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Development of the Radiation Stabilized Distributed Flux Burner

Phase III Final Report – 02/09/1995 – 11/14/1999

J. D. Sullivan
A. Webb

December 1999

Work Performed Under Contract No. DE-FC07-95ID13332

For
U.S. Department of Energy
Assistant Secretary for
Energy Efficiency and Renewable Energy
Washington, DC

By
Alzeta Corporation
Santa Clara, CA

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DISCLAIMER

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Alzeta Report No. 99-70097-212

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PHASE III FINAL REPORT

Prepared by

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SECTION 1
INTRODUCTION

The development and demonstration of the Radiation Stabilized Burner (RSB) was completed as a project funded in part by the U.S. Department of Energy Office of Industrial Technologies. The DOE project is summarized in Section 1.1. Background technical information on premixed porous surface burners in general, and more specifically the RSB, is provided in Section 1.2. Technical approaches to minimizing the generation of NO_x during the combustion process are summarized in Section 1.3. The benefits of redesigning the conventional industrial package boiler to operate more effectively with an ultra-low NO_x burner are discussed in Section 1.4. Performance goals for the RSB integrated with a new package boiler design are quantified in Section 1.5. Technical feasibility of the RSB ultra-low NO_x concept was demonstrated through laboratory and full-scale tests described in Section 2. The design of the RSB boiler-burner package that achieves the performance objectives outlined above is presented in Section 3. An assessment of the market for this product is discussed in Section 4, and the field demonstration of the RSB is summarized in Section 5.

1.1 SUMMARY OF DOE PROJECT

The development of the RSB has been supported in large part with project funding from the U.S. Department of Energy, Office of Industrial Technologies, with the objective of the project being to develop an advanced industrial burner that will benefit end users in major U.S. industries. Additional project partners included Alzeta Corporation as prime contractor, Chevron Corporation, Babcock and Wilcox, and Nationwide Boiler, Incorporated. The targeted market for hardware developed in the project was boilers used for industrial steam generation, with the initial RSB market being more specifically identified as package water tube boilers in the 20,000 to 150,000 lb/hr size range. The development work focussed primarily on emissions control, with the understanding that ultra-low NO_x emissions had to be achieved simultaneously with low CO and air toxic emissions, and without making sacrifices in thermal efficiency, operating costs, or maintenance costs that would limit market acceptance of the product. The technical goals of the project were as follows:

- Demonstrate burner performance that would meet or exceed emissions targets of 9 ppm NO_x, 50 ppm CO, and 9 ppm unburned hydrocarbons (UHC), with all values being corrected to 3 percent stack oxygen.
- Incorporate the burner design into a new industrial boiler configuration that would achieve ultra-low emissions while maintaining or improving thermal efficiency, operating costs, and maintenance costs relative to current generation 30 ppm low NO_x burner installations.

The development and demonstration of the RSB was completed in three phases beginning with laboratory demonstration of the concept and ending with the demonstration of the RSB in an industrial facility. The three project phases were organized to allow an orderly scale up of the burner technology from the initial small scale laboratory work through the full scale field demonstration. The phases are summarized below:

- **Phase 1: Laboratory Demonstration.** The initial concept of the ultra-low NO_x RSB was demonstrated in laboratory scale tests. Laboratory testing was conducted in Alzeta's 3 million Btu/hr (MMBtu/hr) watertube boiler, which was used to simulate the performance of larger industrial water tube boilers. Different methods for achieving ultra-low NO_x were evaluated prior to scale-up in Phase 2. Alzeta also used its PROF (Premixed One dimensional Flame) code to verify the experimental NO_x performance of the burner.
- **Phase 2: Concept Validation at Pilot Scale.** In Phase 2, full scale field tests were conducted in a 62 MMBtu/hr industrial steam generator used to generate steam for Thermally Enhanced Oil Recovery (TEOR). In addition, an industrial burner system was designed, fabricated, and tested in a 100,000 lb/hr Zurn "O" type industrial package boiler used by a central steam plant in San Francisco, California to gain preliminary package boiler field experience prior to the Phase 3 ultra-low NO_x demonstration. This Phase 2 system was required to meet a NO_x emissions guarantee of 30 ppm. Results of the Phase 2 testing were incorporated into the design of the Phase 3 system.
- **Phase 3: Concept Demonstration** A full-scale burner system was provided to an industrial customer in the California Central Valley, with the customer purchasing the burner under standard industrial burner sales

terms. This installation was required by the regional air district to meet sub-9 ppm NO_x emissions and sub-50 ppm CO emissions, which matched the emissions objectives of the DOE project. In addition, during Phase 3, the design of a new industrial package boiler optimized for the RSB was completed. Both the ultra-low NO_x RSB and the RSB boiler-burner package are now commercially available.

1.2 RSB BACKGROUND INFORMATION AND TECHNICAL DESCRIPTION

The Radiation Stabilized Burner (RSB) was developed to overcome limitations of traditional fully-radiant porous surface burners. The benefits of radiant burner technology, which include ultra-low emissions of NO_x and CO and a controlled flame shape, were well known and were previously demonstrated in smaller burner applications. Prior to the start of this project, larger scale industrial applications of porous surface burners had been limited due to the relatively low surface heat release rate (less than 150,000 Btu/hr-ft^2) of the fully radiant porous surface burner. This low heat release rate resulted in very large burner sizes and relatively high capital costs in applications requiring total heat inputs greater than approximately 10 MMBtu/hr. The initial development of the RSB in 1994 dramatically reduced the size requirement and cost of the burner element while maintaining the benefits of controlled flame shape and low emissions traditionally found in the more conventional burners. The semi-radiant RSB shown in Figure 1-1a can be compared to the more conventional fully-radiant burner shown in Figure 1-1b.

The RSB, commercialized under the trade name Pyromat CSB™, can best be described as a fully premixed, semi-radiant, porous surface, natural gas burner. Additional gaseous fuels such as propane and low-Btu waste gases can also be used with this burner technology. Combustion is stabilized on the burner surface by a combination of high and low-flux surface zones. The high-flux zones provide the energy flux necessary to dramatically reduce the size of the burner element relative to conventional fully radiant porous surface burners. The low-flux zones serve to stabilize combustion of the high-flux zones on the burner surface, allowing stable combustion to be maintained even at extremely dilute combustion conditions. The burner can operate at surface heat release rates that are up to ten times higher than traditional radiant burners.

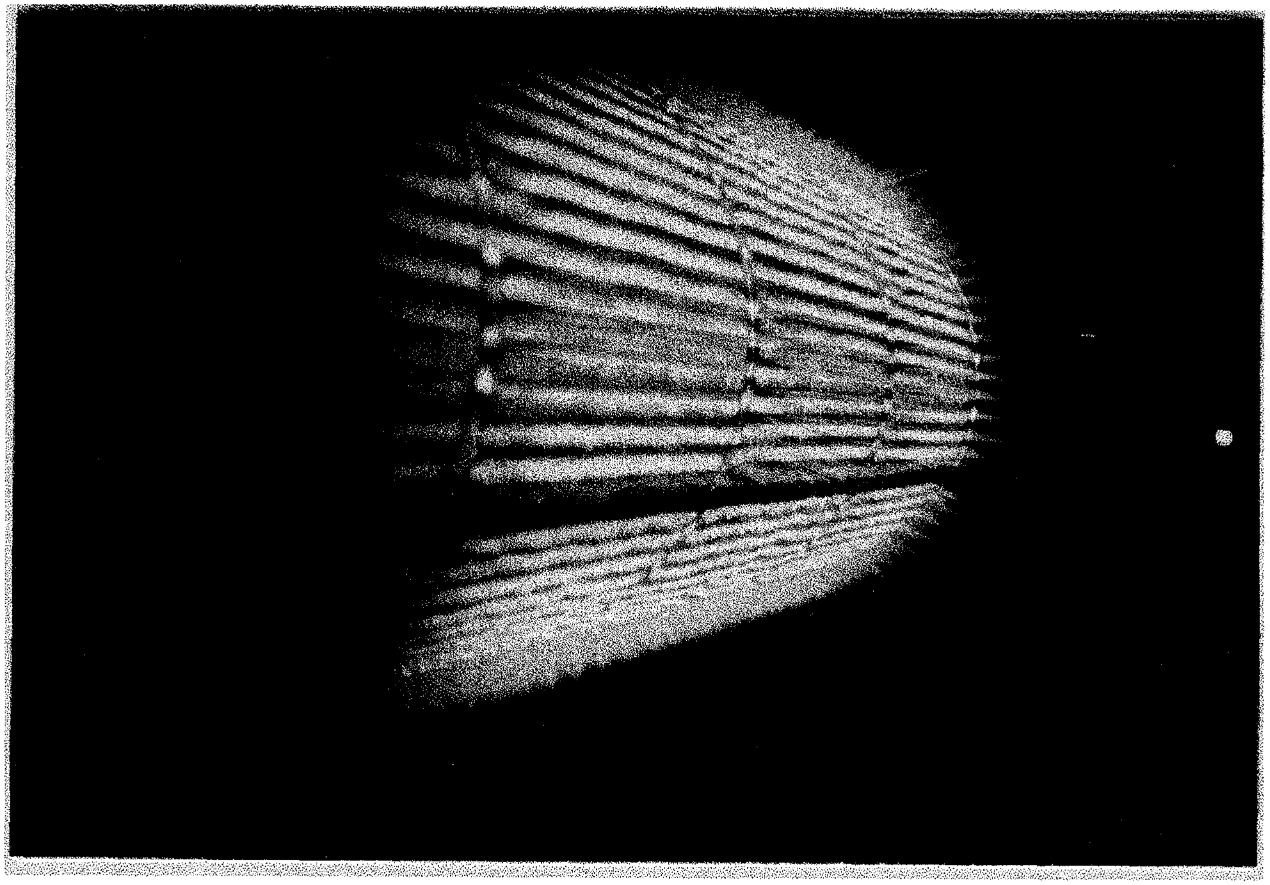

Figure 1–1a. Photograph of the Radiation Stabilized Burner (RSB) showing high–flux blue flame zones and low–flux radiant zones on burner surfaces.

