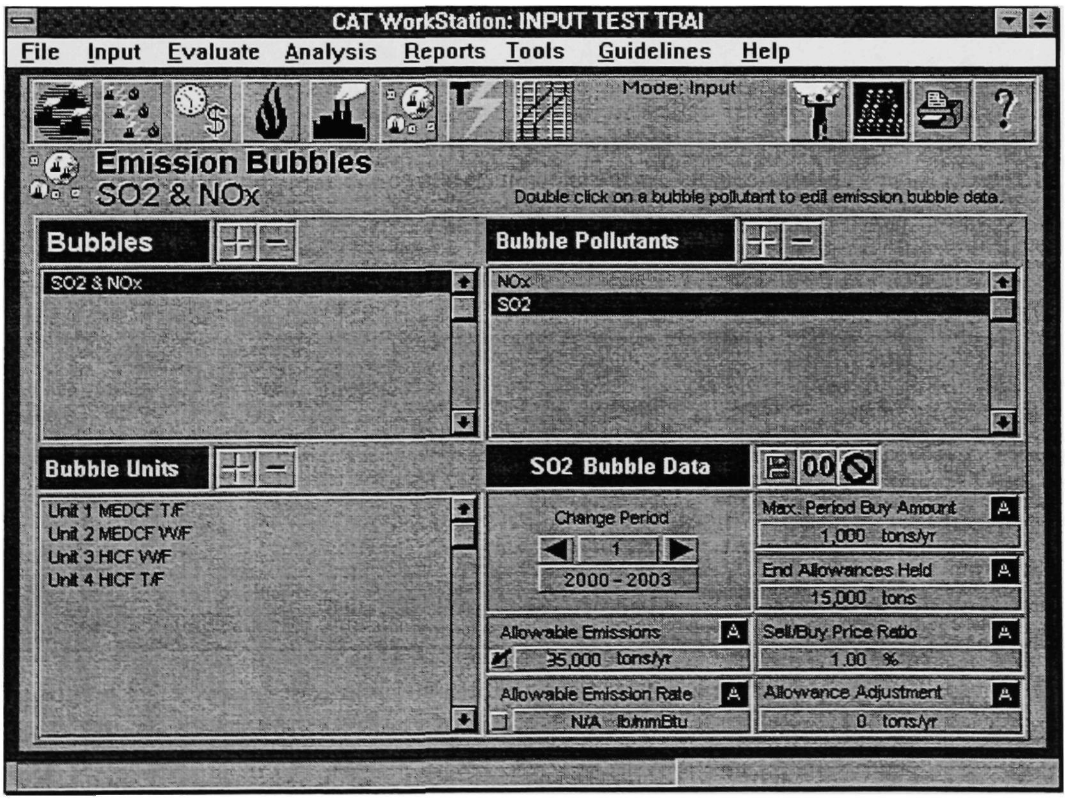

Figure # 8 Creating Emission "BUBBLES" SO2 Emission Rates

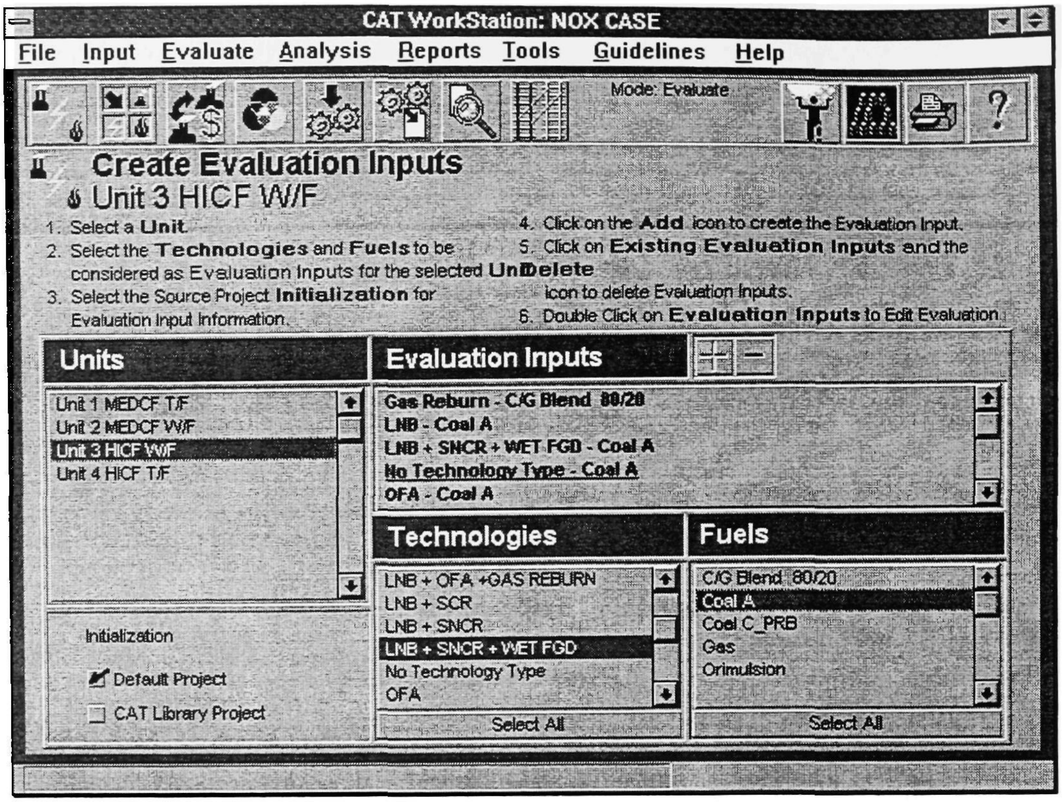

Figure # 9 Creating Unit/Technology/Fuel Combinations

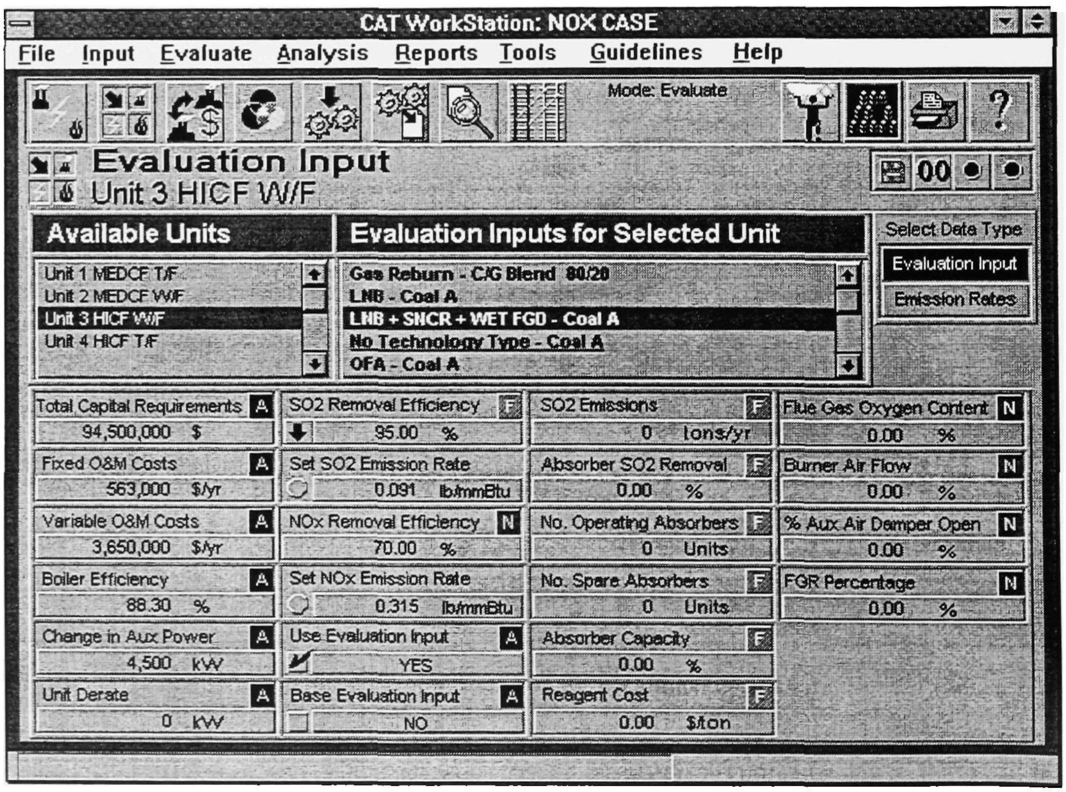

Figure # 10 Data Input screen for Technology COSTS & PERFORMANCE

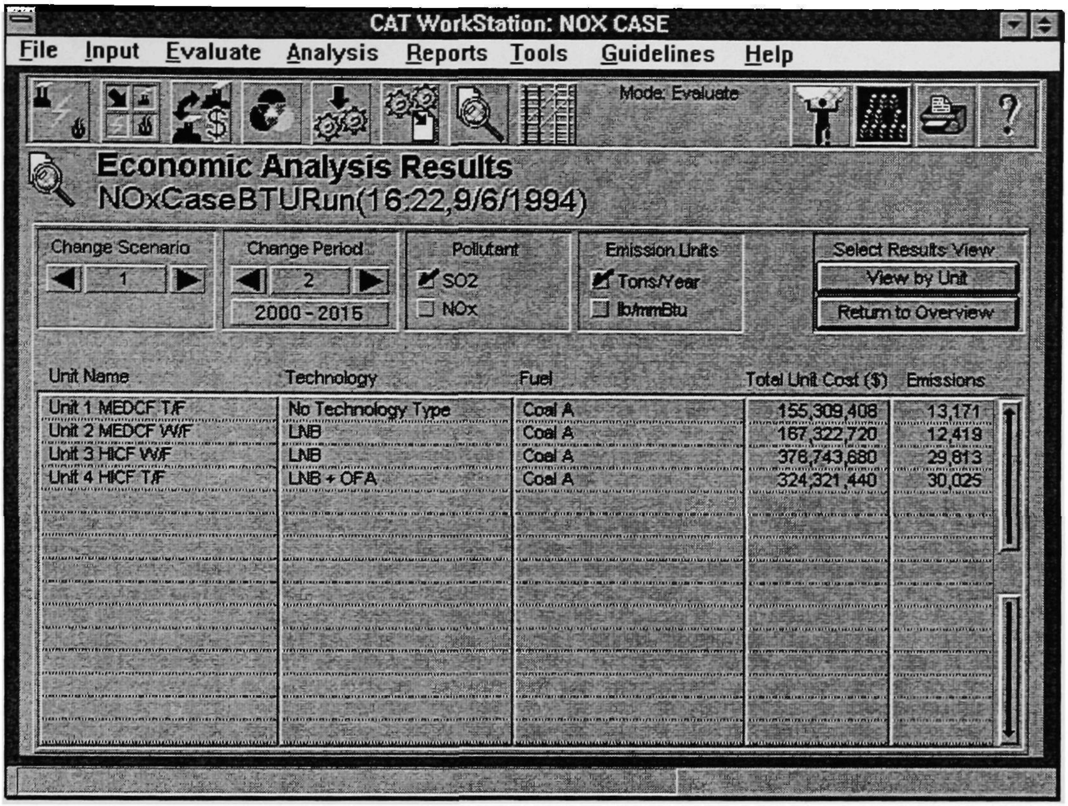

Figure #11 *SAMPLE* **Output showing Units-Technologies-Fuels Selected to meet a specific target Emission Rate for SO_2**

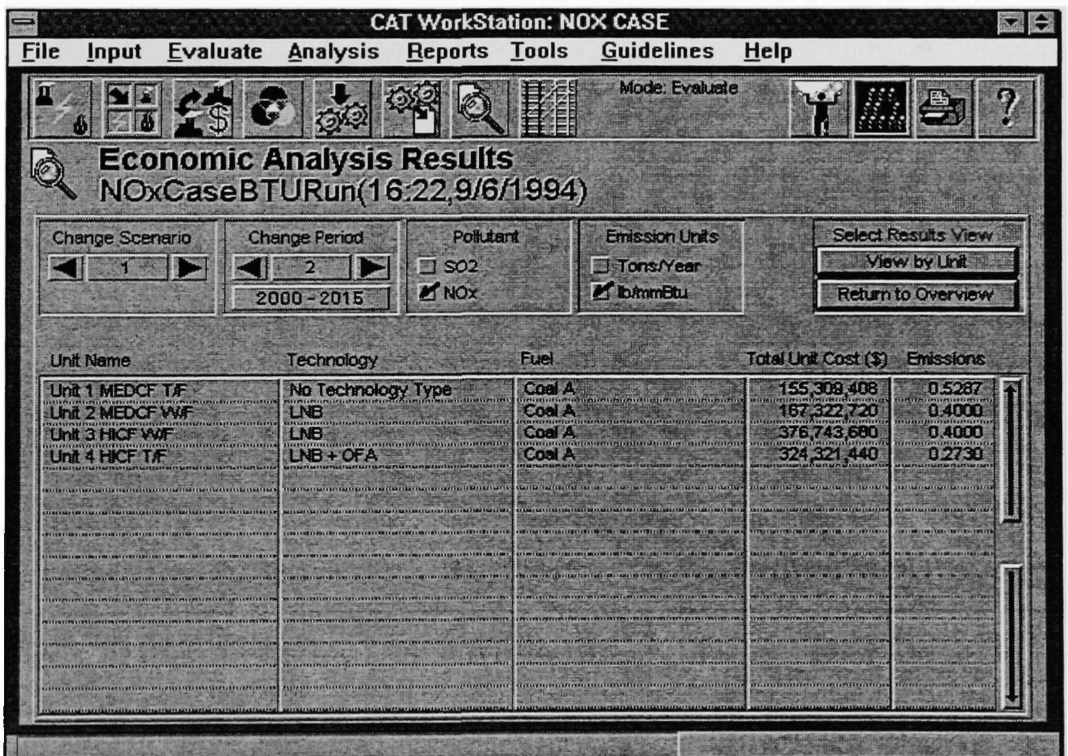

Figure #12 *SAMPLE* **Output showing Units-Technologies-Fuels Selected to meet a specific target Emission Rate for NO_x**

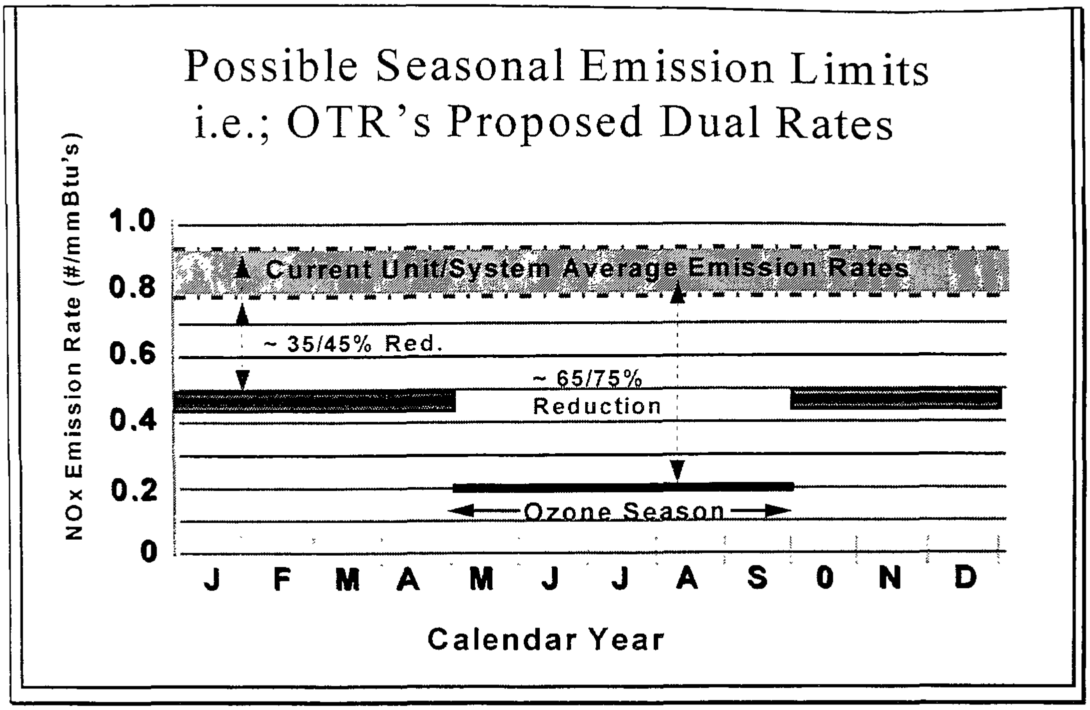

Figure # 12 ***SAMPLE*** **DUAL-YEARLY Target Emission Rates**

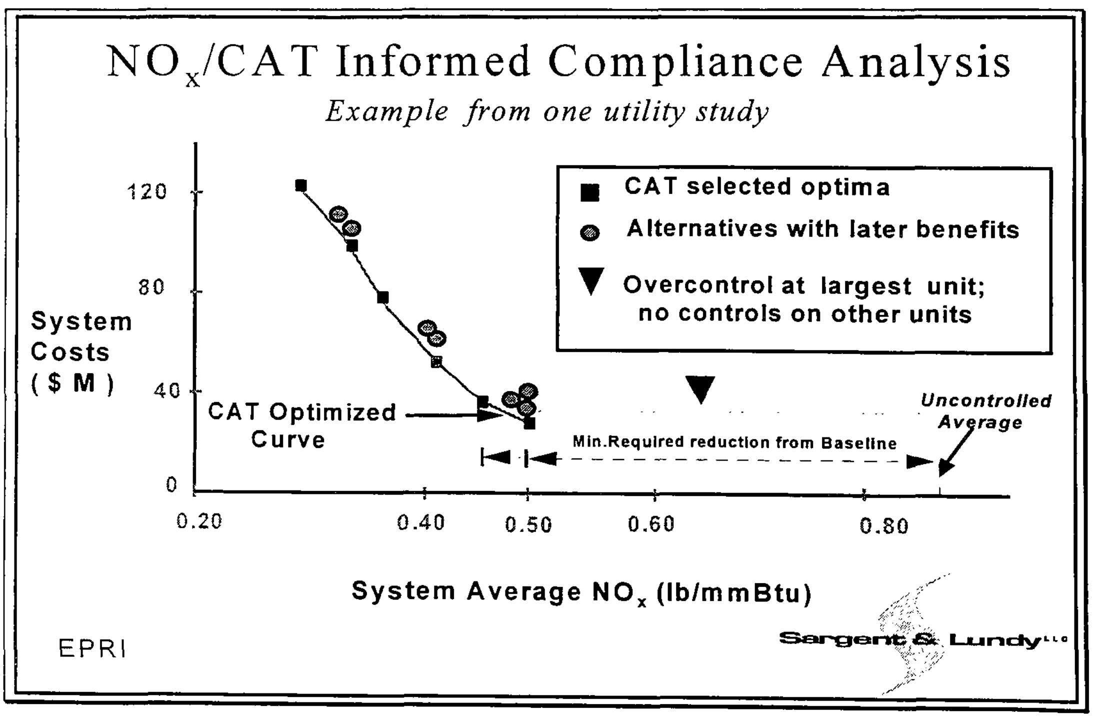

Figure # 13 ***SAMPLE*** **Compliance Chart**

Session 2
Coal Combustion

LOW-NO_x BURNER AND SNCR RETROFIT EXPERIENCE AT NEW ENGLAND POWER SALEM HARBOR STATION

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Abstract

New England Power has recently installed Riley-Stoker low-NO_x burners (LNB) and Nalco Fuel Tech urea-based selective non-catalytic NO_x reduction (SNCR) systems on Units 1 and 3 at its Salem Harbor generating station. In addition, Unit 3 was also retrofit with a two-level overfire air (OFA) system. These two coal-fired units are front wall-fired with unequal burner spacing and have uncontrolled full-load NO_x emissions of nominally 750 ppm (1.1 lb/MMBtu). Unit 1 is rated at 86 MW and has 12 burners, while Unit 3 is rated at 155 MW and has 16 burners. NO_x reduction performance of the LNB, OFA and SNCR systems has been characterized both independently and in combination during the test programs while firing low-sulfur coals.

Unit 1 tests showed that the LNBs provided NO_x reductions of approximately 50 percent at loads above 60 MW using narrow angle coal spreaders. Corresponding ash carbon at these NO_x levels varied between 16 and 35 percent. The SNCR system provided an additional 40 percent NO_x reduction from the LNB baseline at a molar N/NO ratio of 1.2. The corresponding NH_3 slip levels were less than 10 ppm.

On Unit 3, LNB tests showed that NO_x reductions of nominally 10 percent were achieved with the burners alone, using wide angle coal spreaders. The use of OFA, at design levels, provided additional NO_x reductions ranging from 42 percent at full load to 4 percent a minimum load relative to the LNB baseline. Ash carbon levels doubled to levels above 30 percent when the OFA system was operated at design conditions at loads above 110 MW. The SNCR system provided NO_x reductions of 33 percent relative to the LNB/OFA baseline of 0.55 lb/MMBtu, at a molar N/NO ratio of 1.3. Ammonia slip for these conditions was less than 5 ppm.

Background

Under an agreement with the Massachusetts Department of Environmental Protection (DEP), New England Power (NEP) is required to reduce NO_x emissions from the coal-fired units at their Salem Harbor Generating Station (Units 1, 2 and 3). The agreement limits NO_x emissions to a daily average of 0.33 lb/MMBtu from these units. This represents a nominal 70 percent reduction from their baseline NO_x emissions levels of approximately 1.1 lb/MMBtu.

To achieve this NO_x emissions goal, NEP has chosen to retrofit these units with urea-based Selective Non-Catalytic Reduction (SNCR) systems supplied by Nalco-Fuel Tech. Subsequent to the SNCR demonstrations, Unit 1 has been retrofit with low-NO_x burners (LNB) supplied by Riley Stoker. Unit 3 has also been retrofit with Riley Stoker Low NO_x burners and a Riley Stoker overfire air (OFA) system. The Unit 3 LNBs and OFA were installed together as an integrated NO_x control system.

Unit Descriptions

Salem Harbor Units 1, 2 and 3 are front wall-fired B&W boilers. Units 1 and 2 are currently rated at 87 MW gross for normal claim capacity operation, while Unit 3 is rated at 155 MW. These units currently operate with capacity factors of about 80 percent. The units are balanced draft designs, utilizing dual FD and ID fans. Units 1, 2 and 3 were retrofit with new electrostatic precipitators in 1984.

Units 1 and 2 each have 12 burners arranged in three elevations of four burners each. Unit 3 has 16 burners, arranged in four elevations of four burners each. On all three units, the vertical burner spacing is uneven. Spacing between the upper two and lower two burner elevations is less than the spacing between the two center burner elevations.

The Riley Model 90 Controlled Combustion Venturi (CCV) burners retrofit to Salem Harbor Units 1 and 3 are designed to fire either pulverized coal or No. 6 fuel oil. When firing pulverized coal, NO_x emissions are reduced by delaying the fuel/air mixing. This delay is achieved through the use of a venturi coal nozzle and a low swirl spreader design. Together, these result in gradual fuel air mixing, which reduces peak flame temperatures and subsequently, NO_x emissions. The Unit 1 LNBs were installed with narrow angle (i.e., 15 degree) coal spreaders, while the Unit 3 LNBs were fitted with wide angle (i.e., 30 degree) coal spreaders during the testing. The Unit 3 OFA system includes 8 dual elevation ports. The upper elevation of ports is designed to supply two-thirds of the total overfire air, while the lower ports supply one-third of the overfire air. The dampers for each OFA port elevation can be independently controlled to vary the amount of OFA.

SNCR System Description

The SNCR process is conceptually simple. An aqueous solution of urea (or ammonia) is injected into, and mixed with, the flue gas at the correct temperature. Once the mixing is complete, the reagent reacts selectively to remove NO_x. In practical applications, however, the SNCR process can be complicated. Non-uniformities in velocity, temperature, and NO_x and CO concentrations at the injection point pose difficult questions because of the inherent sensitivity of SNCR processes to these parameters. The physical location of the effective process temperature range within the boiler changes, depending on operating factors such as load, fuel type, and length of time operating with a particular fuel. These factors often lead to multiple injection levels. All of these issues are compounded when dealing with a power plant that is required to operate in a cycling mode, as is the case with the Salem Harbor units.

The urea injection systems installed on Salem Harbor Units 1-3 each include a circulation module, a metering module and four distribution modules. Each distribution module controls a single injection level. The NO_xOUT HP (a 50 percent urea solution developed by NFT) is delivered by truck to two chemical storage tanks which supply the urea for all three units. Prior to injection, the urea is diluted with additional water, and transported to the desired injection levels. Figure 1 shows the location of each injection level in the furnaces.

Test Program

Figure 2 presents a time line illustrating the schedule followed for the NO_x retrofit test program at Salem Harbor. This shows that the testing began with the evaluation of the SNCR system installed on Unit 2 in January 1993. Unit 2 testing continued through June. Testing on Unit 1 was performed between August and November 1993. A limited amount of testing was performed on Unit 3 in October, prior to the scheduled LNB/OFA retrofit outage. Testing of the Unit 3 LNB/OFA systems began immediately, while the final optimization of the LNB, OFA and SNCR systems was performed in September 1994. The Unit 1 LNB testing began in November 1994 and was completed in March 1995.

Measurement Techniques

Measurement of gas composition and temperature were required for this project. Table 1 summarizes the species measured and the technique used.

Test Coals

A key element of these test programs was the evaluation of a variety of low-sulfur compliance coals. Table 2 provides analyses of the coals fired during the test periods reviewed in this paper. The initial testing at Salem Harbor, which started in 1993, was performed using the then standard Alpine coal. The Alpine coal is a domestic medium-sulfur, low volatile coal. Subsequent testing was performed using a variety of low sulfur coals. These coals have included a domestic coal (Mingo Logan) as well as two South American coals (Gusare and Cerrejon). The data show that the heating values for all coals varied between 12500 and 13000 Btu/lb. Among other differences, the South American low-sulfur coals have FC/VM ratios which are lower than the other test coals. The Alpine coal had a FC/VM ratio of 3.46 while the low sulfur Mingo Logan coal had a FC/VM ratio of 1.85. In comparison, the South American coals had FC/VM ratios of nominally 1.5.

Table 1
Measurement Techniques

Species	Technique	Measurement Principle
NO/NO_x	Continuous	Chemiluminescent
N_2O	Continuous	Non-Dispersive Infrared
O_2	Continuous	Fuel Cell
CO	Continuous	Non-Dispersive Infrared
CO_2	Continuous	Non-Dispersive Infrared
SO_2	Continuous	Ultraviolet
NH_3	Batch	Direct Nesslerization
SO_3	Batch	Ion Chromatography
Ash Carbon	Batch	Elemental Analysis
Temperature	---	High Velocity Thermocouple

Test Results

Parametric testing has been performed on each unit to evaluate the impact of the retrofit NO_x control equipment on unit emissions and operation. The parametric testing was performed at a minimum of three loads across the operating load range.

For the LNB systems installed on Units 1 and 3, the following process parameters were evaluated:

- Secondary Air Register Settings (swirl and flow)
- Coal Spreader Position
- Windbox/Furnace Differential Pressure
- Excess O_2 Level

In addition, the effect of OFA flow rate was evaluated on Unit 3.

For the SNCR systems, the parametric testing included evaluation of the following process parameters:

- Injection Location
- Reagent Flow Rate
- Dilution Water Flow Rate
- Atomization Pressure

Test results for Units 1 and 3 are summarized in the following sections.

Table 2

Salem Harbor Coal Analyses Summary

Coal Unit(s)	Alpine 1,3	Gusare 1	Mingo Logan 3	Gusare 1,3	Cerrejon 3
Proximate Analysis					
% Moisture	7.46	6.75	6.97	7.74	9.47
% Ash	10.36	7.02	7.56	6.06	4.14
% Volatile	18.42	34.72	30.03	34.30	35.24
% Fixed Carbon	63.76	51.51	55.44	51.90	51.15
Total, %	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis					
% Carbon	73.42	71.52	71.79	72.32	71.06
% Hydrogen	4.07	6.40	4.68	4.83	4.77
% Nitrogen	1.25	1.21	1.35	1.39	1.38
% Sulfur	1.36	0.59	1.07	0.61	0.48
% Oxygen	2.08	6.51	6.58	6.06	8.70
% Ash	10.36	7.02	7.56	7.06	4.14
% Moisture	7.46	6.75	6.97	7.74	9.47
Total, %	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	12,963	12,893	12,891	12,774	12,590
Ash Analysis					
SiO_2	52.53	53.54	51.35	61.22	51.97
Al_2O_3	26.96	22.89	26.81	21.80	21.08
Fe_2O_3	12.11	5.91	11.71	5.28	6.68
CaO	1.53	4.32	1.32	2.80	7.85
MgO	0.69	3.50	0.94	1.80	2.18
Na_2O	0.35	0.35	0.47	0.45	0.78
K_2O	2.36	1.62	2.49	2.18	1.62
TiO_2	1.39	0.94	1.34	0.92	0.87
MnO_2	0.01	0.00	0.05	0.10	0.10
P_2O_5	0.39	0.11	0.20	0.17	0.19
SO_3	0.74	5.75	1.57	3.24	6.63
Calculated Values					
Base/Acid Ratio	0.21	0.20	0.23	0.15	0.26
Silica Ratio	78.6	79.6	78.2	86.1	75.7
FC/VM Ratio	3.46	1.48	1.85	1.51	1.45
Slagging Index	0.29 (low)	0.13 (low)	0.23 (low)	0.09 (low)	0.12 (low)
Fouling Index	0.07 (low)	0.07 (low)	0.10 (low)	0.07 (low)	0.20 (low-mod)

Salem Harbor Unit 1

The pre-LNB retrofit tests on Salem Harbor Unit 1 were performed using both the Alpine and Carbozoulia coals. The post-retrofit tests were performed while firing a low-sulfur, Gusare coal.

NO_x emissions are plotted versus O_2 level in Figure 3. Both pre- and post-retrofit data are shown. The data show that the unit's NO_x emissions were more sensitive to O_2 level when firing the South American coals. The pre-retrofit data showed full-load NO_x emissions to be 1.10 lb/MMBtu when firing the Alpine coal and 0.93 lb/MMBtu at a nominal O_2 level of 4.85% when firing the Gusare coal. Following the LNB retrofit, NO_x emissions were 0.46 lb/MMBtu when firing Gusare coal. The O_2 level for this full load test was 4.4 percent. These data show that the LNBs lowered NO_x emissions by nominally 50% relative to the pre-retrofit tests performed using the Gusare coal.

Figure 4 shows the effect of O_2 concentration on LOI levels. Pre-retrofit data were only taken while firing the Alpine coal. These data show that the LOI was 7.4% at a nominal O_2 of 4.2%. No LOI data were obtained when firing the Gusare coal, since the primary focus of the testing at that time was SNCR system optimization. However, testing performed by plant personnel prior to the retrofit showed that LOI levels were nominally 15% while firing Gusare coal. Post-retrofit tests, performed while firing the Gusare coal, showed that full-load LOI levels were 19.9% at a nominal O_2 of 4.4%. These data show that firing the low sulfur South American coals resulted in a doubling in LOI levels, from 7.4 to 15%, with the original burners. The retrofit low NO_x burners increased LOI levels from 15% to 19% at full load.

Figure 5 shows NO_x emissions plotted versus load (MW) at nominal O_2 levels. When firing the Alpine coal, the 86 MW data show that baseline NO_x emissions averaged 1.10 lb/MMBtu at a nominal O_2 level of 4.2%. At 67 MW, NO_x emissions averaged 0.94 lb/MMBtu while NO_x emissions averaged 0.93 lb/MMBtu at 38 MW. The corresponding O_2 levels for the reduced load tests were 4.8% at 65 MW and 9.8% at 38 MW. These NO_x emissions are somewhat higher than expected for a unit of this size, primarily due to the high furnace heat release rate and the unequal vertical burner spacing. This results in NO_x emissions characteristics similar to those of a cell-fired unit. When firing the Gusare coal, NO_x emissions decreased somewhat. At full load, NO_x emissions averaged 1.0 lb/MMBtu at a nominal O_2 level of 5.2%. When firing the Gusare coal, NO_x emissions decreased nearly linearly with load to 0.72 lb/MMBtu at minimum load.

Following the LNB retrofit, a series of parametric tests were performed to optimize their performance. This work included varying the air register swirl settings, the spreader position, and the windbox to furnace differential pressure. The primary goal of all changes was to reduce LOI emissions, since NO_x emissions with the retrofit narrow-angle coal spreaders were satisfactory. The swirl settings were set with the outer burners having more swirl than the center burner, while the spreaders were set at the same position at each burner. These burner settings were selected to provide balanced O_2 levels at the furnace exit.

Figure 5 also shows NO_x emissions plotted versus load for the post-retrofit testing. These tests were performed while firing the low-sulfur Gusare coal. The data show that post-retrofit full load (e.g., 88 MW) NO_x emissions averaged 0.46 lb/MMBtu at an average O_2 level of 4.4%.

NO_x emissions also averaged 0.46 lb/MMBtu at 65 MW and were 0.45 lb/MMBtu at 30 MW. This shows that the low NO_x burners reduced NO_x emissions from 37 % to 54 % over the load range relative to the pre-retrofit conditions while firing low-sulfur South American coals.

CO emissions were below 50 ppm during all test conditions performed at nominal O_2 levels, for all coals.

The SNCR evaluation began with a series of parametric tests, both before and after the LNB retrofit. The results of these tests showed that the optimum injection level changed with load as shown below:

Load, MW		Injection Levels
Pre-Retrofit	Post-Retrofit	
88 72	88 - 60	2U, 2L
72 - 60	60 - 40	2L, 1
60 - 40	40 - 30	1, 1R

These injection levels were ultimately used during both portions of the testing. The solution flow and atomizing air pressures were set to their full load optimum, since it is not possible to vary them automatically as a function of load. The full load SNCR settings were selected as the optimum because of the unit's high capacity factor.

Figure 6 shows NO_x emissions as a function of Normalized Stoichiometric Ratio (NSR) for Salem Harbor Unit 1. The NSR is defined as follows:

$$NSR = \frac{\text{moles N injected}}{\text{moles initial } NO_x} \quad (1)$$

NSR is used so that the effect of urea flow, taken at different operating conditions, can be compared on a normalized (i.e., non-dimensional) basis. Data are presented for full-load operation, both before and after the LNB retrofit. These data show that the minimum achievable NO_x emissions varied from 0.54 lb/MMBtu at an NSR of 2.0 prior to the retrofit while firing the Alpine coal to 0.39 lb/MMBtu at an NSR of 2.2 when firing the Gusare coal. The post-retrofit SNCR performance while firing the Gusare coal showed that NO_x emissions of 0.28 lb/MMBtu could be maintained at an NSR of 1.2. Note that the initial NO_x levels for this work varied from 1.10 lb/MMBtu when firing the Alpine coal before the LNB retrofit to 0.46 lb/MMBtu when firing the Gusare coal with the low-NO_x burners. The corresponding NO_x reductions ranged from 64% when firing the Alpine coal (pre-retrofit) to 39% when firing the Gusare coal (post-retrofit).

The corresponding NH_3 slip data are plotted versus NSR in Figure 7. These data show that the highest NH_3 emissions were measured pre-retrofit when firing the Gusare coal. This is most likely due to changes in the injection zone temperatures, resulting from changes in coal type.

The low-volatile Alpine coal would be expected to continue burning higher in the furnace relative to the high volatile South American coals. This would result in higher injection zone temperatures when firing the Alpine coal. The pre-retrofit NH_3 slip levels measured at an NSR of about 1.5 ranged from 18 ppm to 48 ppm for the different operating conditions considered. When firing the Gusare coal following the LNB retrofit, the full-load NH_3 slip levels ranged from 3 ppm to 9 ppm over the range of NSRs evaluated.

Salem Harbor Unit 3

After the initial shake down period, a series of parametric tests were performed. For the LNB/OFA system installed on Unit 3, the testing was performed in two parts. The initial testing characterized the performance of the LNB system alone, while both the LNB and OFA were characterized during the final testing. It must be noted that the Unit 3 LNB/OFA system was designed and installed as an integrated system. Thus, tests performed with the OFA system off were intentionally run in an off-design condition in an attempt to quantify the sensitivity of the LNB and OFA systems separately.

Figure 8 shows NO_x emissions plotted versus O_2 level for the following full load operating conditions:

Pre-retrofit ; Mingo Logan coal
Pre-retrofit ; Alpine coal
Post-retrofit ; Gusare coal
Post-retrofit ; Cerrejon coal
Post-retrofit ; Mingo Logan coal

All post-retrofit data were taken with the OFA dampers closed. The effect of O_2 level on NO_x emissions is presented in Figure 8 for these five operating conditions. These data show that the Unit 3 NO_x emissions are very sensitive to O_2 level. The NO_x sensitivity varied between 0.10 and 0.083 lb/MMBtu (74 and 61 ppm) NO_x/percent O_2 before the LNB retrofit. Following the LNB retrofit, this NO_x sensitivity was 0.105 lb/MMBtu (77 ppm) NO_x/percent O_2 when firing the Gusare coal. These NO_x emission levels are all quite high for a wall-fired unit, and are likely due to the unequal vertical burner spacing of this unit, which result in NO_x emissions similar to those of a cell-fired unit.

The effect of O_2 on LOI is shown in Figure 9. These full load data show that the LOI levels were nominally 8% for the pre-retrofit tests when firing either the Alpine or Mingo Logan coals at nominal O_2 levels between 3.5 and 4.0 percent. The post-retrofit data show that the LOI level remained relatively unchanged (e.g., about 8% LOI at a nominal O_2 of 3.7%) when firing the Mingo Logan coal. LOI levels for both the Cerrejon and Gusare coals were significantly higher; 16.1% and 16.3%, respectively, when operating at nominal O_2 levels.

Figure 10 shows NO_x emissions plotted versus load while operating at nominal O_2 levels. Data are presented for the five operating conditions listed previously. These data also shown that the retrofit LNBs had little impact on NO_x emissions as a function of load. This is most easily seen by comparing the pre- and post-retrofit data obtained while firing the Mingo Logan coal. These data show that the maximum NO_x reduction, due to the LNBs alone, was less than 5% at full load and nominally 8 % at minimum load. Note that the South American coals (e.g., Gusare and Cerrejon) provided NO_x emissions of about 0.8 lb/MMBtu at full load, compared to 0.92 lb/MMBtu when firing the Mingo Logan coal. Minimum load NO_x emissions were similar when firing both the South American and domestic low-sulfur coals.

The subsequent tests evaluated the performance of the retrofit LNB/OFA system. The effect of OFA flow on NO_x emissions is illustrated in Figure 11. These data are presented for full load operation while firing the Mingo Logan, Gusare and Cerrejon low-sulfur coals. These data show that the highest NO_x emission levels were measured when firing the Mingo Logan coal; NO_x emissions were 0.51 lb/MMBtu at nominal O_2 levels. NO_x emissions varied from 0.48 lb/MMBtu with the Gusare coal to 0.39 lb/MMBtu with the Cerrejon coal. The data show that use of 3/3 OFA at full load provided NO_x reductions between 39 and 52 percent, relative to the LNB baseline, depending on the coal fired. Note that the 3/3 OFA setting is equivalent to nominally 21% OFA at full load. Also note that the no OFA case corresponds to about 5% OFA. This occurs because the OFA dampers deliberately do not seal tightly, thereby allowing cooling air flow across the dampers at all times.

Figure 12 illustrates the effect of OFA flow on LOI levels for full load operations at nominal O_2 levels. The data show that the highest LOI levels were measured when firing the South American coals. At maximum OFA flow, these LOI levels ranged from 31.5% with the Cerrejon coal to 40.3% with the Gusare coal. When firing the Mingo Logan coal, LOI levels were 16.2% with maximum OFA. This is less than half of the equivalent levels measured when firing the low-sulfur South American coals. The impact of OFA on LOI levels varied with coal type. This sensitivity ranged from 1.3% LOI increase/percent OFA increase for the Gusare coal to 0.6% LOI/% OFA for the Mingo Logan coal.

Figure 13 illustrates the relationship between LOI levels and NO_x emissions for the post-retrofit testing. These data include the data from previous figures reviewing the effects of both O_2 level and OFA on NO_x emissions and LOI. The data show that LOI levels were more sensitive to changes in NO_x emissions when firing the South American coals. This difference in performance is most likely due to the different combustion characteristics of these coals relative to the domestic low-sulfur coals.

Figures 14 and 15 illustrate the performance of the SNCR system installed on Unit 3. Figure 14 shows NO_x emissions plotted as a function of NSR for both pre- and post-retrofit work. Note that the pre-retrofit data were taken at an intermediate load of 115 MW. This was necessary because unit mill problems precluded full load operation while firing 100% coal. These data show that it was necessary to operate at NSRs in excess of 3.0 to reduce NO_x emissions below 0.4 lb/MMBtu. The full-load post-retrofit testing showed that NO_x emissions below 0.3 lb/MMBtu could be achieved when operating at an NSR of 1.3. This is equivalent to a NO_x reduction of 33% from the LNB/OFA baseline. The improvement in SNCR performance is mostly due to: (1) the lower initial NO_x levels encountered following the LNB/OFA retrofit and, (2) better balanced furnace conditions following the LNB/OFA retrofit. Minimum load testing showed that NO_x emissions of 0.31 lb/MMBtu could be achieved when operating at an NSR of 1.1.

NH_3 emissions are plotted versus NSR in Figure 15. The data show that full load NH_3 emissions were less than 5 ppm over the range of NSRs evaluated. At intermediate load, the NH_3 slip was 31 ppm at an NSR of 1.3 for tests performed prior to the LNB/OFA retrofit. As NSR increased to 2.5 and higher, NH_3 emissions exceeded 60 ppm. These NH_3 levels could cause operating problems, such as heat transfer equipment fouling, visible plumes, ash contamination, etc., if they were maintained for any length of time. Minimum load NH_3 slip levels were nominally 30 ppm for tests performed at operating conditions which provided NO_x emissions compliance.

CONCLUSIONS

Based on the results presented in this paper, the following conclusions can be drawn:

- The retrofit of low-NO_x burners incorporating narrow angle (i.e., 15 degree) coal spreaders to Unit 1 provided NO_x reductions varying from 37 to 54% over the operating load range. LOI levels with these burners were in excess of 20% at full load and nominal O_2 levels when firing the Gusare coal

- The SNCR system installed on Unit 1 provided full load NO_x reductions of nominally 40 percent at an NSR of 1.2, relative to the LNB baseline. The corresponding NH_3 slip levels were less than 10 ppm.

- Unit 1 has been able to meet the Massachusetts DEP NO_x emissions limit of 0.33 lb/MMBtu across the operating load range during the controlled parametric tests described previously.

- The retrofit of low-NO_x burners utilizing wide angle (i.e., 30 degree) coal spreaders to Salem Harbor 3 provided NO_x reductions of less than 10 percent. The use of OFA, at design levels, provided additional NO_x reductions ranging from 42 percent at full load to 4 percent at minimum load. Ash carbon levels doubled, to levels above 30%, when the OFA system was operated at design conditions for loads in excess of 110 MW while firing low-sulfur South American coals.

- The Unit 3 SNCR system provided full load NO_x reductions of 33% relative to the LNB/OFA baseline at an NSR of 1.3. Ammonia slip for these conditions was less than 5 ppm.

- Unit 3 has been able to meet the Massachusetts DEP NO_x emissions limit of 0.33 lb/MMBtu at both full and minimum loads during controlled parametric testing.