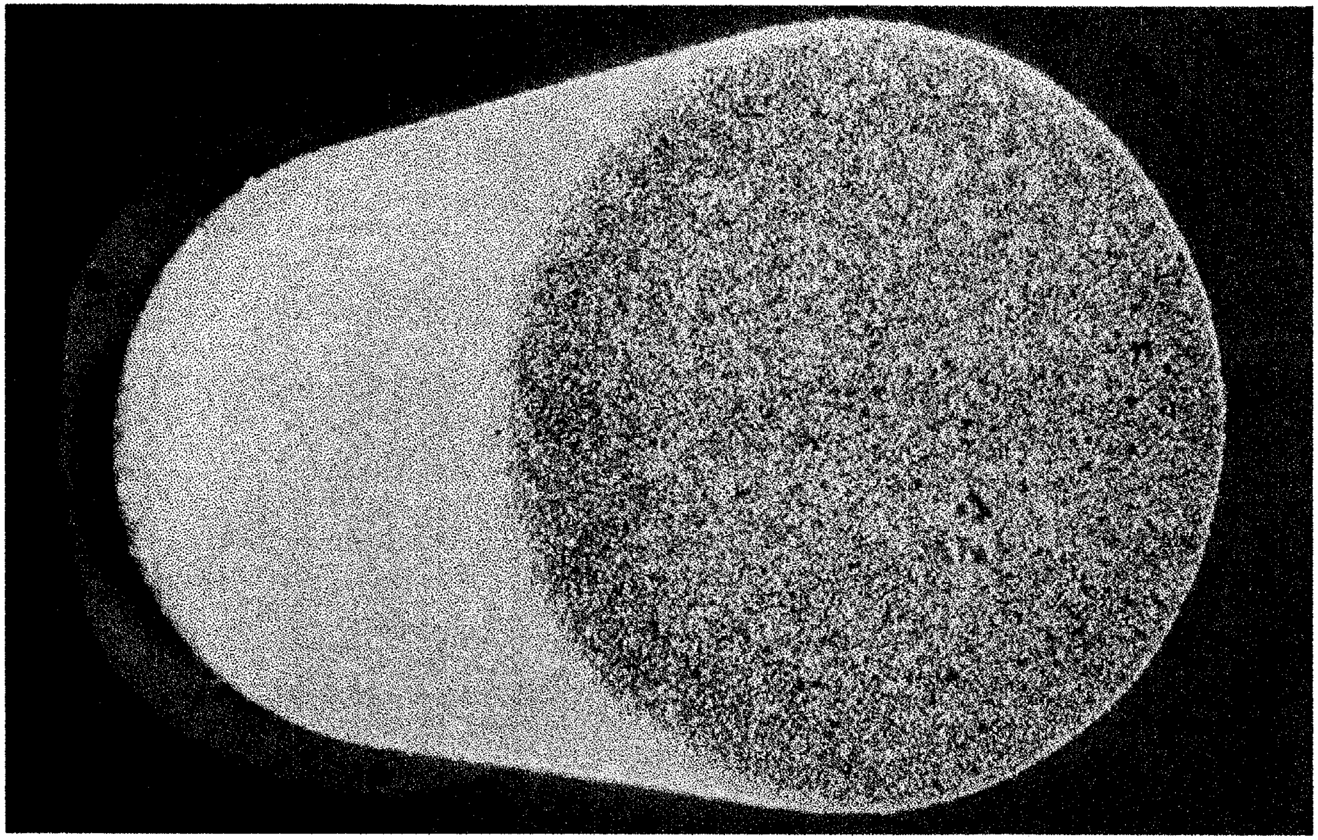

Figure 1–1b. Photograph of a fully radiant Pyrocore™ porous surface burner in a boiler.

The first field demonstration of the RSB was in a 62 MMBtu/hr boiler used to generate steam used for Thermally Enhanced Oil Recovery (TEOR)[1]. The largest industrial package boilers have heat inputs that can exceed 200 MMBtu/hr, so a considerable scale-up of the RSB was required. Extending usage of the burner into larger boiler applications required the design of larger burner elements, and may eventually require the installation of multiple burner elements into a single boiler. The size of the largest single burner element manufactured by Alzeta has increased from 62 MMBtu/hr in 1994 to 180 MMBtu/hr in 1997, with the 180 MMBtu/hr single burner element being large enough to provide the total heat input required of a 150,000 lb/hr boiler. At this time, larger field erected boilers with heat input of greater than 180 million Btu/hr would require multiple burner elements.

The RSB uses a patented technique, combining radiant and blue-flame surface zones, to lower NO_x emissions relative to more conventional porous surface premixed burners. This selectively perforated technique has been demonstrated to provide several advantages over fully perforated burners:

- Lower NO_x emissions at a fixed level of excess combustion air
- Greater flame stability allowing operation with very high levels of excess air or flue gas recirculation (FGR), and with very low Btu fuels
- Greater operating range without combustion-generated noise

This "striped" perforation pattern is shown in Figure 1-2. Two mechanisms are believed to contribute to the NO_x reduction observed with the RSB design. The first mechanism is a more rapid post-flame cooling of each blue-flame zone via the gas phase radiation mechanism. By spreading the flame over a larger surface and by generating relatively high surface area flame fronts, the gas layer thickness at any specific location on the burner is thin (relative to that of a conventional burner) and can more rapidly transfer energy to the process. The second mechanism is the entrainment and rapid mixing of cooler combustion products in the furnace into the high flux zones (a form of internal FGR) that also results in more rapid cooling of the flame. These mechanisms reduce the flame temperature and the corresponding NO_x formation rate.

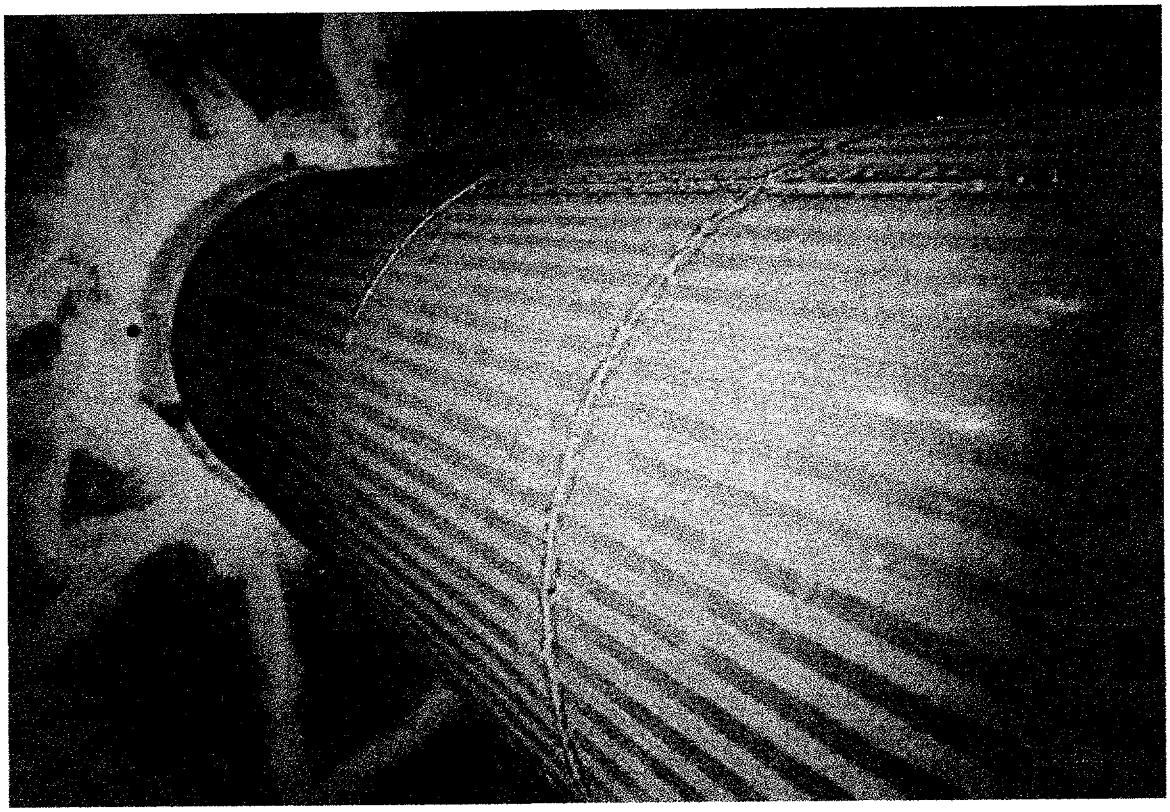

Figure 1-2. The striped perforation pattern of the RSB surface generates high and low flux combustion zones.

1.3 TECHNICAL APPROACH

To achieve the ultra-low emissions targets of this project, several technical approaches were evaluated. In all cases, reducing the *NO_x formation rate* was known to be critical to the success of the approach. Equilibrium NO_x levels, as calculated assuming combustion in a well-stirred reactor, can be on the order of several thousand ppm at typical combustion conditions.

The primary mechanisms that generate most of the NO_x formed during the combustion process occur at a relatively slow rate, so in practice the NO_x emissions from a natural gas fired boiler with minimal NO_x controls will rarely exceed 100-200 ppm, which is well below the equilibrium level. Therefore, the NO_x emissions levels observed in industrial boilers are more a function of NO_x kinetics than of NO_x equilibrium levels.

The technical approaches that were evaluated included:

1. Operation at higher than standard levels of excess combustion air. This reduces the temperature of the flame, and correspondingly reduces the rate of thermal NO_x formation. In addition, the prompt NO_x mechanisms also appear to be reduced by the combination of lower flame temperature and higher O_2 concentration. This approach is the simplest and lowest "first cost" method of NO_x control.
2. Operation with external FGR premixed with the fuel and combustion air prior to combustion. As with the increased excess air approach, this technique works by reducing the temperature of the flame and the corresponding rate of thermal NO_x formation. The formation of prompt NO_x also appears to be slowed. The advantage of this technique, relative to operation at high excess air, is that the FGR system will have a higher thermal efficiency. The ducting and air moving equipment necessary to implement the external FGR approach adds to the complexity of the system.
3. Operation of an ultra-lean first stage RSB, with downstream fuel "staging" to achieve ultra-low NOx emissions without having to operate at a high excess air or high FGR level. This approach requires that heat removal occurs between the first and second stages, so that the combustion in both stages occurs at a low flame temperature where the rate of NOx formation is low. The advantage of fuel staging relative to operation at a high excess air or FGR level is that mass flow through the boiler is minimized, resulting in more effective transfer of energy.

The relative advantages and disadvantages of each technique, specifically when implemented with a premixed surface combustor, are discussed in greater detail below.

1.3.1 Operation with High Excess Combustion Air

It has been demonstrated previously with premixed surface combustors, both radiant and semi-radiant, that NO_x emissions can be reduced by increasing the amount of excess combustion air in the premixed stream. The mechanism for achieving low emissions is simple. By increasing the level of excess combustion air, combustion occurs at a lower temperature, and the formation of thermal NO_x is reduced. In addition, it has been demonstrated that operation at a high level of excess air also reduces the formation of prompt NO_x[2].

NO_x emissions of 9 ppm (volumetric, corrected to 3 percent O_2) can be achieved with the RSB at an excess air level of 60-70 percent. It has been demonstrated that any desired NO_x emissions level (from 30 ppm to less than 9 ppm) can be achieved by adjusting the level of excess combustion air from nominally 30 percent excess air (at the 30 ppm NO_x level) up to 65 percent excess air (at the 9 ppm NO_x level). Even lower NO_x emissions can be achieved if the burner is operated leaner, with the lowest emissions levels being ultimately limited by the lean flammability limit of the fuel-air mixture.

The primary advantage of this NO_x reduction technique is its simplicity. This simplicity is reflected in the simplicity of controls, maintenance, and system design, and is ultimately reflected in the low initial cost of this type of system. The disadvantage is reflected in the high operating cost associated with this approach. If the boiler shell is not modified to accommodate operation at high excess air, thermal efficiency will be reduced and fan power requirements will increase. Although these disadvantages can be overcome with resizing or redesign of the boiler shell, the high excess air design will always have higher operating costs than the FGR or staged burner approaches (in an equivalent boiler shell).

1.3.2 External FGR

The addition of flue gas from the boiler stack back into the flame is an effective and common technique to reduce the peak flame temperature and the formation of thermal NO_x. A portion of the flue gas downstream of the convective section of the boiler is redirected back though the burner either by inducing the flow through the main combustion air fan or by forcing the flue gas back into the burner with an auxiliary stack fan. In either case, additional fan power is required to move the additional mass through the boiler.

In conventional low NO_x burners, NO_x emissions decrease as the level of FGR increases until the stability limit of the burner is reached. The amount of flue gas re-circulated is often limited by burner stability and is usually limited to a maximum of about 20% of the mass of the incoming combustion air. Above this level, burner stability is compromised and excessive CO emissions or burner pulsations can result. With conventional low NO_x burners, the stability limit is often reached well before 9 ppm NO_x emissions are achieved.

The major benefit of using FGR as a NO_x reduction technique is that the thermal efficiency of a burner using FGR will be higher than that of a similar burner operating with high excess air. The thermal efficiency of an FGR-based burner is similar to that of a burner operating at low excess air without FGR, but there is some efficiency penalty associated with increasing the mass flow through the boiler without increasing the amount of heat transfer surface.

The primary disadvantage of using FGR as a NOx control technique is that electric power consumption is increased due to the increase in fan power required to move the increased mass of combustion products through the boiler. This increase in required fan power can be especially dramatic if the FGR level is greater than 20 percent and the boiler shell is not "de-rated" to accommodate the higher mass flow. A doubling of required fan power is common under these circumstances.

FGR can be particularly difficult to apply to package boilers because of the relatively large pressure drop built into package boilers to keep the footprint small. Reference 3 discusses the costs associated with FGR in more detail. Because of the operating penalty associated with an FGR solution, a problem that is most pronounced with package boilers, the necessity of redesigning the package boiler to accommodate high levels of FGR was considered to be crucial to the success of this project.

1.3.3 <u>Fuel Staging</u>

Fuel staging is a technique where fuel is introduced into two separate combustion regions in the boiler furnace. The first stage is combusted very lean to achieve a low flame temperature and low NO_x formation rate (using the same approach as was described in Section 1.3.1). After some heat is transferred from the flame (primarily by gas phase radiant transfer to the furnace walls), additional fuel is added and additional combustion occurs. This "second stage" combustion occurs at a lower temperature than would occur if all of the fuel and air was burned in a single stage. This is a common NO_x reduction technique used in conventional industrial burners. This type of staging is referred to as fuel staging, because additional fuel is added in the second stage.

If properly implemented, staged combustion can be accomplished at an overall excess combustion air level that is typical of what is considered "optimum." This level is usually considered to be about 15 percent excess combustion air. The primary benefit of fuel staging is therefore that additional flow of air or flue gas through the boiler is not required to achieve low NO_x. Therefore, staged combustion provides the promise of delivering low NO_x emissions without decreasing thermal efficiency or increasing fan power requirements.

The disadvantage of staged combustion is that designs are fairly complex, mixing in the flame zone is very critical to successful operation, and the systems can therefore be very sensitive to operate. Scaling of the technology to different sizes and different boiler designs can be problematic.

1.3.4 Selected Approach

The most promising RSB NO_x control approach in terms of balancing ease of operation with low operating costs was determined to be FGR. This approach was determined to be even more advantageous if the other advantages of the RSB, namely compact and controlled flame shape and rapid CO burn out, are utilized in a more advanced boiler design. A boiler designed around the RSB can achieve high thermal efficiency and low fan power requirements, while maintaining the compact footprint required of industrial package boilers.

The second most promising approach was determined to be operation with high excess air. Operation at high excess air is presented as "Baseline Data" in Section 2, where it is subsequently compared to FGR test data from the same test boiler. Additional high excess air data are reported from the TEOR Steam Generator Field Tests. The success of this approach requires that the boiler be redesigned to minimize the loss of thermal efficiency that would otherwise result from this approach. This is the lowest first cost approach to achieving 9 ppm NOx emissions, and as has been demonstrated in the market, many customers will select a lowest first cost approach, because it has the lowest perceived risk. The high excess air burner is therefore viewed as a promising near term solution, which should be eventually phased out completely by proven systems using FGR.

Although fuel staging holds considerable promise because it does not require additional mass flow through the boiler, the approach proved to be the most difficult to implement with the RSB design. Fuel staging test data from laboratory scale tests are presented in Appendix B to this report. Test data and a discussion of staging results are presented in the final section of Appendix C, the Cymric Test Report. Basically, the combination of fuel staging with the RSB as a lean first stage may be particularly difficult to implement because the distributed RSB flame does not lend itself well to rapid second stage mixing. This becomes particularly evident in compact package boiler fireboxes. Also, many of the advantages of staging relative to the other approaches become less significant if the boiler is redesigned to accommodate higher mass flow.

This ranking of NO_x reduction strategies was made with the understanding that to be successful in the market, the high mass flow Alzeta burner designs would have to be incorporated into advanced boilers that were designed to operate at the high mass flow conditions. The design of boilers to achieve this objective is summarized in the following sub-section, and discussed in greater detail in Section 3.

1.4 BOILER REDESIGN TO OPTIMIZE CSB PERFORMANCE

When operated as a high mass flow burner (utilizing either excess air or FGR), the RSB will provide low NO_x in a standard package boiler. However, these undesirable side effects will be observed :

- System pressure drop and volumetric flow will both increase leading to a significant increase in electric power consumption
- Thermal efficiency will be reduced leading to increased fuel usage
- Shell de-rating to combat increased fan power and fuel usage will increase capital cost and the size of the boiler "footprint" on the factory floor

These negative characteristics had to be overcome in order for the RSB to be commercially successful, and the basic design of the industrial package boiler was re-evaluated to determine ways of improving performance. In addition to providing low emissions of NO_x and CO, the RSB has been demonstrated to have the following important performance characteristics:

- Distributed flame shape allowing transfer of heat uniformly over a large surface
- Short flame length above the burner surface, allowing placement of the burner in close proximity to heat transfer surfaces

- Rapid burn out of CO and hydrocarbons, which allows rapid cooling of the flame to minimize NO_x formation, without producing large concentrations of CO or unburned hydrocarbons in the stack.

In Figure 1-1a, it is apparent that the flame zone is maintained in close proximity to the burner surface. This has been substantiated by computational fluid dynamic (CFD) modeling of the burner completed during this project. Recognizing this key characteristic of the burner permits modifications to be made to the traditional package boiler that will further reduce NO_x emissions and improve thermal performance, but which will only work with a premixed surface combustion burner such as the RSB. In addition rapid CO burnout was also critical, because the RSB can only be placed in closer proximity to cooling surfaces if this does not result in increased CO emissions.

Specifics of the RSB boiler-burner design are discussed in detail in Section 3. In general terms the design approach was as follows:

- Boiler footprint is a critical parameter to the end user for several reasons. Package boilers are purchased because they can be shipped from the factory as a complete package, and today's boilers are designed to just fit within the shipping constraints of standard trucking and rail requirements. In addition, space on the factory floor may be restricted, and new designs that required a larger footprint may be impossible to install in an existing plant. Therefore, any modifications to the basic package boiler design had to maintain the existing or a smaller boiler footprint for a given steam capacity.
- The basic package boiler design of steam drum on top, mud drum (or drums) on the bottom, and many rows of water tubes between the drums had to be maintained to the greatest extent possible. Maintaining the basic design will speed market acceptance by reducing the perception of risk, and by allowing boiler manufacturers to use existing manufacturing facilities to build the new boilers.
- The short flame length and rapid CO burnout that are characteristic of the RSB allow for the firebox to be made narrower than the firebox of a conventional boiler. This by itself is not significant. However, by making the firebox narrower, the boiler generating bank (the convective section of the boiler) can be made wider.

- The wider generating bank allows for more tubes to be installed in the generating bank which increases the total heat transfer surface in the boiler. This increases thermal efficiency. The wider generating bank also allows for wider spacing between tubes which reduces fan power requirements. The tradeoff between increasing the heat transfer surface (to increase efficiency) and increasing the tube spacing (to reduce fan power required) is evaluated in Section 3, but both benefits can be realized simultaneously.

1.5 PERFORMANCE TARGETS FOR THE RSB BOILER-BURNER PACKAGE

Having selected dilution with flue gas or air as the best approach for achieving ultra-low NOx emissions with the RSB, redesign of the boiler to take advantage of the other RSB advantages was necessary. If the boiler is designed from the start to accommodate high mass flow, then fan power, efficiency, and boiler footprint can all be controlled and optimized. This is particularly true if the firebox width can be reduced, which is the case with the RSB.

The benefits of the RSB boiler burner package will include:

- **Increased boiler capacity**. Capacity is typically limited by the heat transfer surface constrained inside of a fixed boiler shell size. Designs that significantly increase total exposed tube surface area are described in Section 3, and these designs provide the opportunity to increase boiler capacity without increasing boiler footprint. Increasing capacity within a fixed boiler footprint leads to increased cost effectiveness.
- **Increased efficiency of the boiler for fixed boiler size**. Increasing tube surface area has the additional benefit of increasing the thermal efficiency of the boiler. This translates directly into a cost saving for the plant operator in terms of reduced fuel usage. Heat transfer analysis of the RSB boiler-burner package predicts that thermal efficiency at sub-9 ppm NO_x can match the efficiency of a typical 30 ppm boiler without increasing boiler footprint.
- **Reduced fan power requirements**. By increasing cross-flow tube spacing, pressure drop of the sub-9 ppm burner can match, or actually be lower than, the drop through a conventional 30 ppm boiler.

- **Further reduction of NO_x.** Rapid cooling of the flame is critical in reducing thermal NO_x formation. In large systems, high temperature gaseous species can block the radiation path from the flame zone to the cold tube surfaces. The narrower firebox introduces the combustion products more quickly into the convective section of the boiler, and the inclusion of water tubes in the firebox could even more quickly cool the flame. Since the premixed Alzeta burner completes CO burnout within approximately 1 foot of the burner surface and controls the flame to an area directly above the burner surface, these compact designs are feasible.

Our performance target for the RSB boiler-burner package is to achieve the following conditions:

The boiler will operate at sub-9 ppm NO_x and sub-50 ppm CO while simultaneously providing thermal efficiency, fan power requirement, and a boiler footprint that equal or exceed the performance of today's 30 ppm low-NO_x boiler.

SECTION 2
LABORATORY AND FIELD TEST RESULTS

Tests were conducted during Phase 1 and Phase 2 to evaluate the different NO_x reduction strategies outlined in Section 1 and to select the best technique for achieving the emissions and performance targets in a commercially viable package. Tests were conducted in facilities that ranged in size from 3 MMBtu/hr to 125 MMBtu/hr, and were conducted at three different locations: the Alzeta Laboratory, Chevron's Cymric Field near Bakersfield, California, and at an industrial site in San Francisco, CA. Test facilities, procedures and results are discussed below.

The discussion of test results in this section of the report focuses primarily on the FGR and high excess air tests. FGR and excess air test results are presented in tabular form in Appendix A, along with additional NO_x and CO plots not presented in this section. Staging tests are summarized in this section, and detailed data are presented in Appendix B. Staged combustion tests at Cymric are presented at the end of Apendix C. This focus on the FGR and high excess air results in the main body of the report is intentional, reflecting the greater success of these tests relative to the staging tests.