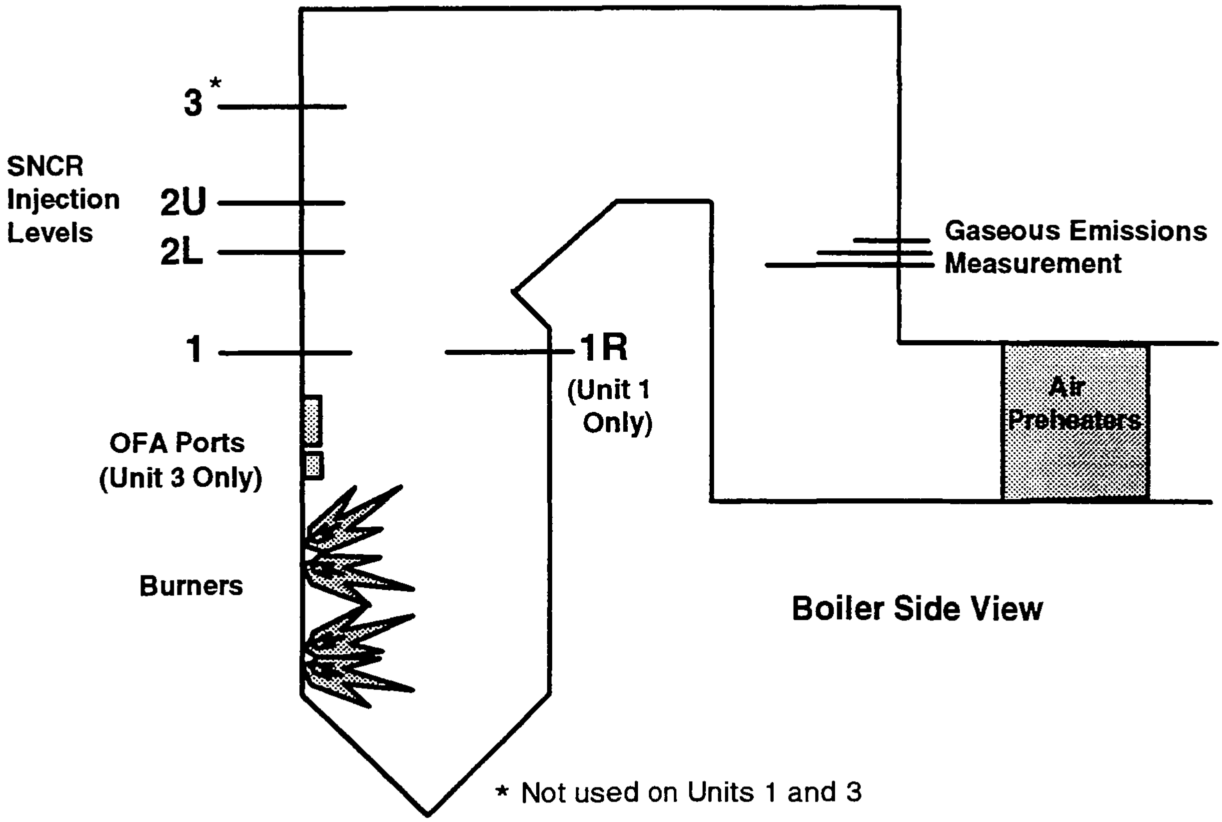

Figure 1
Locations of SNCR Injectors, Salem Harbor Units 1 and 3

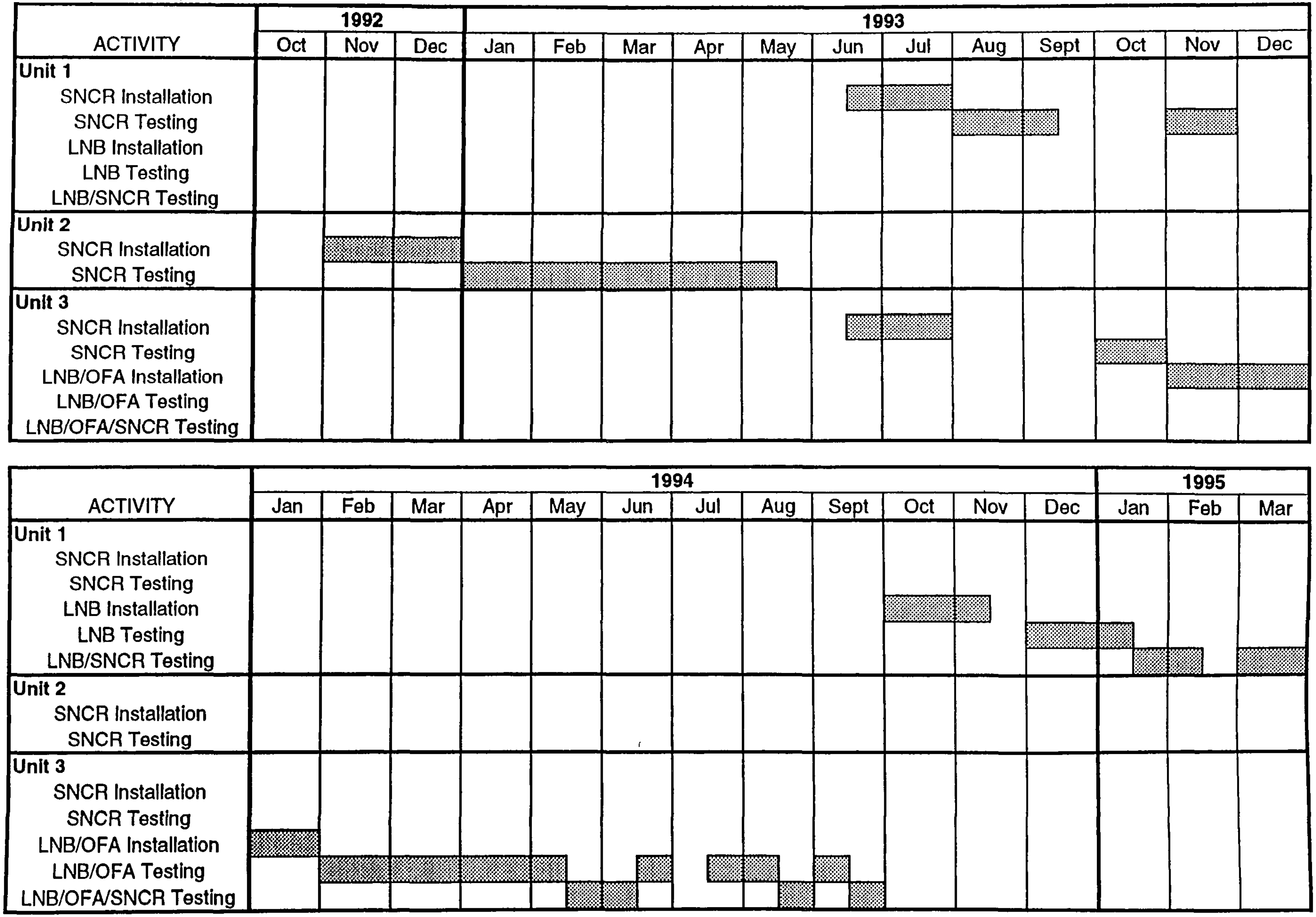

Figure 2
Salem Harbor NO_x Test Program Schedule

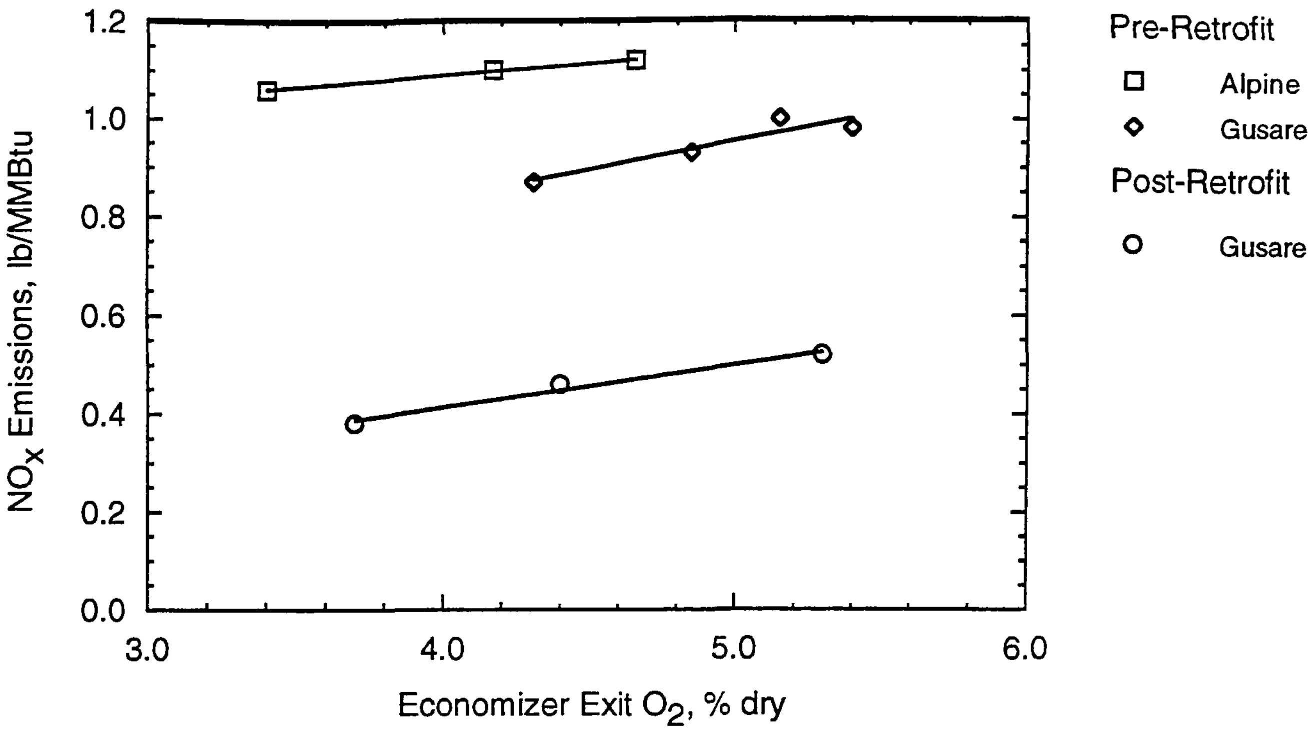

Figure 3
NO_x Emissions versus O_2 Level. Salem Harbor 1, Full Load Operation

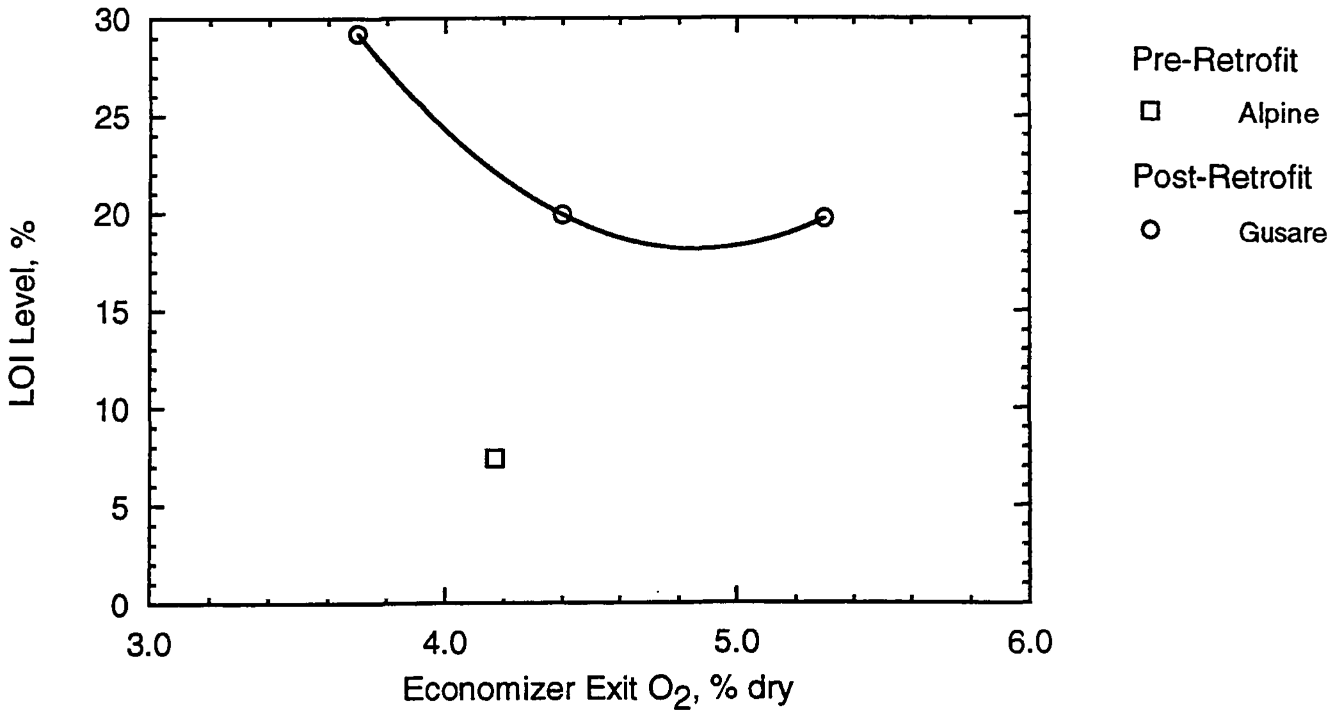

Figure 4
Effect of O_2 Concentration on LOI Levels. Salem Harbor 1, Full Load Operation

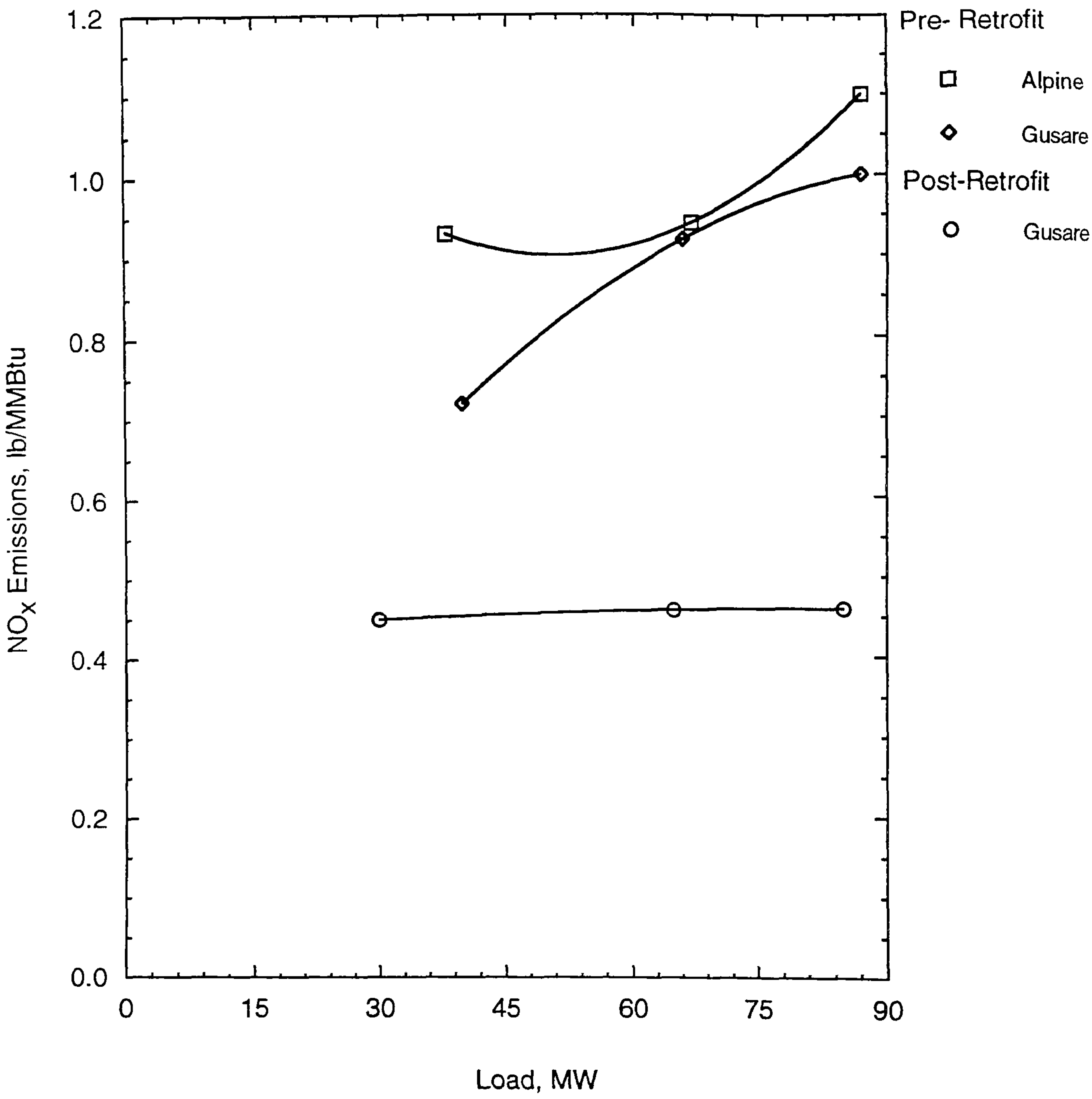

Figure 5
NO_x Emissions versus Load. Salem Harbor 1, Nominal O_2 Levels

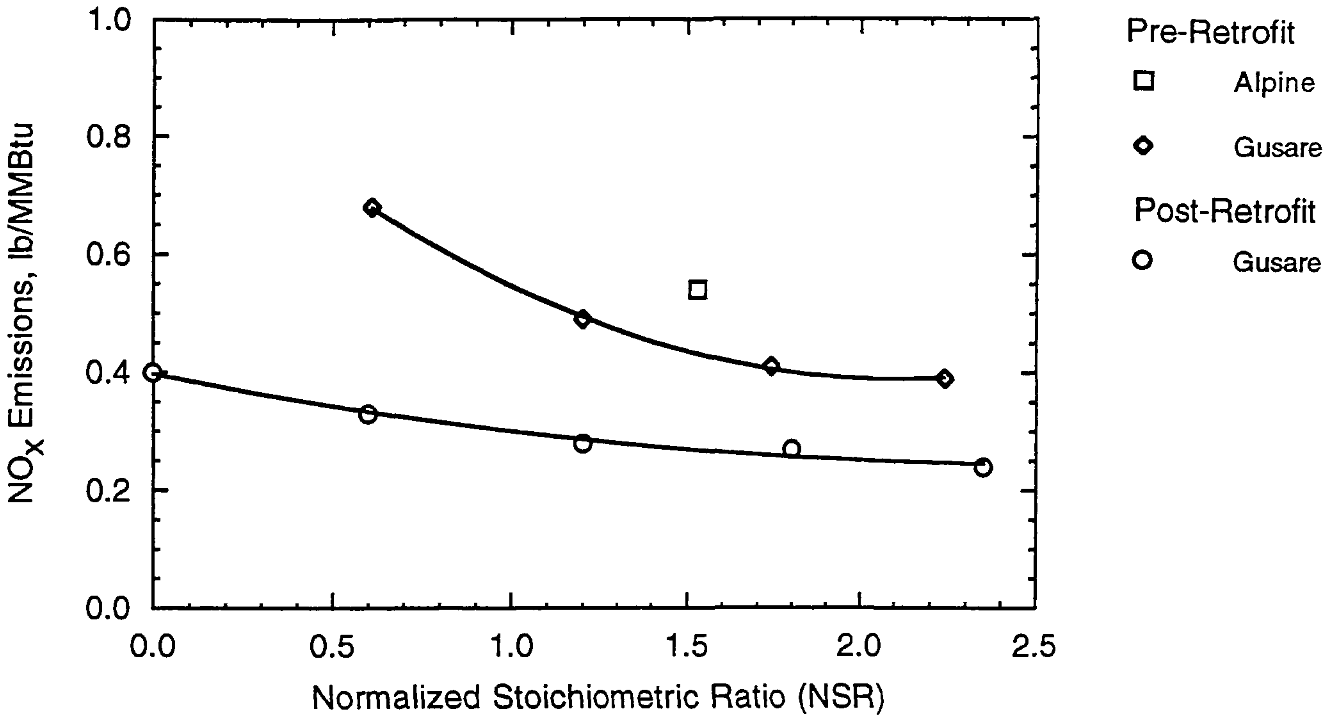

Figure 6
NO_x Emissions versus NSR. Salem Harbor 1,
Full Load Operation at Nominal O_2 Levels

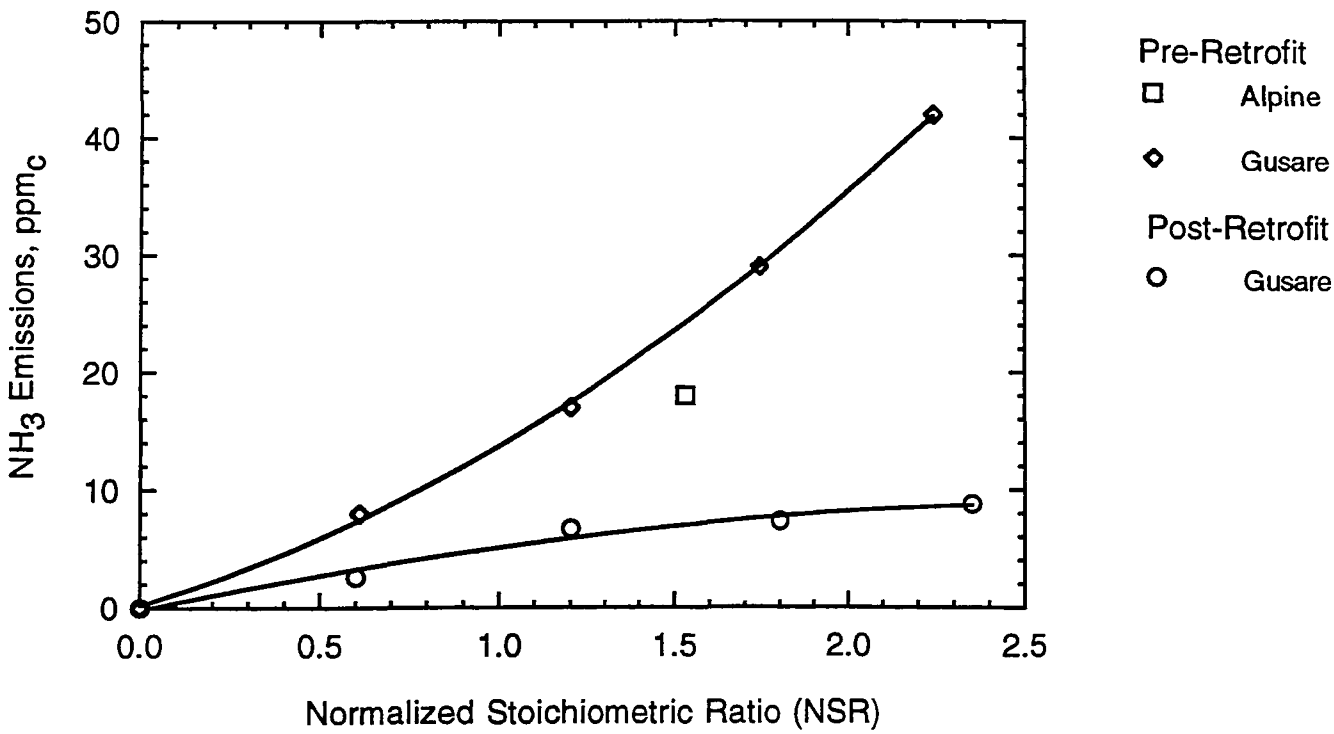

Figure 7
Effect of NSR Variation on NH_3 Slip. Salem Harbor 1,
Full Load Operation at Nominal O_2 Levels

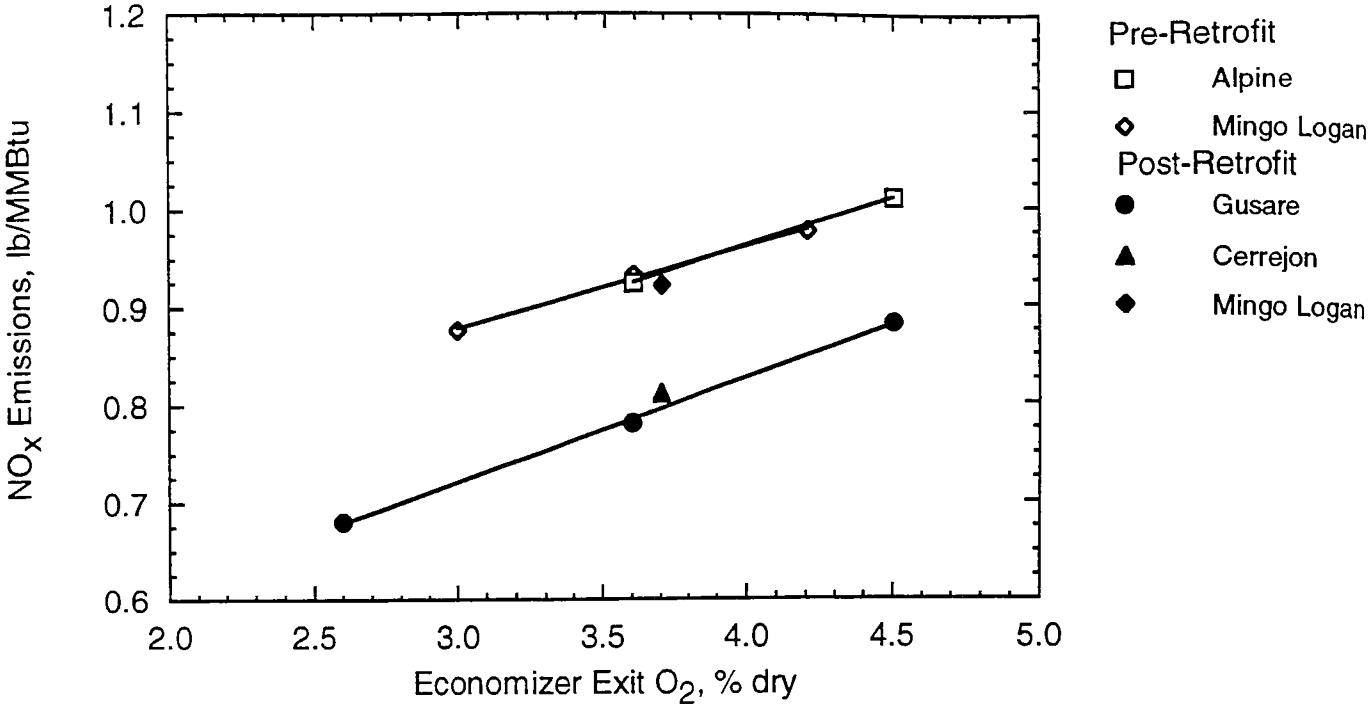

Figure 8
NO_x Emissions Sensitivity to O_2 Level. Salem Harbor 3,
Full Load Operation, OFA Dampers Closed

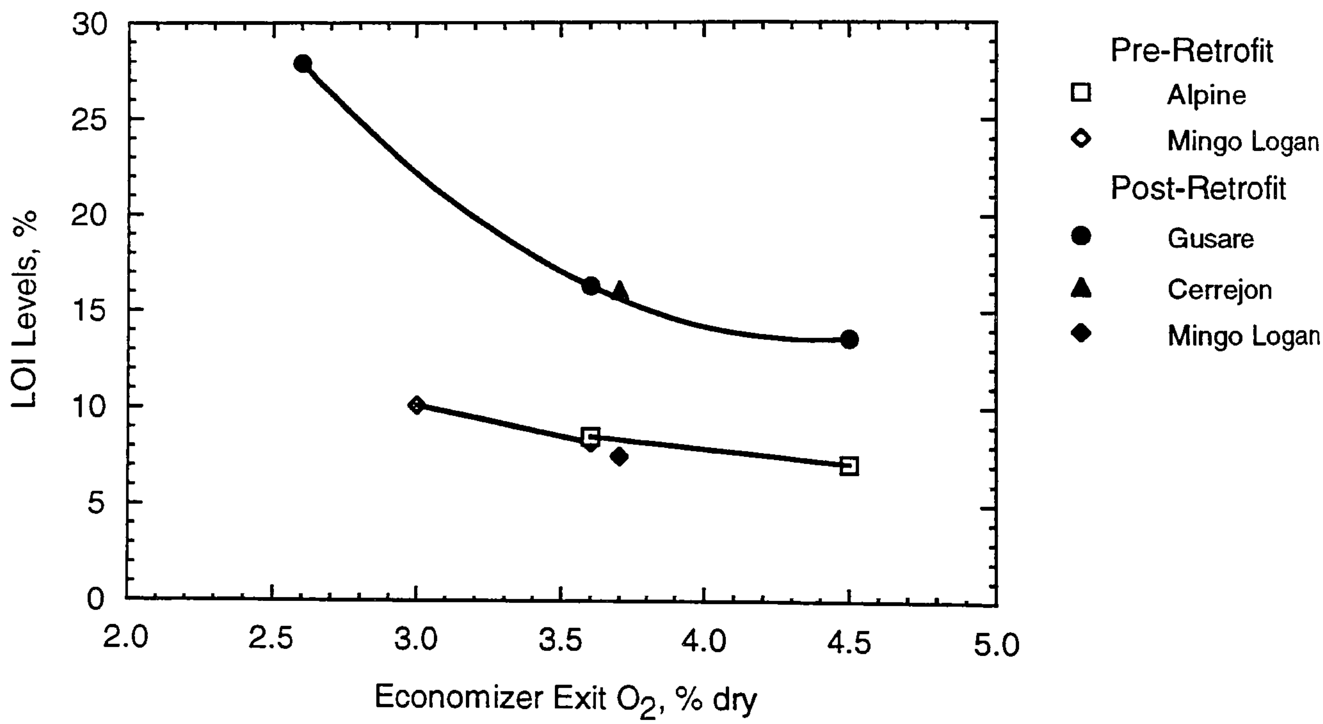

Figure 9
LOI Sensitivity to O_2 Level. Salem Harbor 3,
Full Load Operation, OFA Dampers Closed

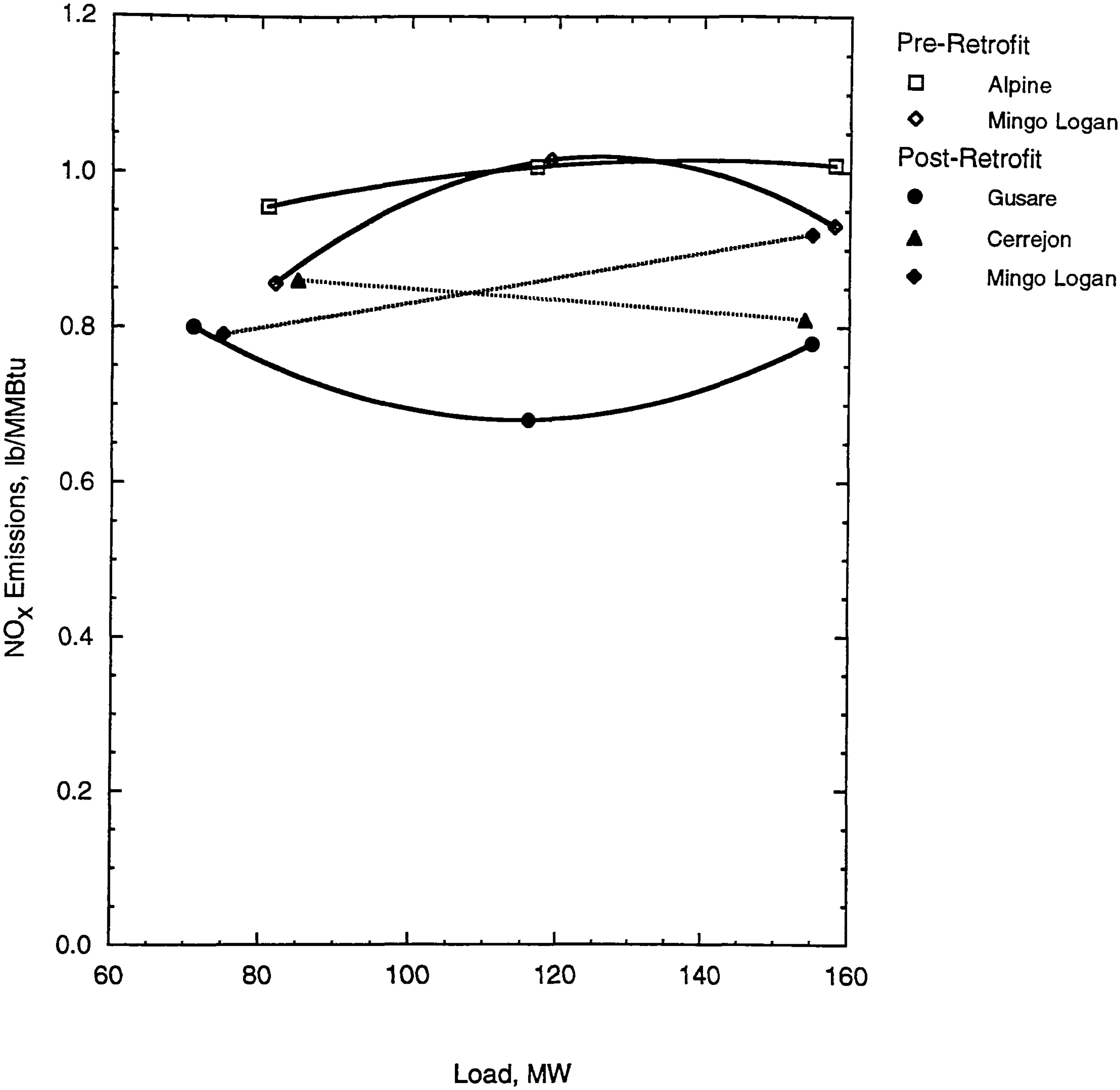

Figure 10
NO_x Emissions Variation with Load. Salem Harbor 3, Full Load Operation, OFA Dampers Closed

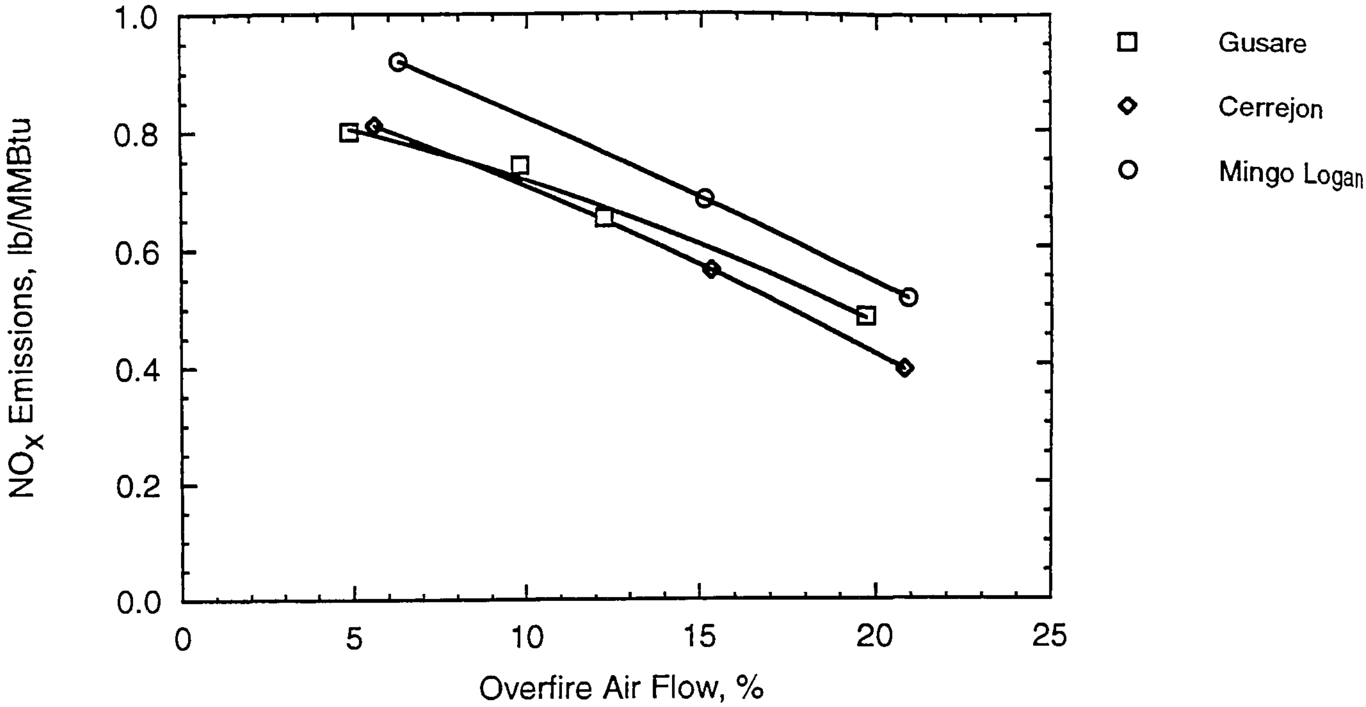

Figure 11
Effect of OFA on NO_x Emissions. Salem Harbor 3, Full Load Operation, Nominal O_2 Levels

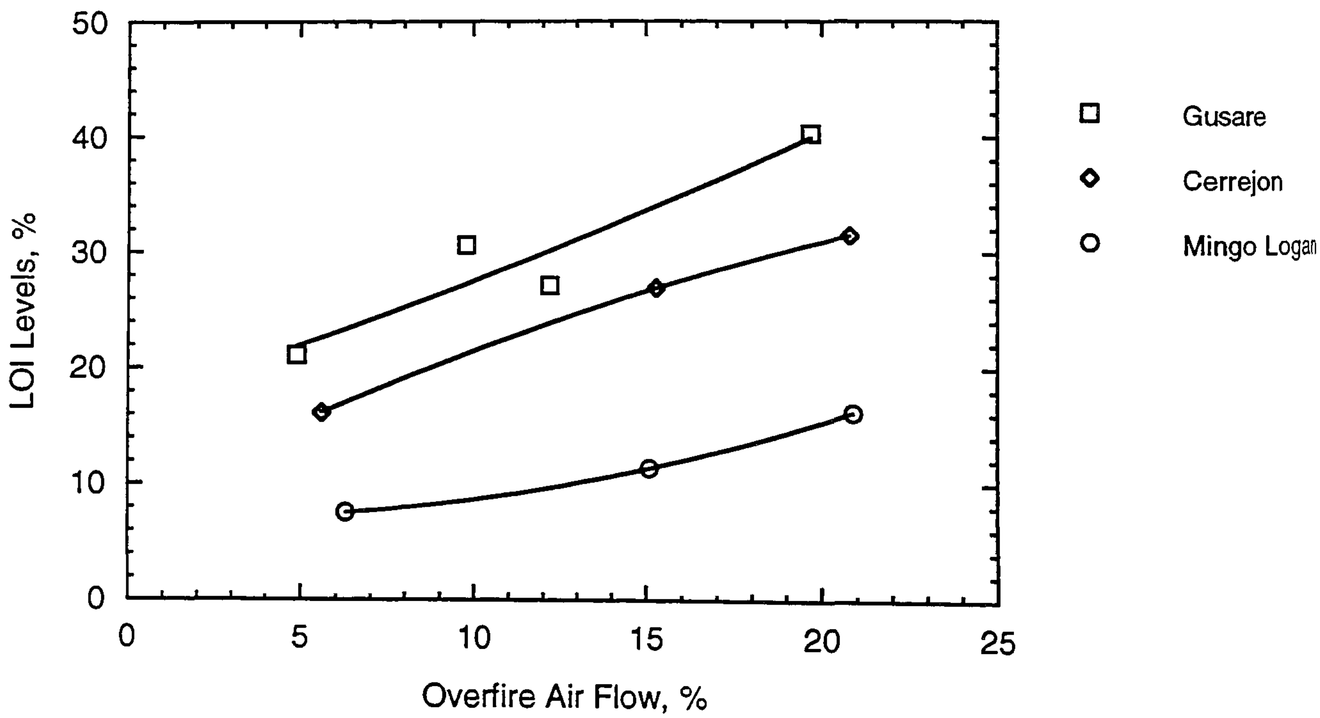

Figure 12
Effect of OFA on LOI Levels. Salem Harbor 3, Full Load Operation, Nominal O_2 Levels

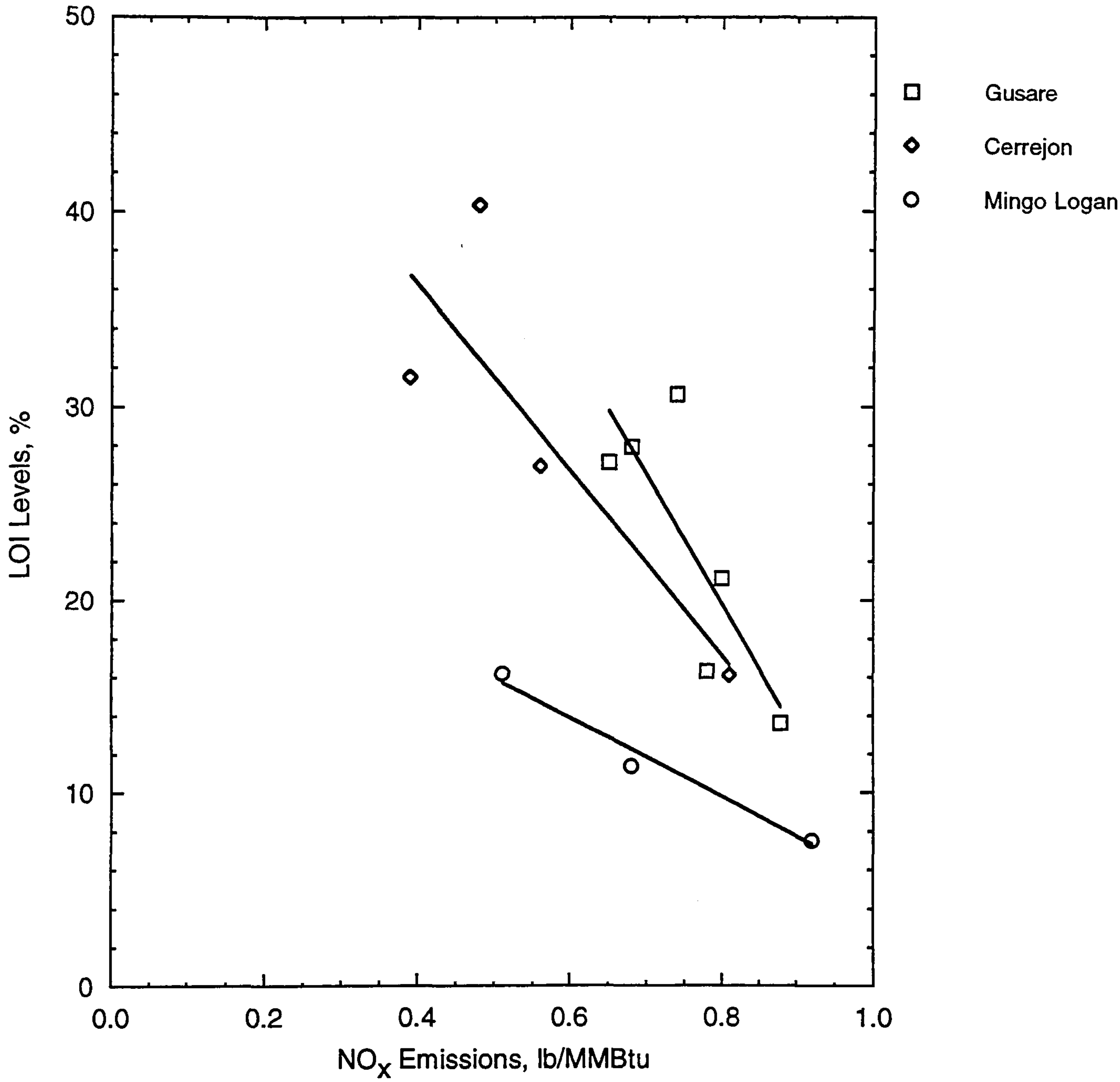

Figure 13
Relationship Between NO_x Emissions and LOI Levels. Salem Harbor 3, Post-Retrofit Full Load Tests

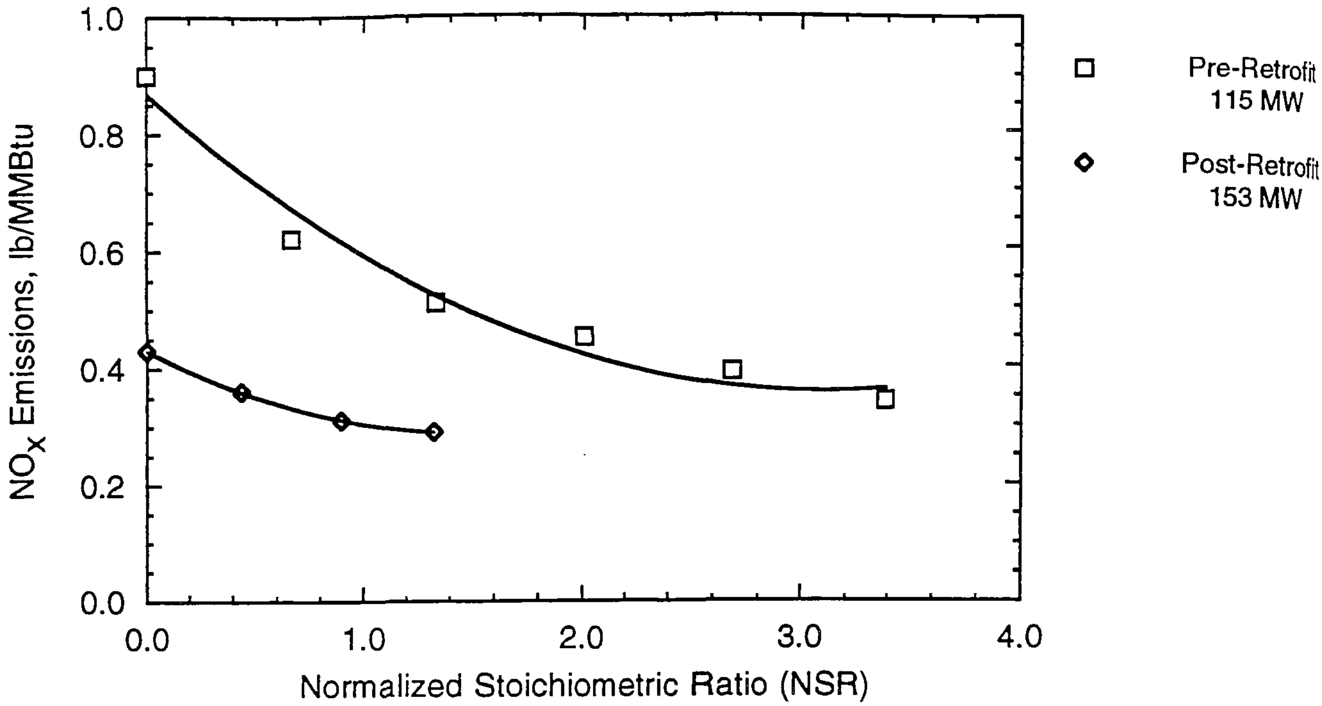

Figure 14
NO_x Emissions Versus NSR, Salem Harbor 3

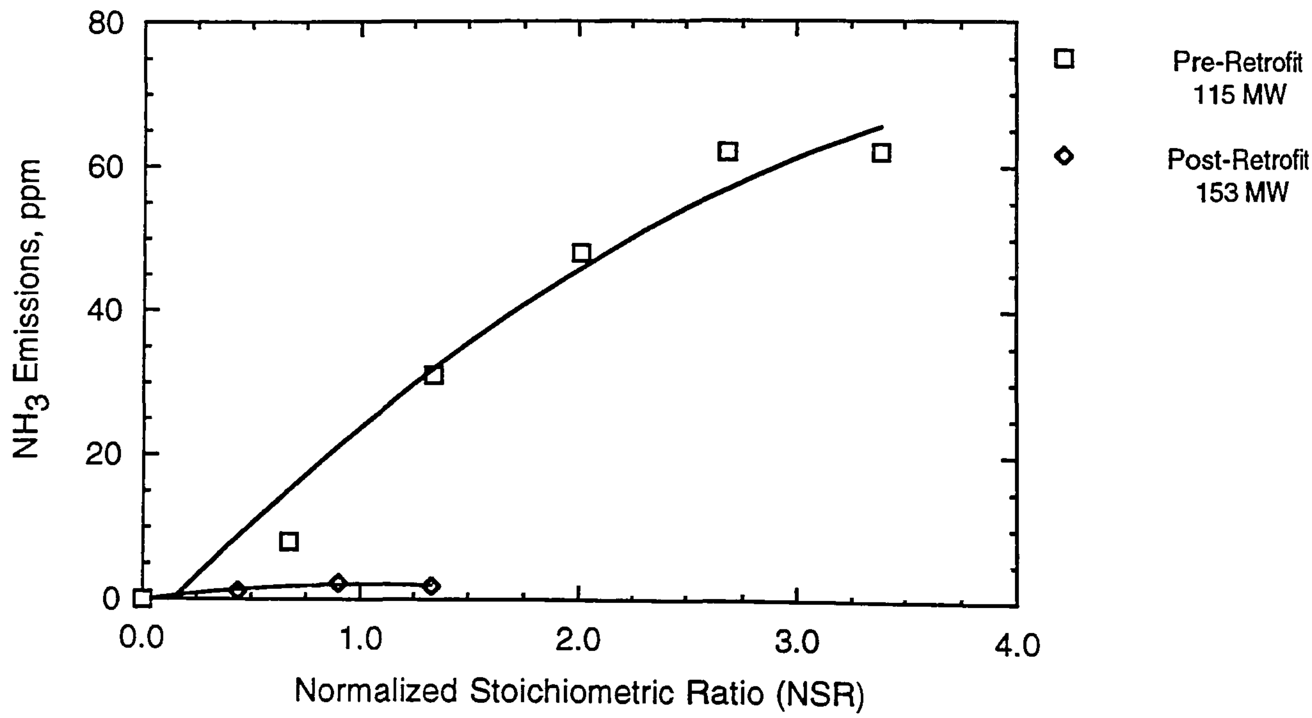

Figure 15
NH_3 Emissions Versus NSR, Salem Harbor 3

AN EVOLUTION OF NOZZLE DESIGN

THE LOW NOX BURNER EXPERIENCE AT THE BALDWIN POWER STATION

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Abstract

Illinois Power Company (IPC) installed low NOx burners on Baldwin Unit 3 in the Spring of 1994. Although the NOx reduction performance of these burners has been outstanding (See Figure 1), IPC suffered catastrophic nozzle failure in the first 8 weeks of operation. The nozzles were then modified and later, replaced. Within 1 week of operation, 2 of the new nozzles also failed. This paper traces the development of the original nozzle, the influences of other nozzle failures on its design, the determination of the cause of the original and subsequent failures, and the current state of the nozzles.

ILLINOIS POWER		BALDWIN UNIT 3		
IN-SERVICE DATE		APRIL, 1994		
UNIT SIZE		600 MWN		
	PERFORMANCE	DATA		
		BASELINE	GUARANTEE	POST CONVERSION
NOx	lb/Mbtu	0.74	0.40	0.31
UBC	%	2.0	4.0	2.0
CO	PPM	30	150	30

FIGURE 1

Introduction

Illinois Power Company (IPC) has five coal fired plants (10 operating units) that are affected by the Clean Air Act Amendments of 1990. Of these units, three (Baldwin 3, Vermilion 2 and Hennepin 2) are Phase I, Group I boilers. IPC's original strategy was to retrofit all of these units with low NOx burners. Recognizing the need to be more cost effective, IPC reanalyzed its system and determined that the system average could be maintained without retrofitting Hennepin 2 (a 240 MW, twin furnace design). Vermilion Unit 2 was retrofit with low NOx burners in the Spring of 1993. Subsequently, a switch in the compliance plan from FGD to allowances made it prudent to convert the Vermilion plant to natural gas operation. As a result, IPC's entire NOx compliance plan depends on the successful operation of the low NOx burners on Baldwin Unit 3.

The outage for the installation of the low NOx burners for Baldwin Unit 3 began in March of 1994 and continued until early May. In addition to the low NOx burners the units' reheater was replaced, additional superheater surface was added and the control system was replaced with a Westinghouse Distributed Control System. Although these projects were basically unrelated, good communications among the principals resulted in a cohesive outage plan and execution. For example, the operation of the secondary air dampers was incorporated into the burner management system and the amount of surface to be added to the superheater was increased further due to the tendency of low NOx burners to reduce steam temperatures.