2.1 LABORATORY SCALE TESTS

Laboratory scale tests were conducted in the Alzeta combustion laboratory using a commercial-scale 3 MMBtu/hr water tube boiler. The small size of the boiler and its location in the Alzeta combustion laboratory allowed for the initial testing of concepts to be conducted quickly. This allowed us to collect and evaluate a large amount of data prior to proceeding to the larger scale Phase 2 field tests. The test facility is described below, followed by a discussion of test results for high excess air and FGR operation.

2.1.1 3 MMBtu/hr Laboratory Watertube Boiler

Laboratory tests were conducted in a commercial-scale watertube boiler manufactured by Unilux Manufacturing Company of Woodbridge, Ontario, Canada. The tube design of the boiler is referred to as a "bent tube" design, with the boiler firebox being similar in tube layout to a industrial package boiler. Water-cooled surfaces form the side, top and bottom walls of the boiler furnace, with only the front and back walls having exposed refractory surfaces. The boiler had 257 ft^2 of heating surface and was capable of providing 2570 lb/hr of steam at 200 psig. The boiler configuration was similar to an 'O' type package boiler with the steam drum and mud drum located on the boiler centerline. A 5-pass convective section was positioned above the radiant firebox.

The internal dimensions of the radiant section were approximately 29 inches high by 39 inches wide by 48 inches deep. This provided a volumetric heat release rate of 100,000 Btu/hr/ft^3 which is similar to that of the industrial package water tube boilers now on the market. By matching the thermal environment of the boiler, including wall temperatures and volumetric heat release, it was believed that laboratory data could be used to predict field test results. Figure 2-1 shows the internal tube geometry of the boiler.

A large viewing window was added to the rear wall of the boiler to view the burner when in operation and to record tests with a video camera. The boiler was equipped with a thermocouple to measure the stack temperature, which allowed a calculation of thermal efficiency. Additional thermocouples and a suction pyrometer were used to measure gas phase temperatures in the radiant section. The facility was connected to Alzeta's pollutant emissions bench where real-time NO_x, CO and stack O_2 measurements were recorded.

The laboratory boiler was equipped with two different RSB configurations during testing: a cylindrical burner was used for high excess air and for external FGR tests, and a planer burner was used for the fuel staging tests. Both burners were fully modulating with approximately 5:1 turndown and could operate up to full boiler capacity. When operated at similar conditions, burner performance was shown to not be a function of burner geometry.

The planer burner had a surface area of 2.8 ft^2 (20 inches by 20 inches) and occupied a portion of the front wall of the boiler. This geometry was superior for fuel staging because it allowed for placement of staged-fuel jets above the burner surface in a geometry that was similar to the placement of jets above a full scale burner with a burner diameter of 30 inches or larger. A cylindrical burner was used for the excess air and external FGR tests (the high dilution flow tests). The burner was 8 inches in diameter and 12 inches long, and represented an accurate sub-scale model of the full scale industrial burner. Since the flame envelope for the high dilution flow burner is more tightly controlled around the burner surface, and there are no additional fuel gas jets above the burner surface, it was decided to model the burner geometry correctly.

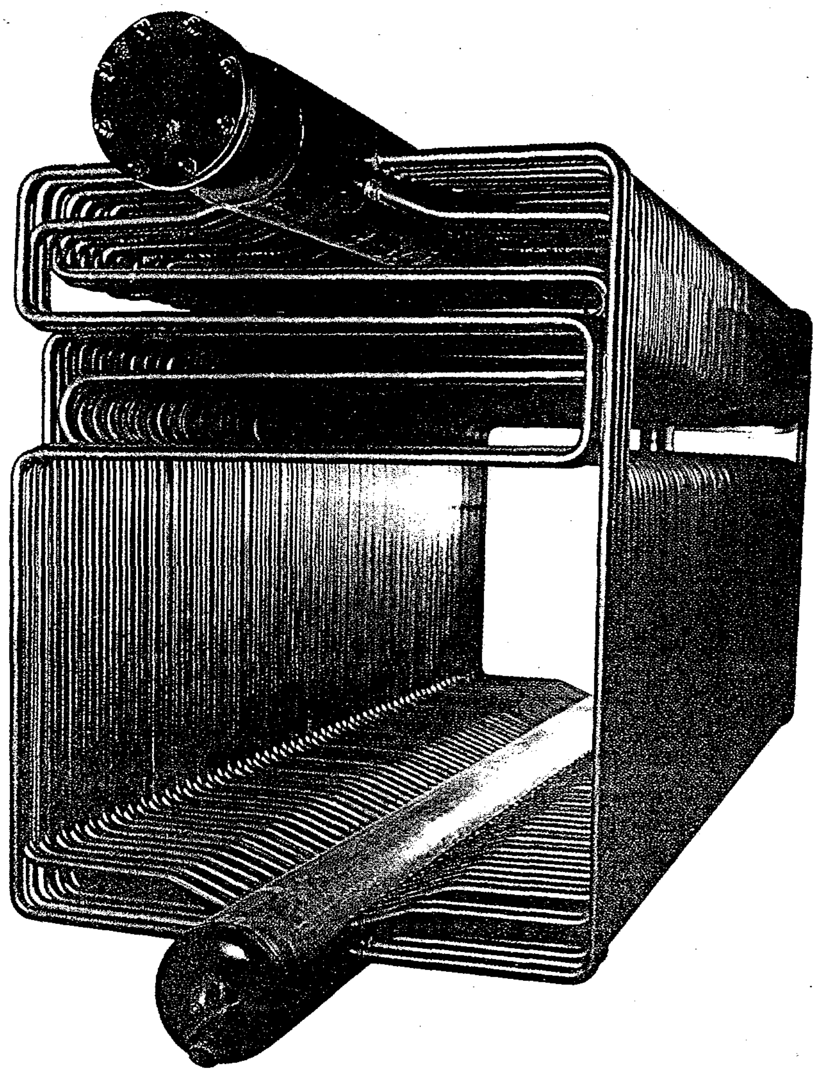

Figure 2-1. Tube layout of the 3 MMBtu/hr laboratory scale boiler. The firebox tube geometry closely models that of an industrial package boiler.

2.1.2 Baseline Tests with High Excess Combustion Air

Baseline tests were completed operating the cylindrical RSB in the Unilux boiler over a wide range of heat input levels and excess air levels. The purpose of these tests was to determine the maximum turndown of the burner (the ratio of maximum to minimum heat input for a fixed burner size), and to determine baseline NO_x levels as the excess air level was varied from 15 percent excess air up to the highest possible level while maintaining stable combustion at the burner surface.

Results were as follows:

- Burner turndown of over 5:1 was demonstrated. This level of turndown is considered to be good in a commercial boiler, but the typical industrial boiler operator would require a turndown ratio of 6:1 to 8:1. It was believed that with better air flow control in an industrial facility, the higher turndown level could be achieved.
- Surface firing rate (total fuel input divided by burner surface area) was demonstrated over the range of 0.25 MMBtu/hr/ft^2 to 1.3 MMBtu/hr/ft^2. Prior to the start of this project, the maximum surface firing rate of the RSB was considered to be 1 MMBtu/hr/ft^2. Increasing this maximum by 30 percent, as was done in this project, increases the cost effectiveness of the burner by allowing greater heat input for a fixed investment in burner surface area.
- Excess air was varied and demonstrated to be stable from 5 percent to over 65 percent. Typically RSB operation would not be recommended at an excess air level of less than 15 percent.
- NO_x emissions levels varied from over 100 ppm at low excess air (highest flame temperature) to under 5 ppm at high excess air (lowest flame temperature).

Results of the baseline excess air tests are shown in Figures 2-2a and 2-2b where NO_x and CO emissions are plotted as a function of excess combustion air. As can be seen in Figure 2-2a, NO_x emissions are strongly influenced by excess air level, but show almost no correlation to surface firing rate of the burner. NO_x emissions of greater than 100 ppm were measured for a few data points at very low excess air levels.