The low NOx burner system installation was competitively bid as a turn key project. Bids were solicited with guarantees of both 0.45 and 0.40 pounds NOx per million BTU. After analysis of these bids the Contract was awarded to International Combustion Limited (ICL).

International Combustion

International Combustion (IC) is part of the Rolls-Royce Industrial Power Group. IC is a boiler OEM, having installed capacity worldwide in a wide variety of fuels including oil, gas and coal firing, since its' founding in the early 1920's. IC provides a turnkey capability in the design, manufacture and installation of fossil fired utility steam generators, heat recovery steam generators, low NOx retrofit systems, specialist combustion systems, rehabilitation, repair and maintenance of steam generators. IC is also a manufacturer of high integrity pressure vessels and fabrications.

The Combustion Systems Business Unit is mainly concerned with the low NOx emission burners. With the advent of the 1990 Clean Air Act Amendments in the USA, considerable work has been carried out by IC in retrofitting utility boilers with low NOx equipment. Since 1992, 15,825MW of low NOx equipment has either been installed or is on order. These projects have either been undertaken on a turnkey basis or a design, supply and advise contract.

Low NOx Burner Design Basis

All low NOx burners supplied by IC are designed in accordance with standard IC design procedures for both coal and auxiliary (secondary) air nozzles. The original Baldwin auxiliary air nozzle free area was used as the basis for the single IC outer coal nozzle. Care was taken that the exit velocities for both inner and outer nozzles were within the specified ranges at full load conditions. IC supplied the inner and outer coal nozzles, with the existing seal plates and coal pipes being re-used. During installation the seal plate was modified with extension guides to enable it to operate over the full tilt range. Due to the original seal's design, it was still possible for it to disengage at full (30 degree) tilt, and therefore a 20 degree tilt limit was imposed.

Baldwin Low NOx System

The Baldwin low NOx conversion consists of 2 levels of separated overfire air (SOFA) along with a complete burner box retrofit of coal and air nozzles (See Figure 2).

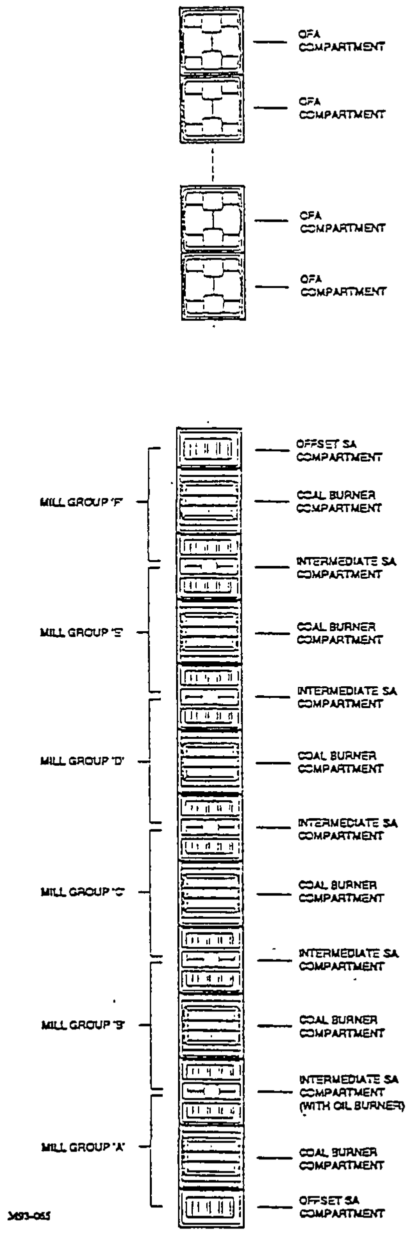

FIGURE 2

Along with this, the coal pipes have been resupported and a new tilt linkage and drive system installed by IC. This pipe support work was undertaken to remove the main tilt binding experienced on this boiler, restoring full burner tilt control.

The original Baldwin coal nozzles, fitted in the spring of 1994, were based upon the successful low NOx burners, operational at Fiddlers Ferry Power Station in the UK since 1985. The Baldwin nozzles, however, are significantly larger than any others produced by IC. The design had been modified following operational experiences at other power plants. These modifications were undertaken to prevent inversion of primary air to secondary air pressure differential across the seal plate. Earlier experience in the USA had shown that this pressure inversion could lead to a leakage of pulverised fuel into the outer nozzle which may ignite and cause nozzle failure. Investigation of this phenomenon at Baldwin revealed that several factors were involved, including cut backs in the unit windbox division plates. The method used to prevent this inversion was to insert an internal steel restriction strip (baffle bar) in the outer nozzle (See figure 3). This causes a back pressure in the fuel secondary air stream, ensuring that the secondary air was at a higher pressure than the primary air, adjacent to the seal plate.

ORIGINAL IC COAL NOZZLE WITH BAFFLE BARS INSTALLED

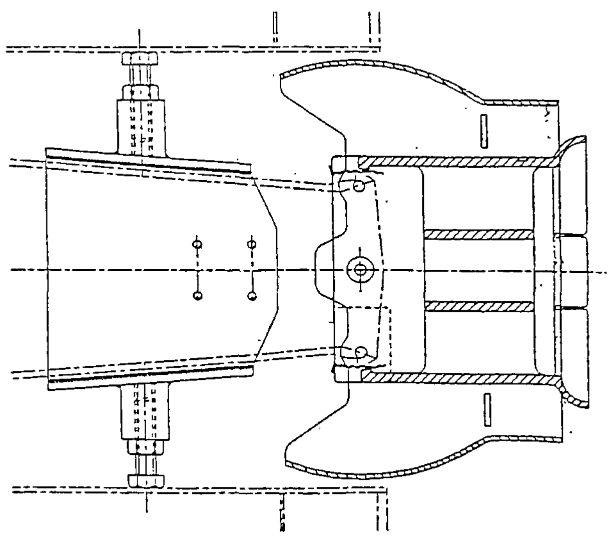

FIGURE 3

Initial Unit Operation

Upon completion of the outage the unit was successfully returned to service. To facilitate operator training and familiarization with the new control system, the unit was operated **without** overfire air for a period of 4 weeks. During this time the NOx emissions levels averaged above 0.50 lbs./mmbtu. Once the operators became comfortable with the new unit control system, the unit was turned over to ICL for optimization. It immediately became apparent that NOx emissions levels would not be a problem. With the overfire air system in service, NOx levels were easily below the limit of 0.45 and the guarantee of 0.40, sometimes reaching as low as 0.26 for hourly averages. LOI levels in the flyash did not increase over baseline levels, staying between 2.0 and 3.0 percent. It appeared that the Baldwin Unit 3 retrofit would be a textbook example of a low NOx retrofit, with an on-time outage, excellent performance and a quick and easy optimization. Unfortunately, this was not to be the case.

It became apparent during the early unit operation, through the use on an in-furnace camera, that strong flame attachment had been achieved on the inner nozzle, indicating a highly reactive coal.

Nozzle Failures

On May 27, the first indications of problems occurred. The permissives for the ignitors on Right Front burner E ceased to function. Upon investigation, it was determined that one of the nozzles had significantly deteriorated and the heat had destroyed the flame scanners. On June 1, the unit was removed from service for a tube leak and the nozzle replaced. On June 13, the Left Front burner C nozzle failed. This failure was much more severe, burning through the windbox and destroying most of the corner. The unit was forced from service for 1 week, returning to service on June 19. During this time IC supplied replacement parts and worked with Illinois Power to effect the quick return to service.

Investigation

During the outage the following interim measures were taken:

1. The nozzle flares were removed.

2. The primary air control devices were recalibrated, and

3. The D mill primary air was placed on maximum constant value.

These actions were carried out to ensure the safe and reliable operation of the unit while IC engineering and R & D investigated the probable causes of the failures, and made recommendations to modify the nozzle to prevent reoccurrence of the situation.

The engineering assessment revealed that:

1. The primary air flow control ramp had not been considered in the initial design.

2. The primary air flows were unbalanced between mill to mill as well as between corners.

3. At minimum load conditions the mean primary air exit velocity was marginal, and

4. At extreme tilts (20 degrees) there were some recirculating flows evident within the nozzle (See figure 4).

VELOCITY VECTORS WITH FLARE REMOVED

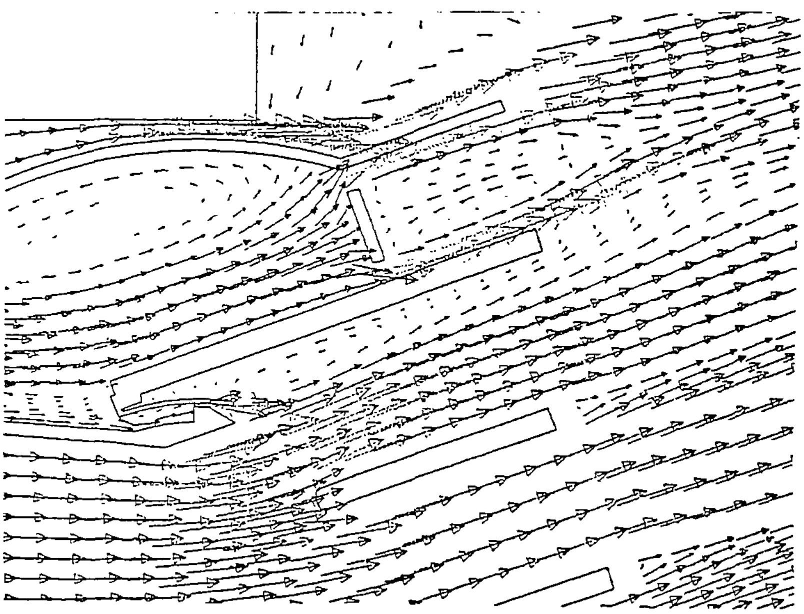

FIGURE 4

Fluid model work by R & D revealed that a rib in the coal pipes, that in some cases was installed with the rib on the bottom, had disadvantages with respect to primary air flows and coal distribution within the pipe. Further the model revealed that at minimum load there was a possible primary air flow variation, within the nozzle, of up to 30%.

Subsequent Operation

Following the units return to service, the furnace camera was used extensively to monitor the nozzles in service. Some flame attachment was still observed on the inner nozzles. As ash accumulated on these inner nozzles, it was removed periodically by rodding out the burners, **with the unit on line.** Although there were no further fires, the overall condition of the nozzles began to deteriorate, with D elevation being removed from general service. It was apparent that the nozzles that had coal pipes with ribs on the bottom were more prone to nozzle pluggage. Throughout these problems, NOx performance and LOI levels continued to be excellent with NOx emissions as low as 0.28 lbs./mmbtu and LOI's below 2%.

Design Basis for New Burners

An extensive design investigation was carried out by IC on the Baldwin nozzles, using the resources within R & D and Engineering, combined with on-site work. The burner configuration was extensively scrutinized, using computational fluid dynamics (CFD) and isothermal modeling techniques. This was carried out to ensure that there was no significant internal recirculation with the nozzle at all tilt angles.

From this work the new nozzle design has emerged (See figure 5):

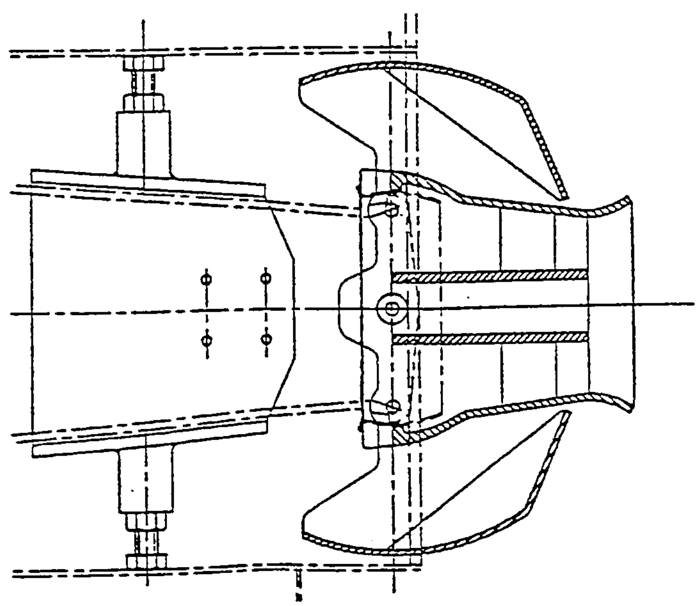

FIGURE 5

1. Exit velocities are now based upon the <u>minimum</u> primary air flows,

2. inner nozzle internal flow splitters have been extended to improve coal flow distribution at extreme (20 degree) tilt angles,

3. nozzle flare sections are now <u>only</u> on the top and bottom (not the sides), and

4. the outer nozzle profile has been modified to provide a single opening adjacent to the inner nozzle, eliminating the restriction strip.

These nozzles were installed in Baldwin 3 and placed in service on January 16, 1995.

Current Operation

Current observations of the coal nozzles show that there is flame attachment on the top burner elevations, though this attachment is sporadic. NOx levels, and all other guarantees, are being met throughout the load range. Within 1 week of installation, however, 2 nozzles on D elevation developed damage. All other burners have been visually inspected and no damage has been found. The two nozzles concerned were replaced and no apparent repeat of the damage has occurred. These two nozzles failures have been attributed to a short period of operation in which the D mill was operated without its normal primary air ramp. This led to an overpressurization of the primary air side of the nozzle, leading to fuel spillage and nozzle failure.

Session 3

Coal Combustion

Advanced Tangential Low NOx Systems - Development and Results

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1. INTRODUCTION

The development of low NOx combustion systems has identified the near burner flame conditions as critical in determining the eventual NOx emission levels. In this paper the development of this criterion, in respect of tangentially coal ('T') fired power generation boilers, is discussed together with their commercial application. The potential ultra low NOx performance of these techniques requires a deeper understanding of coal characteristics in addition to the standard properties involving volatile release rates, the behaviour of particulate clouds and their burning velocities. Aerodynamic properties including fuel air mixing, velocity and particulate distribution are all of fundamental importance and can be studied by means of isothermal physical modelling and computational fluid dynamics (CFD).

Amalgamation of these various aspects into burner and combustion system design can be considered as NOx control by flame management and can be applied to conventional systems as well as to the development of advanced low NOx burner technology. Low NOx equipment based on this technology is known as the EnviroNOx™ system.

2. 'T' FIRED BOILERS (ENVIRONOx™ T)

Burner systems in 'T' or corner fired boilers comprise basically of columns of alternate coal and air nozzles situated in the corners of a rectangular cross section furnace. The fuel and air is directed towards an imaginary firing circle in the centre of the furnace, the resultant mixing producing a 'central fireball' which provides combustion stability for the complete burner system. Because of the larger fuel air mixing paths and greater flame surface exposure to the cooler boiler walls, 'T' or corner fired boilers are lower NOx emitters than similarly sized wall or opposed fired units (I).

The first attempts at NOx reduction in 'T' firing were based on air staging techniques which aimed to reduce the main burner stoichiometry by reducing the corresponding air flow which was added separately at the top of each column to complete combustion. This overfire air (OFA) technology was limited because of the danger of creating reducing conditions adjacent to the boiler walls in the burner region and the consequent corrosion of pressure parts.

Offsetting some of the main burner combustion air to create an oxygen rich atmosphere close to the walls enabled lower stoichiometry to be achieved in the main burner zone. These techniques have been described in several papers (2, 3).

3. APPLICATION OF AIR STAGING FOR NOx REDUCTION IN 'T' FIRING

An OFA/offset air system was installed on the Niagara Mohawk Power Corporation's Dunkirk 1 & 2 boilers. These 100 MW boilers incorporate four coal nozzles in each corner of the furnace. OFA was introduced via two compartments close coupled to the corner burner column (CCOFA) (EnviroNOx™ C).

Isothermal modelling was carried out to ensure the required mixing of the OFA was achieved within the boiler (4). The scale model is shown in Figure 1.

Additional to the air staging a modification to the coal nozzle was also included aimed at bringing the flame front close to the nozzle mouth which is in fact the first stage of converting the nozzles into actual burners with control over the near burner flame region. The use of enhanced flame stabilisation also offered control of NOx at lower firing rates which is not always readily achievable in air staged low NOx systems.

The NOx guarantee figures for the Dunkirk low NOx conversions are given below in Table 1, together with actual performance achieved for CO levels and SH & RH temperatures.

Table 1

PHASE 1 NOx GUARANTEES & ACTUAL PERFORMANCE FOR DUNKIRK UNITS 1 & 2

	UNIT #1			UNIT #2		
Load MW	96	70	46	96	80	33
NOx Guarantee, #/Mbtu	0.32	0.32	0.32	0.32	0.32	0.37
CO Performance, ppm	<32	<30	<36	<62	<22	<67
SH Temperature °F	1000	1009	996	996	1007	1007
RH Temperature °F	1000	974	943	1005	1001	970

NOx guarantees were met at all loads, for both boilers, with reductions from baseline being in the range 33-41%. CO emissions achieved were well below the guarantee level.

Guarantees were also provided for UBC, Boiler Efficiency and SH & RH temperatures:

- All UBC guarantees were met. Indeed there was no significant increase in UBC over the load range against baseline.

- Boiler Efficiency guarantees were met with increases being achieved over the entire load range. However, it should be noted that Niagara Mohawk also replaced sections of waterwall, cold casing and installed new combustion control and burner management systems during the NOx outage.

- All superheat and reheat temperature guarantees were met throughout the load range.

In this "EnviroNOx™ C" system the advantages of enhanced flame front control were seen throughout the range of guarantees. These advances in flame management were the basis of development of a "T" fired coal burner rather than coal nozzle, based on principles established during the development and application of wall fired low NOx burners. The "T" fired burner is known as the FAN (flame attached nozzle) burner and is offered in the "EnviroNOx™ FAN" low NOx burner system. 4.8.

4. DEVELOPMENT AND APPLICATION OF A 'T' FIRED BURNER WITH ROPEMASTER™

a) Flame Attached Nozzle (F.A.N.)

The work on air staging and enhanced flame stability systems suggested lower NOx emissions may be available by replacing the coal nozzles on 'T' fired boilers by purpose designed coal burners.

Low NOx wall firing technology had developed burner flame attachment to control the near burner reactions ie the rapid release of volatiles and hence fuel H_2 into a low O_2 concentration atmosphere and the application of this technique gave rise to the development of the flame attached nozzle (FAN) burner for 'T' firing.

A similar mode of flame retention is used in the FAN burner design to that already proven in low NOx wall firing i.e. the use of flame retention wedges and flares. The material used in this critical region of the burner is a cast IN 657 alloy which has achieved service life of over 4 years in a 500 MW front wall fired UK installation confirming that early flame ignition does not damage correctly designed burners. Therefore the flame retention design principle is secure.

b) RopeMaster™ Development

In order to exercise the necessary control on fuel flow to achieve low NOx operation it is essential to have a good fuel air distribution within the FAN burner nozzle. However pulverised coal levels to travel through coal pipework in a series of "ropes" rather than as a uniformly dispersed stream and therefore a reliable pulverised coal dispersal device is required close to the burner as illustrated in Figure 5.

The form and location of this dispersal device known as the RopeMaster™ was decided following isothermal solids flow modelling work achieving before and after distributions as indicated in Figures 8 and 9.

RopeMasters™ located at the entry to the burner cannot affect the coal distribution from the mill to the burner but have been applied to conventional 'T' fired boiler systems in which coal mal-distribution was thought to be occurring within the coal nozzles. A particular demonstration of RopeMasters™ in a 'T' fired boiler has shown that improvements in performance can be achieved by the correct installation of the RopeMaster™

A set of 16 RopeMasters™ were installed on the boiler at the burner inlets. Pre and post-retrofit testing confirmed a 60% reduction in LOI.

The boiler concerned has only two coal elevations, resulting a relatively shallow fireball. The shallowness of the fireball may be partly responsible for the relatively high pre-Ropemaster™ installation LOI levels (in excess of 10%). Work is in progress to evaluate the impact of Ropemasters™ on deeper fireball units.

The RopeMaster™ may also have further potential for improving coal distribution throughout the coal feeding system from mill to burner in coal fired boilers.

c) **Mark I FAN plus RopeMaster™ - site demonstration**

Following a period of intensive isothermal and CFD modelling work and full scale thermal testing in the International Combustion test facility at Derby in the UK the Mark I FAN configuration was finalised with results as indicated in Figure 3. (FAN burners have been applied to three units at Georgia Power's Yates site (5) together with various air staging configurations as indicated in Figure 4. For comparison purposes, Yates 6 a non-FAN air staged system is included in Figure 4.) A typical FAN nozzle arrangement is shown in Figure 5.

The installation on the 125 MW Yates 4 unit utilising FAN burners only was a final development exercise based on the Mark I version of the FAN burner. No modifications to the corner box air and coal nozzle configuration were made other than the installation of 16 FANs to replace the existing coal buckets.

The NOx performance of the Mark I FAN burner nozzles is shown in Figure 6, which illustrates the NOx variation with excess air at 100% MCR. Contrary to most 'T' fired boilers the FAN burner maintains lower NOx levels at lower loads, 0.40 lbs/10^6 Btu was achieved at 38% MCR with 6.5% excess O_2.

The baseline 100% MCR NOx for Yates 4 was 0.61 lbs/10^6 Btu. The FAN burners achieved 0.44 lbs/10^6 Btu a 28% reduction. Baseline and post retrofit carbon in ash figures were 2.8% and 3.8% respectively.

d) Mark II FAN plus RopeMaster™ - Commercialisation

The change from a Mark I to Mark II burner design derived from the perceived propensity for ash build-up in the region of flame attachment to occur in the Yates 4 furnace. the Mark II burner, based on aerodynamic rather than mechanical flame attachment eliminated this tendency.

As in the Mark I FAN development, extensive use of CFD, isothermal and full scale thermal test rig trials was made.

Yates 5 is a sister unit to Yates 4 and has been equipped with close coupled OFA (CCOFA) and offset air in addition to the Mark II FAN burner. Yates 5 represents the first stage of FAN technology commercialisation. With this system a 48% reduction in NOx was achieved at 100% MCR (from 0.65 lbs/10^6 Btu to 0.34 lbs/10^6 Btu) with an increase in carbon in ash from 2.6% to 4.6%. CO levels after conversion were measured at 13 ppm.

The identical 350 MW Yates units 6 and 7 low NOx retrofit projects provided the opportunity to compare FAN burner and conventional nozzle performance.

Yates 6 was retrofitted with an International Combustion EnviroNOx™ T2 (offset air plus two levels of separated overfire air (SOFA)) in early 1993. Following the exercise of Georgia Powers's option to purchase an identical EnviroNOx™ T2 system for Yates 7, a further decision was made to upgrade the EnviroNOx™ T2 system by adding Flame Attached Nozzles (FANs).

This upgrade provided Georgia Power and International Combustion with an opportunity to evaluate the impact of FANs on an already advanced low NOx system.

Over 50% NOx reduction was achieved in the Yates 7 (FAN burner) unit at 100% MCR compared to a 40% reduction from the air staged only Yates 6 plant. The results are plotted in Figure 7 which show the NOx variation with load. The FAN equipped Unit 7 achieved 0.24 - 0.28 lbs/10^6 Btu NOx at low to medium loads.

With FAN burner installations at the Yates plant unburnt carbon was kept below the 6% guarantee level without the necessity to improve mill performance as may be required on such conventional 'T' fired low NOx systems. Reheat temperatures were kept within an acceptable range.

5. LONG TERM DEVELOPMENT AND COMMERCIALISATION OF ADVANCED FAN BURNER TECHNOLOGY

International Combustion's long term target is the development of FAN based combustion systems capable of operating under commercial conditions with NOx levels at or below 0.1 lbs/MMbtu and on a wide range of coals and boiler designs. Progress to date is encouraging but not without problems.

For instance, as the commercial application of FAN burner technology has developed, potential problems of ash deposition within the flame attachment area of the burner have been identified. A deeper understanding of the characteristics of the various coals fired and the local nozzle aerodynamics are leading to an elimination of the problem and the evolution of the Mark III universal FAN burner.

Work on the Mark II FAN is already under way based on CFD modelling and full scale thermal test work confirming NOx levels around the 0.1 lbs/10^6 Btu level on the combustion test rig, approximately 50% those on the Mark I/II versions tested under similar conditions. Factors which are influencing this improved performance are attention to scarf plate seal design, flow properties within the burner nozzle flame attachment zone plus further attention to the ignition and burning characteristics of the air/pulverised coal mixture within this critical area. This has been shown to be a function of local fuel/air ratio, coal volatiles, coal ash content and system temperature.

The FAN burner technology has also been successfully demonstrated in a co-firing system using 10% of the total fuel heat input from natural gas fired adjacent to the FAN burner. This work was carried out with the Mark II burner design on behalf of Sydgas and Helsingborg Energi in Sweden.

The combustion of this small quantity of natural gas was used to enhance the near burner conditions required for NOx reduction ie high initial temperature coupled with low O_2 concentration. This advanced co-firing system is to be installed in 1995 on a 60 MW boiler targeted at a 0.1 lbs/10^6 Btu NOx emission level. (6)

During the Helsingborg development, a series of coals were fired both with and without gas enhancement. With the low volatile coals, gas firing was required to achieve flame attachment and low NOx operation. This contrasts with the IC front wall burner design which has been demonstrated to handle USA low volatile coals, down to 20% volatile matter, without support fuel, in the low NOx mode. This is possible because of swirl incorporated into the fuel secondary air which is not part of the 'T' fired FAN burner system.

The Helsingborg gas enhanced FAN burner showed a NOx reduction of 40% compared with a datum burner configuration under the test conditions. Approximately _ of the NOx reduction was achieved via the FAN burner and _ from the natural gas enhancement.

Other factors which have to be considered in the development of a universal FAN burner technology are the characteristics of the actual coals to be fired. A considerable data base of the characteristics of world-wide coals has been built up by International Combustion based on Thermo and Gravimetric Analysis (TGA) and Drop Tube Furnace (DTF) techniques.

TGA as well as producing the basic proximate and ultimate coal analyses also fingerprints coals in terms of their comparative reactivity which enables potentially "difficult" coals to be recognised. DTF takes this a stage further by examining coals under "flame conditions" identifying the actual rather than standard volatile matter indicated by proximate analysis. DTF also enables the NOx producing tendencies of the various coals to be compared.

Properties such as the coal Nitrogen content and the Fuel Ratio (which is the ratio of Fixed Carbon to Volatile Matter) are used as NOx indicators in a proprietary NOx factor calculation.

Development work continues on FANs and their associated systems. The target of a 0.1 $lb/10^6$ Btu NOx emission level has already been achieved at full scale on the International Combustion thermal test rig. Commercialisation at or below this level is now judged to be an achievable target.

6. CONCLUSIONS

In the 'T' fired system, air staging with flame attachment has been shown to achieve very low NOx emissions with control of unburnt carbon and CO emission levels.

Enhanced flame performance from the FAN nozzle which converts the 'T' fired coal nozzle into a burner, further improves the performance and ensures that low NOx performance is maintained throughout the load range.

The concept of flame management requires a deeper understanding of coal characteristics in terms of reactivity, ignition and burning velocities plus the behaviour of the particulate flow in addition to the basic coal properties. Thermogravimetric and drop tube furnace technologies can be used for these evaluations.

Isothermal model work and computational fluid dynamics have been used successfully to ensure that mixing patterns in air staged low NOx systems are acceptable and to study particulate and velocity distribution in burner systems.

Advanced air staging and flame management techniques have been demonstrated commercially as being capable of achieving satisfactory low NOx combustion in the 'T' fired boiler.

Continued development of the FAN burner concept has potential for further reduction in NOx levels with an extended range of coals. The burner can also be used in co-firing systems with natural gas to enhance the NOx control aspects of the near burner region of the flame.

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8. ACKNOWLEDGEMENTS

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Dunkirk 1 and 2 - ISO Thermal Furnace Model

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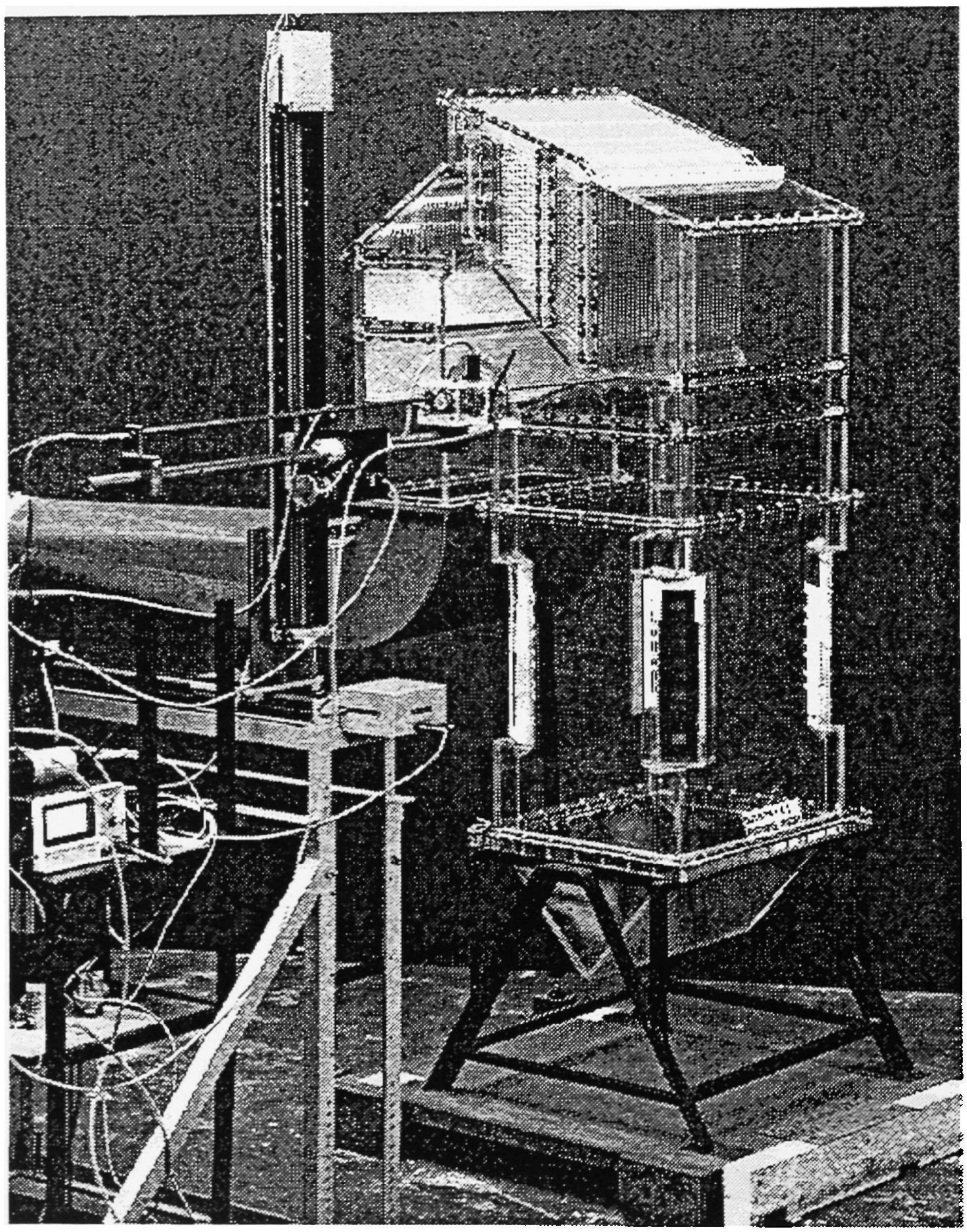

Figure 1

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Nox emissions for FAN burner nozzle

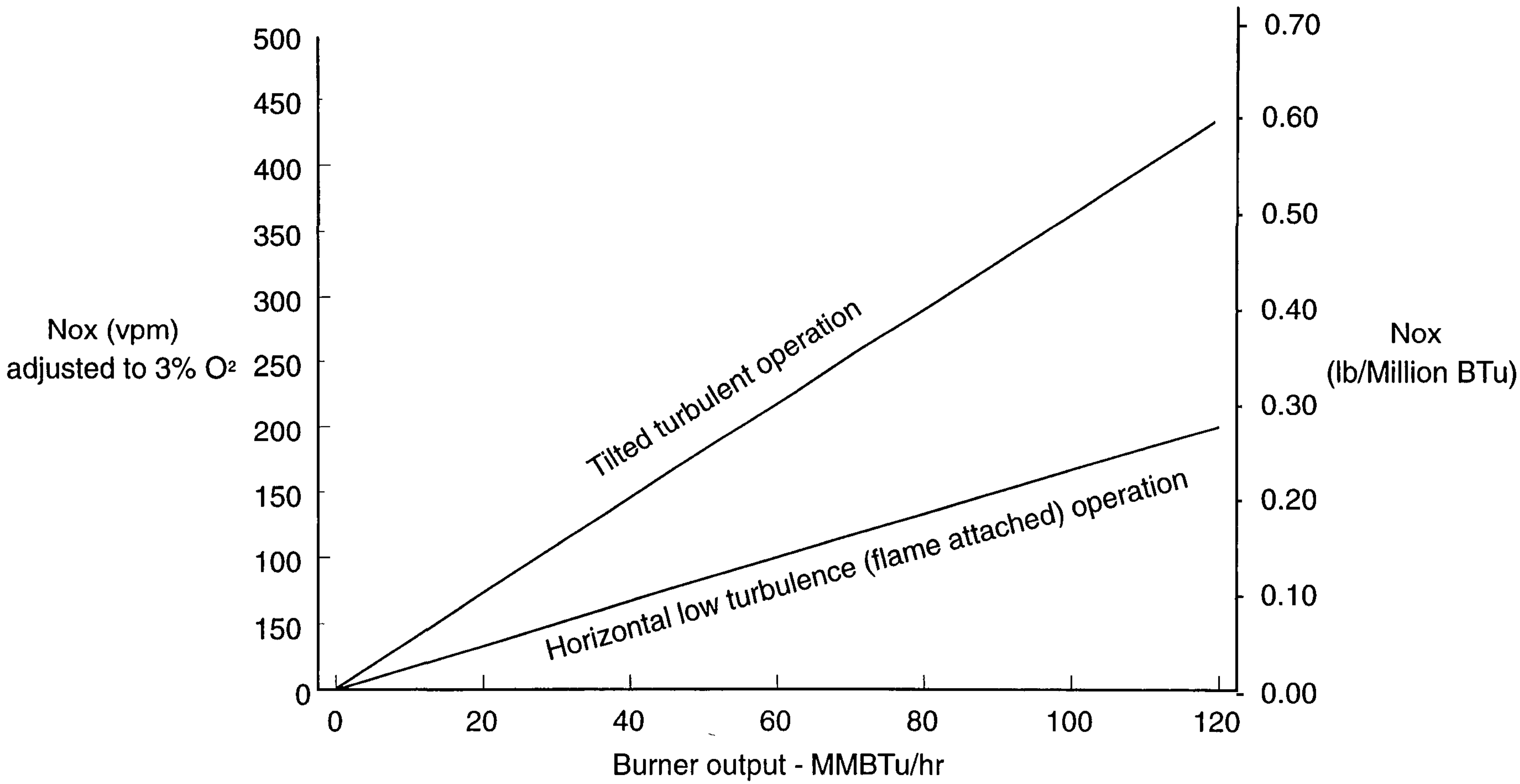

Figure 3

Plant Yates - corner box schematics post retrofit

Boiler Unit	YATES 4	YATES 5	YATES 6	YATES 7
EnviroNOx System	FANS only	CCOFA + FANS + Offset	SOFA II + Offset	SOFA II + FANS + Offset
CORNER BOX CONFIGURATION	FAN FAN FAN FAN	FAN FAN FAN FAN	OFA OFA OFA OFA	OFA OFA OFA OFA FAN FAN FAN FAN FAN
DATE IN SERVICE	APR 1993	APR 1994	DEC 1992	MAY 1994

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Flame attached nozzle (FAN) burner

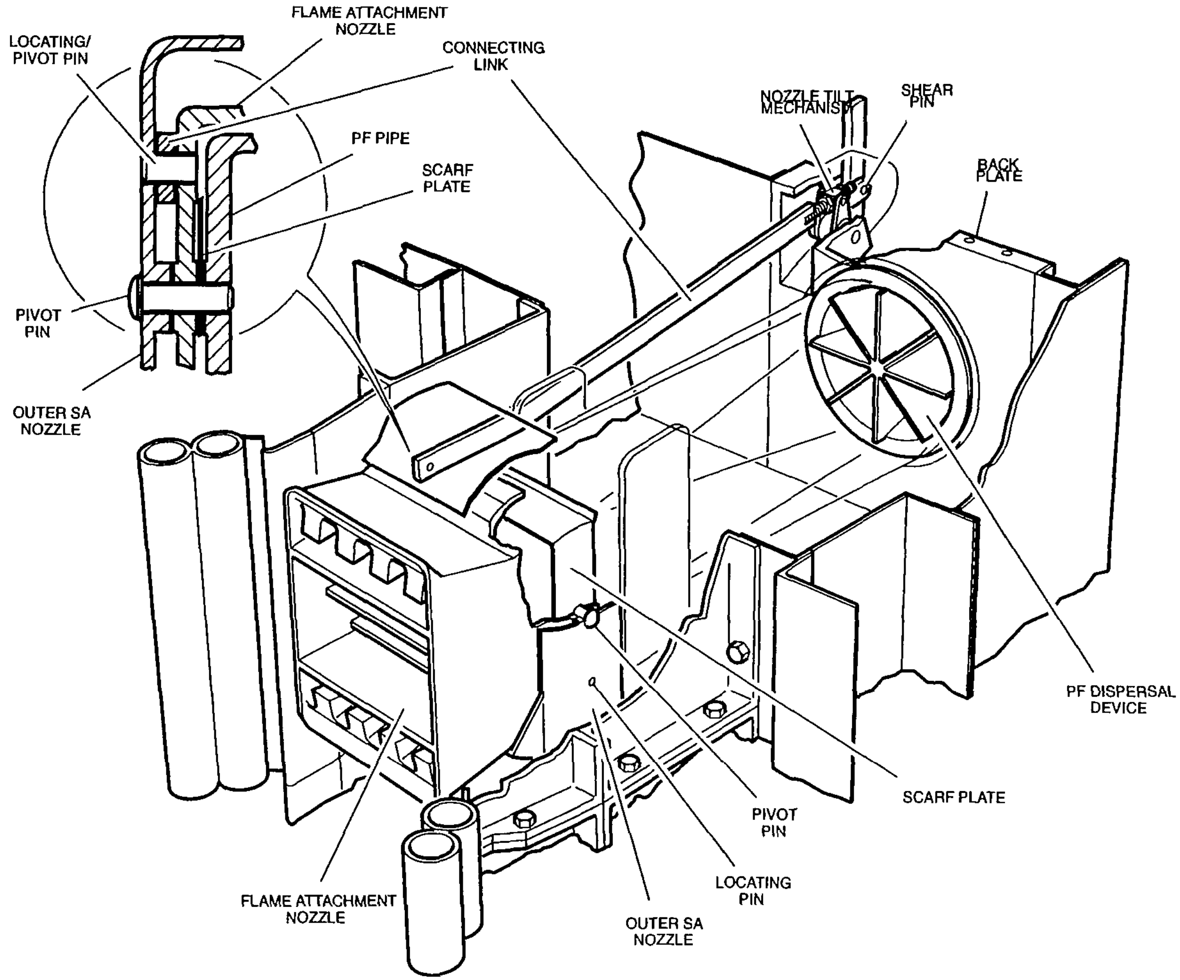

Figure 5

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Yates #4
Nox vs O_2 at full load

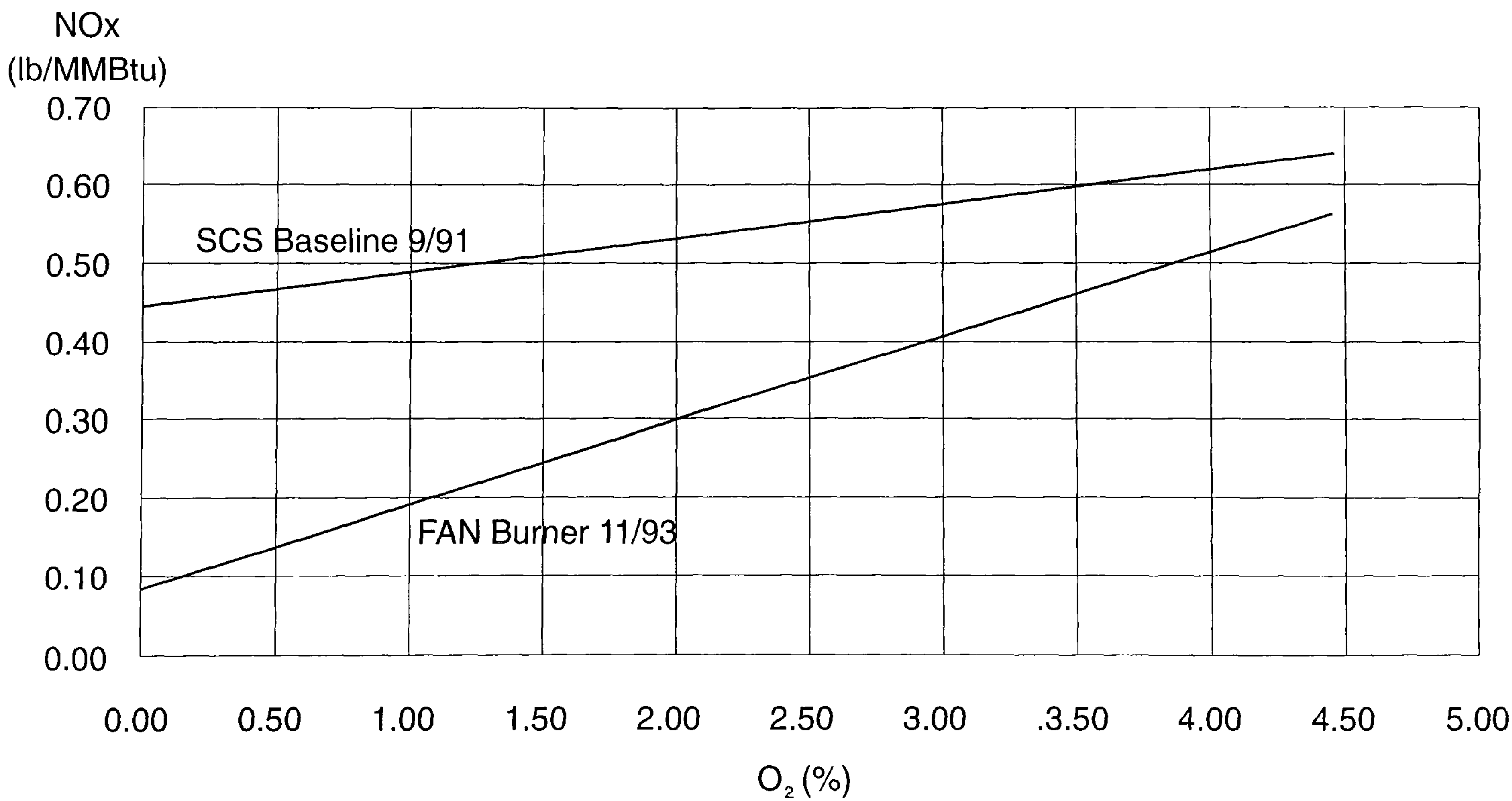

Figure 6

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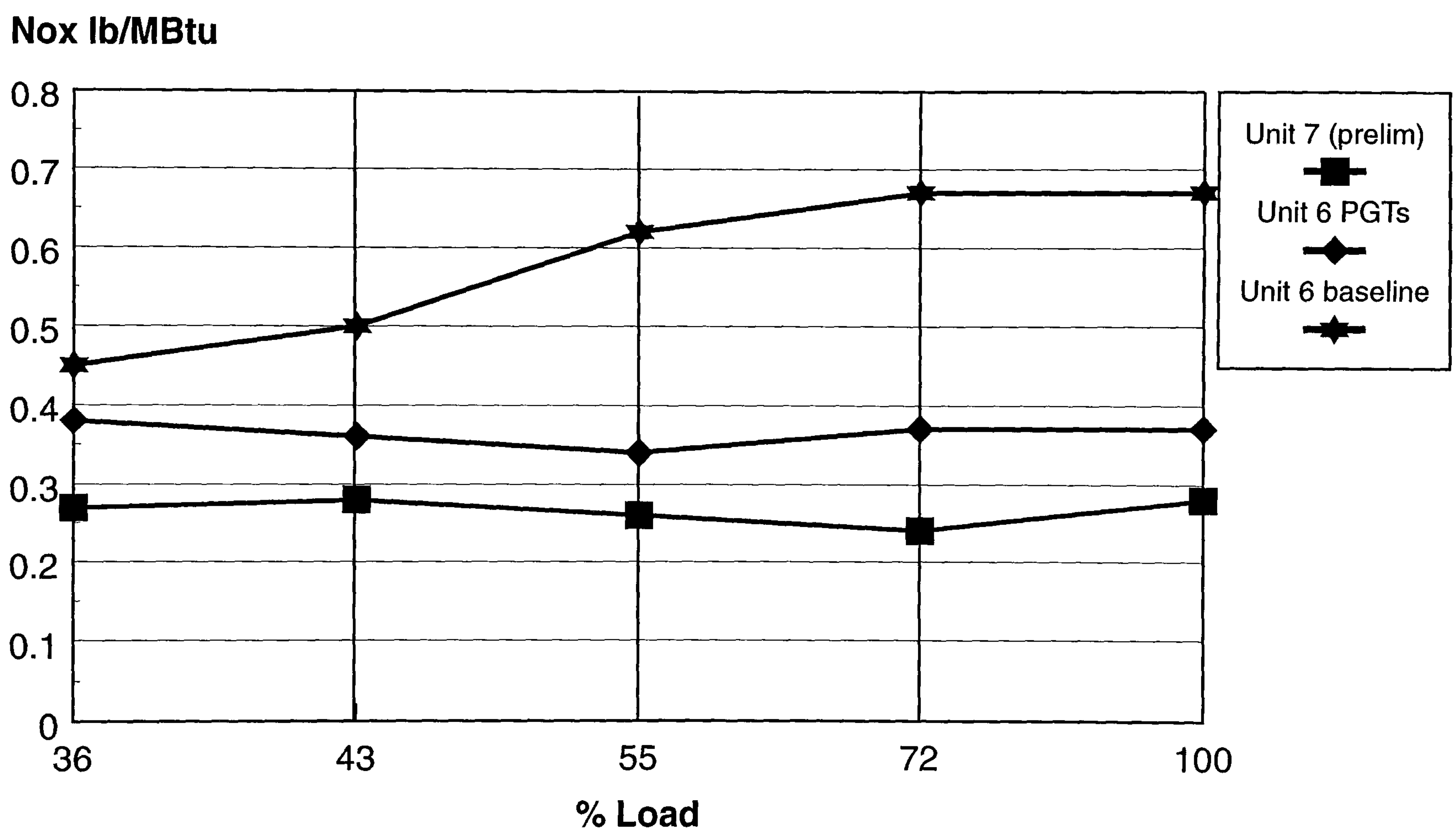
Georgia Power Plant Yates
Unit 6 and 7 - Nox comparison



ROLLS ROYCE

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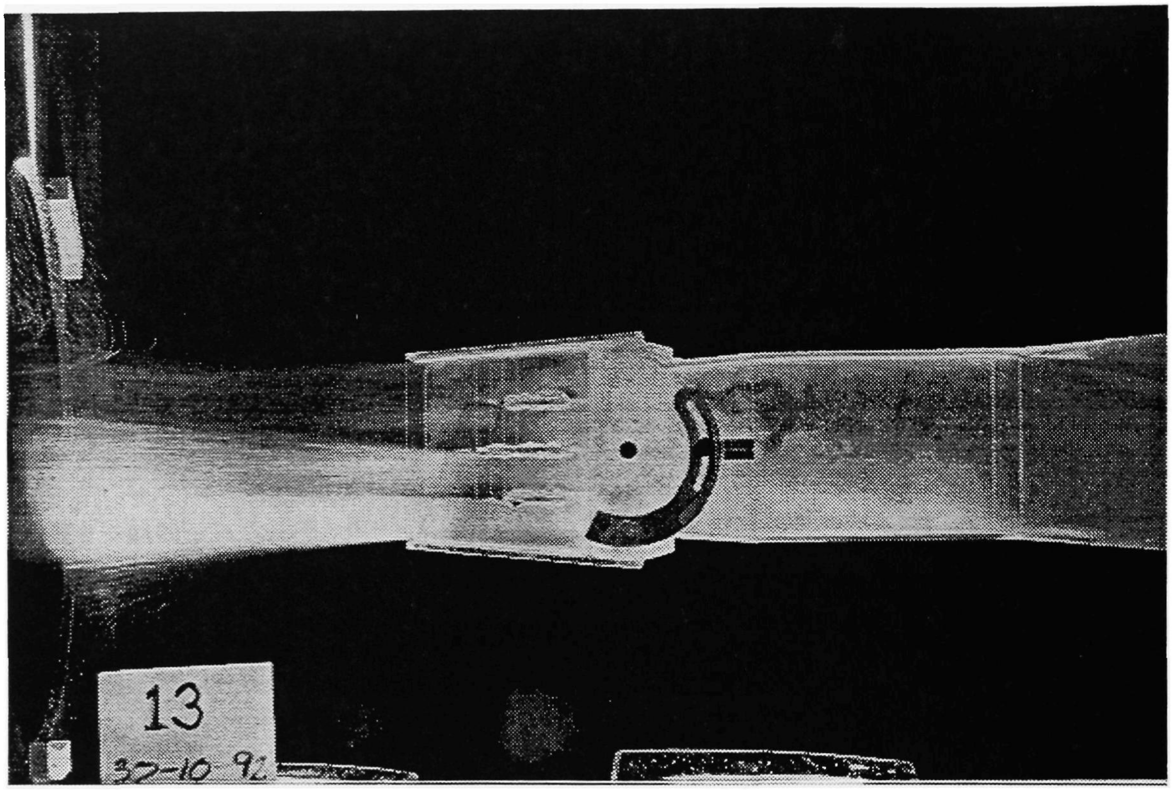
Pulverized coal distribution at nozzle discharge without RopeMaster™



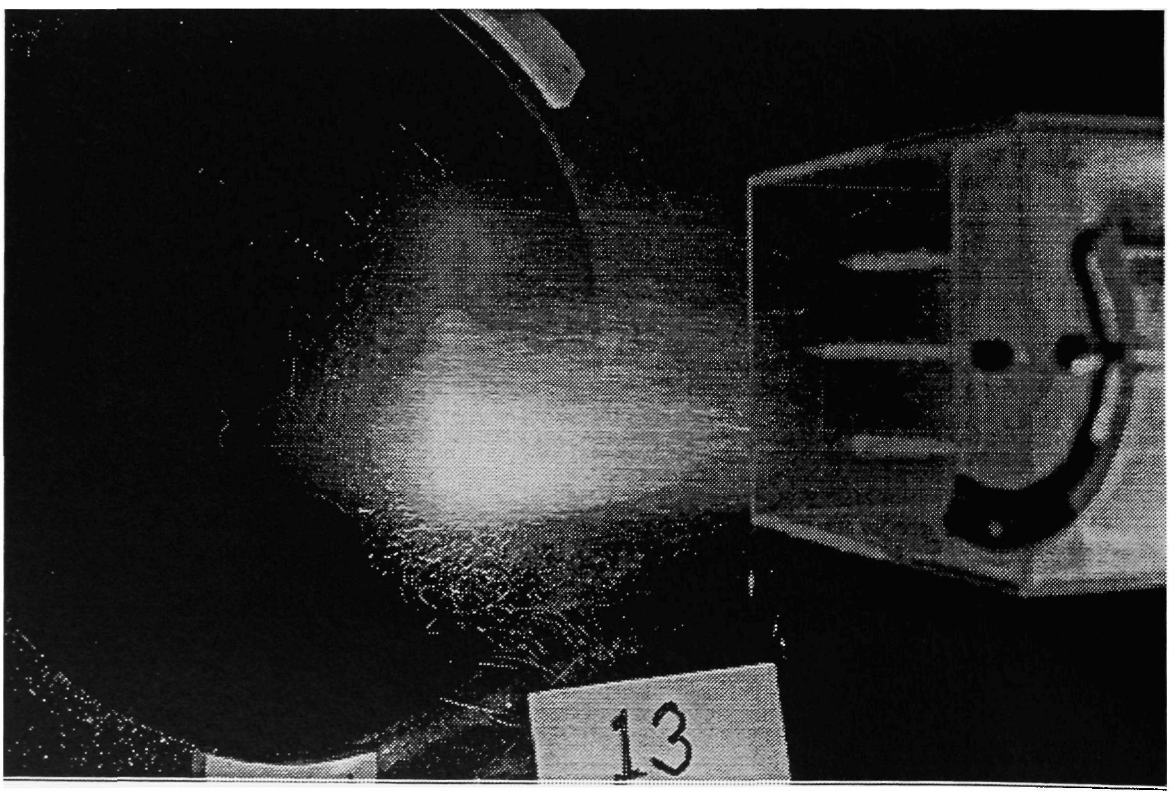


Figure 8

Pulverized coal distribution at nozzle discharge with RopeMaster™

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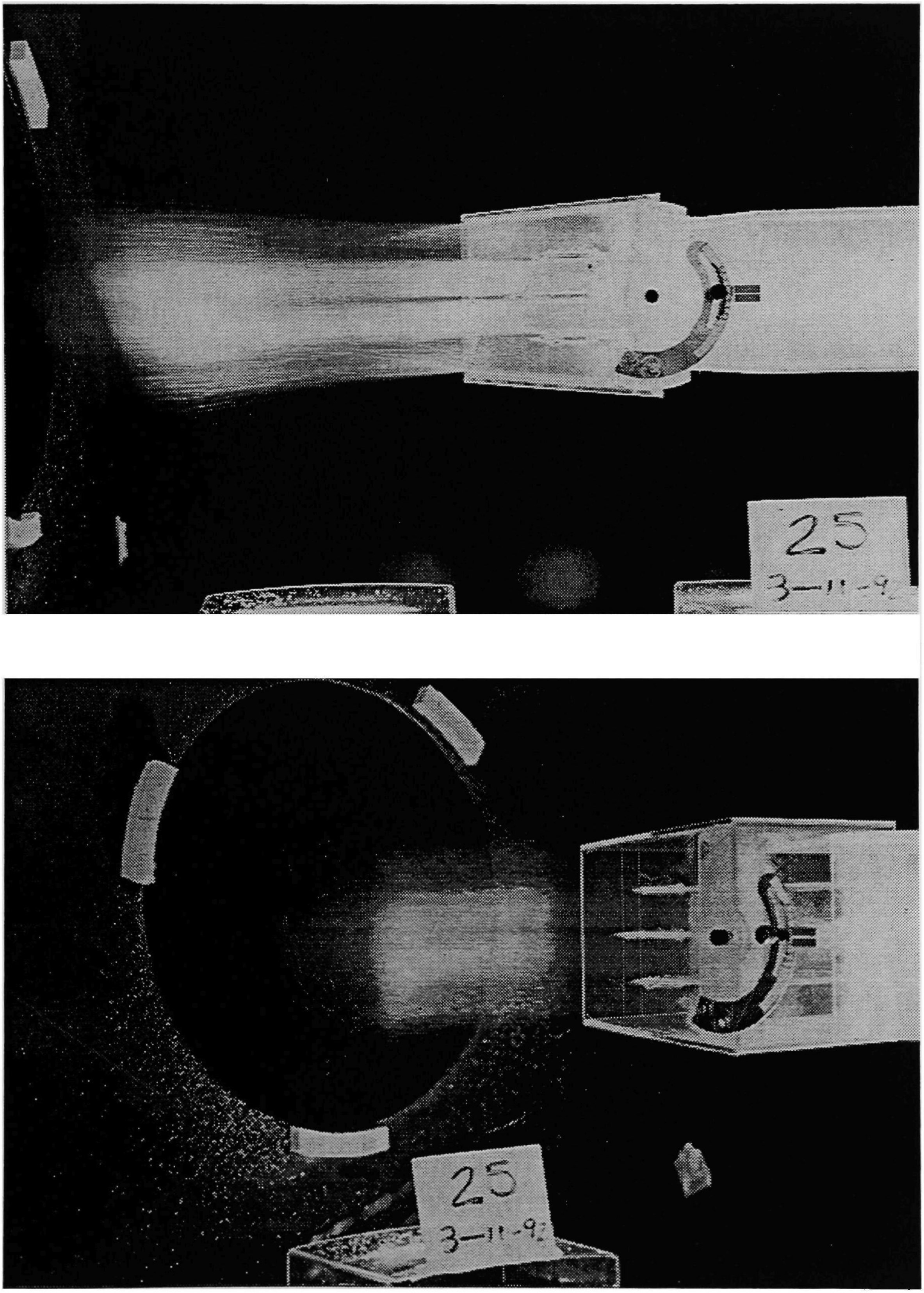

Figure 9

PERFORMANCE OF A CONTROLLED FLOW/ SPLIT FLAME LOW-NOx BURNER SYSTEM ON A TANGENTIALLY FIRED BOILER

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Abstract

Topic presented is the performance of a controlled flow, split flame, low NOx burner system installed on a tangentially-fired furnace, identifying specifically the results of both short term optimization testing and long term emission monitoring. This installation was the first time application of the controlled-flow, split-flame (CF/SF) low-NOx burner design used on wall fired boilers, to a boiler having a tangential firing design. Installation of this low NOx burner system to the furnace occurred without the modification of waterwalls, or addition of separated overfire air. Technical benefit achieved is reduction of fuel NOx production on a per burner basis in a tangentially-fired boiler, with the burners operating at near stoichiometric conditions. Combination of optimized burners along with vertical secondary air staging was found to provide the desired emission reduction over the entire boiler load range. Ash LOI and unit efficiency values were found to remain consistent with pre conversion, baseline data values.

Introduction

A first time demonstration project involving retrofit low NOx burners was undertaken beginning in 1992 on the 310 MW, Unit 7 boiler at Wisconsin Electric's Oak Creek Power Plant, which is located 20 miles south of Milwaukee on Lake Michigan. This demonstration project has been a joint effort between Foster Wheeler Energy Corporation (FWEC) and the Wisconsin Electric Power Company (WEPCo).

The Unit 7 boiler at Oak Creek Power Plant is designated as a Phase I unit under the 1990 Amendments to the Clean Air Act. The goal was to reduce NOx emissions on this unit to less than 0.45 lb./MBtu by January 1, 1995, with minimal impact on LOI and unit efficiency. Baseline readings taken prior to conversion in 1992 indicated that a 30 to 40 percent reduction in NOx emissions would be needed across the entire load range to achieve this goal.

The objective of the demonstration project was to achieve the required emission reduction and to confirm the adaptability of wall-fired low-NOx burner technology to a tangentially fired furnace by developing a commercially offered tangential low NOx burner (TLNB) system. To accomplish this objective, all of the original burners were replaced with retrofit burners of a prototype design in the Spring of 1992. A production burner system was developed based upon the experience gained from eighteen months of operational testing of the prototype TLN burners, and was installed to replace the prototype burners on Unit 7 during a scheduled turbine overhaul outage in the spring of 1994. Table I provides a chronology of project phases.

TABLE I
CHRONOLOGY OF PROJECT PHASES

Test Phase	Activity	Time Period
Baseline Testing	a. Obtain baseline data	Dec. 1991 -Jan. 1992
Prototype TLNB	a. Original Burner Removal and Prototype TLN Burners Installed	Feb. 7 - May 29, 1992
	b. Testing Prototype TLN Burners Alone	July - Aug. 1992
	c. Testing Prototype TLN Burners W/SAS* *(Secondary Air Staging created through idle top burners)	Sept. - Oct. 1992
	d. Duplication of above prototype tests on state sulfur compliance coal	Nov. - Dec. 1992
TLNB System	a. Removal of Prototype TLNB & Installation of Production TLNB System	Nov. 29, 1993 - Mar. 7, 1994
	b. TLNB System initial optimization period	Mar. 7 - June 1, 1994
	c. TLNB System final optimization period	Oct. - Dec. 1994
	d. TLNB System installed on Oak Creek Unit 8.	Jan. - April 1995

Unit Description

Oak Creek Unit 7 has a four corner, tangentially-fired, pulverized coal furnace of controlled circulation design. Manufactured by Combustion Engineering Corp. in 1965 as a pressurized furnace, the unit was converted to balanced draft in 1970. The boiler is rated at 2 x 10^6 lbs/hr. evaporation at 2,620 psig, with steam conditions of 1050/1000 ^oF for the superheat/reheat temperatures. Twenty pulverized coal burners, on five levels, are supplied by five CE model RPS 683 bowl mills of a pressurized-exhauster design. Auxiliary start-up and coal ignition fuel was switched during the subject burner retrofit from two levels of oil to five levels of gas.

TLN Burner Description

The windbox is partitioned with division plates. Flow is regulated for each partitioned burner lane by a secondary air damper and proportioned into three zones to create staging at the burner. The controlled flow is measured by flow elements installed in the primary and secondary air systems. The flow to the secondary air staging level and burners is shown schematically in Figure 1.The tip of the burner has a tilting split flame design. Arrangement of a single burner cell is shown in Figures 1 and 2.

Figure 1
TYPICAL SECONDARY AIR SYSTEM FOR A TLN BURNER MODULE

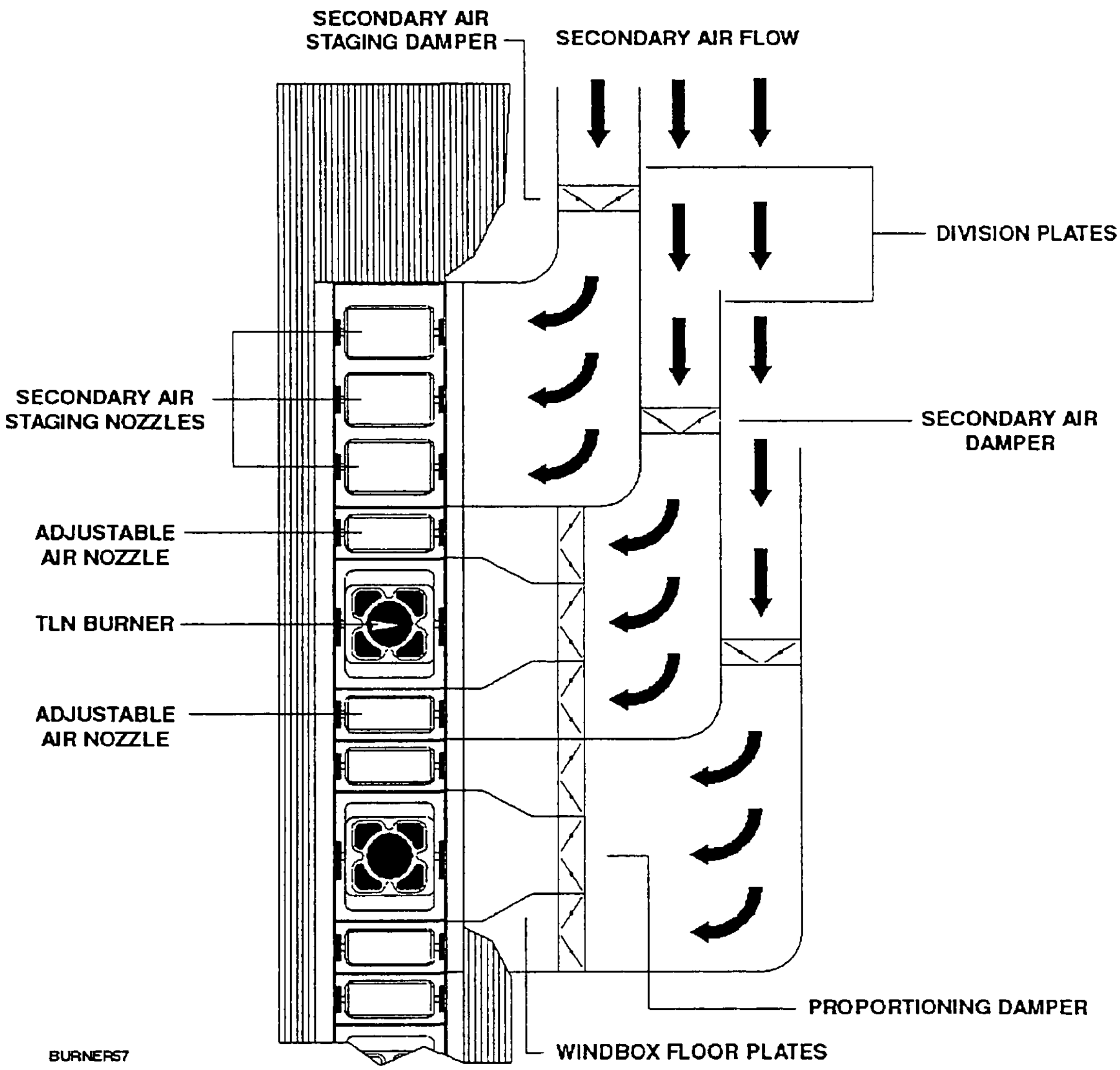


Figure 2
TYPICAL CORNER ARRANGEMENT OF TLN BURNER MODULE

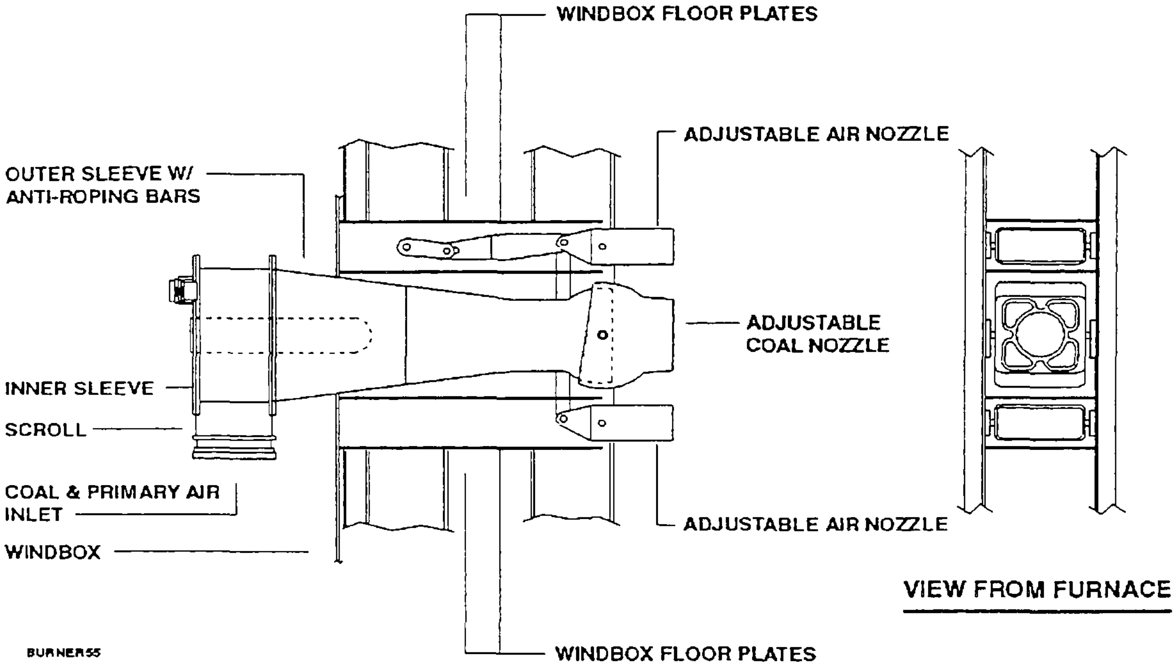
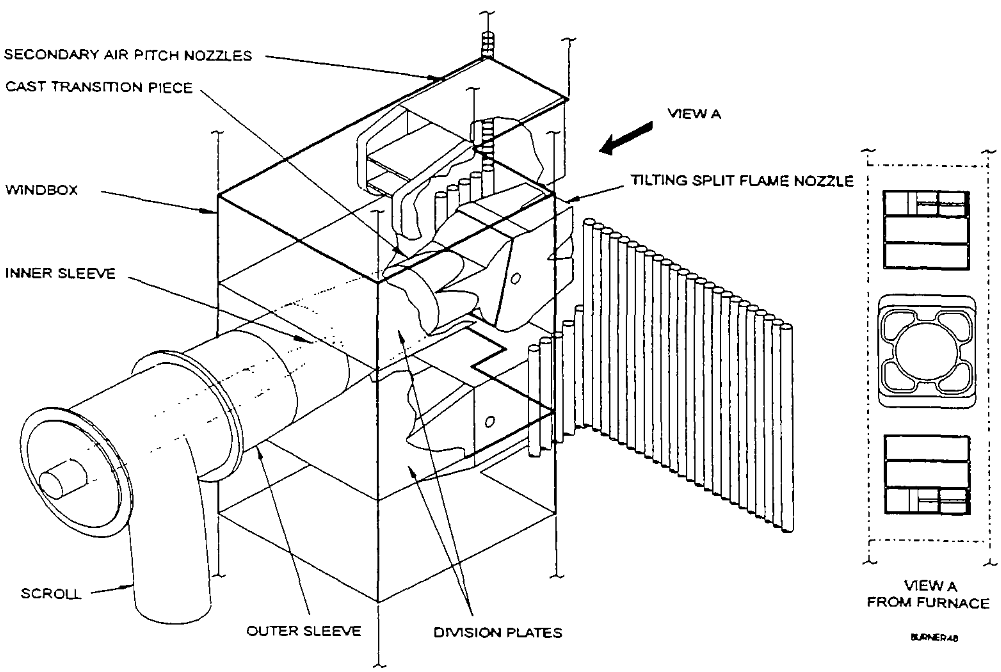


Figure 3
TANGENTIALLY FIRED LOW NOx BURNER (TLN)
MODULE ARRANGEMENT



Performance

Initial Comparison

Table II shows a comparison of the baseline operating data with the prototype TLNB system. This is provided for comparison of unit operating data to show that there was little or no change from the acceptable baseline, pre conversion test data, when operating on the midwestern bituminous coal fired during the testing of the prototype TLN burners.

TABLE II
BOILER PERFORMANCE COMPARATIVE DATA ON MIDWESTERN BITUMINOUS COAL
BASELINE VERSUS PROTOTYPE TLNB

Parameter	Baseline	TLNB
Load (MW)	300	300
FW Flow (KPPH)	1816	1824
SH Spray (KPPH)	53	42
RH Spray (KPPH)	40	46
Throttle Press.(psig)	2402	2404
MS Temp.(^{0}F)	1061	1043
RH Temp. (^{0}F)	1013	1003
NO_x (lb/10_6 Btu)	0.68	0.38
Unburned Carbon(%)	9.19 @ 4.2% O_2	8.0 @ 3.5% O_2
CO (ppm)	20 - 40	20 - 40

Performance Following 1992 Coal Change

Coal was switched in the fall of 1992 from midwestern bituminous (1.6 percent sulfur, 6.8 percent ash, and HHV of 13,850 Btu/lb.) to a western bituminous coal (0.6 percent sulfur, 13 percent ash, and HHV of 13,000 Btu/lb.). This was to comply with a state fuel sulfur limit. Volatiles and fixed carbon for both coals were similar.

A change in performance was seen on all four furnaces at Oak Creek. On Oak Creek 8, the "sister" unit to Oak Creek Unit 7, which had not been modified to a low NOx burner system, it was noted that the spray requirements were diminished. Inability to repeatedly obtain desired reheat and superheat temperatures on Unit 7 was observed. Ash deposits on the furnace walls were noted to be drier and less adherent to the walls. The sheets of dry ash were also noted to be "self shedding." A problem in the prototype burner tilts restricted effective temperature control.

Performance of Production TLN Burner System

Burner Tilts. Improvements in the coal nozzle tilt design permitted the production burners to achieve the design steam temperatures by means of controlled burner nozzle tilt.

Ash Deposits. The ash deposit pattern in the furnace was noted to have changed from the baseline, pre conversion pattern. The furnace walls were notably cleaner, and with the stable low NOx burner ignition point being closer to the burners, there is a feeling that more heat is being absorbed by the waterwalls. Flyash LOI was similar to values on the non-converted sister unit, Oak Creek Unit 8, and averaged in the range of 3 to 5 percent LOI.

Ash Characteristics. The original higher excess oxygen carried on the pre conversion furnace of 4.2% O_2, provided a much more radiant fire, and the ash on the walls from the midwestern coal was noted to glaze and become more adherent to the tubes than the drier western coal ash.

Steam Temperatures. Selective soot blowing of the rear convective superheat elements, along with the furnace exit aperture reheat bundles, was found to enable design steam temperatures of 1050 °F/1000 °F (superheat/reheat) to be maintained at full load. Temperatures are not a problem at low load. Soot blowing in the furnace was found to reduce steam temperatures.

Exit Oxygen and Furnace Temperature Profiles. The furnace exit oxygen and steam temperature profiles across the furnace are more even following the balancing of air flows to each burner. Evidence of a more uniform gas flow was confirmed by the lack of a higher ash wear area that had typically been observed during outages on the pre-conversion furnace.

Flame Stability. Balancing of air flows to each burner also resulted in more stable flames at low load and eliminated what is referred to as "cold corners", which were burners on the pre-conversion unit that had an ignition point farther from the corner.

Emission Test Results

Short Term, Single Point Test Results

Table III shows the best repeatable results obtained for the short term, single load point optimization testing. Single point tests were each two hours in length with the a test variable controlled. A test matrix was followed to determine the effects of altering the test variable. All end of day tests were repeated on the following day of testing to ascertain that conditions could be repeated. A total of 152 tests were conducted on 70 non-consecutive test dates to define the response of the new burner system to variations in adjustable parameters.

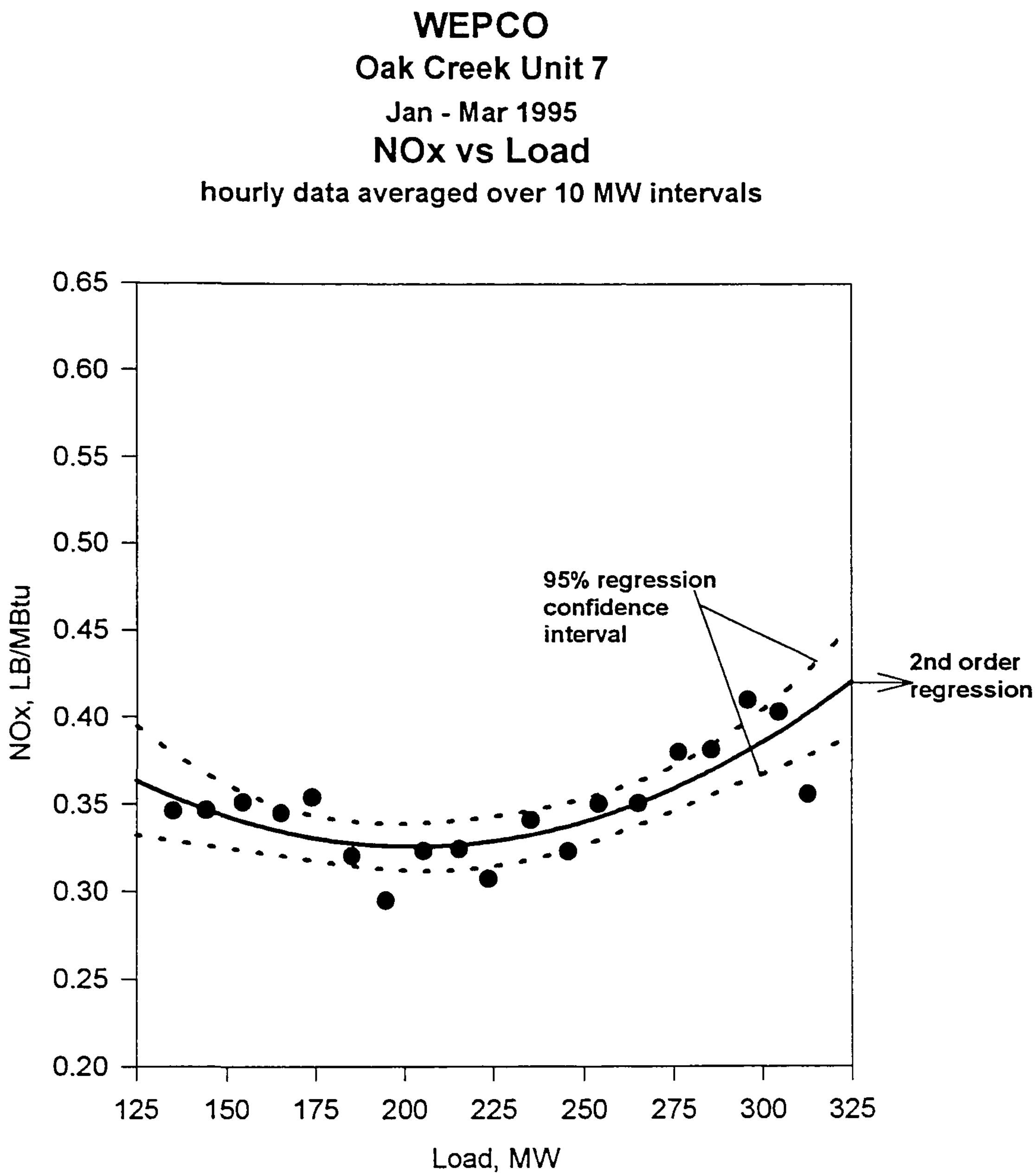
TABLE III
OAK CREEK UNIT 7 TLN BURNER DEMONSTRATION RESULTS SUMMARY
NO_X (lb/MBtu) EMISSIONS VERSUS LOAD (MW) COMPARISON

Test Phase (Dates)	Low Load (125 MW)	Medium Load (230-260 MW)	Full Load (260-300 MW)
	NO_X Emissions lb./MBtu		
Baseline (pre conversion) (12/91 - 1/92)	0.67	0.61	0.68
Production TLNB - (3/94 - 12/94)	0.31	0.28	0.35

Long Term Emission Test Results

Table IV displays the unit CEM hourly averages at each 10 megawatt load point along the daily load curve of Oak Creek Unit 7 for the period of January 1, 1995 to March 15, 1995. The data for this 74 day period was obtained from certified stack CEM data. For comparison, the rolling hourly average for the unit during the first two months of 1995 was 0.364 lbs.NOx/mmBtu.

Table IV



Conclusion

The goals of the demonstration project have been achieved. A production burner system was developed and unit performance has been acceptable while achieving low NOx emissions. Final tuning of boiler controls is in progress. Conversion of the similar Oak Creek Unit 8 tangentially fired furnace to an identical low NOx burner system has been accomplished and that unit is going into service in mid - April 1995.

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2. Morris, E. L., and Sweeney, T. W., "Development Of A Tangentially Fired, Controlled Flow, Split Flame Low-NOx Burner System On A Coal Fired Utility Boiler," Presented at *Electric Power Research Institute, "Workshop On NOx Controls for Utility Boilers",* Scottsdale, AZ , May 1994.

3. Morris, E. L., and Sweeney, T. W., "Application Of Controlled Flow, Split Flame Low-NOx Burners On A Tangentially Fired Boiler," Presented at the ASME Joint International Power Generation Conference in Phoenix, AZ , October 1994.

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LOW NOx FIRING TECHNOLOGY OF MITSUBISHI HEAVY INDUSTRIES

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Abstract

This paper presents super low NOx combustion technologies successfully developed by MHI (Mitsubishi Heavy Industries, Ltd.) and its use in practice.
PM (Pollution Minimum) burners directly reduce NOx from the burners themselves and MACT (Mitsubishi Advanced Combustion Technology) system, an in-furnace NOx removal system, reduces NOx generated from the main burners within the boiler. These firing systems are applicable to coal, oil, gas and also to other exotic fuels like Orimulsion or CWM(Coal Water Mixture) . MRS (Mitsubishi Rotary Separator) mills minimizes unburnt carbon with its reliable ultra-fine grinding of coal and hence contribute to low NOx.
These technologies have been applied in various combinztions to 227 boilers for both new installation and retrofit jobs. Large 1,000 MWe oil or gas fired boilers and 700 MWe coal fired boilers have been put into commercial use, and a 1,000 MWe coal fired boiler is under commissioning. The technologies have been applied to small sized boilers for industrial use as well. All the delivered systems have been working both domestic and overseas to the customers' satisfaction.

Introduction

Reduction of NOx emission has been and will be a very important issue from the viewpoint of environment preservation. The worldwide tendency is toward reducing NOx emission from thermal power stations as well as other sources. Fig. 1 shows the Japanese governmental regulation on NOx emission applied to new large plants. It was first enforced in 1973, amended four times and has become severer with every amendment. Due to the keen interest of the population around the power plants, emission levels severer than governmental regulation are actually applied. Corresponding with such tendency, MHI has continuously developed new low NOx firing technologies.

The latest Mitsubishi Low NOx System is shown in Fig. 2 as a whole set. Each system can be supplied individually or in combinations according to the required NOx level. Based on results from our test furnaces and abundant experiences in the field, NOx level of PM burners are, 20 to 40 ppm for gas, 75 to 100 ppm for oil and 100 to 200 ppm for coal. MACT combined with PM burners can still further reduce it to 10 to 20 ppm for gas, 45 to 60 ppm for oil and 60 to 150 ppm for coal. MRS mills, which contributes to the reduction of unburnt carbon in fly ash, can reduce NOx to 60 to 100 ppm for coal in combination with PM and MACT with same unburnt carbon level as for a fixed separator mill. This is summarized in Fig. 3.

Concept of PM Burner

As pure diffusion combustion has its limits in application of low NOx oil firing, a NOx reduction theory based on theory of premixed combustion and concept of offset firing was considered.

Fig. 4 shows the principle of NOx reduction of the PM burner. It forms a fuel-rich flame and a fuel-lean flame. In case of gas firing where flame is formed as a premixed flame, NOx of the two flames are obtained at "C_1" and "C_2" Overall NOx becomes "C" as a mean value for PM burners which is substantially lower than NOx "B" by conventional burners at same overall excess air "X". For liquid fuels, diffusion combustion occurs in the fuel-rich zone to produce stable combustion. The overall NOx, therefore, becomes "C'" as the mean value. It is also much lower than "A" of conventional burners.
When firing coal, NOx changes according to ratio of primary air/coal. Dividing flame into two types contributes to achieving low NOx in a similar manner as the oil or gas fired PM burner.
The PM burner is applicable to both circular and opposed (or front) fired boilers. Structure of the burner nozzles and burner configuration are designed to have shapes which fully realize the ability of NOx reduction. Furthermore, they can be arranged exactly to fit existing boilers in case of retrofit jobs, considering the NOx level requirement and furnace designed.
Typical configuration of PM burners for the circular corner firing is shown in Fig. 5. For oil PM burners, specially designed atomizers produce two oil spray patterns, inner sprays for fuel-rich flame named 'Conc' (concentrated) and outer sprays for fuel-lean flame named 'Weak'. Separate gas recirculation SGR, depending on various conditions like NOx, steam temperature control, etc., is injected above and below the oil burner ports if required. The inner spray ignites simultaneously with mixing of fuel and air and forms the diffusion flame. On the other hand, ignition of the outer spray is delayed and takes place after mixing with air from auxiliary air ports. This process is like premixed combustion. In this manner, two types of flames are formed and NOx is suppressed according to the PM principle.
Coal PM burners are equipped with separators at burner inlet as shown in Fig. 6.The separator divides coal and air mixture in the coal pipe into two different ratio of primary air/coal. The Conc nozzle is provided with a unique flame holder at its outlet to stabilize the Conc flame, which in combination with the lower air to coal ratio in the Conc burner, show remarkable changes in burner characteristics, especially ignition stability, heat flux distribution and furnace heat absorption, from older corner fired burners. Gas recirculation is used only for occasions where the range of coal quality requires it.

Concept of MACT

We conducted series of experiments in our laboratory to develop optimum MACT configuration, which utilizes the entire furnace volume as the reducing zone, to confirmed the NOx reducing mechanism described by the following chemical reactions;

$$CmHn + O_2 \rightarrow Cm'Hn'^* + CO + H_2O$$

$$NO + Cm'Hn'^* \rightarrow Cm''Hn'' + N_2 + CO + H_2O \qquad * \ : \ \text{Radicals}$$

$$NO + Cm'Hn'^* \rightarrow Cm''Hn'' + NHi + CO + H_2O \qquad NHi \ : \ \text{Compound of N \& H}$$

Two sequential reactions, NOx reducing reaction and burn-out reaction occur in the two reaction zones above the main burners as shown in Fig. 7. A part of fuel extracted from main fuel is injected from UB (Upper Burner) with recirculation gas and used as a NOx reducing agent by supplying hydrocarbons into a reducing atmosphere. A part of air named AA (Additional Air) is extracted from main air and used to burn out remaining unburnt combustibles. Burning-out of the unburnt is completed between the AA and the furnace outlet.
Further efforts were made to apply MACT to coal firing, where usage of upper burner fuel is more complicated. If one uses coal for upper fuel, the system becomes complex and more prone to having high unburnt, and if one uses oil or gas, the economy is the question. So we developed Advanced MACT system, the concept of which is shown in the right side figure of Fig. 7. In Advanced MACT there is no UB because we found out that the hydrocarbons carried over from the main burner zone has good reactivity in the reducing zone. It almost can get the same NOx reduction effect as UB-MACT by controlling the amount of air in the main burner zone and the reducing zone by over-fire air and the AA.

Concept of MRS mill

The characteristics of the MRS mill is shown in Fig. 8. It is equipped with a forced rotating separator instead of a fixed conventional cyclone separator. Pulverized coal carried up to the upper part of the mill is classified by centrifugal and impinging forces generated by rotating vanes and the fines are led to burners. Coarse particles separated from fines fall back onto a grinding table and re-ground. Fineness can be properly adjusted for different coals by adjusting rotating speed of the vane.
Fig. 9 shows the relation between the amount of particles through 200 mesh and residue on 100 mesh. Residue on 100 mesh that affects unburnt carbon is extremely reduced by MRS.
Same principle can be applied to tube mills to achieve extremely good finess with substancially lower power than normal tube mills, which is attractive from viewpoint of maintenance (Fig. 10).

Field application and demonstration of PM, MACT and MRS

As the result of various combustion and pulverizing tests conducted in our test facilities and in the field, we achieved remarkable reduction in NOx and unburnt carbon.
Experiences with utility boilers are show in Fig. 11. NOx could be reduced to about or less than half of conventional burners, and we are still on the way to drastically improve the technology by refining and simplifying the systems or by totally new ideas to realize the concept.
Fig. 12 is a trend chart of a 600 MW oil and coal mixed firing boiler equipped with the MACT. NOx was dramatically changed to half when the UB-MACT was use. Fig. 13 also shows NOx of the boiler. Excellent low NOx was achieved with the MACT. As the boiler is equipped with the oil firing PM burners as well as the MACT, very low NOx was obtained solely by the PM burners even when the MACT is out of use.
MHI`s experiences in low NOx firing with large capacity coal fired boilers equipped with PM, Advanced MACT(A-MACT) and MRS are presented in Fig. 13. The data plotted on the figure are from boilers which are supercritical sliding pressure operation boilers ranging in size from 500MW to 1000MW, firing various kinds of coals and have high load changing capability corresponding to middle load use like DSS (Daily Start-and-Stop) operation. They show excellent operation capability since commercial operation. They achieved quite low excess air operation(about 15%) over a wide load range and it contributed to low NOx performance as well as high efficiency. NOx was very low as shown for mainly Australian coal and we can summarize that we achieved the following. (Unburnt carbon is 2 to 3% in flyash or even less.)

(1) Stable ignition by PM allowed very low excess air in main burner zone.
(2) Optimum air supply ratio to OFA/AA maximized NOx reducing effect by A-MACT.
(3) High fineness obtained by MRS contributed not only to low unburnt carbon, but also to low excess air and low NOx.
(4) The latest design philosophy applied to the 1000MW unit reduced the NOx as much as 15% from previous units.

CUF(Circular U-shaped Firing) System

CUF systems have the following features, which make it a very attractive circular firing system.

1. Firing with longer flame path assures low unburnt carbon.
2. Ignition stability is substantially improved and excess air in the primary combustion zone can be reduced more than a conventional circular firing system(CCF) which results in lower NOx.
3. Because of the high stability of ignition, application to very low volatile coal firing, even anthracite is possible.

Fig.14 shows the basic principle of the CUF system. The relatively high radiation heat flux and the U-shaped flame path ensures longer residence time in the same sized furnace compared to the traditional circular corner firing most manufacturers apply, giving the CUF the advantages mentioned above. Fig.15 shows the comparison of test result in a test furnace for CCF and CUF showing substantial quantitative differences. Fig16. shows the low load capability of the

CUF system compared to other systems. Fig, 17 is an actual application to an industrial boiler.

Conclusions

As described above, we have developed a series of NOx reducing technologies and already put quite a number of them into commercial use with customers' satisfaction. These technologies have been used not only by MHI alone, but also by licensed manufacturers throughout the world. The concept and technology has been refined year by year and the NOx level achieved to date are exteremely low. We are developing still better technology for the PM and MACT concept to get the best performance out of these innovative firing systems. We hope our low NOx technologies will contribute to the environmental protection in the United States and other parts of the world.