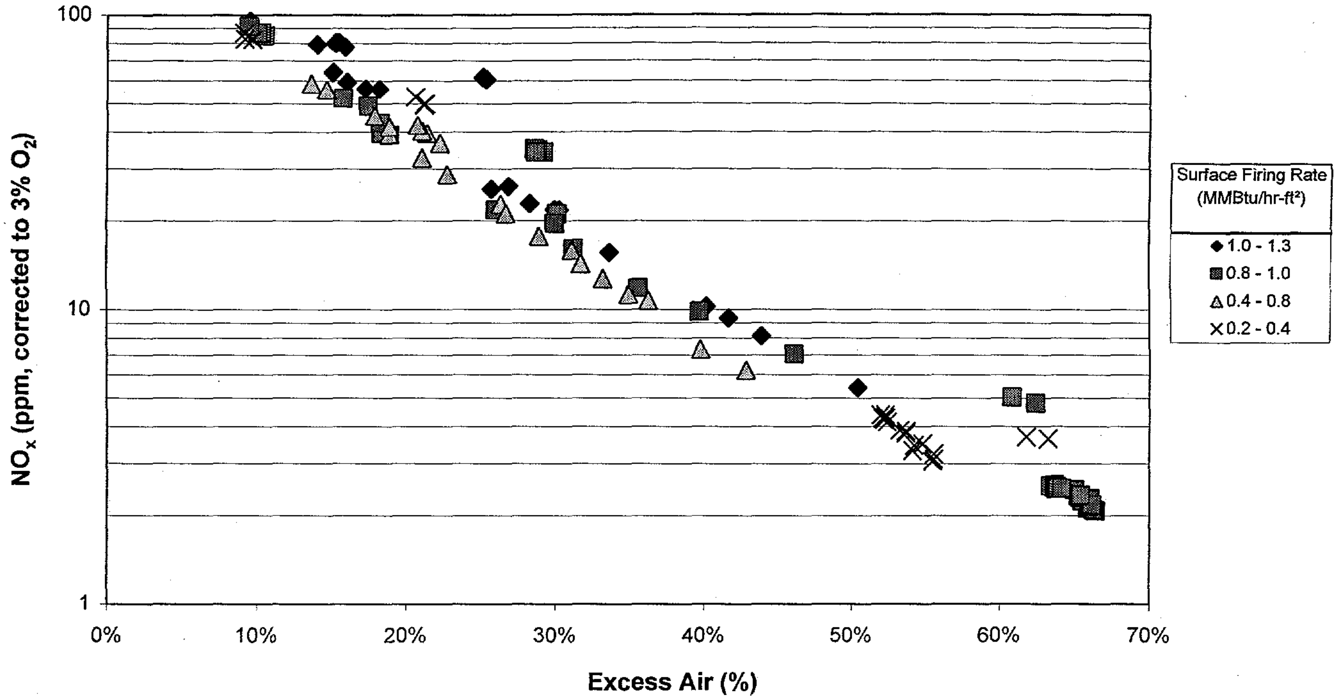

Figure 2-2a. NO_x versus Excess Combustion Air for Various Surface Firing Rates

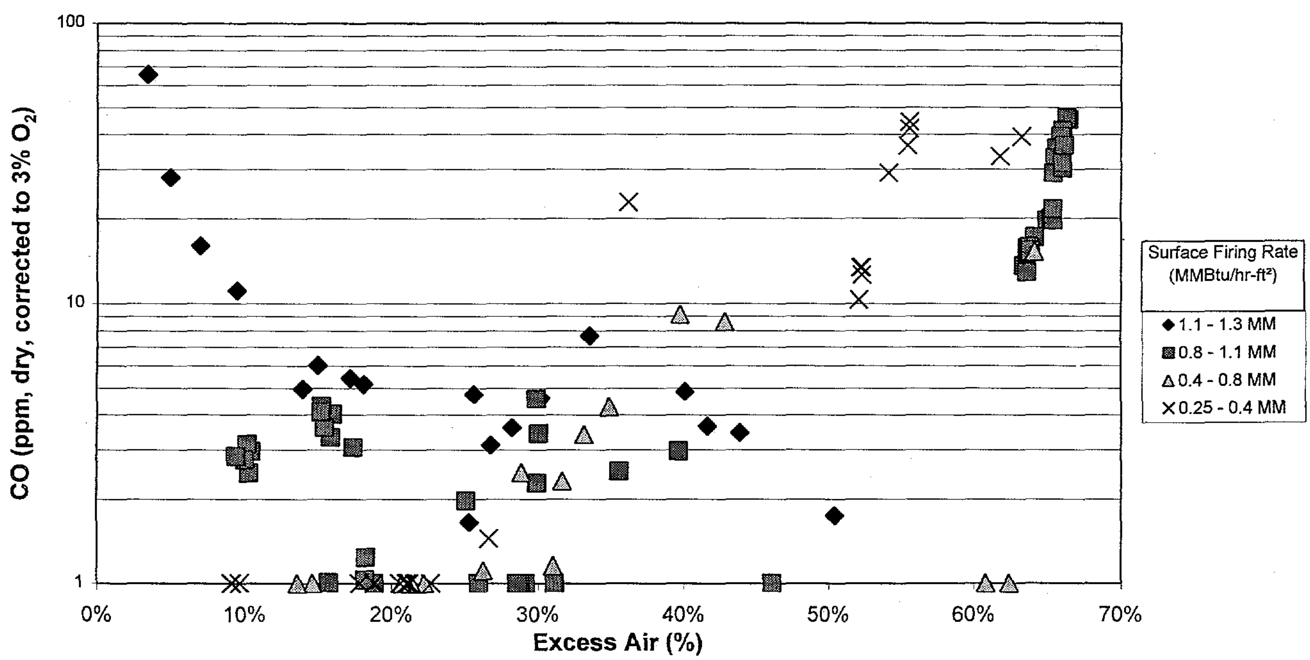

Figure 2-2b. CO versus Excess Air for Various Surface Firing Rates

Although these data followed the observed trends well, they are not included in Figure 2-2a. These data are omitted from the plots to increase the size of the plot area in the more interesting 1-10 ppm data range. A plot of all excess air data is included in Appendix A along with the tabular data.

The correlation of NO_x emissions data to the single excess air variable was considered to be a surprising, but very promising result. A stronger dependence of NO_x emissions on the surface heat release rate of the burner was expected. This simple correlation to only the excess air parameter will simplify the controls required of the ultra-low NO_x burner in industrial applications. NO_x emissions of sub-9 ppm were observed at excess air levels of 50 percent and higher.

CO emissions did not correlate as well to a single variable, but still behaved in a predictable manner. As shown in Figure 2-2b, CO was observed to be highest at very low excess air (where there is limited oxygen available to completely oxidize CO to CO_2), and at very high excess air (where the flame temperature is too cool to allow for complete CO burnout in the firebox). In most cases the CO was very low (less than 10 ppm), and in almost all cases the CO level was below the 50 ppm project target.

2.1.3 Laboratory External FGR Tests

Following the baseline excess air tests, tests were undertaken to study the performance of the RSB with external flue gas recirculation as a means of reducing NO_x emissions without having to operate at a high level of excess combustion air. As with most NO_x reduction techniques, the major challenge was to lower NO_x emissions without negatively impacting the very low CO emissions of the RSB.

The laboratory boiler was modified to allow the primary blower to induce flue gas from the stack into the combustion air stream, where together they were premixed with the fuel. The amount of flue gas recirculation was controlled manually by an in-line damper on the FGR duct. Tests were conducted over the full range of surface firing rates, over the excess air range of 5 percent to 30 percent, and with FGR ratios ranging from 0 to 30 percent. FGR is defined as the mass of flue gas recirculated divided by the mass of fresh combustion air. At 20 percent FGR, 20 lbs of flue gas is recirculated back through the boiler for each 100 lbs of fresh combustion air. The total mass flow through the boiler under these conditions would be 120 lbs, with only 100 lbs of combustion products exiting the stack.

The NO_x and CO emissions results as a function of excess combustion air are shown in Figures 2-3a and 2-3b respectively. The NO_x plot of Figure 2-3a does not show the clear trend of NO_x decreasing as excess air is increased that was shown with excess air operation in Figure 2-2a. In addition, most of the NO_x data lay between 10 and 30 ppm on the plot, with only two points being at 9 ppm or lower. One positive result is that 9 ppm NO_x emissions were achieved at slightly less than 15 percent excess air. The CO results are similar to the earlier excess air CO results, in that CO begins to increase rapidly as the excess air level is reduced to below 5 percent.

The reduction in NO_x that was observed in the earlier plots of the excess air data was attributed to a lowering of the flame temperature, and hence of the rate of NO_x formation, that occurred as excess air was increased. FGR provides a similar effect, in that the flue gas acts to cool the flame by diluting the combustion products with flue gas (which is essentially non-reactive). With this in mind, the FGR data are replotted in Figures 2-4a and 2-4b for NO and CO as a function of total dilution. The original baseline data are included in the plots.

Total dilution is defined as the amount of mass flow passing through the boiler that is in excess of the mass of air and fuel required for stoichiometric combustion, and is presented as a fraction of stoichiometric air flow. In the absence of FGR, total dilution is equivalent to excess air. With FGR, the total dilution can be calculated as:

$$(1 + \text{excess air}) \times (1 + \text{FGR}) - 1$$

As is shown in Figure 2-4a, a good correlation exists between NO_x and total dilution. In addition, the FGR results compare well with the excess air data, showing that a common explanation can be used to explain the NO_x emissions under both modes of operation. At about 50 percent total dilution, NO_x emissions should be below 9 ppm. A typical 50 percent total dilution operating condition could be 20 percent excess air and 25 percent FGR, or could just as likely be 15 percent excess combustion air and 30 percent FGR. Sub-9 ppm NO_x emissions were achieved at FGR rates greater than 30%. In general, the burner operation was stable up to the highest FGR rates. At FGR rates above 30% burner stability became a concern. CO data showed the same trend with total dilution as was shown with excess air, in that CO is highest at the two operating extremes of very high and very low total dilution.