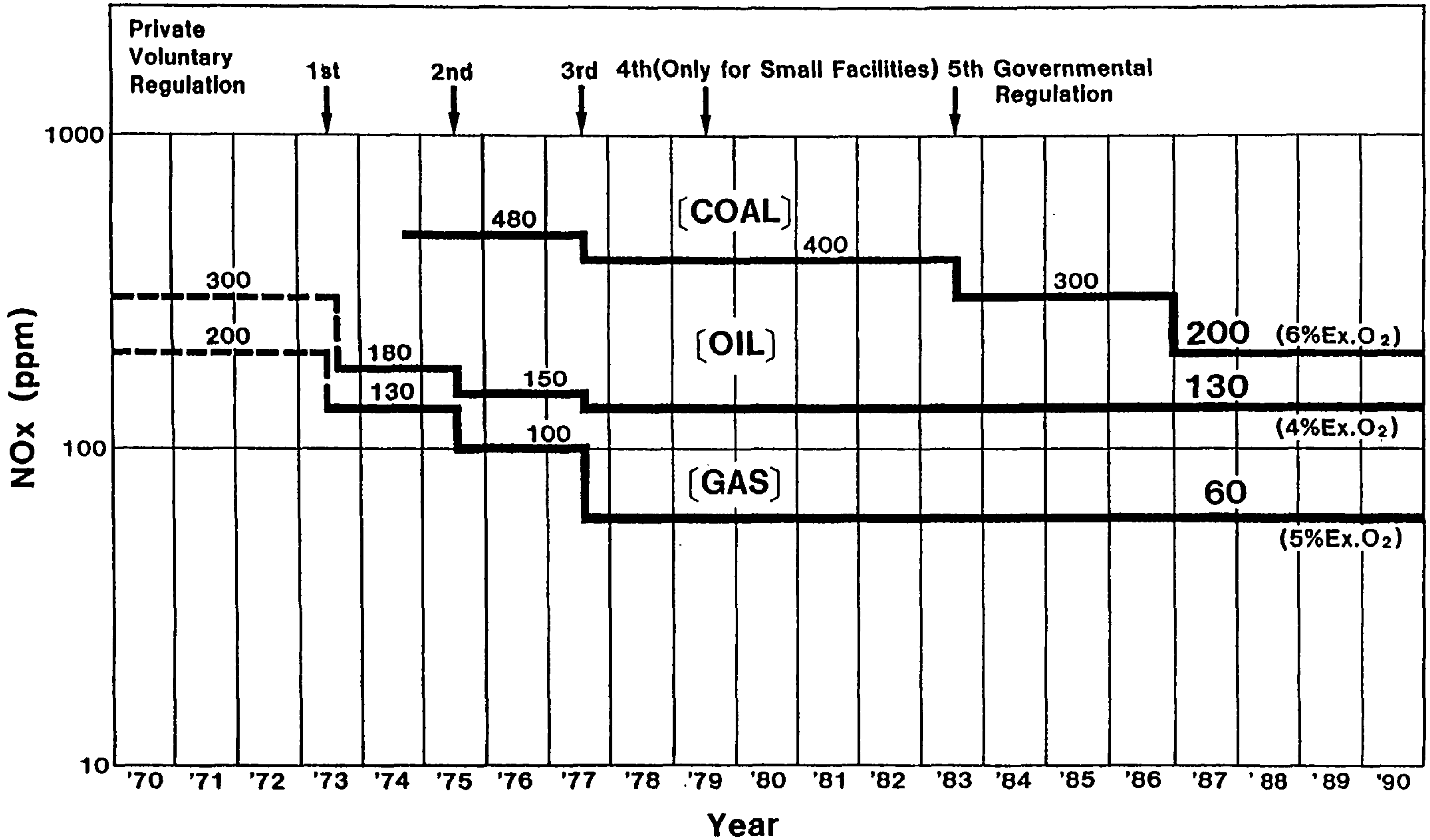


Fig.1 NOx Governmental Regulation for New Large Plants in Japan

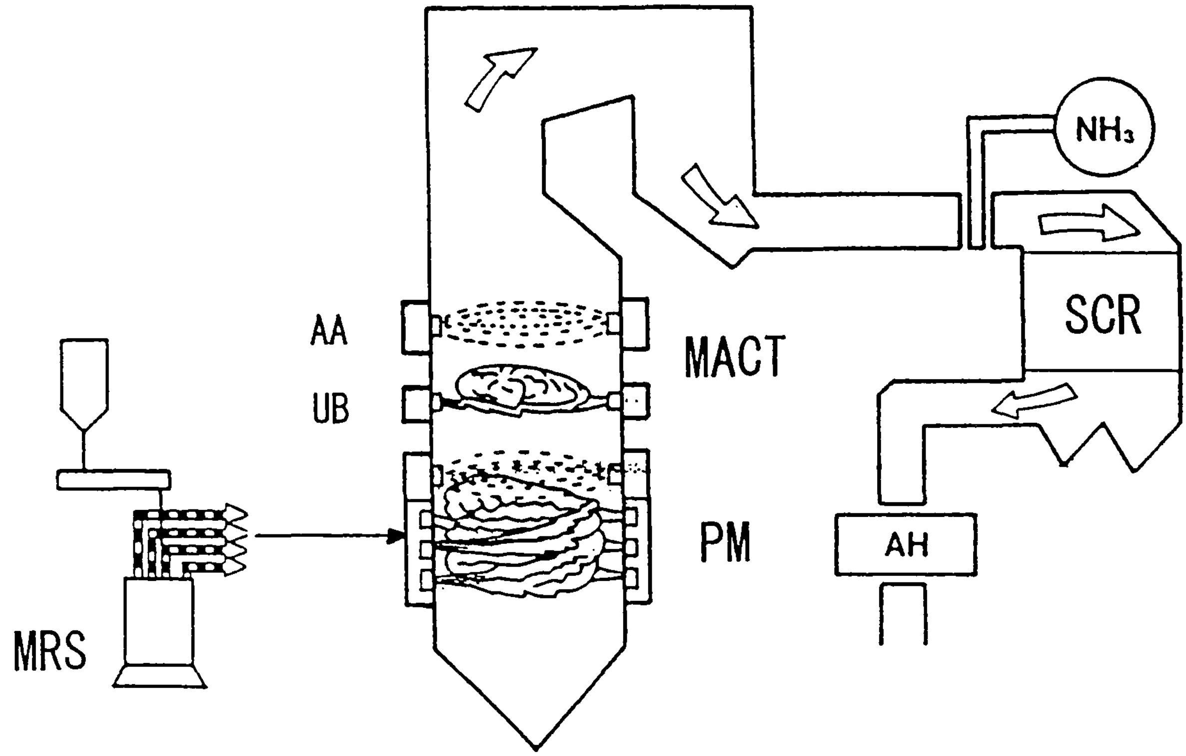


Fig.2 Mitsubishi deNOx System

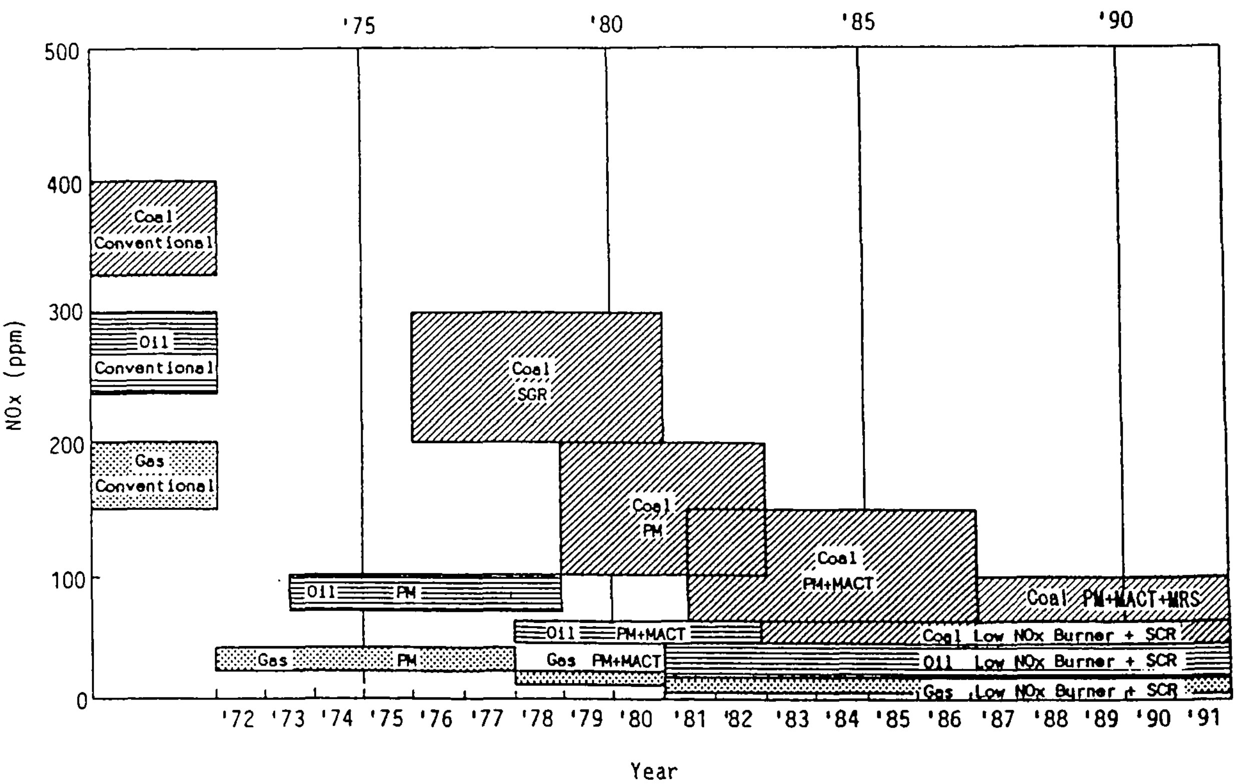
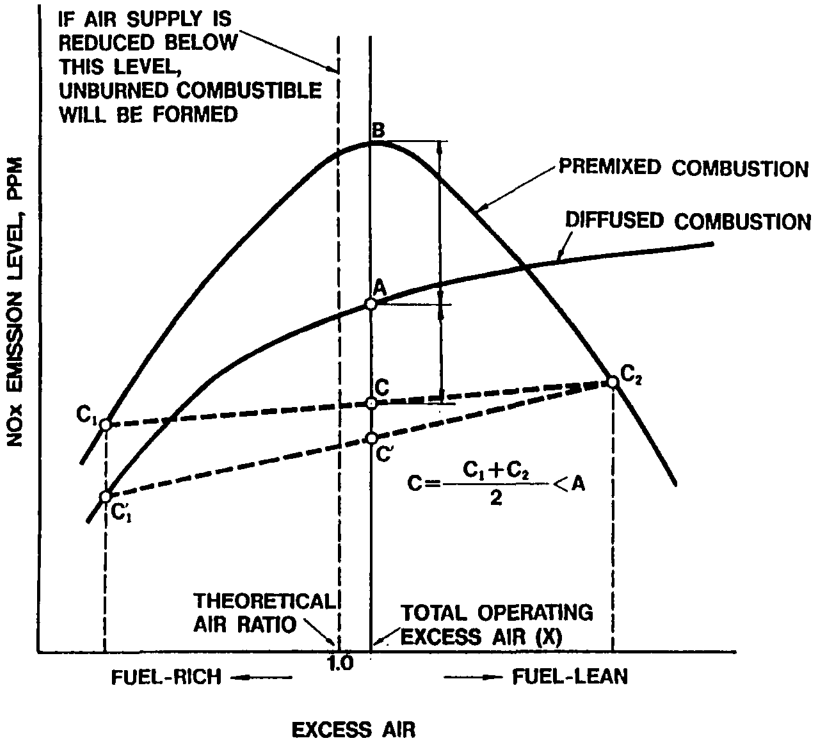
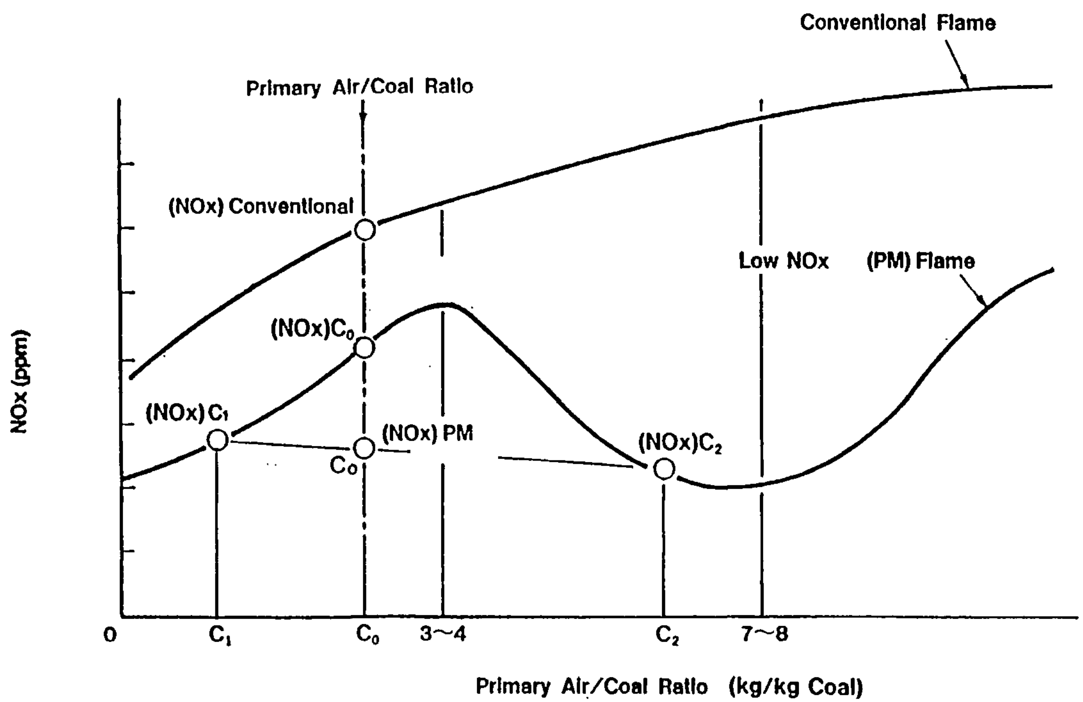


Fig.3 History of MHI' s Low NOx Technology



Oil and Gas



Coal

Fig.4 NOx Reducing Principle of PM Burner

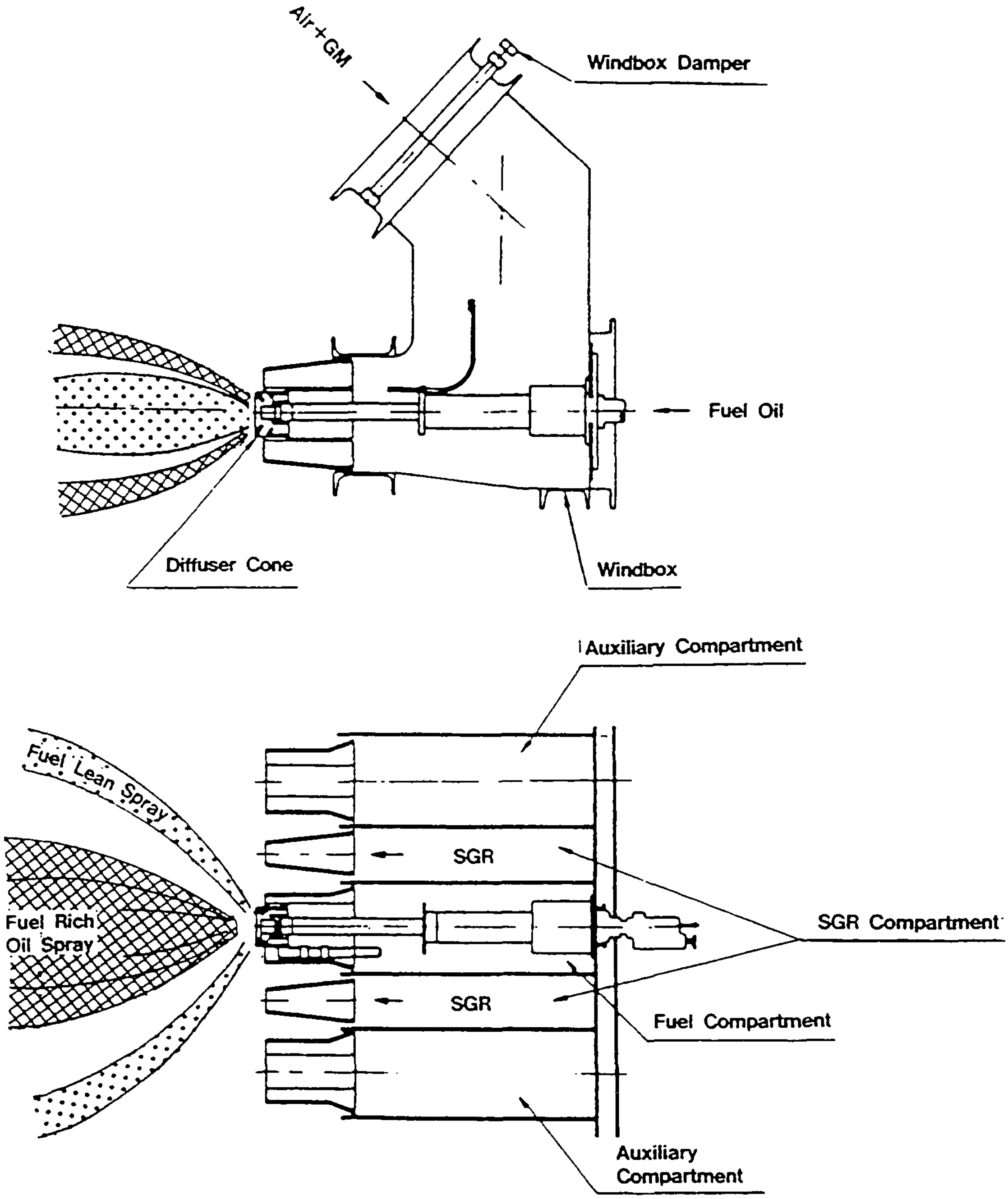


Fig.5 Oil PM Burner for Corner Firing

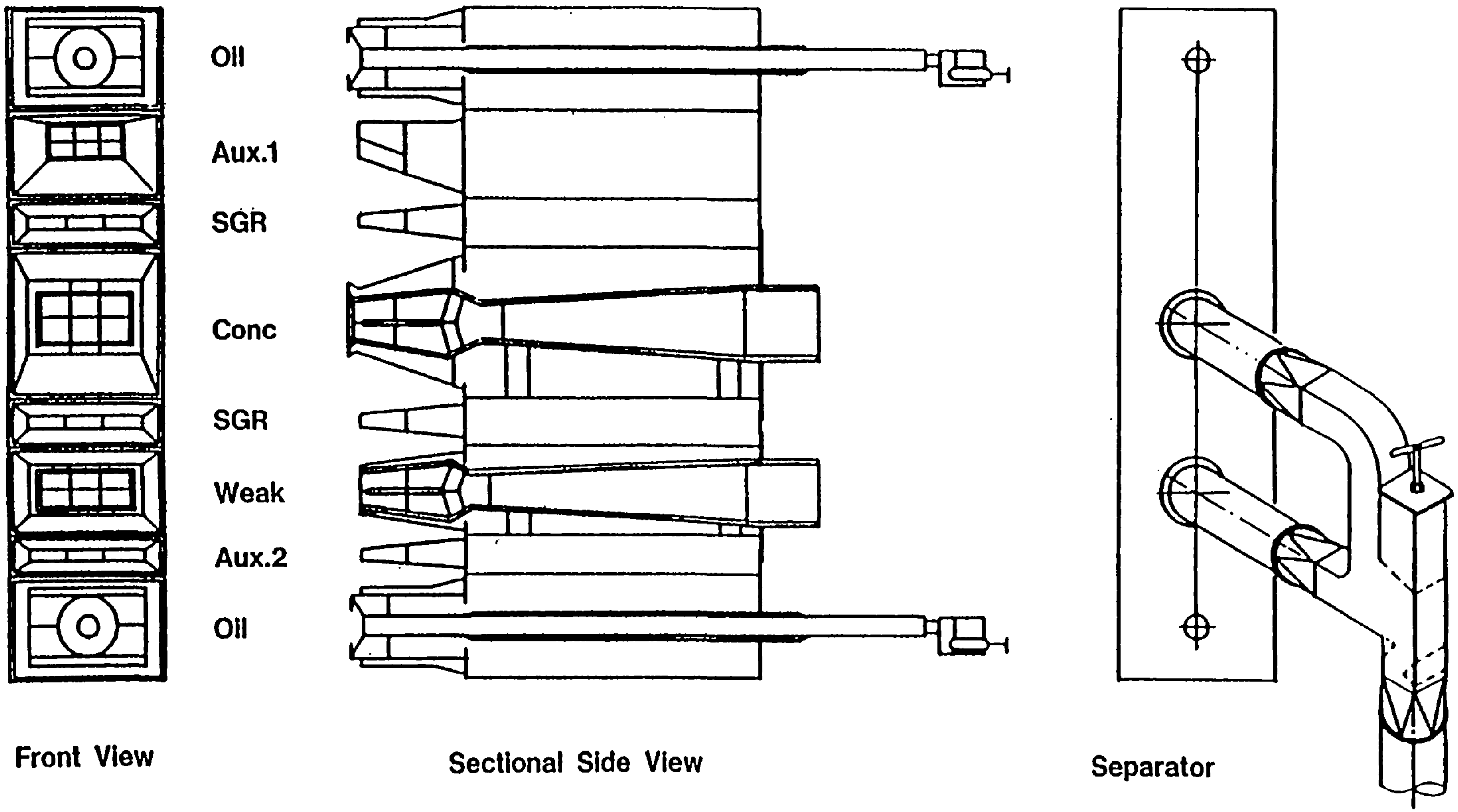


Fig.6 Coal PM Burner and Separator

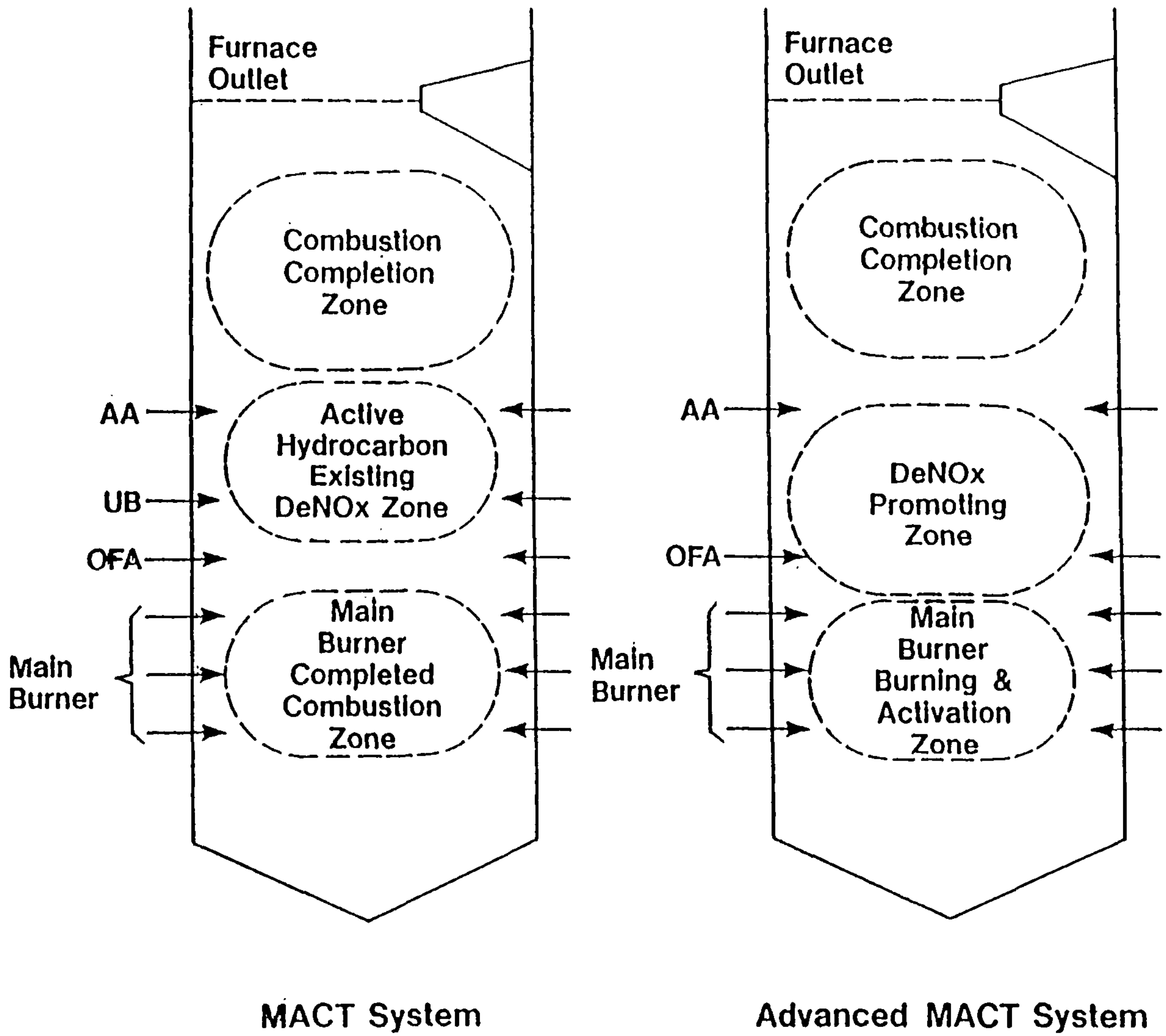


Fig.7 Concept of A-MACT

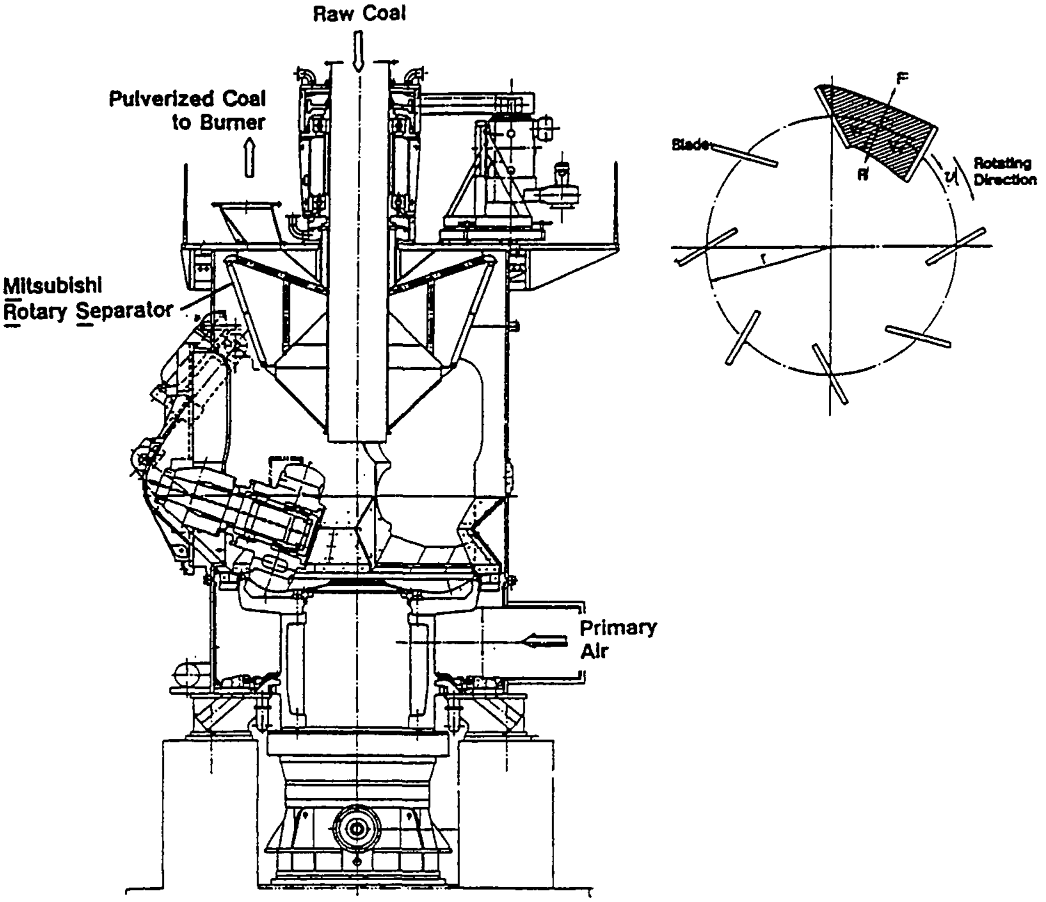


Fig.8 Structure of MRS Mill

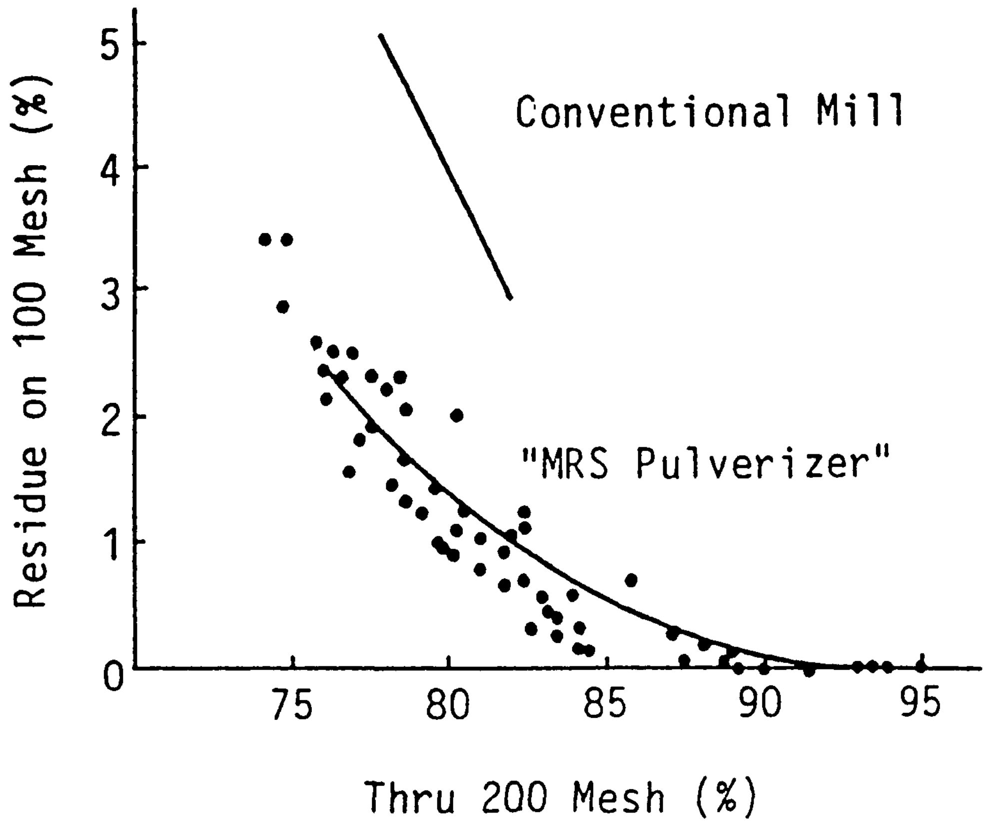


Fig.9 Coal Fineness Obtained by MRS Mill

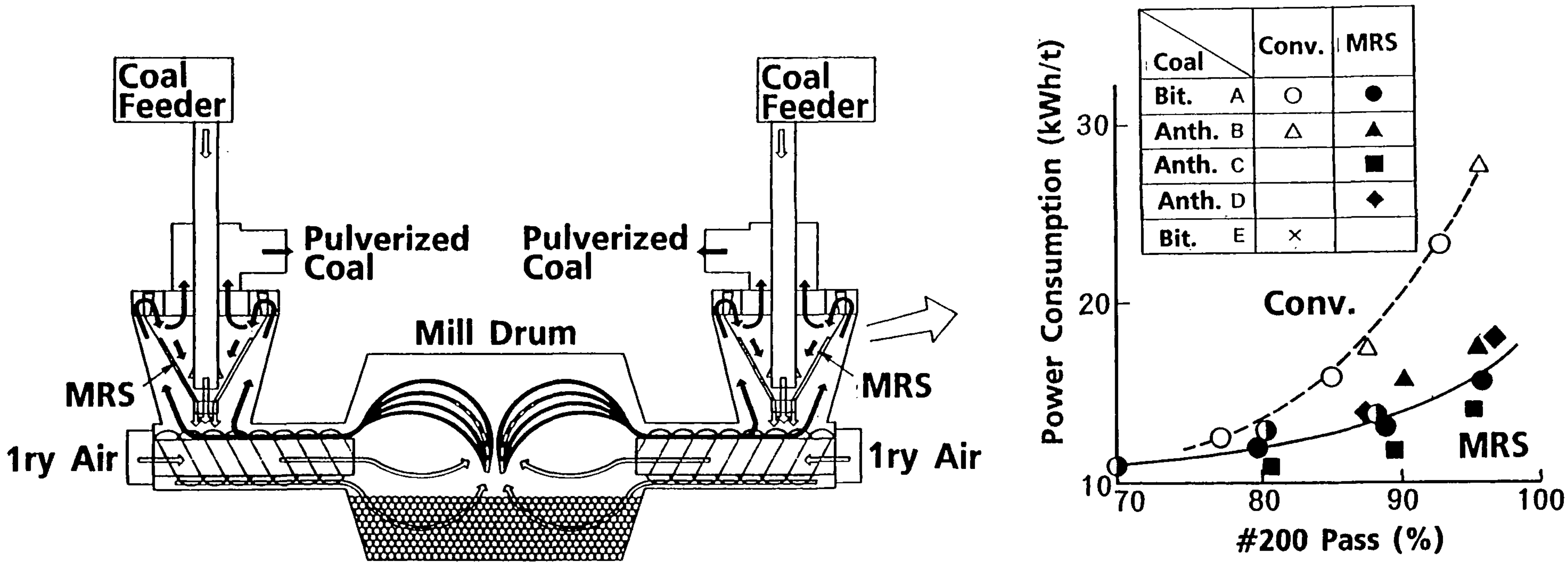
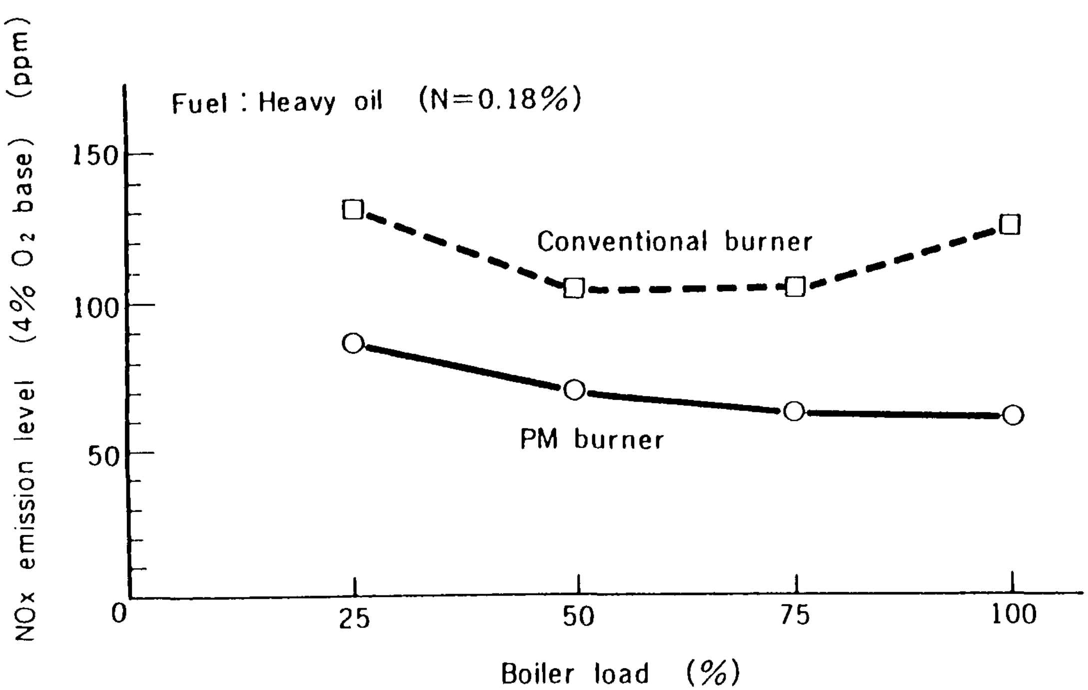


Fig.10 MRS Tube Mill



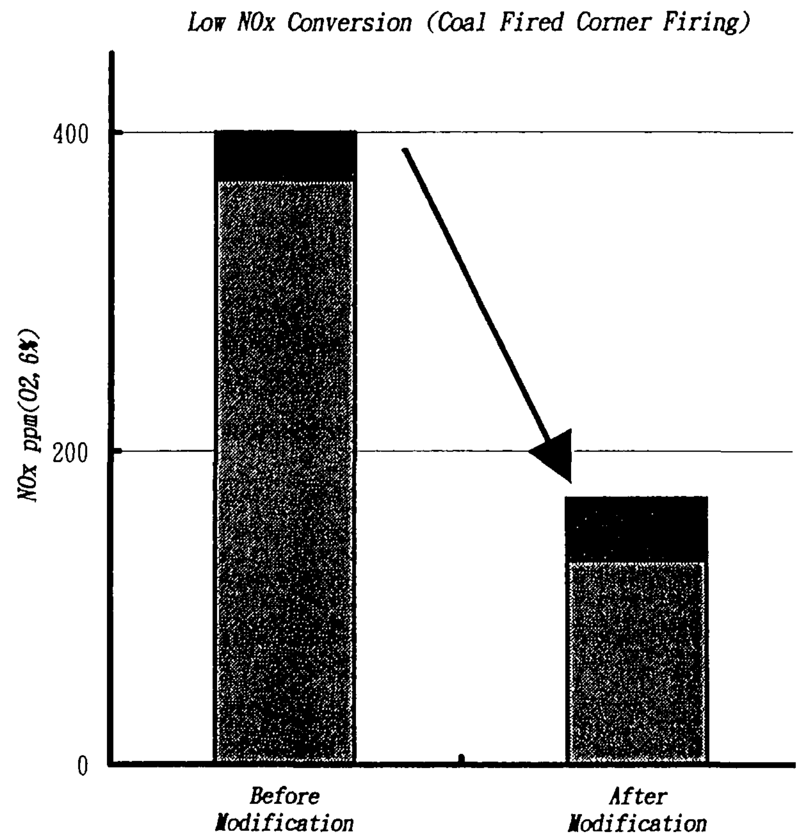
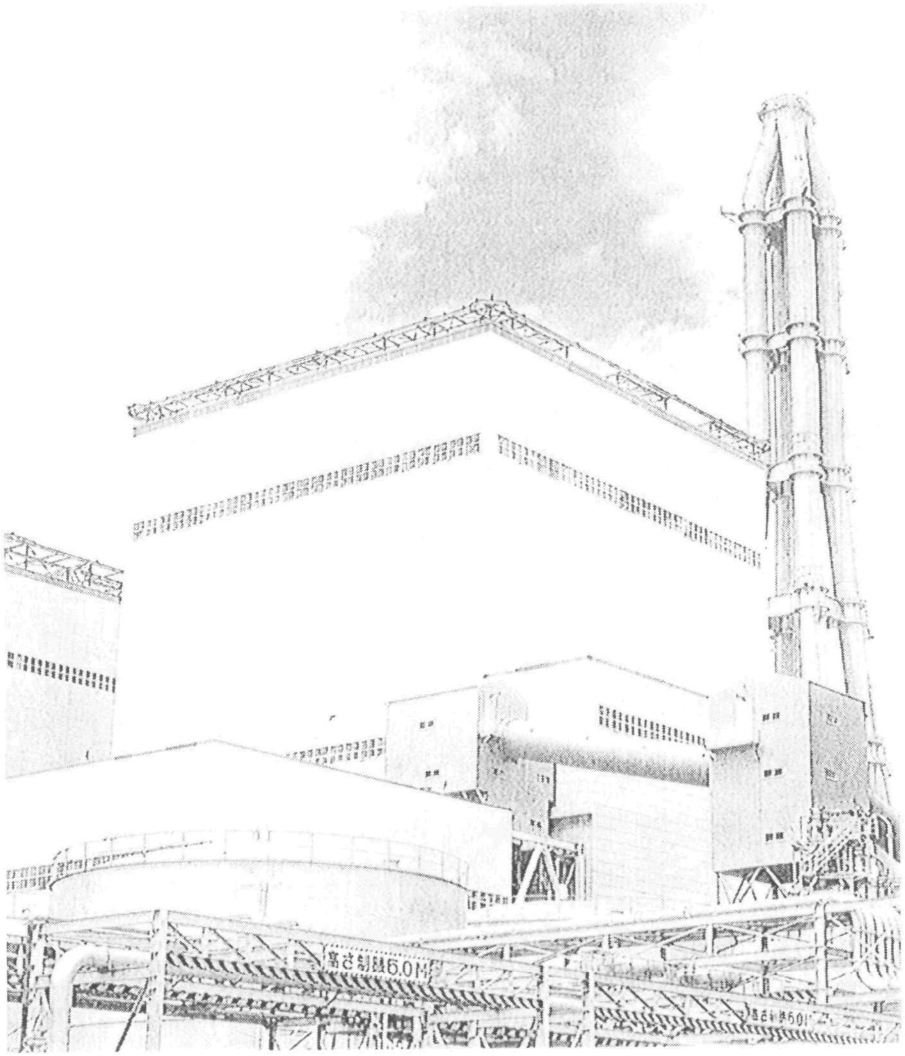


Fig.11 Low NOx Performance of PM Burner



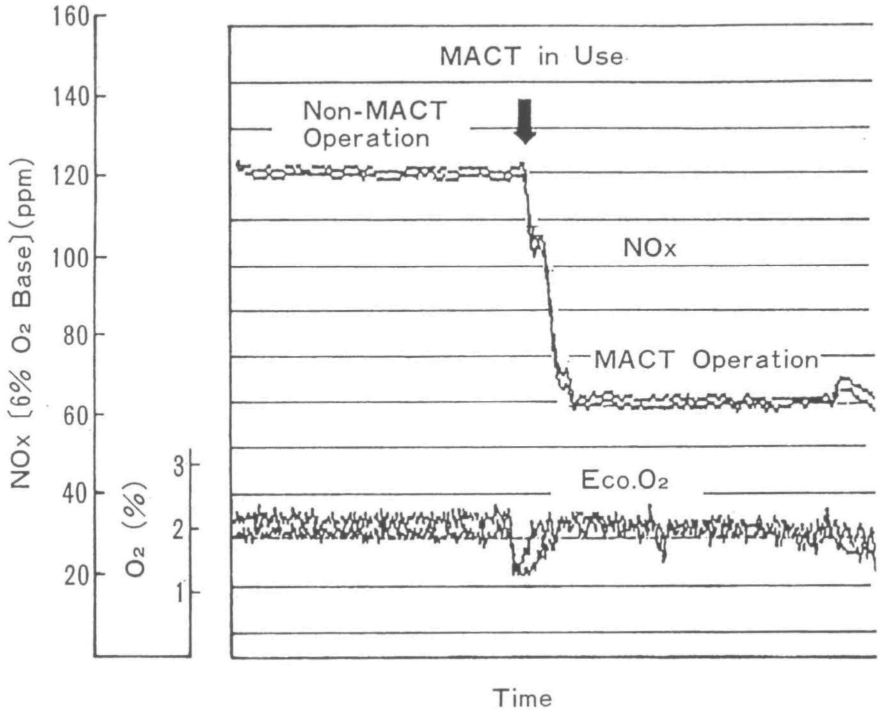


Fig.12 NOx Reduction by MACT

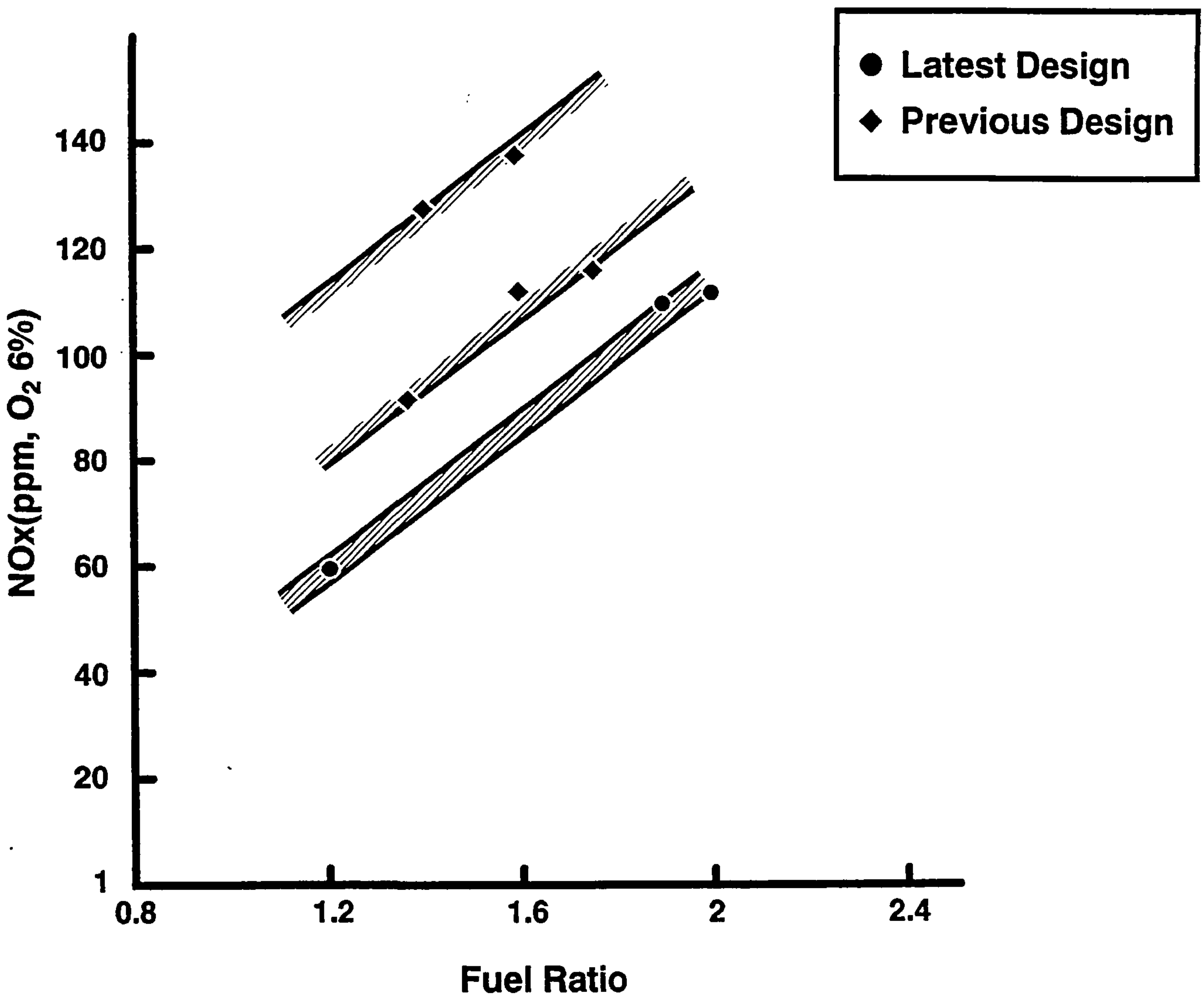


Fig.13 Performance of Coal Fired Low NOx Firing Systems

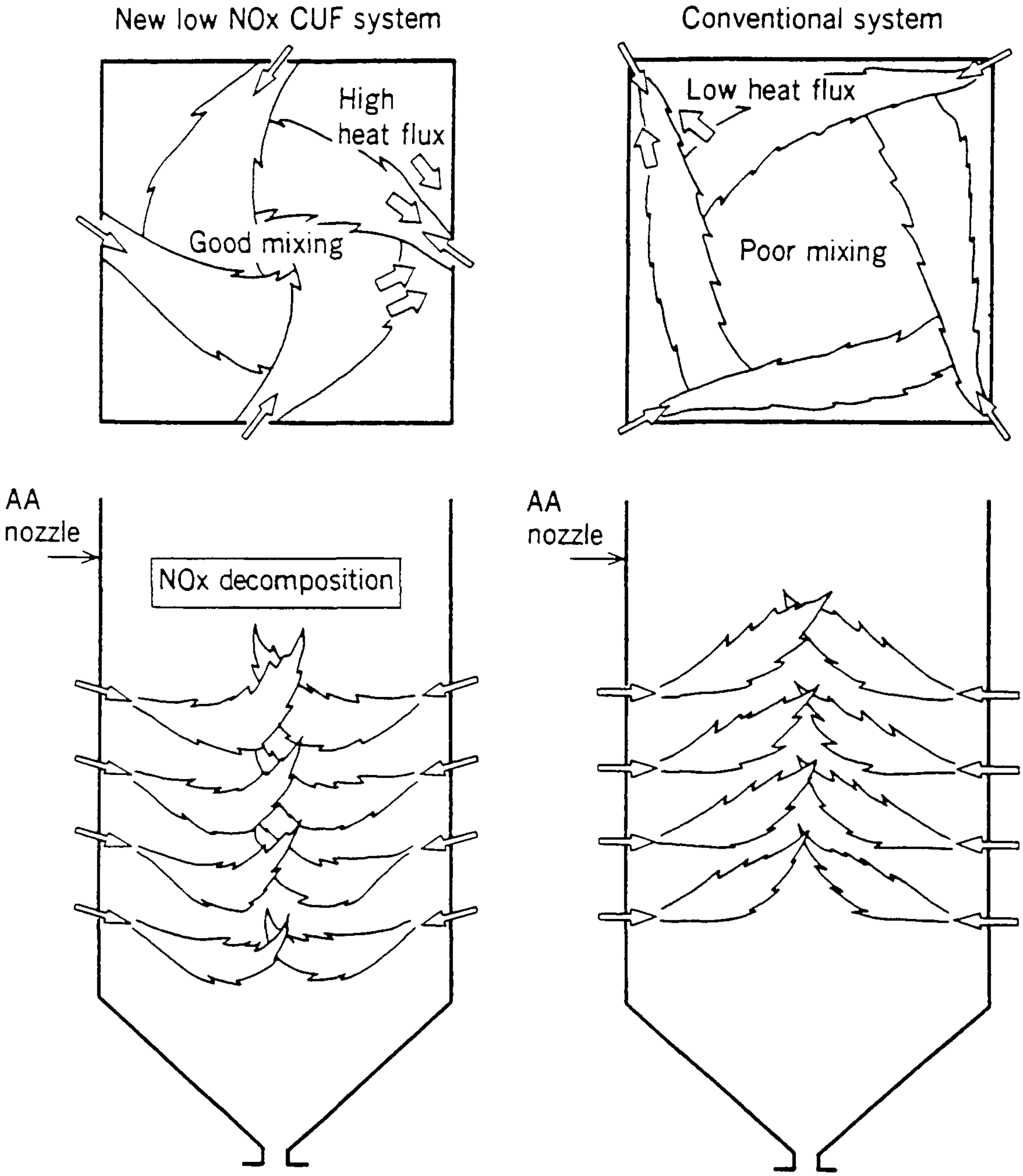


Fig.14 Burner Arrangement in CUF and Corner Firing Systems

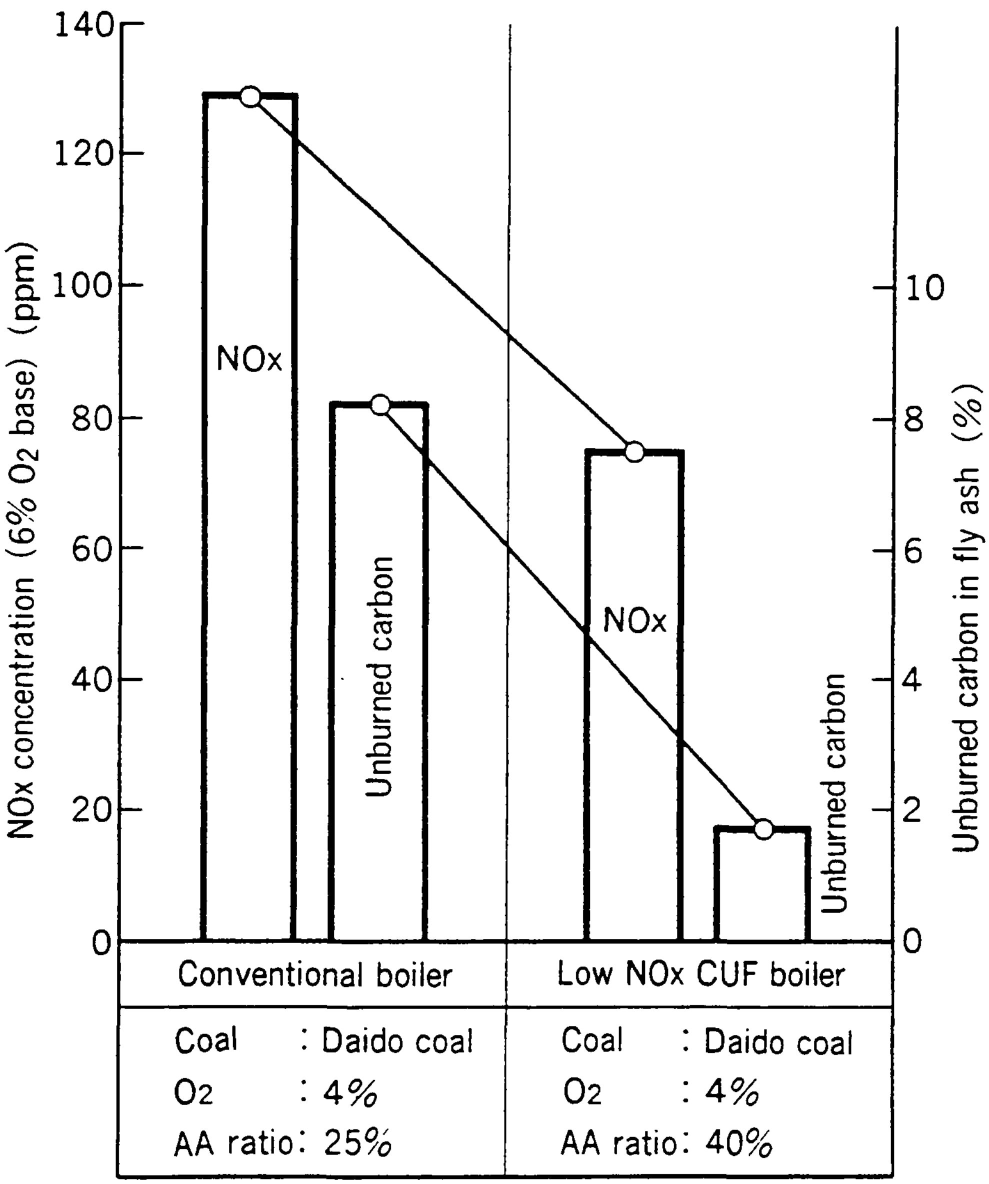


Fig.15 Comparison of NOx and Unburned Carbon between CUF and Circuler Corner Firing

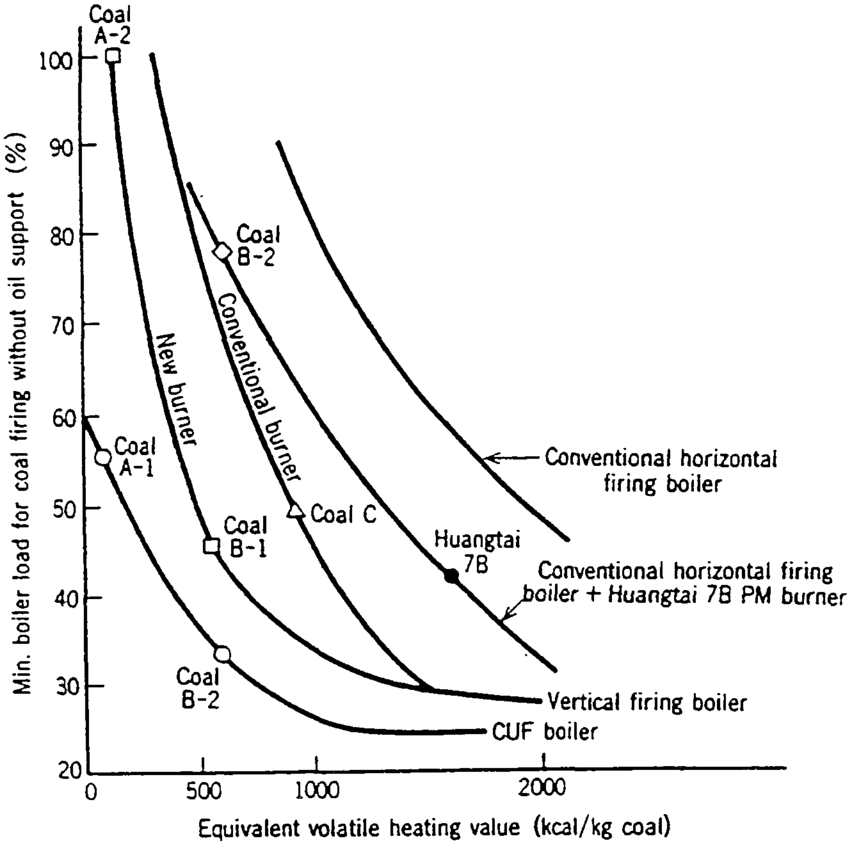


Fig.16 Equivalent Volatile Heating Value vs. Practical Min. Boiler Load without Oil Support

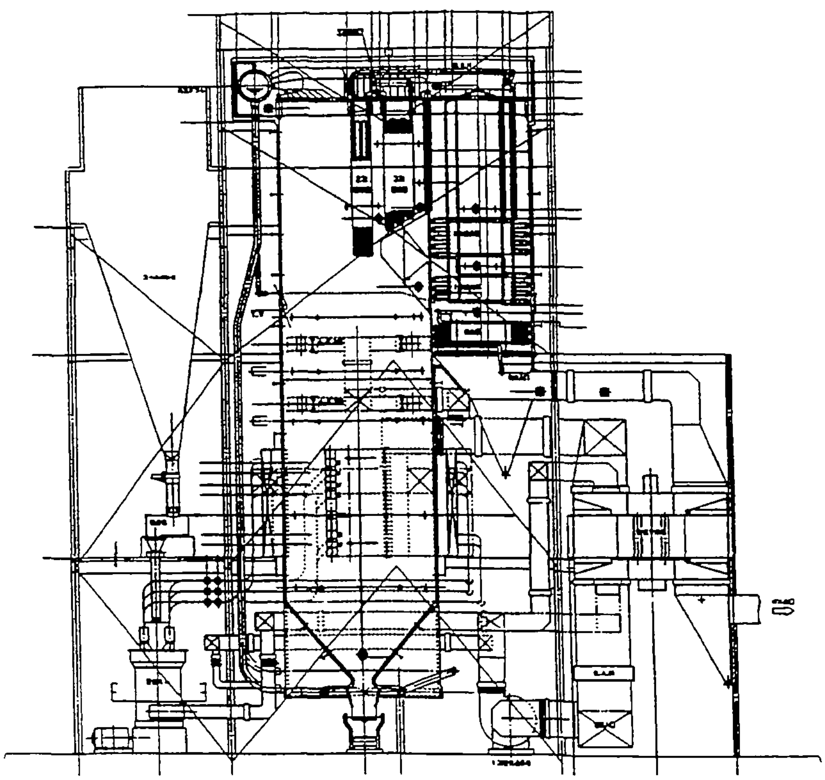


Fig.17 350 ton/h CUF Boiler

Impact of Secondary Air Distribution on NO_x Generation Rate in large Utility Boilers

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Abstract

NO_x generation rate in a boiler is a function of the fuel type, the fuel combustion mechanism and the quantity and distribution of air supplied to the combustion chamber. This paper addresses the latter issue. Secondary air flow bias is typically caused by air heater fouling, approach duct geometry, and windbox geometry. Bias in the secondary air distribution creates fuel rich regions along side fuel lean regions in the boiler. .This results in incomplete combustion, high NO_x generation rate in the fuel lean regions, excessive slag and corrosion. This paper presents the results of a study conducted at the TVA Shawnee Fossil Plant on the impact of the secondary air flow bias on boiler performance and NO_x generation rate. The study utilized an integrated approach using field test data, physical model tests, and numerical simulations using the Radian Furnace Simulation Model. Limited by the unit forced draft fan capacity, the study focused on low cost modifications resulting in improved boiler performance with minor fan pressure losses. The numerical simulations produced modest reduction in NO_x generation rate.

INTRODUCTION

The coal boiler secondary air flow distribution at the burners and the windbox pressure losses are controlled by the air heater fouling, the approach duct geometry, the windbox geometry, and the burner register settings. Extreme register settings could divert flow from one burner to the other, with large associated pressure losses. Biases in the secondary air flow distribution have been linked to reduction in the combustion performance efficiency, increased NO_x generation rate and increased slag in the combustion chamber. Given the physical plant confining space, construction costs, and fan capacity limitations, a well designed windbox would provide nearly uniform air flow distribution at the burners. The registers are then used to optimize the secondary air flow velocity into the combustion chamber. Optimal secondary air inlet velocity is dictated by the coal composition and the operating load. Previous studies (B&W, 1991) of this problem have shown that NO_x generation rate can be reduced by as much as 20% with an optimized windbox.

The Shawnee Steam Plant (SHF) Units 1-9 are coal burning, 150 MW, front wall, concentric firing boilers. Each unit is divided into two sections. Each section has 4 rows of burners. Each row consists of two burners. A schematic representation of a typical SHF unit is shown in Figure 1. The air is supplied to each side of each unit via an axial flow, fixed blade forced draft fan. Each fan was designed to deliver 208,000 cfm at 10.8" SP (Figure 2). Currently, each fan is operated in the range of 240,000 cfm to 300,000 cfm. The secondary air flow bias in the windbox is due to duct geometry downstream of the air heater, air heater fouling, and windbox geometry. Due to the variable extent of fouling and localized variations in duct layout, each side of each unit exhibits different duct bias. However, common geometric denominator includes flow separation and biasing due to a sudden drop and a sudden lateral change in direction, and a 26 inch I-beam obstructing the flow field. The result is adverse magnification of the air flow bias. This maldistribution manifests itself in low air flow rate at burner levels B and C. This bias is suspected to be the root cause of low combustion performance at levels B and C producing slag [burner eyebrows] and water wall corrosion.

Repeated attempts were made to improve the windbox air flow distribution in these units. The first modification to the windbox on all the units was implemented in 1972. The modification consisted of a set of vanes in the windbox of each unit. The vanes were intended to redistribute the flow field in the windbox, near the burners. Since, additional vanes were installed in the windboxes of these units without successful resolution to the flow distribution problem. These vanes adversely impacted the windbox head pressure losses, adding 2 inch w.g. to the total windbox pressure losses. The result of the reduced windbox pressure head is reduced combustion performance and increased likelihood of windbox fires.

The above mentioned vanes were intended to resolve the flow maldistribution downstream of the windbox duct; i.e., attempting to restore a disturbed flow field. However, significant savings are obtained by preventing the flow field from being disturbed. This is accomplished by placing vanes in the approach duct, and guiding the air into the appropriate burner levels. This approach is the basis of the problem resolution strategy.

The recommended windbox optimization strategy is constrained by minimum physical changes to windbox geometry, low construction costs, physical space, and fan capacity.

SOLUTION APPROACH

The problem resolution strategy consist of

1) assessment of previous SHF secondary air flow distribution studies,
2) development of optimal windbox vane design using physical model techniques,

Figure 1
SHF Burner and Boiler Layout

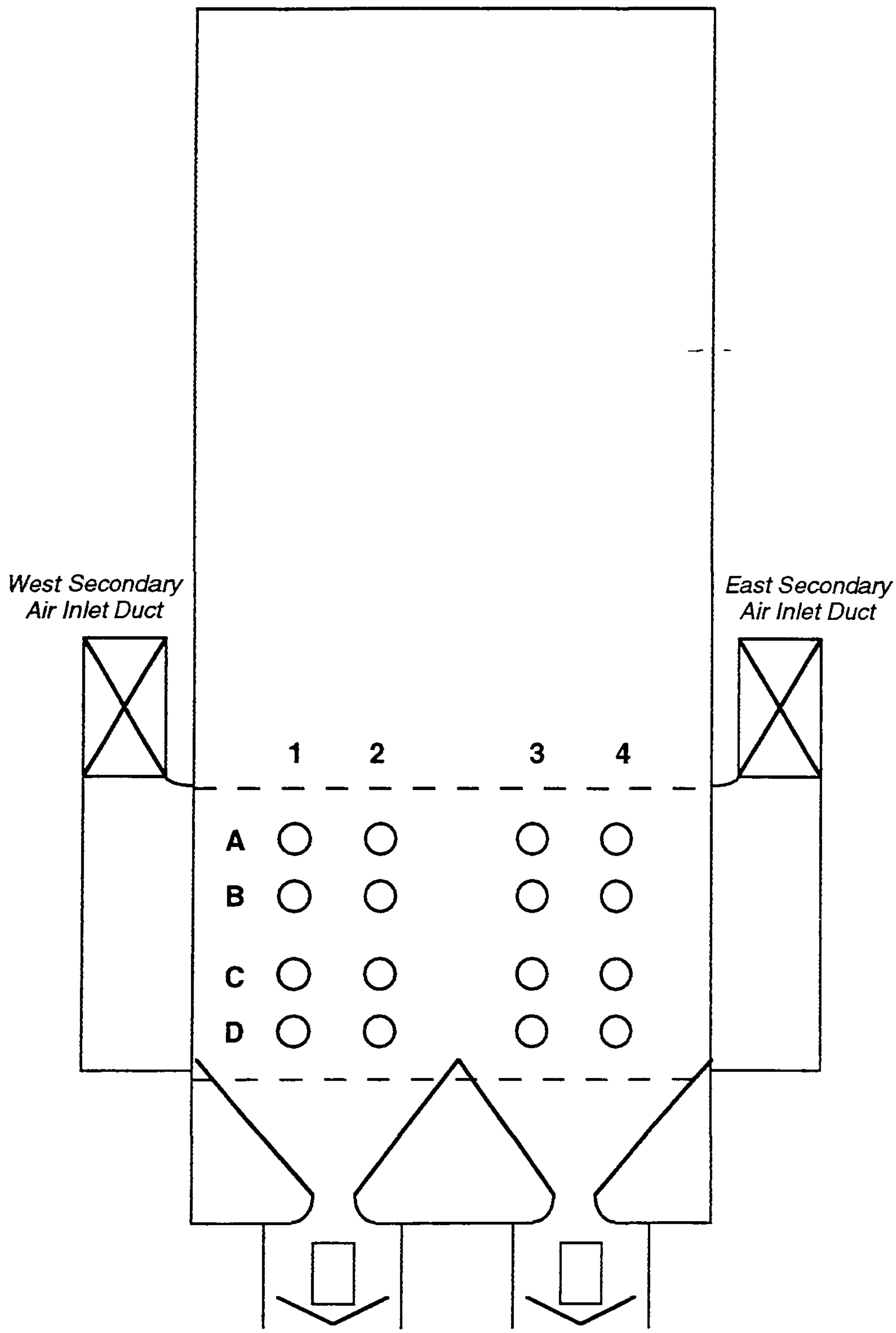
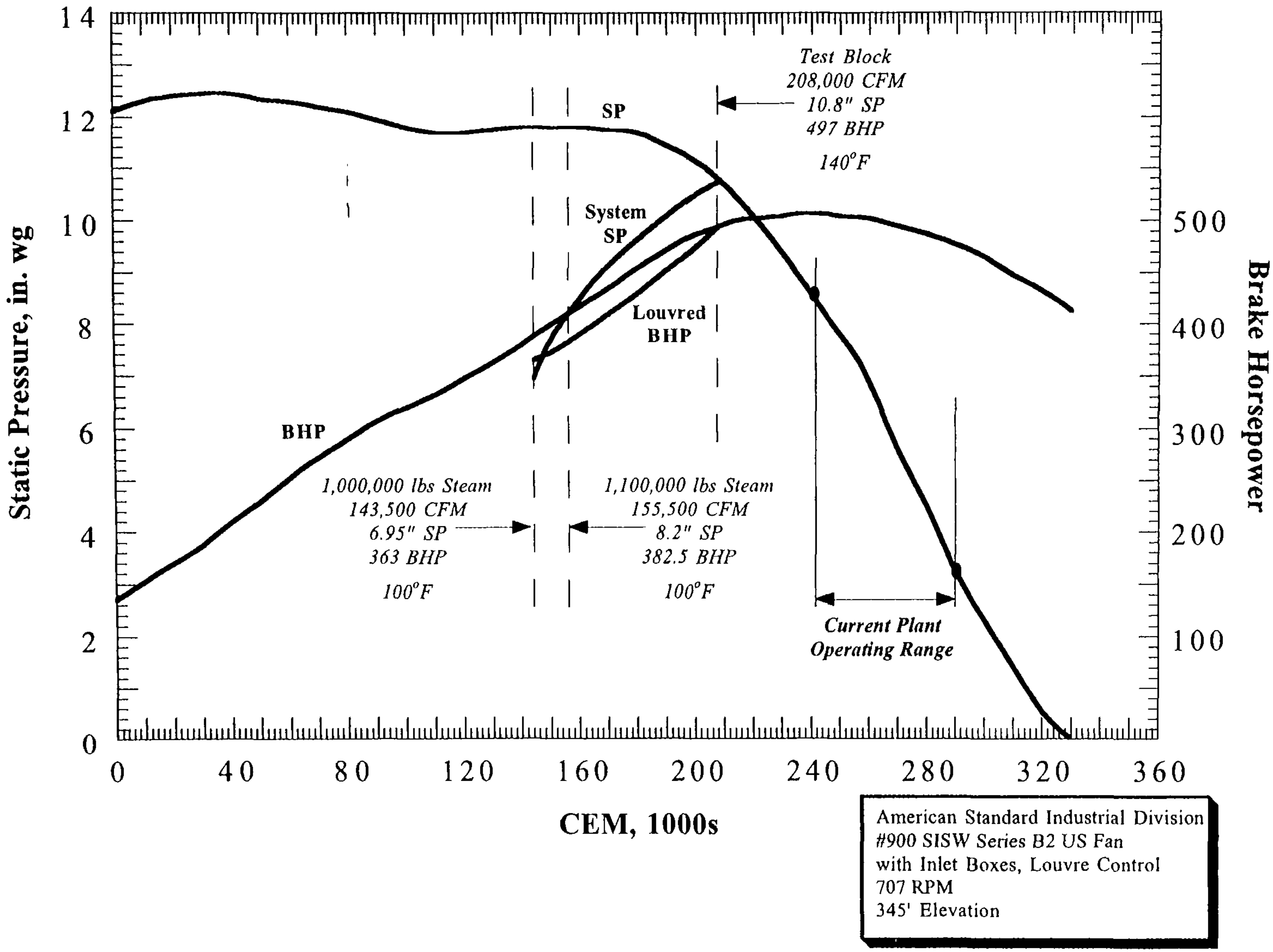


Figure 2
TVA Shawnee Steam Plant
Forced Draft Axial Fan Performance Curve



3) evaluation of NO_x generation and slag and corrosion potential using the Radian Furnace Simulation Model.

The objective of this work is to improve the windbox air flow distribution to achieve the following goals:

i) minimize fan pressure losses;
ii) optimize secondary air flow rate to each burner;
iii) reduce NOx emissions;
iv) reduce slag and corrosion in the combustion chamber.

Assessment of field data

The SHF data consisted of a series of hot air velocity traverses taken at the entrance to the windbox. A summary of the resulting relative volumetric flow rates to each burner level are presented in Table 1 for boiler units 3, 4, 8, and 9. The data shows that burner levels A and D receive an average of 63% of the total air flow, with burner level C receiving less than 16% of the total air flow as shown in Table 1. The low air flow to levels B and C is due primarily to flow separation around the I-beam.

The proposed design was developed with careful attention to the available fan head, and the system losses. Figure 3 shows the system curve of the plant forced draft fans. These are fixed blade, axial fans. The fan test block was based on 208,000 cfm at 10.8 in w.g. static pressure, with 497 BHP at 140 degrees F. The operators logs indicated that these fans are operating in the range of 240,000 to 300,000 CFM at 8.5 to 2.3 in. w.g. static pressure. The air heater pressure losses are about 3 to 5 in. w.g. Prior to 1972, the windbox pressure losses were about 0.4 in. w.g. Installation of various vanes and shrouds increased the windbox pressure loss by up to an additional 2 in. w.g. Thus, little to no pressure head remained at the secondary air registers resulting in low velocity head available to drive the flame away from the burners. This condition is conducive to slag at the burner wall (eyebrows) and windbox fires.

The new vane distribution system is intended to reduce windbox pressure losses and thus aid the coal combustion performance. Improved combustion efficiency at, or perhaps lower, mean combustion temperature should reduce NOx generation rate, combustibles in the convection pass, and reduced slag and corrosion.

Physical model setup

A Plexiglas 1:15.8 cold flow physical scale model of the Shawnee Unit 2 boiler and secondary air flow system was constructed at the TVA Engineering Laboratory. Air was supplied from a bi-axial fan with maximum capacity of 125 cfs. The fan air flow was determined from a differential pressure nozzle calibrated at 60 degrees Fahrenheit. The actual model air flow rate was corrected to the ambient temperature using the ideal gas law. The model tests were completed at model flow rates above 30 cfs with a model Reynolds number above 50,000 [well into the fully turbulent regime]. The

TABLE 1

Secondary air flow distribution at four SHF units

All tests at Full Load (138 MW-150 MW), Secondary air temperature ranges from 620 F-650 F

Hot air volumetric flow rate (cfm) data was collected at Shawnee Steam Plant for Units 3,4,8,9

Unit 3 7-12-72

Burner level	Flow rate fraction	West side	East side	
A	1.45	111532	112059	1.45
B	0.81	62097	63447	0.82
C	0.65	49948	46914	0.61
D	1.09	83622	85661	1.11
Sum		307198	308080	

Unit 4 1-3-73

Burner level	Flow rate fraction	West side	East side	
A	1.45	114025	105388	1.33
B	0.94	73675	71001	0.90
C	0.63	49378	55716	0.70
D	0.99	77698	84706	1.07
Sum		314776	316811	

Unit 8 7-18-72

Burner level	Flow rate fraction	West side	East side	
A	1.72	75250	41250	1.34
B	0.90	39250	25750	0.84
C	0.47	20625	18375	0.60
D	0.91	39625	37875	1.23
Sum		174750	123250	

Unit 9 7-24-73

Burner level	Flow rate fraction	West side	East side	
A	1.23	43250	70750	1.67
B	0.79	28000	36000	0.85
C	0.76	26625	23250	0.55
D	1.22	43125	39250	0.93
Sum		141000	169250	

burners were modeled using a modified form of the Thring-Newby criteria. The model results were extrapolated to the prototype conditions using Euler's scaling criteria.

The maximum and minimum velocities, and the coefficient of variance are computed for each case. Computed values are normalized to the mean mass flow rate in the inlet duct. The final design velocities and variances are normalized to the mean air volumetric flow rate in each burner level. The system pressure losses are measured for each case and evaluated in light of available fan capacity.

Numerical Model Setup

The Radian Furnace Simulation Model (FSM) is a full capability, three dimensional, Computational Fluid Dynamics (CFD) model. The model solves the fluid flow, heat and mass transfer equations using the Control Volume method implemented in the PHOENICS code developed by and distributed by CHAM Limited. The Radian FSM solves an additional set of coal combustion and chemical equilibrium equations compiled and implemented by Radian Corporation. The code accurately predicts the furnace flow field, thermal profile, combustion kinetics, NO_x generation rate, and boiler wall slag and corrosion. The FSM has been successfully applied to radiant type, front wall and rear wall coal furnaces as well as CE tangential fired units. The model predicts the following boiler parameters and operating conditions:

- furnace temperature profile
- furnace flow field velocity profile
- furnace coal combustion rate profile
- furnace NO_x generation profile
- unburned carbon at the furnace exit
- O_2 at the furnace exit
- furnace exit gas temperatures
- furnace slag potential
- furnace tube corrosion potential.

The Radian FSM was adapted to a the west side section of SHF Unit 6. The results of the simulation are directly applicable to the other units. The model consists of 18X24 cells in the lateral domain, with 47 cells in the vertical domain. The model input allows for burner to burner variation in coal feed rates, primary air mass flow to coal mass flow ratios, and secondary air distribution. The secondary air to each burner is input from the physical model test results for the original windbox layout and the new segregated windbox design. The numerical analysis evaluates the impact of load, secondary air bias and orientation on NO_x generation rate, slag and corrosion. The simulated boiler scenarios are designed to evaluate the impact of

1) reducing load,
2) reducing excess oxygen,
3) improving secondary air register bias.

4) and modifying the swirl generators to carry the combustion gases up the wall.

Each computer run provides the following information:

1) flow velocity profiles at various planes in the furnace,
2) thermal profiles at these planes,
3) average flue gas exit flow rate,
4) average NOx concentration at the furnace exit,
5) average excess oxygen at the furnace exit,
6) slag indices for each of the furnace walls,
7) high temperature corrosion indices at each of the furnace walls,
8) low temperature corrosion indices at each of the furnace walls.

RESULTS

Physical Model Validation

The physical model base case constitutes a windbox without any flow distribution devices. For each test, the air flow distribution was measured at

1) the approach duct,
2) the inlet to the windbox,
3) upstream of the burners,
4) and the entrance to the convection pass.

The impact of the air flow bias in the approach duct was simulated using flow deflectors located in the approach duct. The deflectors created a severe disturbance in the air flow profile. The level by level air flow rate was measured in the model and extrapolated to the prototype conditions assuming volumetric air flow rate of 300,000 cfm on each side of the boiler, with average air temperature of 630 degrees F. The results of that test are shown in Table 2. The results shown in Table 2 correlate well with the data collected at the plant. Both data sets indicate flow bias toward burner level A, and to a lesser extent burner level D. Burner levels B and C are negatively biased.

Vane Design Development

The design development precluded duct or windbox skin modifications. Vanes presented optimal, low cost flow redistribution devices. Preliminary testing program covered an extensive list of alternative vane designs. The detailed analysis was focused on a vane design consisting of three (3) vanes extending from within the approach duct to downstream of the inner burners as shown in Figure 3. The test results are summarized in Table 3. The vanes segregate each burner level from the neighboring levels. The vanes are spaced in the approach duct so as to ensure nearly uniform volumetric air flow rate to each burner level. The burner to burner variation can

TABLE 2

Shawnee Windbox Velocity profile data analysis

No Vanes, beam as of 1/23/95 with flow disturbed

Date: February 22, 1995

Pressure differential (in.w.g.):

Windbox to combustion chamber =	1.19
Left inlet to combustion chamber =	1.20
right inlet to combustion chamber =	1.11
left inlet to windbox =	0.00
right inlet to windbox =	0.08

Burner level	Flow fraction	West side	East side	
A	1.30	97838	118641	1.58
B	0.74	55735	47142	0.63
C	0.76	57054	53925	0.72
D	1.19	89373	80282	1.07
Sum		300000	299990	

Flow rates

1	2	3	4	Level
48649	29595	38235	43015	A
44595	36892	39706	39338	B
45000	30811	33088	46691	C
36486	27973	25735	34191	D

Normalized values

1	2	3	4	Level
1.30	0.79	1.02	1.15	A
1.19	0.98	1.06	1.05	B
1.20	0.82	0.88	1.25	C
0.97	0.75	0.69	0.91	D

Coefficient of Variance= 18.5%

NOTE: Plant flow rate 300,000 cfm each duct, temp=630 deg.

TABLE 3

Shawnee air flow distribution (cfm) predicted with the physical model

Proposed flow divider vanes extending from the inlet duct to the burners

Simulation Date: February 9, 1995

Pressure differential (in.w.g.):

Windbox to combustion chamber =	1.26
Left inlet to combustion chamber =	1.53
right inlet to combustion chamber =	1.59
left inlet to windbox =	0.28
right inlet to windbox =	0.34

Average additional windbox pressure loss due to vanes =	0.27

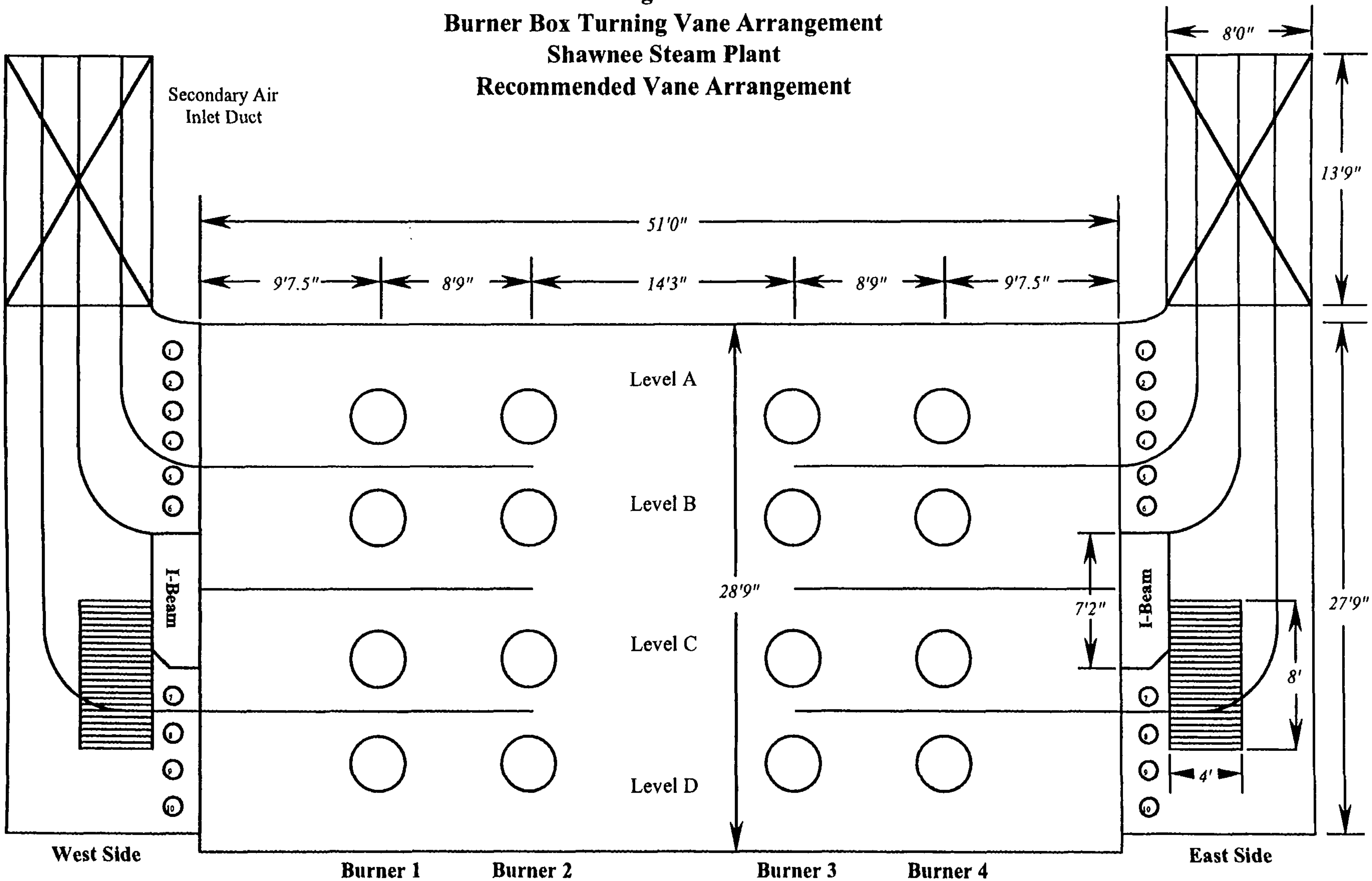
Burner to burner flow distribution

	Aif flow rates				Normalized values				
level	1	2	3	4	1	2	3	4	Level
A	37079	37921	36181	38819	0.99	1.01	0.96	1.04	**A**
B	38571	36429	30789	44211	1.03	0.97	0.82	1.18	**B**
C	42737	32263	38646	36354	1.14	0.86	1.03	0.97	**C**
D	38839	36161	38258	36742	1.04	0.96	1.02	0.98	**D**

Coefficient of Variance= 8.7%

NOTE: Plant flow rate 300,000 cfm each duct, temp=630 deg.

Figure 3
Burner Box Turning Vane Arrangement
Shawnee Steam Plant
Recommended Vane Arrangement



be further reduced by installing porous plates or well designed, multiple level air registers.

The burner box side to side air flow is nearly symmetric in spite of side to side differences in windbox entrance. This was demonstrated with paraffin wax smoke injected into the flow field on each side. The smoke entering from each side expands into the furnace on that side. Negligible amount of smoke was observed at the opposite windbox or furnace side. This observation indicated that, although the right to left side air flow bias might impact each side of the furnace, it does not significantly impact the opposite side. On each side of the windbox, the vanes are to be located in the duct such that uniform volumetric air flow rate reaches each level. The variances between the burners in Level A segment are functions of the first vane and the roof of the approach duct. Due to the severe change in direction in the upper portion of the segment (inner radius influence), burners A1 and A4 are subjected to lower air flow rates than burners 2 and 3. A porous plate between A1 and A2 is designed to further distribute the flow field. New burners or new registers would make up for this remaining, but reduced bias. The I-beam located on each side of the furnace significantly distorts the flow field approaching level C. The new design ensures adequate air supply to this level.

The recommended vanes reduce the available system pressure by less than 0.3 in. w.g. Given that the existing vanes and shrouds reduce available pressure by 1.8 in w.g., the net gain with this system is about 1.5 in. w.g. Consequently, the forced draft fans should have the capacity to maintain adequate windbox to combustion chamber pressure differential. At 300,000 cfm, the available windbox total head should be approximately 1.5 in. w.g.

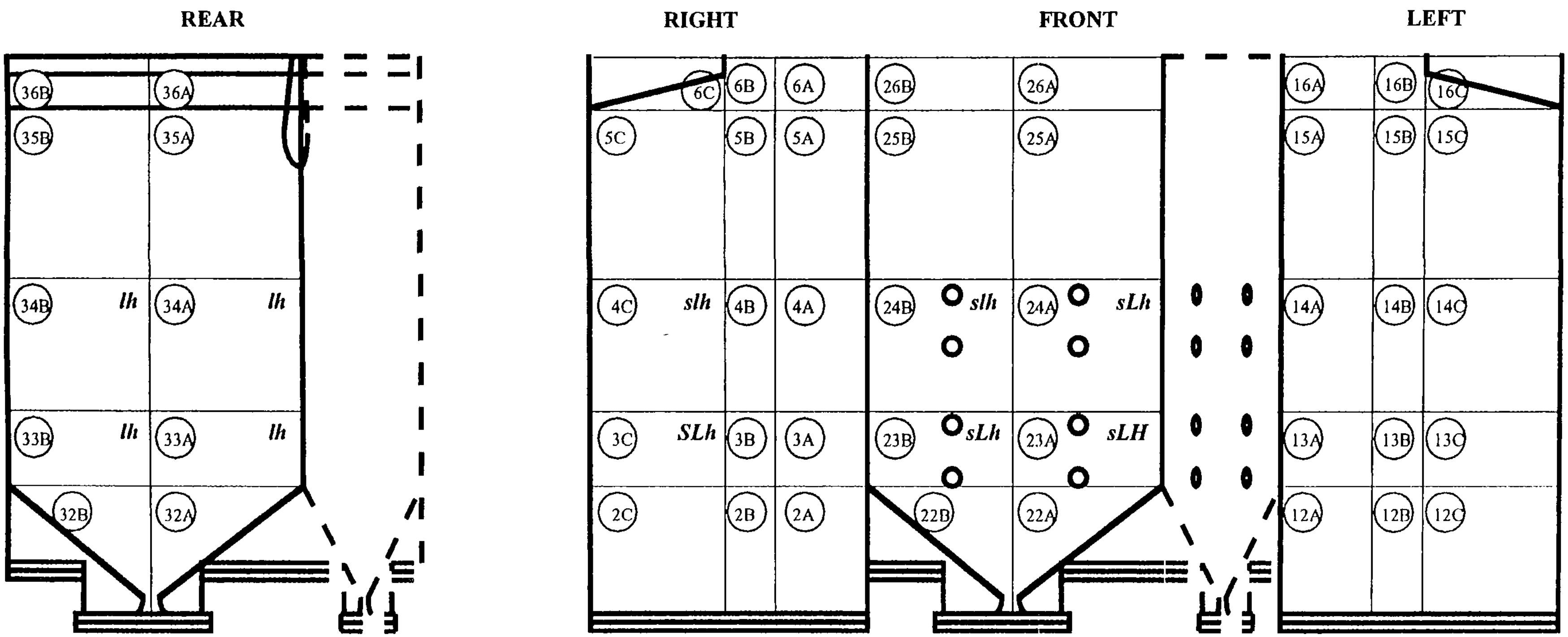
NOx and Index Computations

The numerical simulation scenarios are presented in Table 4. The simulation results are shown in Boiler Diagrams 1 through 5. Diagrams 1 and 2 constitute the baseline conditions at full load and minimum load respectively. Slag and corrosion are observed near the burner region in both cases, although less severe for the minimum load scenario. While at full load, additional slag and corrosion potential corresponds to the reduced secondary air supply to the right side of the boiler. A comparison of diagrams 1 and 3 suggests that slag and corrosion potential on the sides of the boiler are successfully minimized with improved burner to burner bias. Reducing the excess oxygen adversely impacts the lower left side of the furnace as shown in Diagrams 1 and 4. Finally, a change in the swirl orientation of the inner burners to counter clockwise (e.g. flue gas travels up the wall) appeared to have minimal impact on slag and corrosion rates as shown in Diagrams 1 and 5.

The final NO_x results of these simulations are not available at this writing. The NO_x and index computation results will be presented at the symposium.

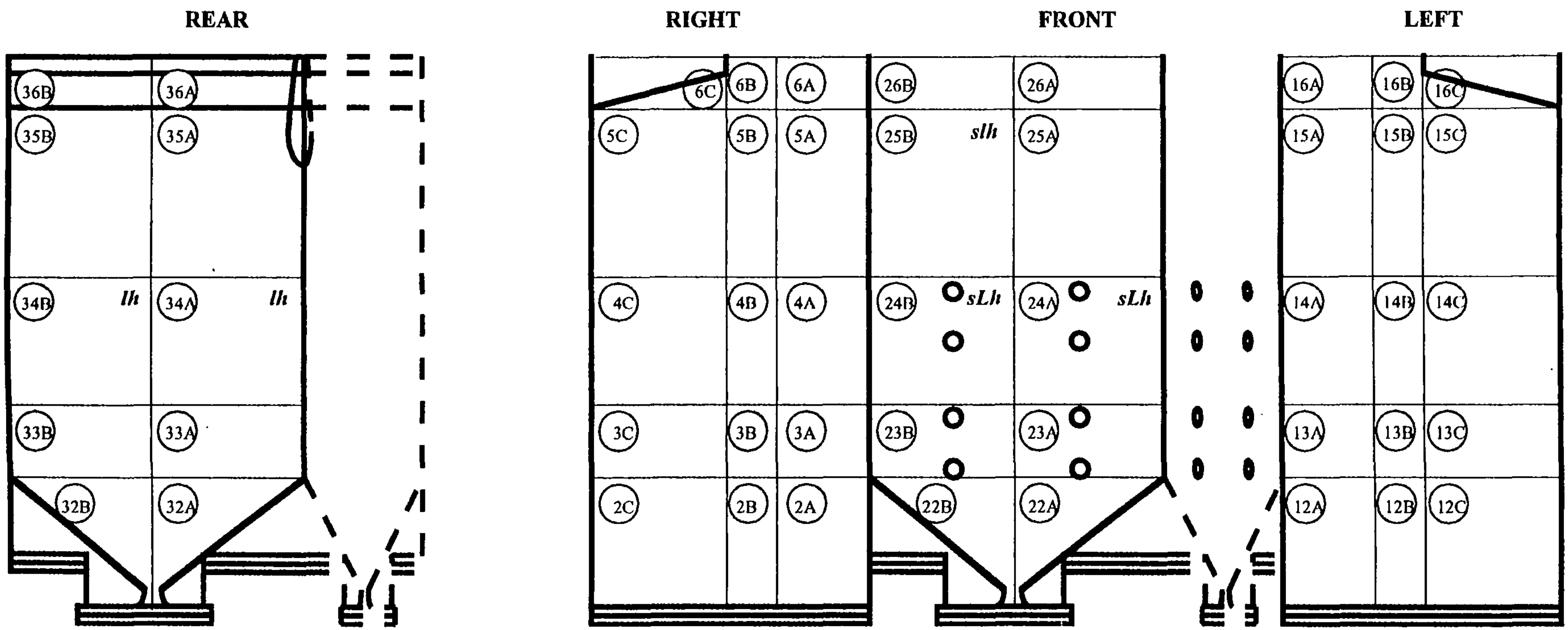
		TABLE 4			
SHF Furnace Simulation Model Scenarios (4/12/95)					
	Baseline full load	Baseline minimum load	Secondary air reduced bias*	Low O2 full load	Secondary air up the wall
Case Number	1	2	3	4	5
Coal A (kpph)	22.5	15	22.5	22.5	22.5
Coal B (kpph)	22.5	15	22.5	22.5	22.5
Coal C (kpph)	22.5	0	22.5	22.5	22.5
Coal D (kpph)	22.5	0	22.5	22.5	22.5
Load (MW)	150	50	150	150	150
Primary air ratio	1.8	1.8	1.8	1.8	1.8
%O2, dry	4.0%	5.0%	4.0%	2.0%	4.0%
Secondary air bias					
A1	78%	78%	103%	78%	78%
B1	85%	85%	118%	85%	85%
C1	89%		97%	89%	89%
D1	81%		98%	81%	81%
Average	83%	82%	104%	83%	83%
A2	122%	122%	97%	122%	122%
B2	113%	113%	82%	113%	113%
C2	109%		103%	109%	109%
D2	124%		102%	124%	124%
Average	117%	118%	96%	117%	117%
Swirl					
intensity (omega)	14	14	14	14	14
Orientation	CW	CW	CW	CW	up the wall
* The secondary air bias listed here results from the proposed vane design					

Diagram 1
SHF Slag and Corrosion Potential
Baseline, Full Load



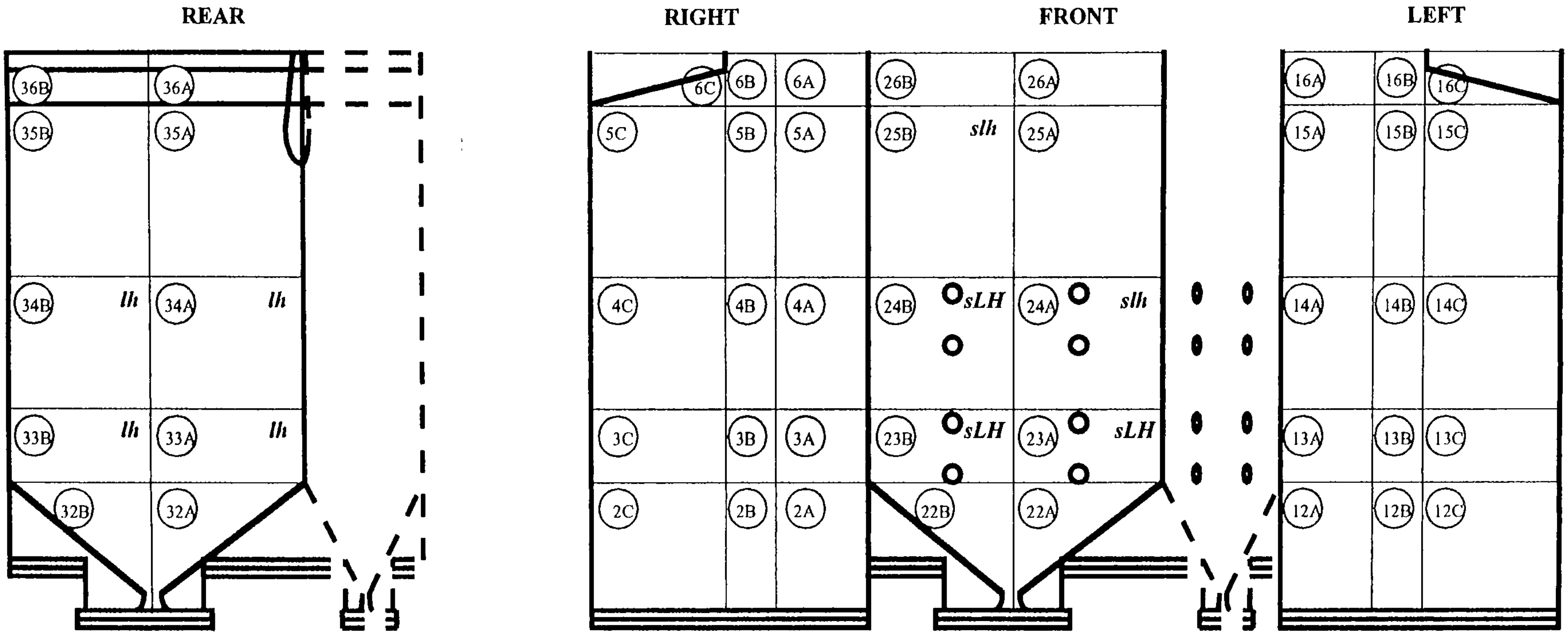
s	Moderate Slag
S	Extensive Slag
l	Moderate Low Temperature Corrosion Potential
L	Extensive Low Temperature Corrosion Potential
h	Moderate High Temperature Corrosion Potential
H	Extensive High Temperature Corrosion Potential

Diagram 2
SHF Slag and Corrosion Potential
Baseline, Minimum Load



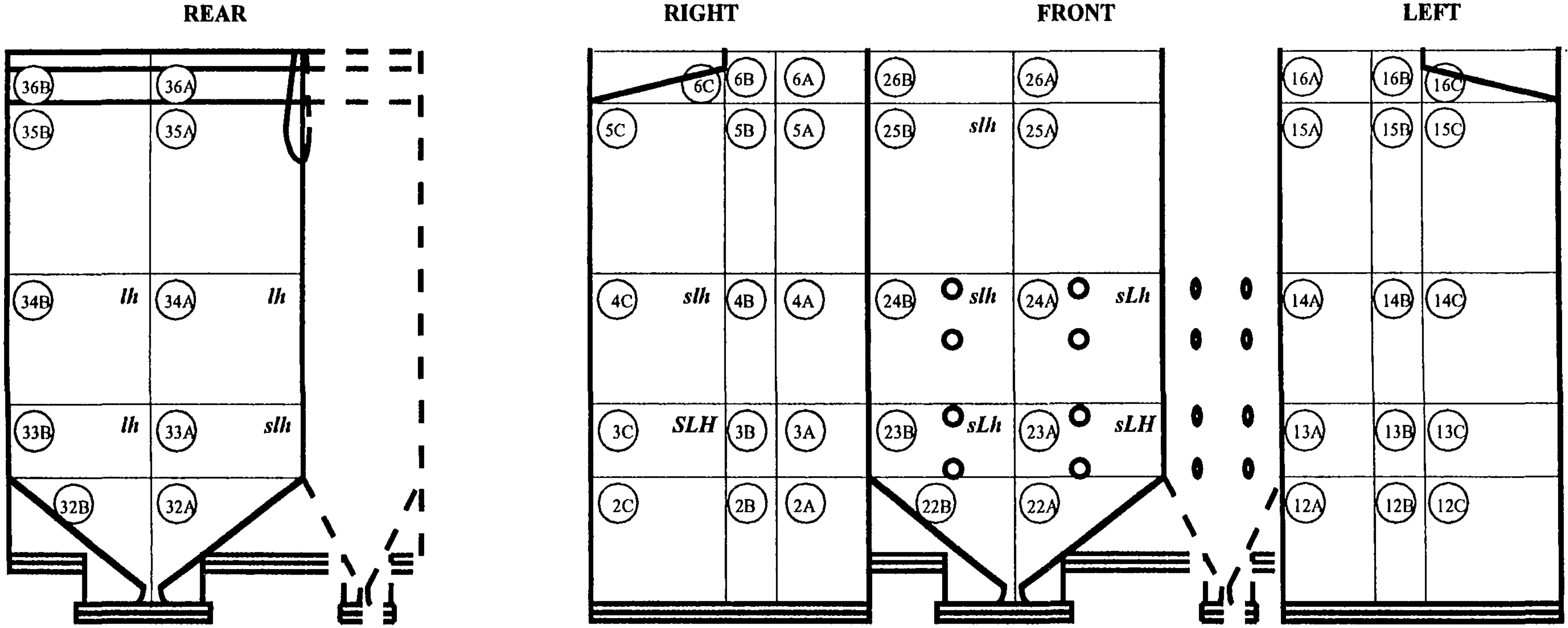
s	Moderate Slag
S	Extensive Slag
l	Moderate Low Temperature Corrosion Potential
L	Extensive Low Temperature Corrosion Potential
h	Moderate High Temperature Corrosion Potential
H	Extensive High Temperature Corrosion Potential

Diagram 3
SHF Slag and Corrosion Potential
Secondary Air Reduced Bias, Full Load



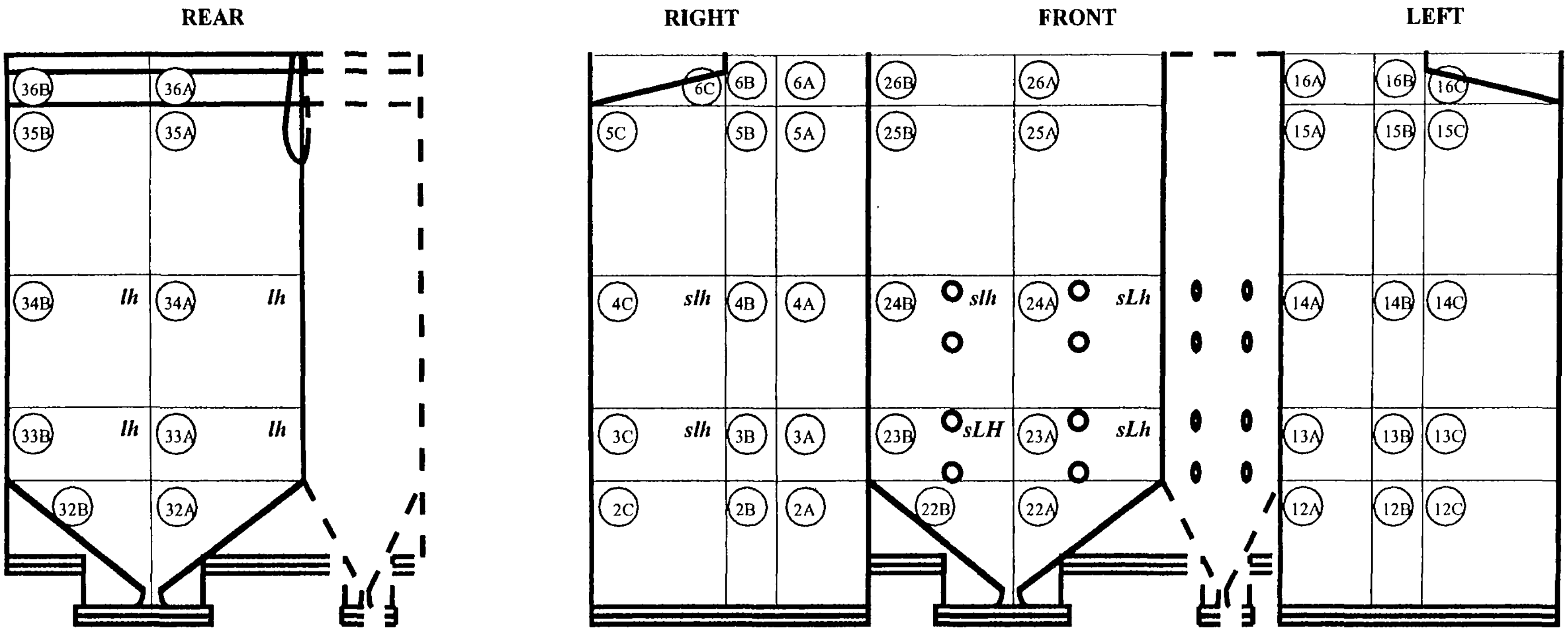
s	Moderate Slag
S	Extensive Slag
l	Moderate Low Temperature Corrosion Potential
L	Extensive Low Temperature Corrosion Potential
h	Moderate High Temperature Corrosion Potential
H	Extensive High Temperature Corrosion Potential

Diagram 4
SHF Slag and Corrosion Potential
Low Excess O_2, Full Load



s	Moderate Slag
S	Extensive Slag
l	Moderate Low Temperature Corrosion Potential
L	Extensive Low Temperature Corrosion Potential
h	Moderate High Temperature Corrosion Potential
H	Extensive High Temperature Corrosion Potential

Diagram 5
SHF Slag and Corrosion Potential
Secondary Air Up the Wall, Full Load



s	Moderate Slag
S	Extensive Slag
l	Moderate Low Temperature Corrosion Potential
L	Extensive Low Temperature Corrosion Potential
h	Moderate High Temperature Corrosion Potential
H	Extensive High Temperature Corrosion Potential

CONCLUSION

The study illustrates the usefulness and flexibility of an integrated approach utilizing field data, numerical modeling, and physical modeling to solve complex boiler systems engineering problems. The study yielded a low cost, efficient design to reduce the windbox bias. The reduction in windbox bias is expected to significantly reduce NO_x generation rate and improve boiler performance.