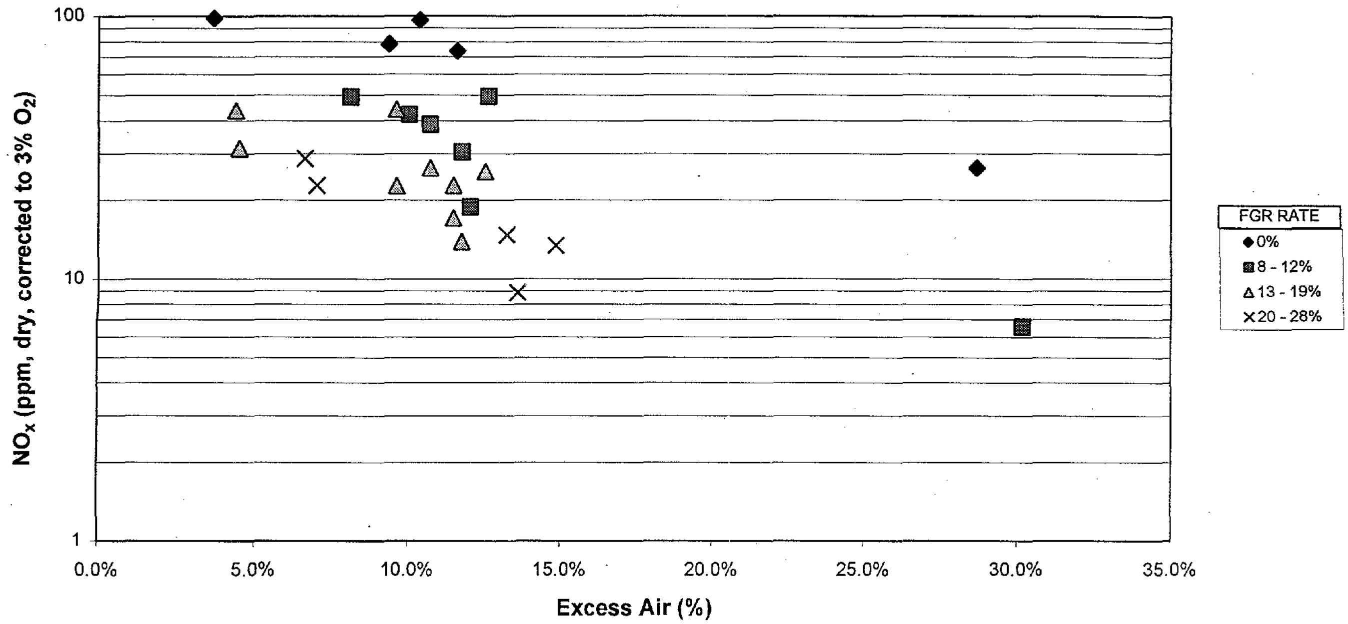

Figure 2-3a. NO_x versus Excess Air at Various Flue Gas Recirculation Rates

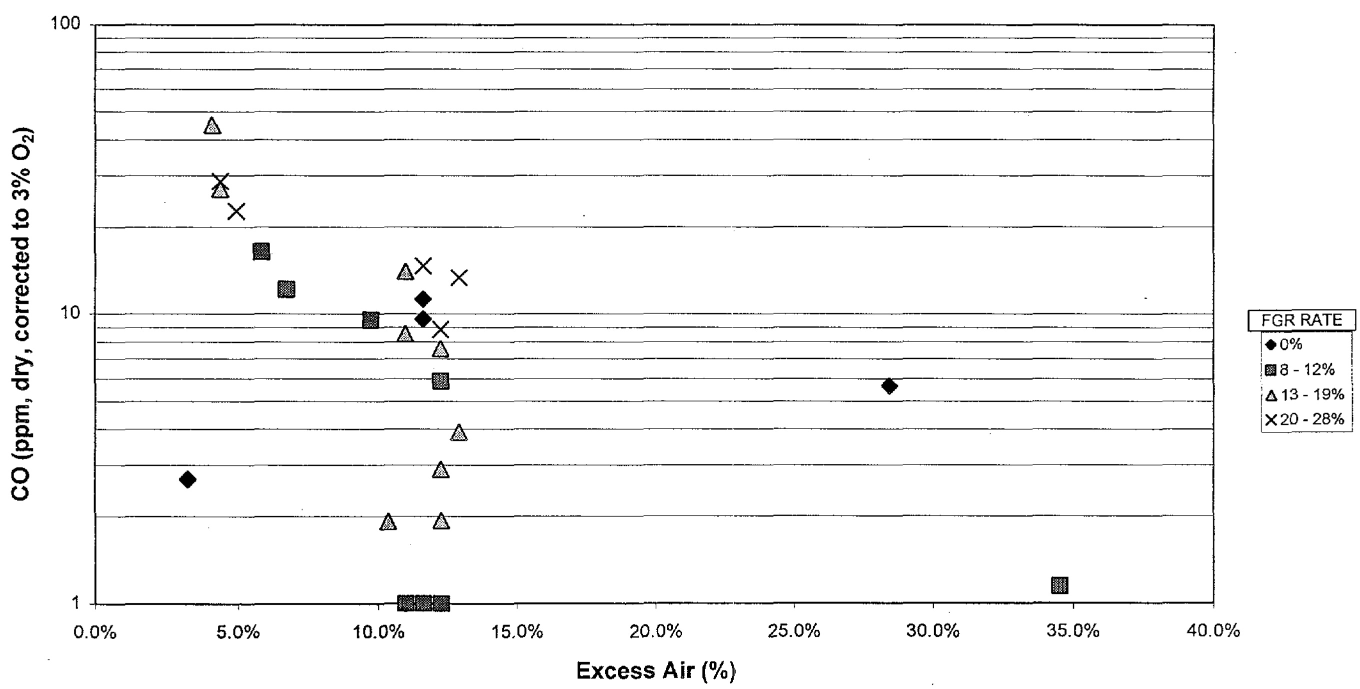

Figure 2-3b. CO versus Excess Air for various Flue Gas Recirculation

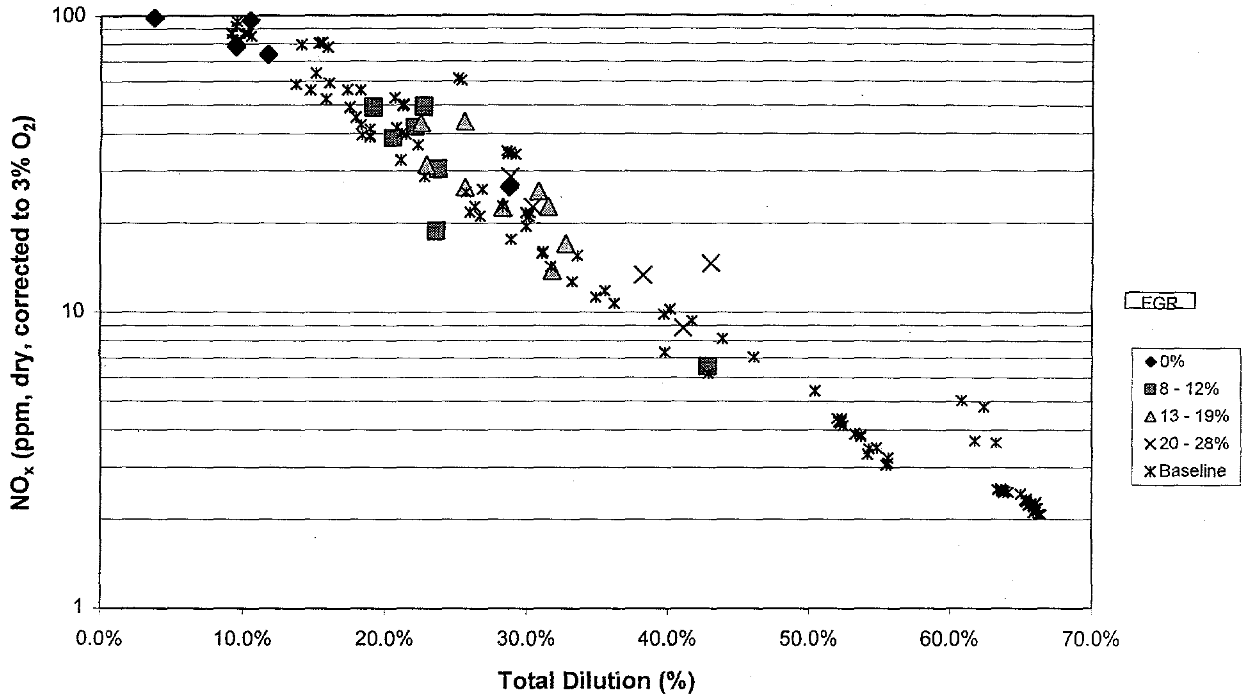

Figure 2-4a. NO_x versus Total Dilution in Laboratory Boiler for various Flue Gas Recirculation Levels

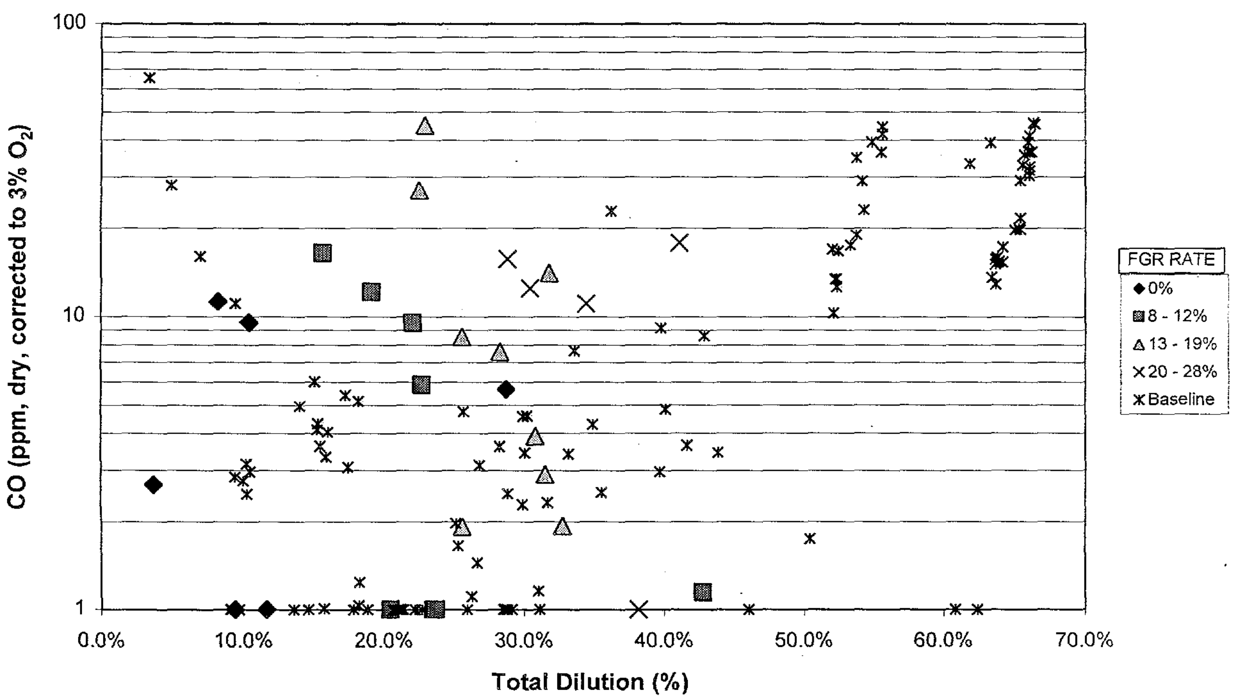

Figure 2-4b. Carbon Monoxide versus Total Dilution in Laboratory Boiler for various Flue Gas Recirculation Rates

2.1.4 Laboratory Tests with Combustion Air Preheat

Although combustion air preheat is not common with industrial boilers, there are installations that use preheat to increase thermal efficiency. Energy from the flue products can be transferred to the incoming combustion air using a heat exchanger. Since the main drawback to the simple ultra-low NO_x high excess air burner described in Section 2.1.2 is viewed to be a decrease in thermal efficiency, this technique for improving efficiency was determined to be of interest. An air-to-air heat exchanger was installed on the laboratory boiler to test the effect of preheat on emissions performance.

NO_x emissions results are presented with baseline NO_x data in Figure 2-5 with NO_x being plotted as a function of total dilution (equivalent to excess air in this case, since there is no FGR). The preheat data are observed to lay above the non-preheat data, meaning that at an equivalent level of dilution, the points with combustion air preheat will have higher NO_x emissions than will the points without preheat. Another interpretation of this is that if a specific emissions level is targeted (such as 9 ppm), additional dilution will be required to achieve that NO_x level if the combustion air is preheated. Based on Figure 2-5, it appears that approximately 15 percent higher total dilution is required at a combustion air preheat level of 450°F in order to achieve the 9 ppm NO_x emissions level. CO emissions continued to be low, and are presented in Appendix A as Figure A-3.

In was recognized that data with and without FGR correlated well to the total dilution variable, and that this correlation was due to the fact that total dilution was a good indicator of flame temperature. In order to correlate data with a significant amount of preheat, the baseline data and the preheat NO_x data are plotted as a function of adiabatic flame temperature in Figure 2-6. Adiabatic flame temperature was calculated as a function of preheat temperature and excess combustion air using a chemical equilibrium code. As seen in Figure 2-6, the data with and without preheat correlate well, with sub-9 ppm NO_x emissions occurring at adiabatic flame temperatures of 2850°F or lower. CO emissions are plotted in Appendix A as Figure A-4.

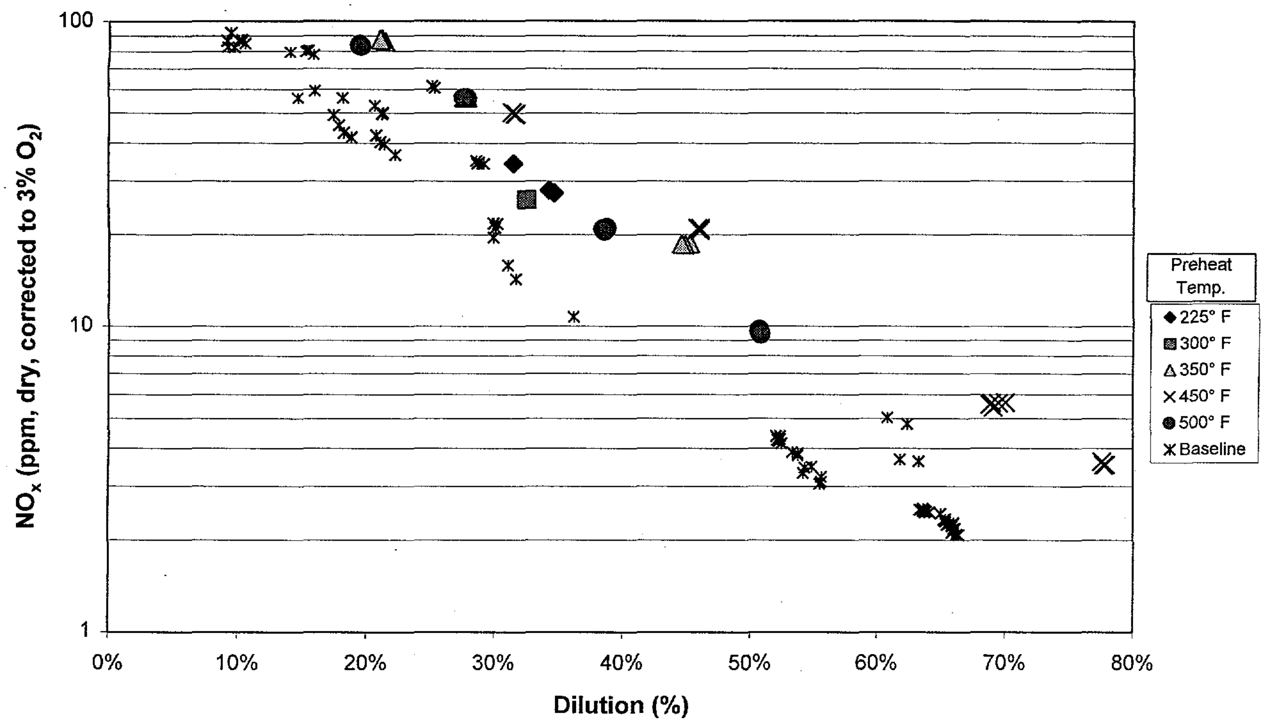

Figure 2-5. NO_x versus Total Dilution for Various Levels of Combustion Air Preheat, with Baseline data