ACKNOWLEDGMENTS

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RI-JET BURNER FOR REDUCING NO_X EMISSIONS IN TANGENTIALLY FIRED BOILERS

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Abstract

A new type of low-NO_x burner has been developed for NO_x reduction of tangentially fired boilers. The basic idea of the RI-JET (Rapid Ignition) low-NO_x burner is to create a high-temperature reducing flame near the burner tip. In order to promote rapid ignition and to form a reducing zone near the burner, the RI-JET burner is equipped with a flame stabilizer in the coal nozzle, an axial swirler in the secondary air nozzle and a guide sleeve between the secondary and tertiary air nozzles. By now, this new low-NO_x combustion technology has been applied in two power stations, where the NO_x reductions achieved by RI-JET burners and an over-fire air system varied between 50 and 75% and, at the same time, unburned carbon was below 5%. The flame was stable over the normal load range 50-100%, and the flame stability was independent of the burner zone stoichiometric ratio. Low NO_x and UBC values were therefore achieved also when operating the boiler at low load.

Introduction

A new-generation low-NO_x burner, the RI-JET burner, for tangentially fired boilers has been developed in IVO Internationl Ltd, and an international patent application has been filed under the Patent Corporation Treaty. The basic idea of the **RI-JET (Rapid Ignition)** low-NO_x burner is to create a substoichiometric zone very close to the burner tip, and the two-stage combustion is carried out by means of a single burner. This single burner staging technique combined with staging in the main vortex with OFA is very effective in lowering NO_x emissions, combining the advantages of swirl-stabilized burners and tangentially stabilized combustion. With a typical jet flame it is difficult to control NO_x emissions and unburned carbon because of delayed ignition (normally 1-2 meters from the burner tip) and uncontrolled combustion air mixing in the primary combustion zone.

Basic features of the RI-JET burner

The RI-JET burner is equipped with a flame stabilizer, which promotes rapid ignition of the pulverized fuel; hence it is possible to allow a high-temperature reducing zone to be formed near the burner. Combustion air is divided into secondary and tertiary air streams; the secondary air has a swirling motion in order to bring hot combustion gases from the flame to enable the rapid ignition, and the tertiary air is separated from the primary combustion zone by a guide sleeve to form a reducing flame. Nonuniform pulverized coal distribution in the coal pipe has an adverse effect on the NO_x level and unburned carbon. To correct this the RI-JET burner is equipped with a venturi, which forces coal particles into the middle of the coal pipe. After the venturi, the particles are concentrated near the flame stabilizer, thus enhancing the ignition and flame stability by using specially designed pulverized coal concentrator technology. When enhancing the ignition, the carbon residue in the fly ash will remain < 5% also in substoiciometric combustion conditions.

For each boiler, before starting the detailed burner design, the furnace thermal behavior (temperature, oxygen, CO, NO_x, residence times, slagging etc.) is analyzed using the special ARDEMUS boiler model and the steam performance using process simulator SOLVO. The burner zone height and location of over-fire air ports are decided on the basis of these analyses. For detailed burner design IVO IN has developed a single burner combustion model.

Modifications made

Naantali Power Plant

The Naantali Power Plant is owned by IMATRAN VOIMA OY, which is the biggest power producer in Finland (4000 MW_e). The Naantali Power Plant is situated in the southern part of Finland, and consists of three identical units, whose total fuel input is 3 * 125 MW_e. The Sulzer-type boilers produce 420 t/h steam each and the turbine has a high-pressure and a low-pressure part (HP 180 bar, 530 °C; LP 42 bar, 540 °C). The boiler is supplied with coal from three coal mills and the burners are located at the corners (tangentially fired). All the coal burned is imported mainly from Poland and Russia.

Because strict requirements were set for NO_x emissions, the low-NO_x investments were started in unit 2. This modification only applied to two-stage combustion, and with this system it was difficult to achieve the official emission limit 180 $mgNO_2/MJ$ (540 $mgNO_2/m^3n$). As a consequence of unit 2 results, more advanced technology was needed. The next modification was carried out for unit 3, including 12 RI-JET low-NO_x burners with four OFA nozzles without any changes in the windbox. The old burners were equipped with a tilting system delivered by Combustion Engineer but the new RI-JET burners are vertically fixed. The old coal mills were equipped with rotating nozzle rings for reducing the amount of primary air; coal fineness was not improved. Guarantees for Naantali included NO_x value below 170 $mgNO_2/MJ$ (510 $mgNO_2/m^3n$) and unburned carbon in fly ash below 5%.

Detmarovice Power Plant

CEZ operates 12 000 MW_e and is the biggest electricity producing company in the Czech Republic. The company owns mostly brown coal -fired power plants, but Detmarovice is the largest hard coal -fired power plant in the Czech Republic (4 * 540 MW_f). The boilers are of the Benson type, producing 650 t/h of high-pressure steam (HP 180 bar, 540 °C; LP 36 bar, 540 °C). The boiler is tangentially fired and it is supplied with coal from four coal mills.

Retrofitting started in the summer of 1994 from unit 1 and because of the good results unit 2 will also be modified by IVO IN during the summer of 1995. Unit 1 was retrofitted with 16 RI-JET2 burners and an OFA system in the summer of 1994. IVO IN decided that modifications to the windboxes, mills and existing burner openings (plug-in design) were unnecessary. During the design process it was obvious that fineness of the coal particles was poor after the milling process but enhanced ignition was supposed to compensate it. At the moment, the official emission limit to NO_x emissions in the Czech Republic is 230 $mgNO_2/MJ$, but in the future it is expected to be at the Central European level, 150 $mgNO_2/MJ$. IVO IN guaranteed the following values in Detmarovice: NO_x emission 150 $mgNO_2/MJ$ and unburned carbon in fly ash below 3.5%.

Coal quality

The NO_x formation depends on the chemical and physical properties of the combusted coal. The most important factors affecting NO_x formation are the fuel ratio (fixed carbon/volatile matter) and the coal nitrogen content; the higher the fuel ratio and the nitrogen content are, the higher the NO_x emission (1) is. From the physical properties the most important one is the coal particle size after the milling process. A small particle size gives high nitrogen volatile yield and high flame temperature, promoting NO_x reduction. At the Detmarovice Power Plant especially one mill was in a very bad condition, giving 3-4% of coal particles bigger than 500 μm. The following table gives the properties of burned coal at the Naantali and Detmarovice power plants.

Table 1 -
Coal properties in actual cases

	Naantali	**Detmarovice**
Volatile content (dry,%)	33	24
Fixed carbon (dry,%)	51	54
Ash (dry,%)	16	22
FR-ratio (-)	1.5	2.3
N (dry,%)	1.1	0.9
Fineness (< 74 μm)	55	45
Fineness (> 200 μm)	5-10	5-15

NO_x and UBC test results

In both projects NO_x and UBC guarantees were achieved easily and the summary of the main results is presented in Figure 1. NO_x reduction achieved by RI-JET burners only was 50% and with two-stage combustion it was 70-75%, depending on the coal mill combinations. At Naantali unit 3, NO_x reduction was 50% with two-stage combustion; this lower value was due to the lower initial NO_x value. When comparing the performance of different low-NO_x combustion systems, the NO_x reduction itself is not important, but the final NO_x emission level.

The flame was stable over the normal load range 50-100% and the stability was also independent of the burner zone stoichiometric ratio. The guaranteed NO_x and UBC values were therefore achieved also when operating the boiler at low load. At the Detmarovice Power Plant there were no changes in the slagging behaviour after the modification. At the beginning of the Naantali project, some ash buildup was observed in the burner zone. However, after some modifications to the burner cooling system the ash buildup was eliminated.

The extremely low UBC level in the case of Naantali is explained by the high reactive coal (FR = 1.5) and the high-temperature stable flame. The stabilizing technology also compensates low coal fineness, as seen from the Detmarovice results.

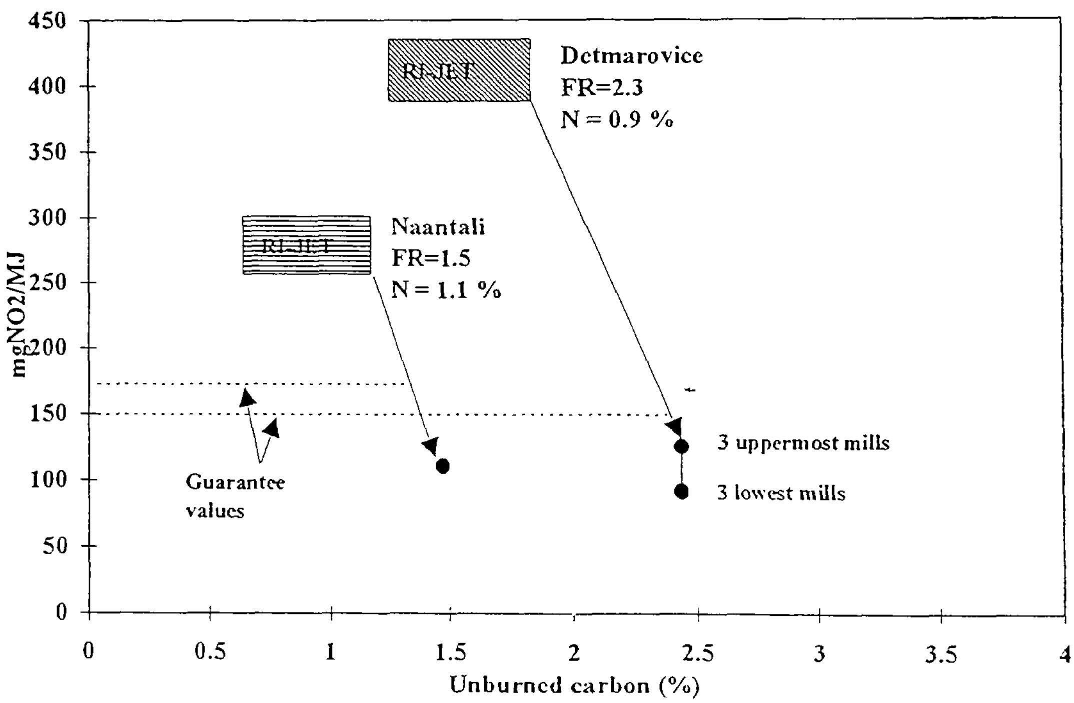

Figure 1
NOx and UBC results before and after low-NOx modifications

The most important parameter affecting coal combustion phenomena is the coal/air (C/A) ratio, which is determined as the coal mass flow (kg/s) per primary air amount (kg/s) of one mill. If the amount of primary air is very high (low C/A value), coal particles are far from each other, resulting in poor heat transfer and low combustion rate. In the other case (high C/A value) there is lack of oxygen, suppressing the flame. In industrial applications the C/A value typically varies between 0.3 and 0.5. For NO_x reduction and the combustion rate (UBC control) there is an optimum limit for the C/A value, and when the C/A value is too low it is difficult to achieve a reducing flame in the primary combustion zone (Figure 2). We also found correlation between the C/A value and the boiler efficiency: the higher the C/A value is, the lower the boiler end temperature is.

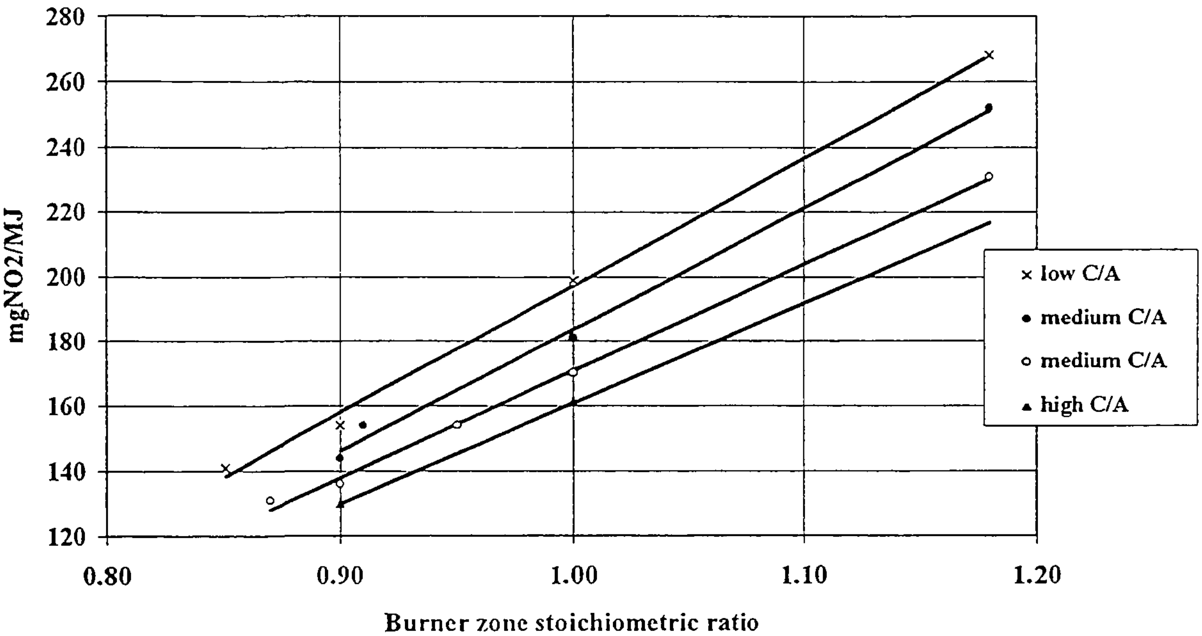

Figure 2
C/A-value and stoichiometric ratio vs. NO_x emission at the Naantali power station

During commissioning it was observed that when lowering the amount of primary air (higher C/A value) the flame became more stable and highly luminous, resulting in a high flame temperature. This means that the combustion rate is accelerated, and the final effects can be seen in Figure 3. With a high C/A value the amount of unburned carbon is not very sensitive to the burner zone stoichiometric ratio.

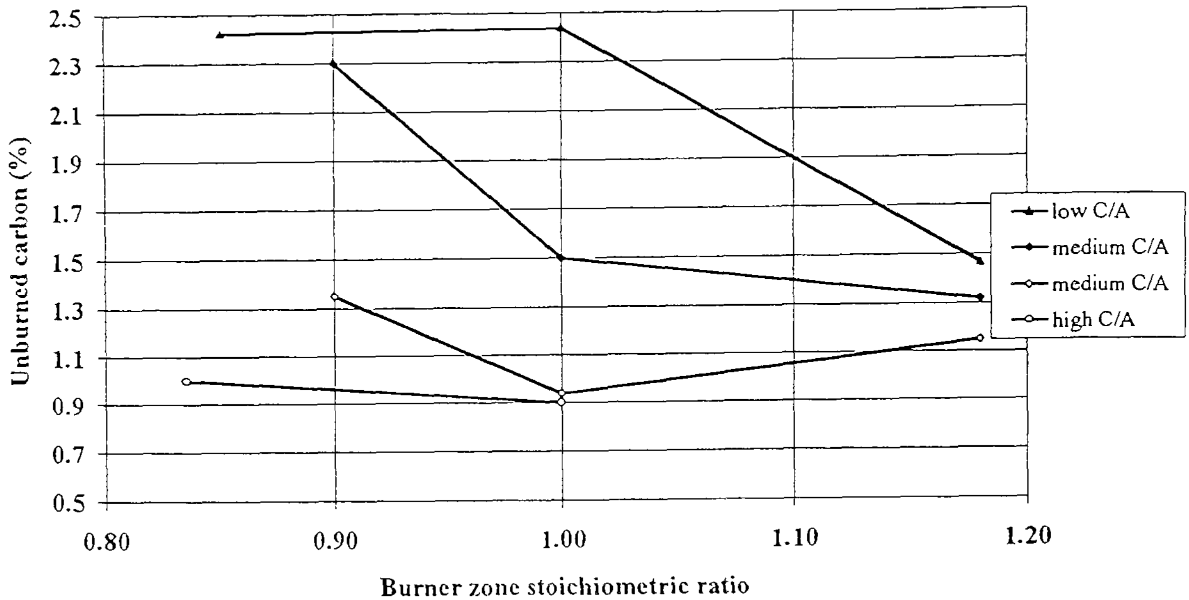

Figure 3
C/A-value and stoichiometric ratio vs. UBC at the Naantali power plant

Steam performance

Changing the ignition point near the burner tip has an effect on the boiler steam performance, decreasing the amount of reheat steam injections, and on the boiler efficiency, lowering the flue gas temperature before FGD. At the Naantali Power Plant, the flue gas temperature before FGD decreased 5 °C after the low-NO_x modification and the amount of reheat steam injections reduced 15 t/h. At the same time there was no change in the reheat steam temperature. In the case of Detmarovice the reheat steam injections decreased from 20 t/h to 0 t/h when operating at full load and at the same time there was no change in the reheat steam temperature, increasing the electric efficiency from 37.9% to 38.1%. At partial load, the reheat steam injections were 0 t/h and the reheat steam temperature decreased 15 °C, lowering the electric efficiency from 37.8% to 37.7%. The effect of two-stage combustion on the steam performance was very small compared with the change in ignition behavior.

Summary

In the case of swirl burners and wall-fired boilers, very low NO_x emissions have been achieved with high-temperature reducing flames, which is possible using the flame stabilizing technique. Now this principle has also been applied to tangentially fired boilers. This technology, combined with the over-fire air system, has potential for high NO_x reduction and still low unburned carbon in fly ash. Instead of the burner zone stoichiometric ratio, the C/A value and coal quality also have a remarkable influence on NO_x emissions and unburned carbon. In the future more attention will be given to coal mill performance and coal quality.

Burners with controlled aerodynamics in the primary combustion zone have a capability to achieve 50 - 75% NO_x reduction.

REFERENCES

1. T. Uemura et al. 1991. Update 91 on Design and Application of Low-NO_x Combustion Technologies for Coal-Fired Utility Boilers. *EPRI/EPA's Joint NO_x Control Symposium, 1991.*

LOW NO_X MODIFICATIONS ON FRONT-FIRED PULVERIZED COAL FUEL BURNERS

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Abstract

Burner optimizations and modifications were performed on Public Service of New Hampshire's Schiller Units 4, 5, and 6. These are Foster-Wheeler 50 MWg pulverized coal and No. 6 fuel oil-fired boilers with six burners each. Burner optimizations consisted of fuel flow, primary air, secondary air testing and balancing. Burner modifications consisted of the addition of circumferentially and radially staged flame stabilizers, circumferentially-staged coal spreaders, and modifications to the existing pulverized coal pipe. NO_X emissions on Unit 6 of .41 lb/mmBtu were achieved at optimized burner settings at full load with all burners in service and without the use of overfire air or bias firing. This represented a 50% NO_X reduction from the average pre-modification baseline NO_X emissions of .81 lb/mmBtu prior to the optimizations and burner modification program. NO_X emissions as low as .38 lb/mmBtu were achieved with the use of overfire air. There was essentially no quantifiable change in LOIs (baseline LOIs averaged 40%). Furnace excess O_2 as low as 1.2% was achieved with CO emissions of less than 200 ppm. Total installed costs including the overfire air system were approximately $7/kW.

Background

Public Service of New Hampshire's Schiller Station is located in the City of Portsmith, New Hampshire on the Piscataqua River separating the States of Maine and New Hampshire. Schiller Station Units 4, 5, and 6 are natural circulation Foster Wheeler Corporation boilers (Figure 1) designed for 425,000 lb/hr of steam at 1,285 psig at 950°F superheat. The boilers were built in the 1950's and designed for firing coal and No. 6 fuel oil. Coal was fired on Unit 4 briefly. In the early 1980's, the units were refurbished to burn 1% sulfur bituminous coal and No. 6 fuel oil. Six Combustion Engineering (CE) RO-type coal and oil burners were installed, arranged in two rows of three burners per row. Two CE pulverizers sized for the capability to operate at approximately 45 MWg were added. In the late 1980's, the burners on all three units were modified in an attempt to reduce LOIs and eliminate windbox fires. The Unit 4 burners were replaced with a design similar to the CE RO burner, however, with a reduced coal pipe length and diameter, reduced burner throat size, and the addition of coal spreaders. The Unit 5 burners were modified to a reduced length and diameter coal pipe and the addition of coal spreaders. The Unit 6 burners were replaced with a design similar to the original CE RO burners, however, with a reduced length and diameter coal pipe, reduced throat diameter, and narrower throat exit angle.

Title I of the 1990 Clean Air Act required that the Schiller Station Units 4, 5, and 6 make a significant reduction in the emission of nitrous oxide (NO_X). Regulations imposed by the State of New Hampshire instituted NO_X limits of .5 lb/mmBtu. Public Service of New Hampshire performed baseline NO_X emission testing on these units and at optimized burner setting, baseline NO_X emissions ranged between .8 and 1.0 lb/mmBtu. Public Service of New Hampshire's assessment of the cost of retrofitting these units with low NO_X burners was prohibitively high. In an attempt to reduce the capital cost requirement of bringing these three units into compliance, Public Service of New Hampshire and RJM Corporation jointly funded a NO_X reduction program to achieve NO_X compliance through burner optimizations and minor burner modifications.

NO_X Reduction Program

The NO_X reduction program stretched over two years for all three units to suit the Schiller Station normal maintenance outage schedule of 24 months for each unit. The initial NO_X reduction program was conducted on Unit 5, including testing with two different design coal spreaders. These results were published in a paper entitled "Modifications of Front-Fired Pulverized Coal Burners" [1] given at the May 1994 EPRI NO_X Conference in Scottsdale, Arizona. Unit 5 achieved a 40% NO_X reduction. In order to improve on the NO_X emission results achieved on Unit 5, the flame stabilizer diameter was reduced and an alternate design coal spreader was designed for Unit 4. A 45% NO_X reduction was achieved on Unit 4 from the original baseline NO_X emissions. Further improvements were incorporated into the Unit 6 conversion, including placement of the flame stabilizer at the end of the coal pipe. This resulted in a 50% reduction of NO_X emissions from the original baseline NO_X emissions of .81 lb/mmBtu. The NO_X reduction program on each unit consisted of two phases, an optimization phase and a burner modification phase. There were slight differences in the program for each unit since the burner configurations were different, and an attempt was made on each subsequent unit to improve performance.

The NO_X Optimization phase consisted of testing and balancing the secondary airflow, primary dirty airflow and coal flow. The Burner Modification phase consisted of Computational Fluid Dynamics (CFD) modeling of the baseline and modified burner, modifications to the coal pipe, and the addition of circumferential and radial staged flame stabilizers and circumferentially staged coal spreaders. In the case of Unit 6 the burner throat diameter was enlarged and the exit angle was modified back to the original design.

NO_X Optimization Phase

The objective was to balance secondary airflow, dirty airflow and coal flow within ±5% of the mean. The secondary air was measured utilizing RJM Corporation's proprietary Air Distribution Analysis (ADA) methodology. The ADA has the ability to measure the burner secondary air perimeter loadings while determining the average airflow through the burner. The back plate rings on Unit 5 and shrouds installed on Units 4 and 6 outside the air register vanes were adjusted to achieve a secondary air balance within ±5%. The dirty air and coal flow was measured by a reverse impact pitot tube and rotorprobe. Balancing was achieved by changes to the coal line orifice plates on Units 5 and 6. Adjustable orifice pulverized coal trim dampers were installed in the burner line coal pipes on Unit 4 for balancing. The baseline and final primary airflow, secondary airflow, and coal flow distribution deviations are identified in Table 1.

Table 1

Total % Deviations from the Mean

	Unit 4		Unit 5		Unit 6	
	Baseline	Final	Baseline	Final	Baseline	Final
Primary Dirty Air	7.9	2.1	15.9	6.30	42.2	6.6
Secondary Air	20.17	8.19	11.9	8.50	17.8	8.21
Coal Flow	51.0	10.4	37.9	26.9	--	4.84

Burner Modification Program

RJM Corporation used Fluent CFD and NO_X software on a Sun Sparc 10 computer to model parametric burner changes. The objectives of this portion of the project were to predict the percentage reduction in NO_X with the addition of a flame stabilizer and to determine whether the combustion in the internal recirculation vortex of the burner approximated stoichiometric proportions. The baseline burner geometry (burner as modified in 1990) for Unit 5 is shown in Figure 2. The model predicted NO_X emissions of the baseline burner of .33 lb/mmBtu. The model inputs were altered to reflect the addition of the staged coal flame stabilizer. The model predicted NO_X emissions for the modified burner of .1 lb/mmBtu or a 70% NO_X reduction. Because of the various modeling assumptions involved (coal volatilization and burnout characteristics, coal sizing and distribution, coal composition, turbulence modeling, combustion rate constants, etc.) the absolute levels of NO_X predicted are only approximate. Nevertheless, the computed results are useful in comparing trends and in quantifying the relative effectiveness of the two burner designs. Subsequent to completion of the program, additional CFD modeling determined the assumption for coal distribution exiting the coal pipe was incorrect and had a significant effect on model results.

The radially and circumferentially staged flame stabilizer (patent pending) is a low NO_X enhancement of the patented conventional radially staged flame stabilizer which has already been installed on over 2000 MW of coal-fired utility boilers. The design of the flame stabilizer was established utilizing an axisymmetric three-dimensional model. Figure 3 shows the staged, flame stabilizer design. The design maintains the primary air (15%) to secondary (85%) airflow split, and radially and circumferentially stages the secondary airflow to maximize the cyanide NO_X reduction reaction. The primary air was conveyed in the centrally located coal pipe. The secondary air comprised an outer zone around the flame stabilizer, unstaged and staged zones within the flame stabilizer, and an inner ignition zone. The secondary airflow characteristics were evaluated for design of the flame stabilizer at the flame stabilizer face exit plane diameter.

The flame stabilizer vanes were set to achieve the circumferentially staged zones by varying the vane exit angles and the number of blades in each zone. The staged section had twelve vanes and the unstaged section had four. The more axial flow angle of the unstaged zone and reduced blockage from fewer vanes permitted an increased secondary flow for the unstaged zone. The design ratio of 1.35 was achieved at a five degree flow exit angle difference.

An evaluation was made of the swirl number for the secondary airflow. Swirl number is a measure of the tangential-to-axial momentum of the secondary air exiting the plane of the flame stabilizer. The swirl number determines the size of the internal recirculation zone. For optimum combustion and low NO_X emissions, a swirl number less than 1.0 is desirable when integrated for the flow. Lower swirl numbers (<.5) may cause burner instability and ignition problems. Higher values (>1.5) create overswirl, which results in an oversized recirculation zone creating a hotter, more turbulent flame and the potential of gas recirculation into the register. Table 2 below is a summary of the final aerodynamic analysis results for each unit.

Table 2

Aerodynamic Ananysis
(Per Burner)

	Unit 4	Unit 5	Unit 6
Coal Flow lb/sec	2.2	2.2	2.2
Primary Airflow lb/sec	3.9	3.9	3.9
Secondary Airflow lb/sec	22.4	22.4	22.4
Burner Throat Diameter - Inches	28	28	30
Flame Stabilizer Exit Plane Diameter- Inches	31	40	30
Flame Stabilizer Diameter - Inches	24	27	24
Air Register Vane Setting - % Open	80	80	80
Integrated Swirl Number	.69	.90	.66
Burner Secondary Air Draft Loss - Inches w.c.	5.52	2.88	6.33

The staged flame stabilizer was mounted upstream of the coal pipe discharge except on Unit 6 where it was mounted on the end of the new, extended coal pipe. New coal spreaders were fabricated which provided separation of the individual coal jets to coincide with the staged sections of the flame stabilizer. The coal pipe was extended eleven inches (18 inches on Unit 6) to the beginning of the burner throat. Figures 4, 5, and 6 show the modified burner with the new, staged flame stabilizer and coal spreader for Units 4, 5, and 6, respectively.

Public Service of New Hampshire installed an overfire air system in six (6) existing observation doors one elevation (10 feet) above the upper burner level. Four (4) front-wall ports and two (2) side-wall ports near the rear of the furnace were utilized. On Units 4 and 6 two (2) rear wall ports were utilized instead of the side wall ports. Overfire air was taken from the top of the windbox. Each port was equipped with butterfly dampers.

Test Results

Baseline NO_X emissions were obtained on each unit by Public Service of New Hampshire prior to the NO_X reduction program. This data was taken at optimized settings and included some testing with the boiler observation doors above the burners open.

Final NO_X optimization testing was performed on each unit after the fuel and air were balanced and after the installation of the burner modifications. The baseline and final NO_X versus CO emissions results for each unit at optimized conditions without overfire air is listed in Table 3 below. On Unit 5, 34 MWg was the highest load achievable on coal firing.

Table 3

	Unit 4	Unit 5	Unit 6
Load MWg	46	34	50
Baseline NO_X Emissions - lb/mmBtu	.99	.84	.81
Baseline CO Emissions - ppm_v	19	11	60
Baseline O_2 - %	4.7	4.9	1.3
Modified NO_X Emissions - lb/mmBtu	.53	.49	.39
Modified CO Emissions ppm_v	3	20	38
Modified O_2 - %	1.8	1.5	1.5
NO_X Reduction	45%	40%	50%

Test results on Unit 6 with a smaller diameter, staged flame stabilizer located at the end of the coal pipe yielded significantly improved results over Units 4 and 5. Boiler operational adjustments for each unit provided similar results. With the reduced NO_X emission values on Unit 6, adjustments such as excess oxygen and overfire air had less of an impact than on Units 4 and 5. The following summarizes operational test results on Unit 6.

Boiler Load

Testing was conducted at the 2 mill maximum load of 50 MWg, and the 2 mill minimum load of 37 MWg. This was both with and without overfire air. At 50 MWg, average NO_X emissions were .41 lb/mmBtu reducing to .36 lb/mmBtu at 37 MWg. Opening the overfire air dampers reduced average NO_X at the full load condition to .40 lb/mmBtu and .33 lb/mmBtu at the 37 MWg condition. At the 1 mill minimum load of 21 MWg with the upper burners firing coal and the center lower burner on oil, NO_X emissions were .37 lb/mmBtu. This was without overfire air. Figure 7 is a plot of NO_X emissions versus boiler load at 37 MWg and 50 MWg at optimized burner settings.

Furnace Excess O_2

Throughout the boiler and burner optimization testing, data was taken at various excess furnace O_2 levels both with and without overfire air. Figure 8 is a plot of NO_X emissions versus furnace excess O_2 for the optimized burner settings. This is plotted at 50 MWg and 37 MWg with and without overfire air. At 50 MWg furnace excess O_2 ranged between 1.2% and 2.8% O_2 without overfire air. NO_X emissions at 1.5% O_2 were .39 lb/mmBtu. With the overfire air ports open at 50 MWg, furnace excess O_2 ranged between 2.3% and 2.8% O_2. Reducing excess O_2 from 2.8% to 1.2% resulted in a 21% NO_X reduction.

Figure 9 is a plot of furnace excess O_2 versus CO emissions for the optimized data at both 50 MWg and 37 MWg with and without overfire air. CO emissions at 50 MWg ranged between 0 ppm and 250 ppm at O_2 levels of 2.75% and 1.2%, respectively, without overfire air. At 60 ppm of CO emissions, furnace excess O_2 without overfire air would have been 1.5% versus 2.6% with the overfire air ports open, or a 1.1% O_2 reduction.

Overfire Air

Various combinations of overfire air ports and percent openings were tested to determine the effect of the overfire air system. The amount of overfire air was calculated from the decrease in the windbox-to-furnace differential pressure. Opening the four front ports to 50% open yielded approximately 4% overfire airflow, resulting in a negligible NO_X reduction. Opening the four front ports to 100% open yielded 8.2% overfire airflow, with a 4.7% reduction of NO_X emission. Closing the four front ports and opening the two rear ports to 100% yielded approximately 4% overfire airflow, however, a 3.7% NO_X reduction was realized. Opening the six overfire air ports to 100% resulted in 9.7% overfire air yielding an 8.1% reduction of NO_X emissions. The rear ports, although only adding 1.5% additional overfire airflow, resulted in an additional 3.4% of NO_X reduction. Figure 10 is a plot of NO_X reduction versus the amount of overfire air. This data is with the six dampers 100% open.

Loss on Ignition

Loss on Ignition (LOI) averaged approximately 40% on the units prior to the NO_x reduction program. Contributing to the cause of the high LOIs were the high moisture content of the coal (12%), operating the pulverizers above their maximum rating, and insufficient grinding of the coal due to high pulverizer amps with less than 70% passing through 50 Mesh. Post NO_x reduction program LOIs were essentially unchanged averaging within ±5% of the pre-modification average.

Summary

NO_x reductions on Unit 6 of 50% were achieved from the pre-NO_x reduction program optimized baseline conditions. This resulted in NO_x emission levels of .41 lb/mmBtu without overfire air. Figure 11 is a plot of NO_x versus CO emissions at 50 MWg for both the baseline and modified burner. NO_x reductions of 54% were achieved with the use of overfire air ducted into existing observation doors. Furnace excess oxygen levels of 1.5% were achieved without overfire air with CO emissions of 60 ppm_v. LOIs averaged approximately 40% with the modified burners. This was within ±5% of the premodified burner average LOIs.

Installed Costs

The complete installed costs for each unit are identified below. The costs include direct and indirect expenses, exempt and non-exempt labor, materials, and outside purchases. The total cost includes the burner optimizations and modifications, secondary air shrouds, removing windbox partition plates, air register repairs, refractory throat repairs or in the case of Unit 5 and 6 replacement of the burner throats, the overfire air system, and testing.

- Unit 4 $6.81/kW
- Unit 5 $6.25/kW
- Unit 6 $7.62/kW

References

1. Owens, B., Hitchko, M., and Broderick, R. G., "Modifications on Front-Fired Pulverized Coal Fuel Burners", presented at the Members Only EPRI NO_x Conference, Scottsdale, AZ (May 1994).

Northeast Utilities
(PSNH) Schiller Unit #5
Boiler Cross Section Side View

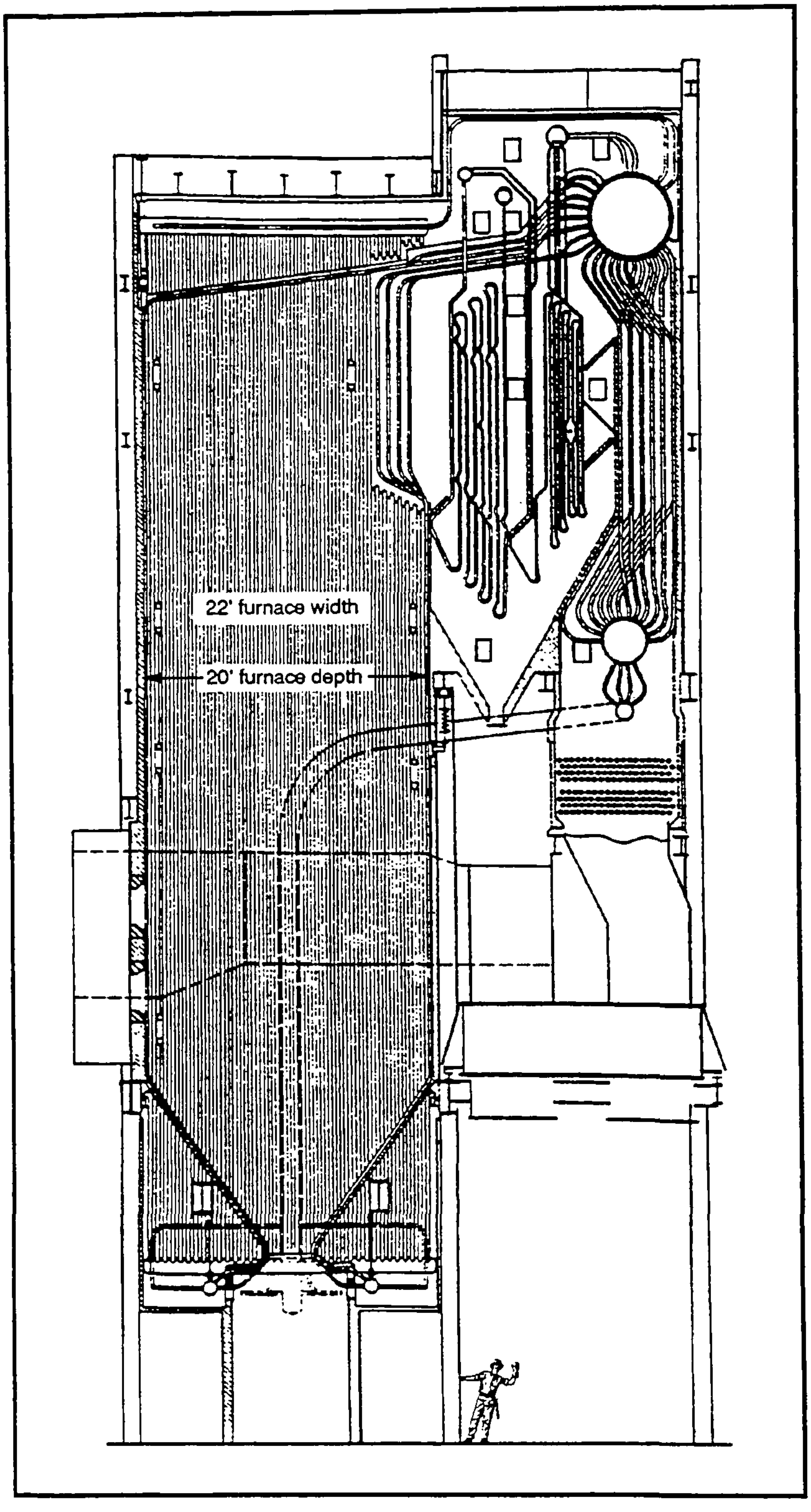


Figure 1

Northeast Utilities (PSNH) Schiller Unit #5
Burner Cross Section (Mod 1 and Mod 2 Coal Spreaders)

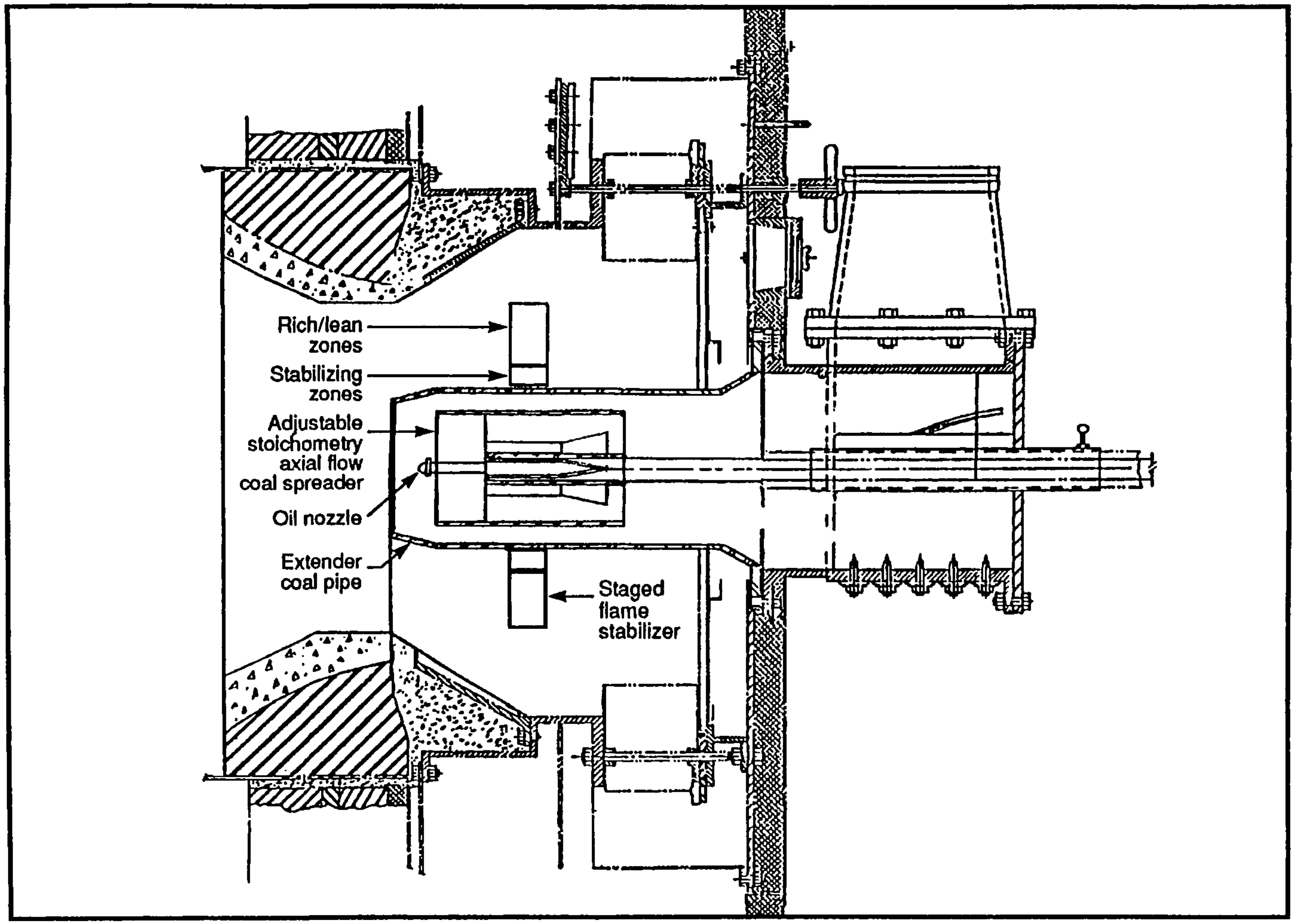


Figure 2

Staged Flame Stabilizer

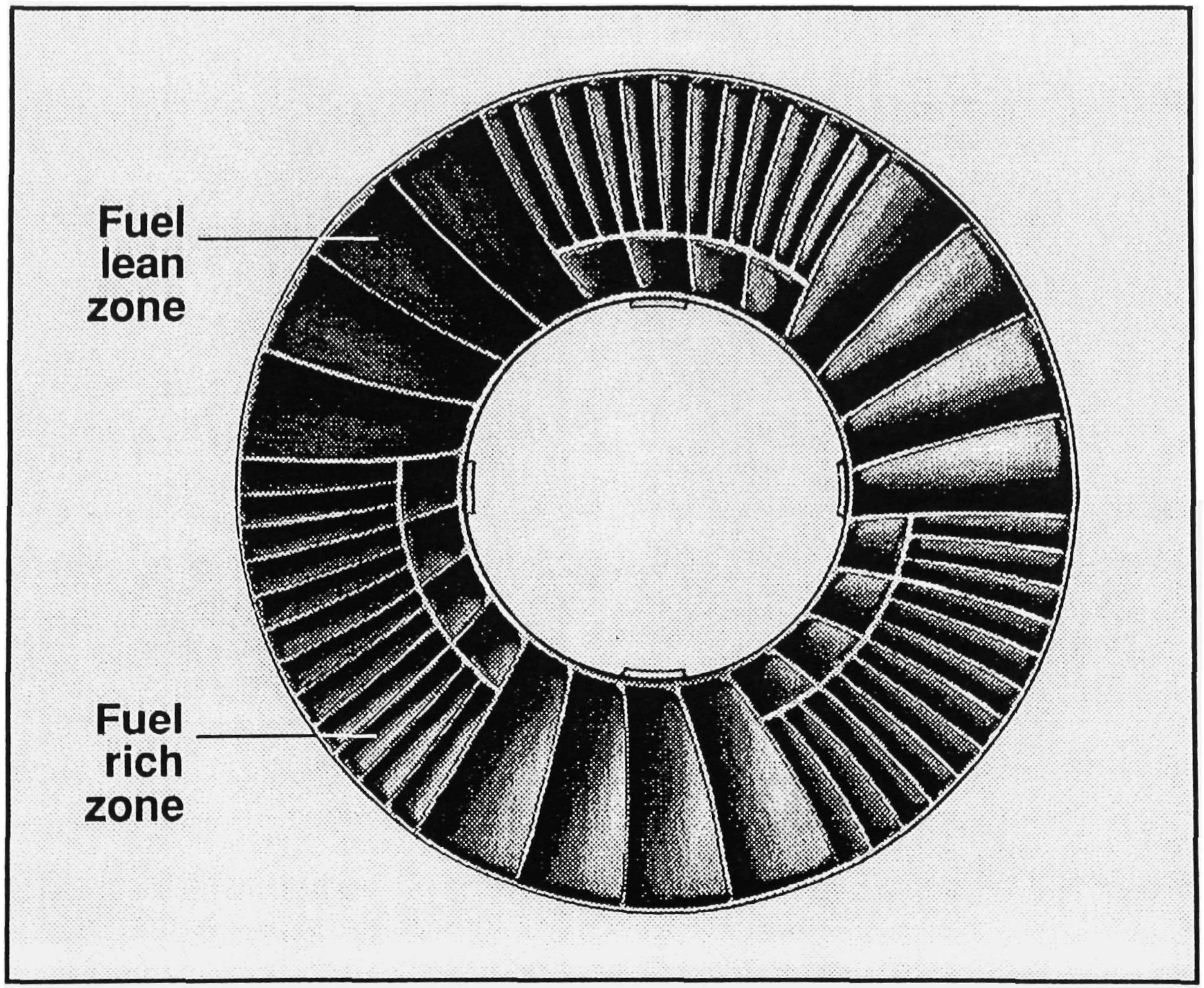
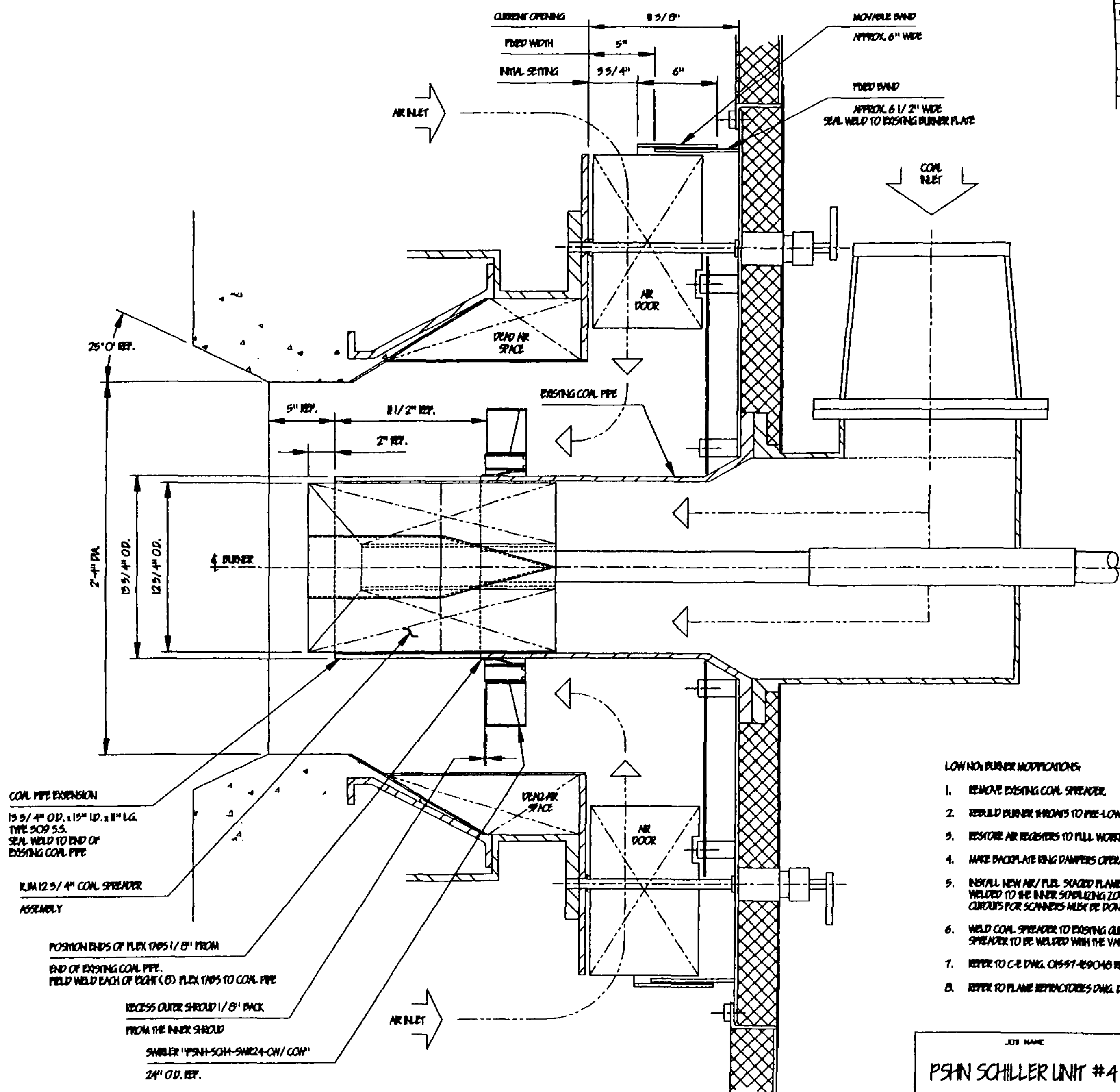


Figure 3

REVISIONS				
No.	DESCRIPTION	DWN.	CHK'D.	DATE
0	CLIENT REVIEW	RCP		12/4/94



LOW NOx BURNER MODIFICATIONS:

1. REMOVE EXISTING COAL SPREADER.
2. REBUILD BURNER THROATS TO PRE-LOW NOx RETROFIT CONDITION.
3. RESTORE AIR REGISTERS TO FULL WORKING CONDITION.
4. MAKE BACKPLATE RING DAMPERS OPERATIONAL. SET TO DIMENSIONS IN AIR TEST REPORT.
5. INSTALL NEW AIR/FUEL STAGED FLAME STABILIZERS. THE RICH/LEAN SECTIONS MUST BE WELDED TO THE INNER STABILIZING ZONE INSIDE THE FURNACE. SEE DWG. PSNH-SCH4-SWR24-CW/CCW. CUTOUTS FOR SCANNERS MUST BE DONE IN FIELD.
6. WELD COAL SPREADER TO EXISTING GUIDE PIPE AFTER FLAME STABILIZER IS INSTALLED. SPREADER TO BE WELDED WITH THE VANES STRADDLING THE RICH/LEAN JOINTS.
7. REFER TO C-E DWG. O1557-E9046 REV. O. FOR ADDITIONAL DETAILS.
8. REFER TO FLAME REFRACTORIES DWG. D-6525-02-095-005-5, FOR ADDITIONAL DETAILS.