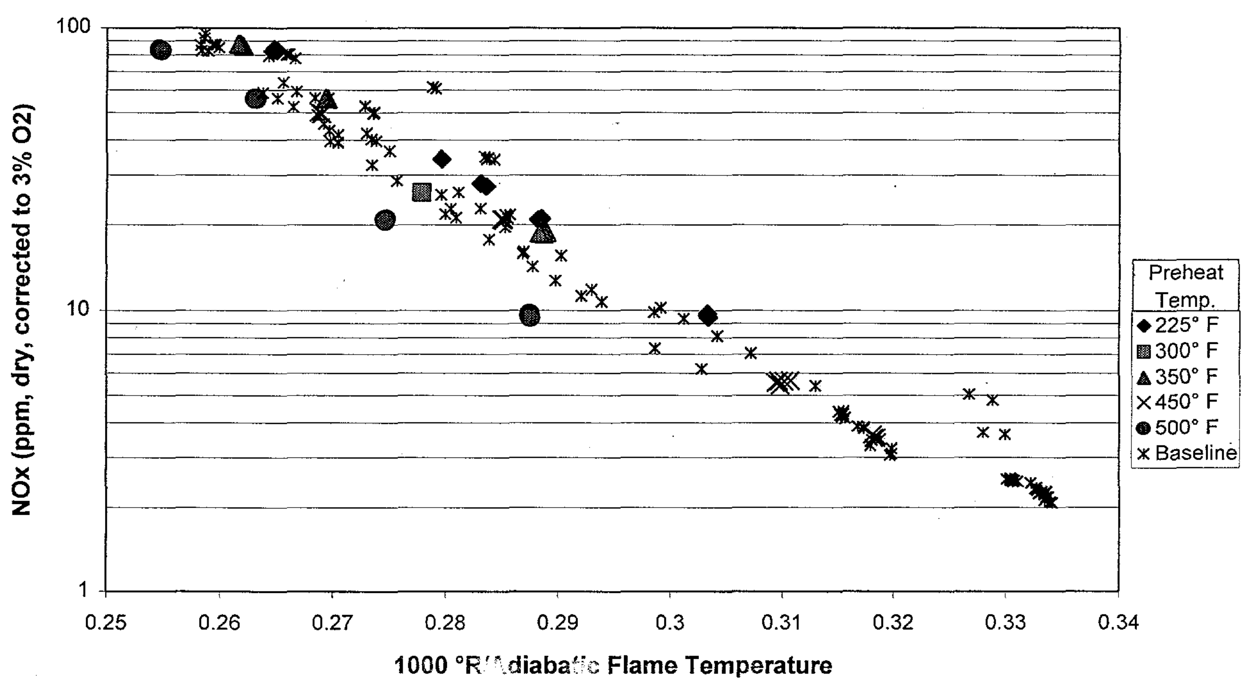

Figure 2-6. NO_x versus Reciprocal Adiabatic Flame Temperature in Laboratory Boiler for Various Levels of Combustion Air Preheat, with Baseline Data

From a practical standpoint, the increase in system complexity that would result from the use of combustion air preheat would probably offset the efficiency benefit, particularly if a specific NO_x level is targeted. While efficiency could be increased by several percent by preheating the combustion air, achieving the 9 ppm NO_x level would then require approximately 15 percent additional mass flow through the boiler. Additional heat transfer surface would have to be installed in the boiler to transfer heat to the steam-side of the boiler. The cost of the air-to-air heat exchanger and the additional boiler tube surface may be too high to justify the efficiency benefit that would result.

2.1.5 Laboratory Tests with FGR and Preheat

A last set of tests was conducted in the laboratory to test the effect of combining combustion air preheat and FGR. In reality this was viewed as an advanced FGR test, since FGR is in many respects a cost effective method of combustion air preheat. Preheat levels of up to 600°F were tested. NO_x results are presented in Figure 2-7, where emissions are presented as a function of total dilution for the baseline tests, the preheated combustion air tests, and the preheated FGR tests. The original FGR test data are not included, but were shown earlier to correlate well with the baseline results. The preheat level of the mixed FGR-air stream was not measured in those tests, and in general the FGR temperature was so low that the mixture temperature was probably less than 100°F above ambient.

As shown in Figure 2-7, both sets of preheated data show higher NO_x at a fixed level of total dilution when compared to the baseline data. When plotted versus adiabatic flame temperature in Figure 2-8, the baseline and preheated combustion air data fall on the same curve. The FGR data with preheat actually fall below the curve for the other two sets of data. This means that at a given adiabatic flame temperature, the preheated FGR stream will generate less NO_x than will the baseline or preheated combustion air steam. The difference at 9 ppm NO_x is about 150°F (2850°F AFT required for the baseline and preheat tests and 3000°F AFT required for the FGR tests).

These results do not seem intuitive, and the total difference in the two sets of data can be explained by a 5-10 percent total variation in total dilution. It was therefore assumed (until better data are available) that NO_x can be correlated to adiabatic flame temperature independently of preheat level or amount of FGR. In practice, this means that while it is desirable to use FGR to minimize excess air, and to increase efficiency,

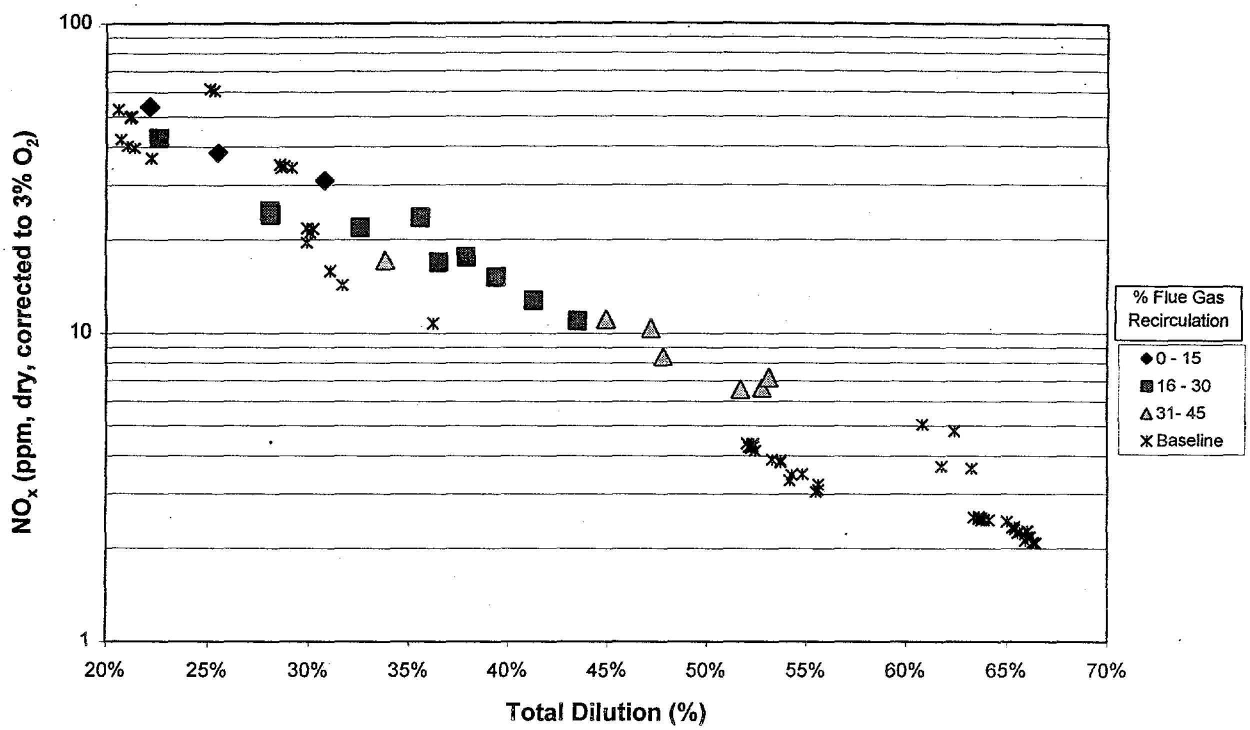

Figure 2-7. NO_x versus Total Dilution in Laboratory Boiler with Preheat for a Variety of Levels of Flue Gas Recirculation, with Baseline Data

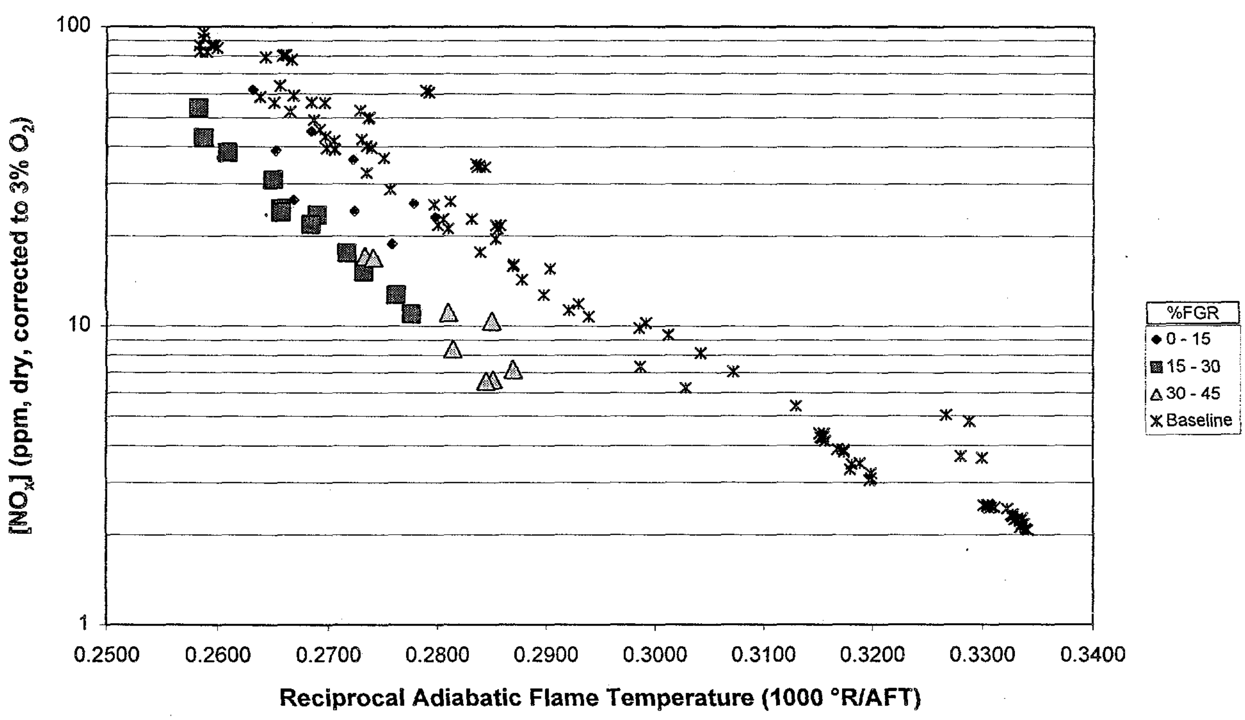

Figure 2-8. NO_x versus Reciprocal Adiabatic Flame Temperature in Laboratory Boiler with preheat for a Variety of Levels of Flue Gas Recirculation, with Baseline Data

combustion air preheat does not provide as significant a performance advantage. Addition flue gas energy transfer to the water-side of the boiler would be more effective method of increasing thermal efficiency. Heat transfer to the incoming combustion air increases the adiabatic flame temperature, which increases the total dilution required to achieve a given emissions level, which could offset the desired efficiency gain by decreasing the effectiveness of the boiler as a heat exchanger.