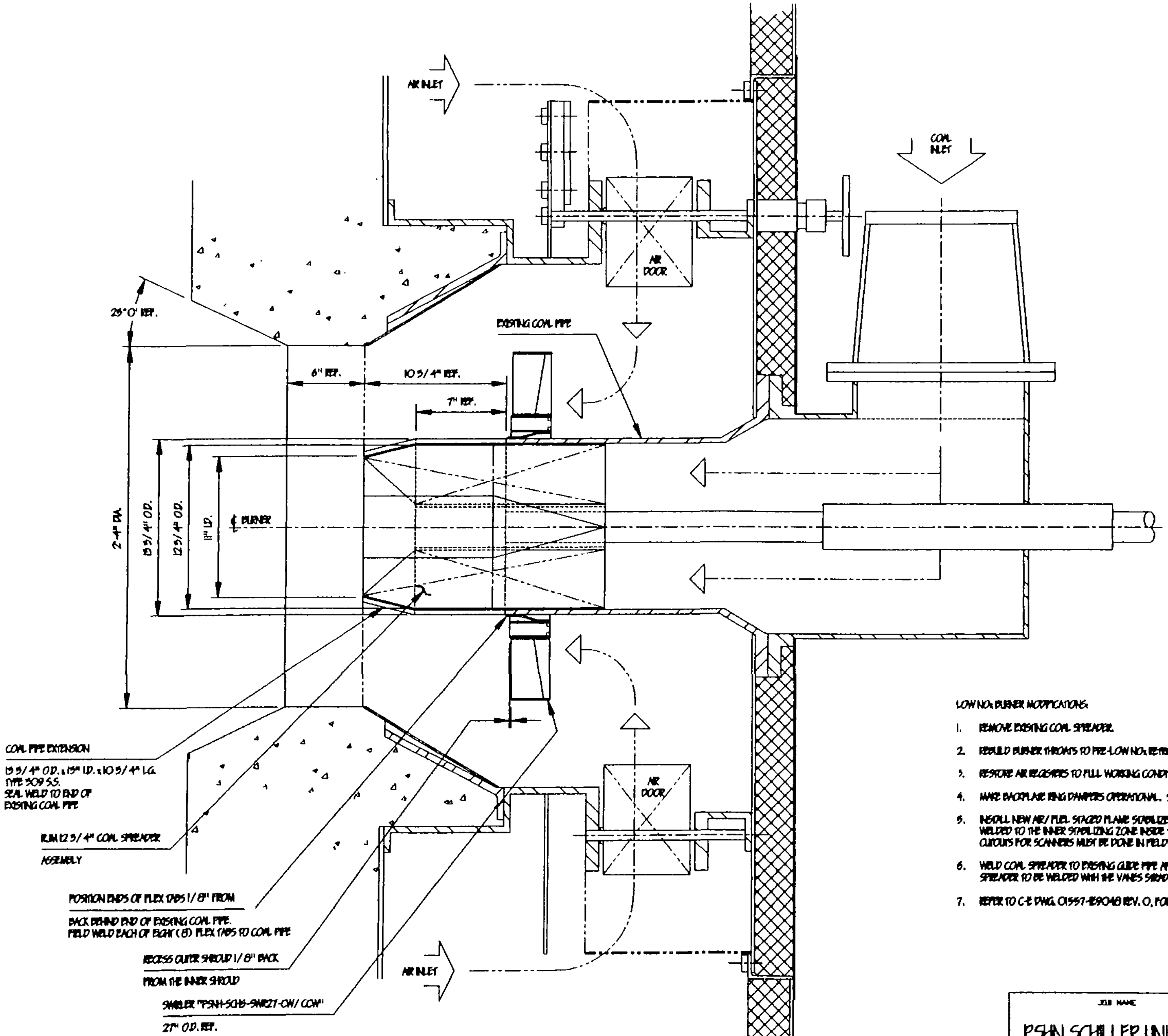
TYPICAL SECTION THRU BURNER

NOT A TRUE PROJECTION

Figure 4

JOB NAME: PSNH SCHILLER UNIT #4	RJM CORPORATION, TEN ROBERTS LANE, RIDGEFIELD, CT. 06877
	RJM PROJECT NUMBER: 921430
DRAWN BY: RCP — DATE: 12/4/94	TITLE: LOW NOx BURNER MODIFICATION
APPROVED BY: — DATE:	SIZE: C — DWG. NO.: 921430/10-4 — REV.: 0
	SCALE: --- — SHEET 1 of 1

REVISIONS				
No.	DESCRIPTION	DWN.	CHK'D.	DATE
O	CLIENT REVIEW	RCP		12/4/94



LOW NO_x BURNER MODIFICATIONS:

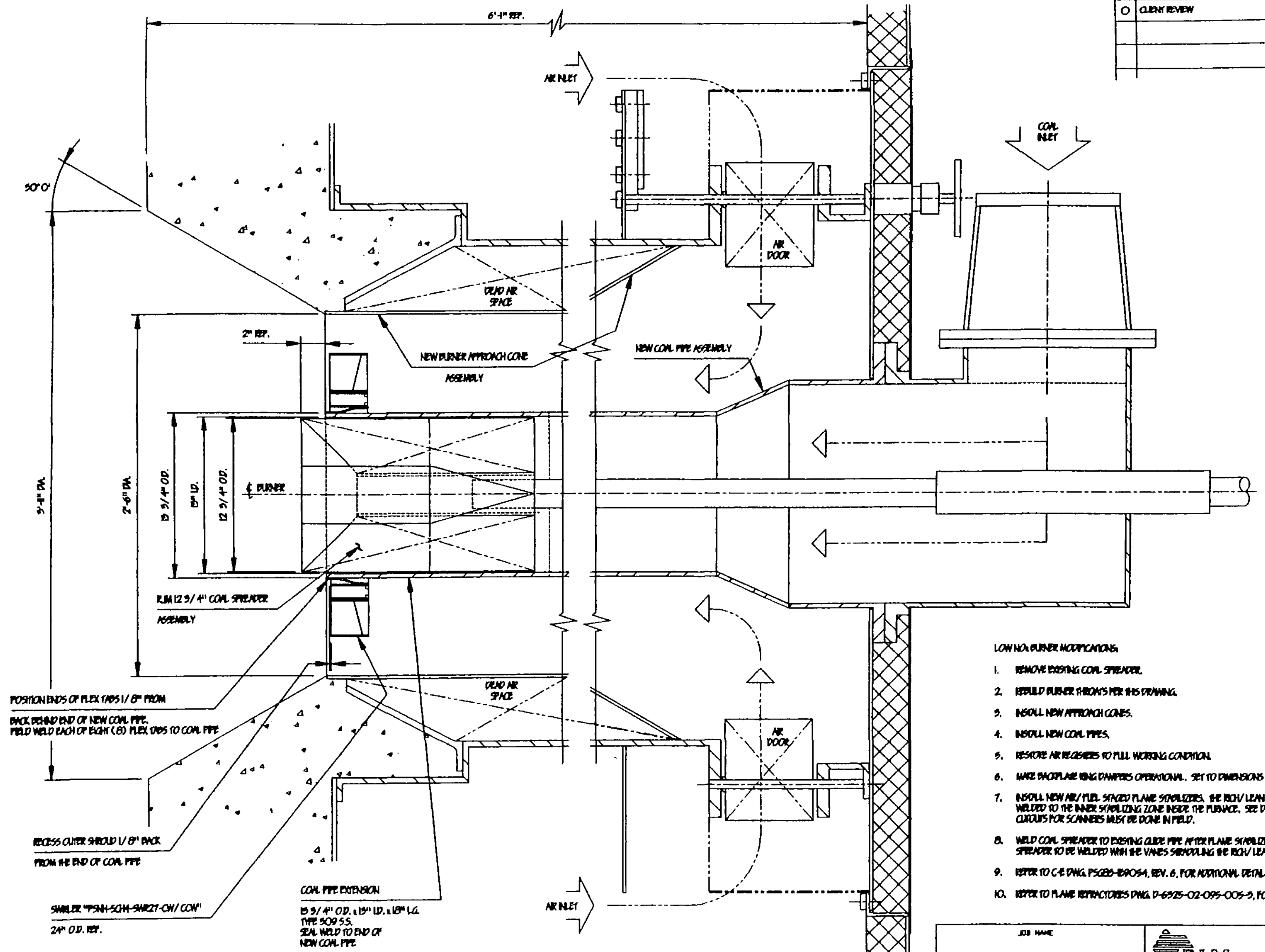
1. REMOVE EXISTING COAL SPREADER.
2. REBUILD BURNER THROATS TO PRE-LOW NO_x RETROFIT CONDITION.
3. RESTORE AIR REGISTERS TO FULL WORKING CONDITION.
4. MAKE BACKPLATE RING DAMPERS OPERATIONAL. SET TO DIMENSIONS IN AIR TEST REPORT.
5. INSTALL NEW AIR/FUEL STAGED FLAME STABILIZERS. THE RICH/LEAN SECTIONS MUST BE WELDED TO THE INNER STABILIZING ZONE INSIDE THE FURNACE. SEE DWG. PSNH-SCHS-SWR27-CW/CCW. CUTOUTS FOR SCANNERS MUST BE DONE IN FIELD.
6. WELD COAL SPREADER TO EXISTING GUIDE PIPE AFTER FLAME STABILIZER IS INSTALLED. SPREADER TO BE WELDED WITH THE VANES STRADDLING THE RICH/LEAN JOINTS.
7. REFER TO C-E DWG. 01557-189048 REV. O, FOR ADDITIONAL DETAILS.

TYPICAL SECTION THRU BURNER

NOT A TRUE PROJECTION

Figure 5

JOB NAME	RJM CORPORATION, TEN ROBERTS LANE, RIDGEFIELD, CT. 06877
PSNH SCHILLER UNIT #5	RJM PROJECT NUMBER: 921430
DRAWN BY: RCP — DATE: 12/4/94	TITLE: LOW NO_x BURNER MODIFICATION
APPROVED BY: — DATE:	SIZE: C — DWG. NO.: 921430/10-5 — REV.: O
	SCALE: --- — SHEET 1 of 1



TYPICAL SECTION THRU BURNER

NOT A TRUE PROJECTION

Figure 6

REVISIONS				
No.	DESCRIPTION	DWN.	CHK'D.	DATE
0	CLIENT REVIEW	FCP		12/4/94

LOW NOx BURNER MODIFICATIONS:

1. REMOVE EXISTING COAL SPREADER.
2. REBUILD BURNER THROATS PER THIS DRAWING.
3. INSTALL NEW APPROACH CONES.
4. INSTALL NEW COAL PIPES.
5. RESTORE AIR REGISTERS TO FULL WORKING CONDITION.
6. MAKE BACKPLATE RING DAMPERS OPERATIONAL. SET TO DIMENSIONS IN AIR TEST REPORT.
7. INSTALL NEW AIR/FUEL STAGED FLAME STABILIZERS. THE RICH/LEAN SECTIONS MUST BE WELDED TO THE INNER STABILIZING ZONE INSIDE THE FURNACE. SEE DWG. PSNH-SCH5-SWR27-CW/CCW. CUTOUTS FOR SCANNERS MUST BE DONE IN FIELD.
8. WELD COAL SPREADER TO EXISTING GUIDE PIPE AFTER FLAME STABILIZER IS INSTALLED. SPREADER TO BE WELDED WITH THE VANES STRADDLING THE RICH/LEAN JOINTS.
9. REFER TO C-E DWG. PSGB3-159054, REV. 6, FOR ADDITIONAL DETAILS.
10. REFER TO FLAME REFRACTORIES DWG. D-6525-02-095-005-3, FOR ADDITIONAL DETAILS.

JOB NAME: PSNH SCHILLER UNIT #6	RJM CORPORATION TEN ROBERTS LANE RIDGEFIELD, CT. 06877
DRAWN BY: FCP DATE: 12/4/94	RJM PROJECT NUMBER: 921430
	TITLE: LOW NOx BURNER MODIFICATION
APPROVED BY: DATE:	SIZE: C DWG. NO. 921430/10-6 REV. 0
	SCALE: --- SHEET 1 of 1

NORTHEAST UTILITIES - SCHILLER UNIT 6
NOx EMISSIONS vs LOAD
50 MWg COAL FIRED BOILER

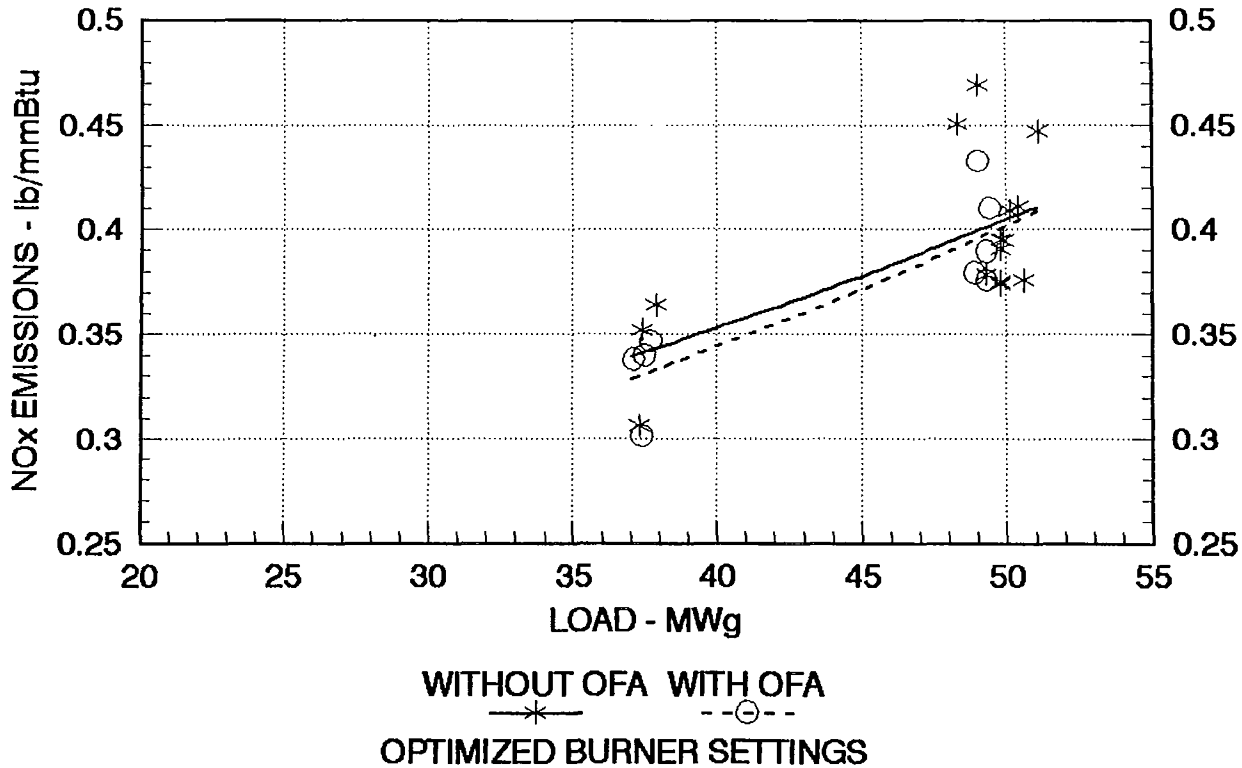


Figure 7

NORTHEAST UTILITIES - SCHILLER UNIT 6
NOx EMISSIONS vs EXCESS OXYGEN
50 MWg COAL FIRED BOILER

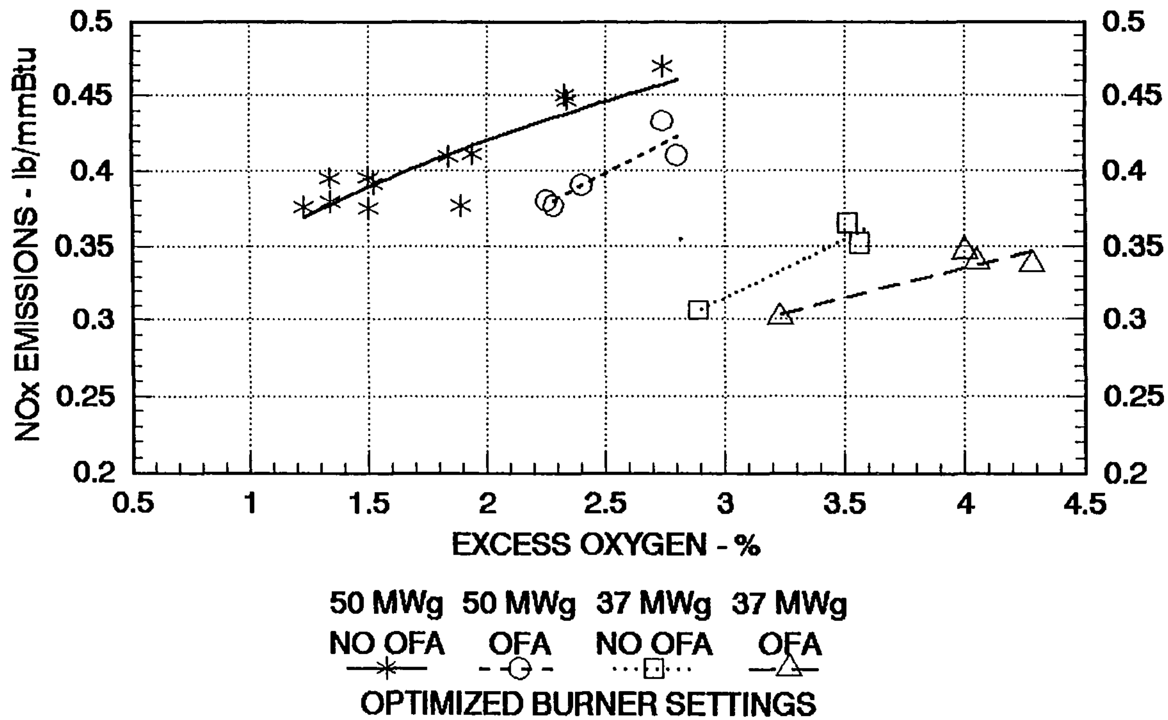


Figure 8

NORTHEAST UTILITIES - SCHILLER UNIT 6
EXCESS OXYGEN vs CO EMISSIONS

50 MWg COAL FIRED BOILER

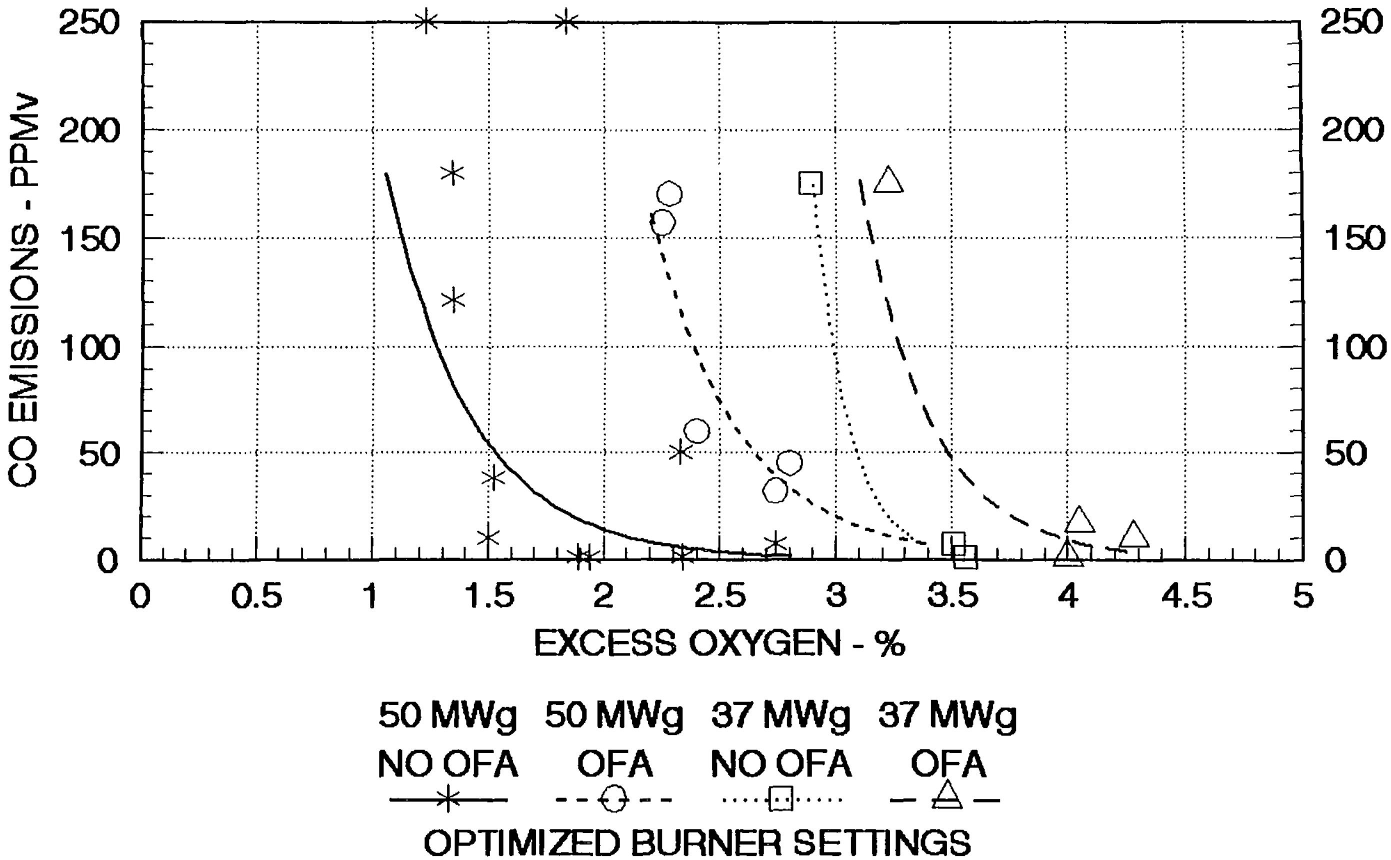
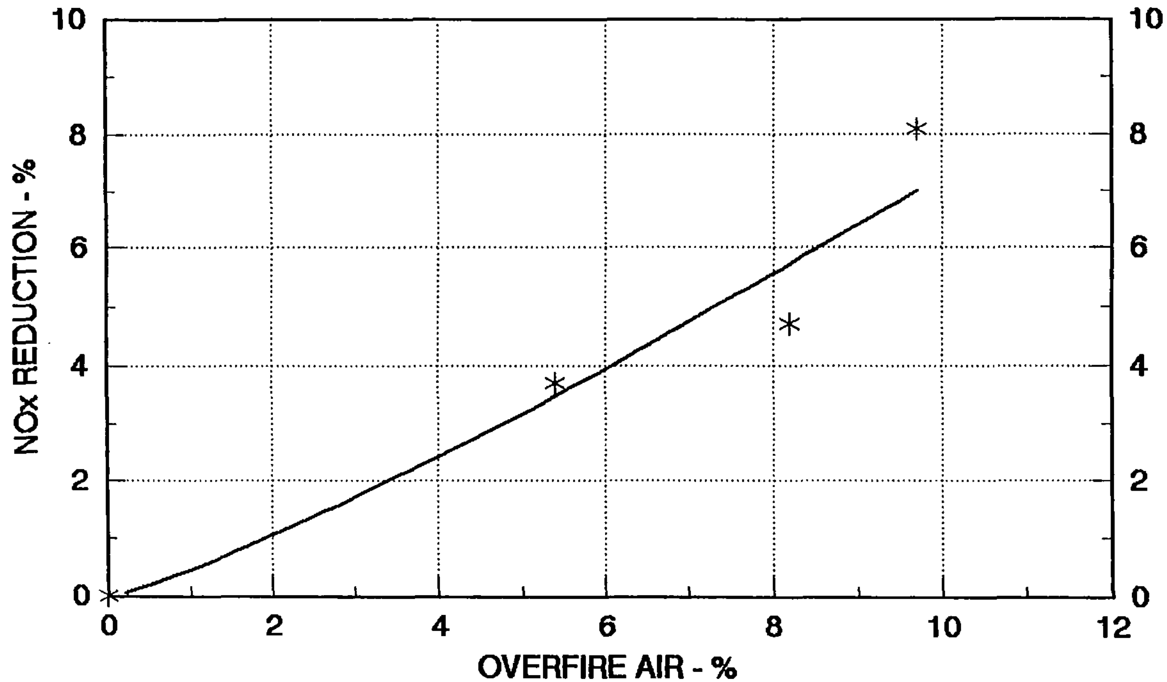


Figure 9

NORTHEAST UTILITIES - SCHILLER UNIT 6
NOx REDUCTION vs OVERFIRE AIR
50 MWg COAL FIRED BOILER



50 MWg

Figure 10

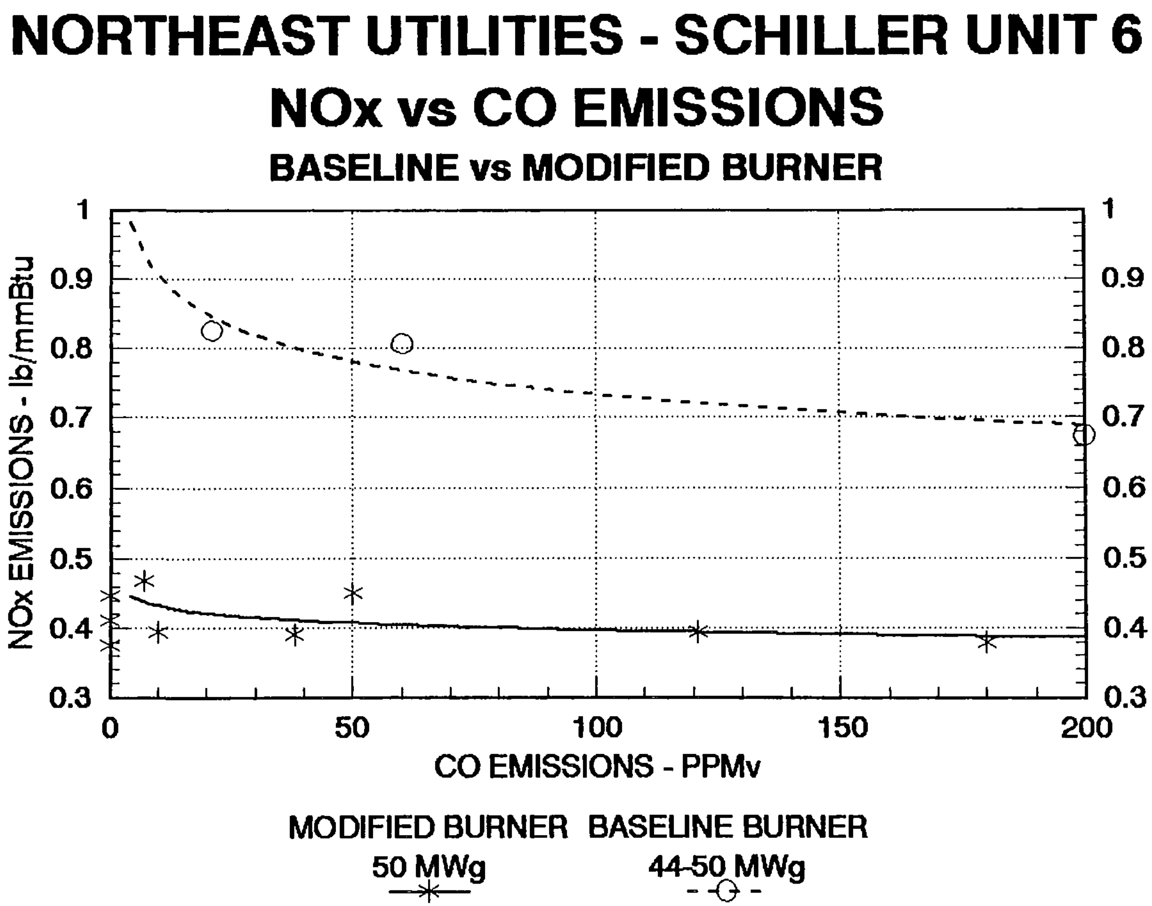

NORTHEAST UTILITIES - SCHILLER UNIT 6
NOx vs CO EMISSIONS
BASELINE vs MODIFIED BURNER
NOx EMISSIONS - lb/mmBtu
CO EMISSIONS - PPMv
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0
50
100
150
200
MODIFIED BURNER
50 MWg
BASELINE BURNER
44-50 MWg

Figure 11

Non-OEM Experience with NO_X Reduction Applications

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Abstract

Heightened global environmental awareness and mandated deadlines for emission compliance required by the Clean Air Act, demand operators to increase controls on boiler emissions. For decades, the utility boiler industry has been dominated by the large OEM's. In the past, boiler owners would approach the company that originally designed the boiler or burner system to design a burner system to reduce emissions. It was commonly believed that the boiler manufacturer had the greatest expertise in the area of NO_X reduction. Current experience demonstrates that boiler owners are accepting new approaches to reducing NO_X from non-OEM designers and suppliers. This paper outlines new approaches being applied by boiler operators to reduce NO_X emissions .

Several steps are imperative for a successful NO_X reduction program and each step of this process will be described with examples presented. Concepts that will be examined are:

- Practical designing concerns of theoretical Low NO_X combustion
- Reviewing scope requirements required to reduce emissions
- Teaming with the Customer to facilitate retrofit design and installation

The emphasis of this paper is not directed at the theory of how the components reduce NO_X , but how to effectively apply proven technology that reduced NO_X emissions.

Theory as Applied to Reality

The theoretical effects of NO_X reduction through controlled combustion is well documented. Scores of papers are written each year discussing NO_X reduction methods demonstrated in test boilers or highly controlled scale models. This work is invaluable in determining which techniques have the greatest relative impact in reducing NO_X emissions. Designers use these results as the foundations for a NO_X reduction application. The true measure of success of NO_X research is in the bridge spanning theory and real world applications. We find that it is the methodology of applying the theory to the real world that differentiates between a supplier of Low NO_X burner components and a designer of engineered systems that reduce NO_X.

A successful NO_X reduction retrofit begins with a review of the combustion basics. Considerable improvements to combustion performance and improved emissions can be realized by controlling and balancing the air and fuel. The boiler demands a relatively fixed quantity of energy to produce steam at the desired outlet conditions. The combustion system views the boiler from a gross level for total air and total fuel. The fuel and secondary air are assumed to be balanced. Many of these assumptions are built in to the boiler control logic. Greater successes in NO_X reduction applications are achieved by eliminating assumptions from the design and replacing them with actual field measurements. It is this process that leads to maintaining or increasing boiler efficiency while reducing NO_x emissions.

Design Analysis

The initial design step of a combustion modification to reduce emissions is to perform the combustion calculations and compare the design to actual operating data. This review examines the boiler heat release, Primary Air flows, fuel flows, Secondary Air flows, overfire air flows, coal conduit velocities and the relative velocity of the remaining air streams. During the design analysis, the boiler excess air and Primary Air to fuel ratios and fuel properties can be adjusted. If conflicts or design errors exist between the original design and the current operating conditions, they can be identified and made part of the retrofit early in the design process. This analysis tends to highlight the unique features of each boiler. The design can be adapted to meet the unique features of each application, rather than use a "one size fits all" approach.

System modeling is an additional tool that is used to verify design changes. Several computational fluid dynamic (CFD) modeling software packages are available for DOS and UNIX based systems. The CFD application used in the design process allows designers to economically examine design in a timely manner. Opinions vary as to the value of the absolute results generated by CFD modeling, however the use of the relative results produced in modeling is widely accepted. A parametric study using CFD modeling generates a good cause and effect relationship unique to the current design application. Using these general relationships allows prioritization of design guidelines. This system adds confidence in applying common design features to the unique requirements of each retrofit application.

Mechanical Design

Design verification is of little value if, mechanically, the equipment can not operate as designed. The air registers, burners and OFA systems must be robust in design. If an air register or OFA damper cannot be adjusted during all normal boiler operations, or if it is not reliable for long term operations, its value is limited.

Because of the harsh environment in which the burner registers operate, designing a burner register that operates reliably over the long term has been a challenge. Burner register air flow control dampers are often known to bind during operation, thus, its functionality is lost. Burner register air flow control designs can be categorized as one of three approaches:

- A daisy-chain, linkage style register with adjustable register vanes
- A sliding shroud register
- A parallel, four-bar linkage with adjustable register vanes

Two inherent problems in the daisy-chain linkage design are the mechanism's susceptibility to binding, and the resulting non-uniform air flow circumferentially about the air register due to cumulative linkage hysteresis. To prevent binding, individual linkage hysteresis must be increased to unacceptable levels, while adjusting each linkage to provide uniform damper position accelerates binding. Adjustable vane style registers, however, provide superior air flow control and repeatability relative to the sliding shroud style registers. Due to the mechanical simplicity of the sliding shroud register, the problems of binding with long term

Legend

A. Register Main Body
B. Outer Register Doors
C. Inner Register
D. Inner Register Inlet Opening
E. Outer Register Outlet Cone
F. Inner Register Outlet Cone
G. Burner Inner Barrel
H. Burner Outer Barrel
I. Burner Tip Casting
J. Burner Tip Wedge (fuel-lean section)
K. Centering Ring
L. Centering Ring Jack Bolt

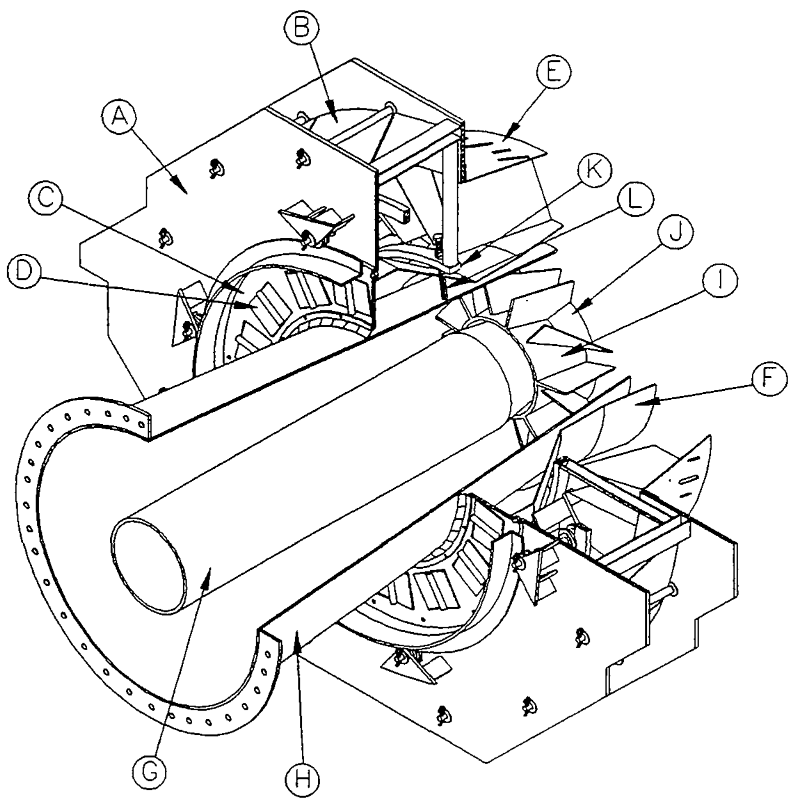

Figure 1 ATLAS Air Register Isometric Cutaway View

operations are greatly reduced. The sliding shroud registers do not provide air flow control with the accuracy found in the adjustable vane design. With these two designs, one must trade-off mechanical reliability for air flow control accuracy. Our experience has shown that the parallel, four-bar linkage is not susceptible to the same linkage binding problems as the daisy-chain linkage mechanism.

The four-bar linkage applies equal control movement and force to each register vane so that air flow is circumferentially uniform and control is repeatable. The parallel, four-bar mechanism is designed so that all moving parts are self-centering. This design feature allows the control mechanism to accommodate thermal growth and thermal cycles.

Our experience has shown the parallel, four-bar linkage mechanism to be a reliable design in long term operation. Air registers using this mechanism have been in continuous service for over eight years without a mechanical failure or operational problem. This type of field success is critical to the Operations and Maintenance groups. The knowledge that the NO_X reduction equipment will not be a constant maintenance item builds acceptance with the staff that will operate and maintain the equipment.

Fundamentally, our design philosophy is that each application is unique. By differentiating which of the existing components can effectively be adapted to the low NO_X design and which components must be replaced, the scope of the project can be considerably reduced. Not only does this represent a competitive edge in terms of project cost, it also maximizes continuity between the original system and the proposed retrofit. We find it advantageous to maintain existing coal conduit routing, windbox structure, electrical routing, and any high energy piping systems when possible.

Instrumentation & Control

After the analytical and mechanical design are complete, the equipment must be accurately controlled to maximize NO_X reductions. As mentioned earlier, one of the major goals of our design is to remove assumptions concerning air flow distribution. The air register control logic does not directly effect air flow demand, but acts as a distributor of combustion air. Because this system only distributes air flow, a relative burner to burner flow measurement is adequate for most control schemes. Depending on the application, the air register flow indication can be a local differential pressure gauge or a differential pressure transmitter. These air flow signals provide the operator with the information required to balance secondary air flows on a burner by burner basis. The actual flow balancing is accomplished through a manual or electronic damper positioner. If desired, the air register flows can be automatically controlled, balancing all air register flows to within a fixed tolerance. While not all applications require automatic control of the flow control surfaces, optimum NO_X reduction occurs with the more advanced control schemes.

Defining the True Scope of Work

Our experience shows that limiting the scope of the project to supplying air registers, burners and overfire air systems is short sighted and generates an incomplete scope of work. The above items are components that comprise only a part of the retrofit equation. The design parameter commonly assumed to be operating within the requirements of the new burner system is the fuel delivery system. For most coal NO_X reduction projects, the equipment designer will state the required fuel distribution and fuel fineness to the user. As part of the NO_X reduction project, it must be verified that the fuel handling and delivery system is adequate to supply the fuel within the burner fuel specification. Therefore, we believe that pulverizer performance is an integral parameter in the success of the NO_X reduction project.

We have adopted the philosophy that includes an examination of the fuel supply system as part of the NO_X reduction project offering. This examination includes an inspection or review of the pulverizer internals, the pulverizer control logic, current operating practices and equipment maintenance, as applicable. The examination results are reported to the Customer as recommendations, which will assure that the fuel delivery system meets design specifications. Identifying the operating condition of the pulverizers early in the NO_X reduction project allows all parties ample time to review the fuel delivery system and logically plan for corrections. A mill performance correction plan can be part of the NO_X reduction scope or left to other parties; regardless of where the responsibility lies, mill performance should be addressed.

In many cases the NO_X reduction project is implemented in conjunction with other capital projects. Upgrading the existing combustion control and/or burner management system to a distributed control platform is not uncommon. This work might not be included under the NO_X reduction package, but we believe that we can provide valuable information to the logic design of the controls upgrade. Our experience is that joint coordination meetings with the NO_X reduction project team, controls upgrade team and plant operations team brings together all aspects of the changes. The goals of the coordination meeting are that all control interconnections are identified, design and fabrication schedules coordinated, instrument compatibility verified, and an acceptable control philosophy generated.

Finally, an issue that must be identified in the project's scope of work is the calibration of existing measurement and control equipment. Items included in this category are Primary Air flow measurement, Secondary Air flow measurement, excess oxygen probes, flow balancing dampers and fan inlet vanes, as appropriate. Depending on plant instrumentation maintenance, control loops using these devices can operate with instrumentation grossly miscalibrated. Even though the system is considered to be in working condition, the resulting performance can be poor. We request calibrating the major flow signals relative to a flow traverse, verifying the excess oxygen measurement relative to HVT traverse and verifying damper position demand versus actual final damper position. By requesting these calibrations, assumptions and design requirements can be verified. The costs associated with these calibrations are offset by the time costs saved in controls fine tuning, burner fine tuning, and increased controllability. In addition, we have found that the Operations staff have a greater confidence and sense of ownership in the new systems.

Project Teaming Atmosphere

In many industries, "project teaming" is the buzz word for the 1990's. The success of a comprehensive NO_X reduction project is dependent upon the teamwork of all parties involved. A retrofit on an existing unit is more difficult than an original design in that the degrees of design freedom in terms of space, orientation and operation are limited. Design information must be obtained, generated and distributed in a time compressed manner, which requires the designer, fabricator, installer, the customer's operations and maintenance work well together.

The customer's responsibility in this team is to:

- Clearly define their project requirements
- Identify the time frames for the project
- Locate existing equipment drawings and specifications
- Collect past operating data, equipment history and personnel experience

This information, when supplied by the customer, reduces material delivery concerns, provides continuity between the old and new system and decreases contract interpretation issues.

The customer can be better prepared for NO_X reduction projects by taking advantage of planned outages to verify drawing dimensions for future NO_X reduction projects. Many questions regarding field dimensions and routing can be answered prior to initial retrofit design. The installation of NO_X reduction equipment on a retrofit requires accurate detail information of the equipment in place. By our experience, we recommend that drawing dimensions be verified on site, including burner windbox internals, fuel delivery systems and routing and spacing for auxiliary equipment.

The system designer can be better prepared for NO_X reduction projects by taking advantage of the operating experiences of the plant personnel with the existing equipment. Many questions regarding undocumented daily operating practices that plant personnel use can be vital to the overall design. Items such as actual excess air versus load, mill start-up sequences, soot blowing cycles, unique firing sequences and load versus burner elevation in service, etc. often indicate operating parameters that are not reflected in the original design. These unique operating practices often require special attention in field verification and design.

Our view to the retrofit process is that a pact has been established between a Low NO_X System supplier and a boiler operator. The system supplier designs components with specific operating conditions. Subsequently, if the equipment is not operated in the intended manner, the system simply will not work as expected. The customer, specifically the operations and maintenance staffs, must share ownership in the new operating methods. For this to take place, the system supplier must properly convey the operations requirements to the customer and the customer must properly convey the operations limitations. Each party has valuable information which could determine the success of the project.

Results

When these philosophies have been implemented on previous Low NO_X applications, the successes have been measured not only in terms of emissions reductions, but also in terms of reducing customer trauma. Our approach to the NO_X retrofit process has allowed us to document the following specific improvements in each of the areas discussed:

- Practical Design
  - Air register mechanical reliability, eight years without a mechanical or operational failure
  - Low NO_X air register and burner reduced NO_X by 30 to 40% from baseline emissions
  - CFD verified OFA designs reduced NO_X by 30 to 45% from baseline emissions

- Scope Identification
  - Mill balancing reduced NO_X by 10 to 20% from baseline emissions
  - Identifying scope provided a smooth tie-in from the burner retrofit to DCS and BMS issues

- Teaming Approach
  - Field changes result in less than 2.5% of the contract value
  - Contract milestones have been maintained