2.2 TEOR STEAM GENERATOR FIELD TESTS

Tests at a scale more representative of a typical industrial package boiler were conducted in a Thermally Enhanced Oil Recovery (TEOR) steam generator near Bakersfield, California. This site was selected for testing because it provided an opportunity to test in a facility of the appropriate scale, and with a furnace temperature that was representative of an industrial boiler.

2.2.1 Test Facility

The test facility was a working boiler used for TEOR steam generation, and in exchange for receiving access to burner performance data, Alzeta was allowed to modify the steam generator to conduct tests by the equipment owner, Chevron. The steam generator manufacturer was Struthers, and this specific boiler design is used extensively in TEOR applications. The capacity of the boiler was 62.5 MMBtu/hr. The steam generator, shown in Figure 2-9, had a radiant section 9.5 feet in diameter by 37 feet long. The watertubes made one pass through the radiant section, were 3 inches in diameter, and were arranged parallel to the steam generator centerline on 6-inch centers. The units typically operate at a steam pressure of 1100 psig corresponding to a steam temperature of 550°F.

The steam generator was equipped with a Pyromat CSB30-4SO-30 burner element. The burner was cylindrical and 30 inches in diameter by 120 inches long. This burner was installed originally in 1994, then modified with the addition of fuel staging rings in 1995 for Phase 1 tests. For FGR tests, additional burner modifications were made in 1997. The active burner length was not changed, but an FGR line was added to connect the exit of the convective section to the inlet of the blower. Modified staging rings were also added between segments in 1997. The staging rings placed between each segment allowed for three independent injection locations for air and gas along the

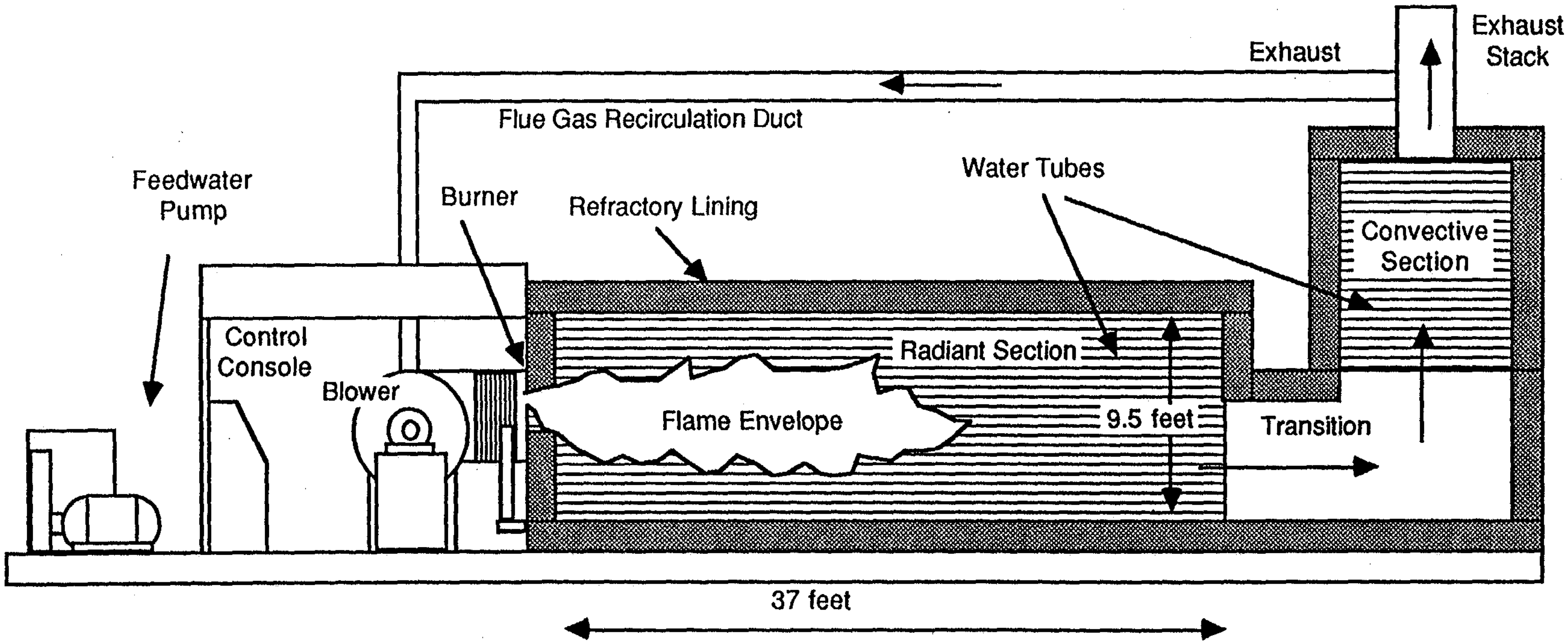

Figure 2-9. Typical 50,000 lb/hr Oil Field Steamer with Conventional Low NOx Burner Using Flue Gas Recirculation (simplified schematic)

length of the burner. Staging results are described in Appendices B and C. FGR tests are reported below.

The steam generator was equipped with viewports in the front, side, and rear walls. Temperature measurements were made from thermocouples located to measure the gas temperature along the radiant section, the exposed and insulated tube wall temperatures and the tube temperature before the convective section. Heat flux was measured using a heat flux probe.

2.2.2 FGR Tests

The NO_x and CO emissions results of the Cymric FGR tests are shown in Figures 2-10a and 2-10b. The FGR data points illustrate the same trend as was observed in the laboratory, due to NO_x formation with the RSB burner being a function of total dilution (or adiabatic flame temperature), regardless of whether the diluent is air or flue gas. NO_x emissions are plotted as a function of adiabatic flame temperature in Figure 2-11. Data from the laboratory scale tests are included in this plot. It is observed that there is minimal effect of scale in these test results, although there is more data scatter in the field tests. This additional data scatter was attributed to the greater difficulty in obtaining test data in the field relative to the laboratory testing.

Figure 2-12 shows the NO_x emissions for specific values of excess air. In Figure 2-12, the region where excess air is below 20% is labeled "high efficiency," and the region where NO_x levels are below 10 ppm is labeled "low emissions." The intersection of these two regions is labeled in the figure, and represents the targeted burner performance. Results indicated that the required performance was achievable, but with little margin for error. Operation at slightly higher excess air, and therefore a lower FGR level, would bring the NO_x emissions further below the 9 ppm target, and the tests were therefore judged to be a success.

Temperature data and heat flux data collected during the Cymric tests were supplied to the B&W Power Generation Group in Barberton, Ohio for analysis. The purpose of supplying B&W with data was to allow them to evaluate the impact of an extended surface burner on boiler performance. Their intent was to analyze the benefits of using the RSB in a boiler configuration that has reduced firebox dimensions and additional tube surface in the boiler firebox.

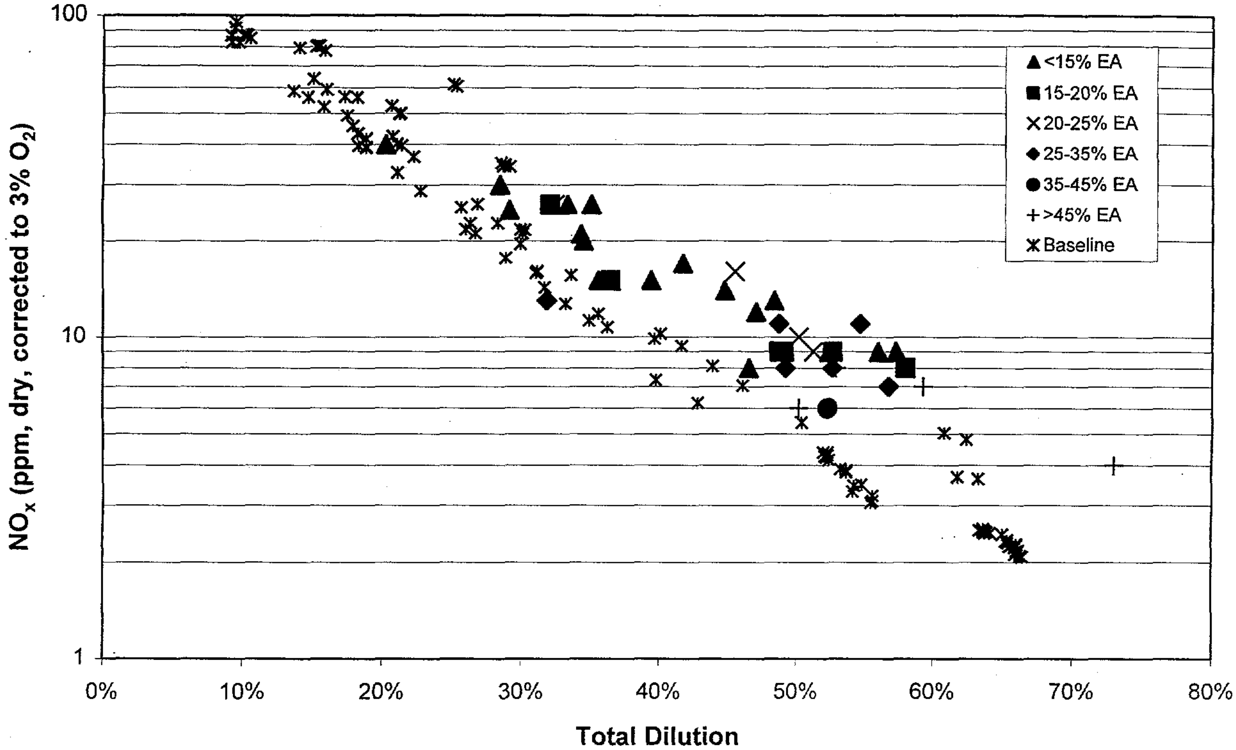

Figure 2-10a. NO_x Concentration versus Percentage Total Dilution in Field Test Boiler for Varying Levels of Excess Air, with Baseline Data

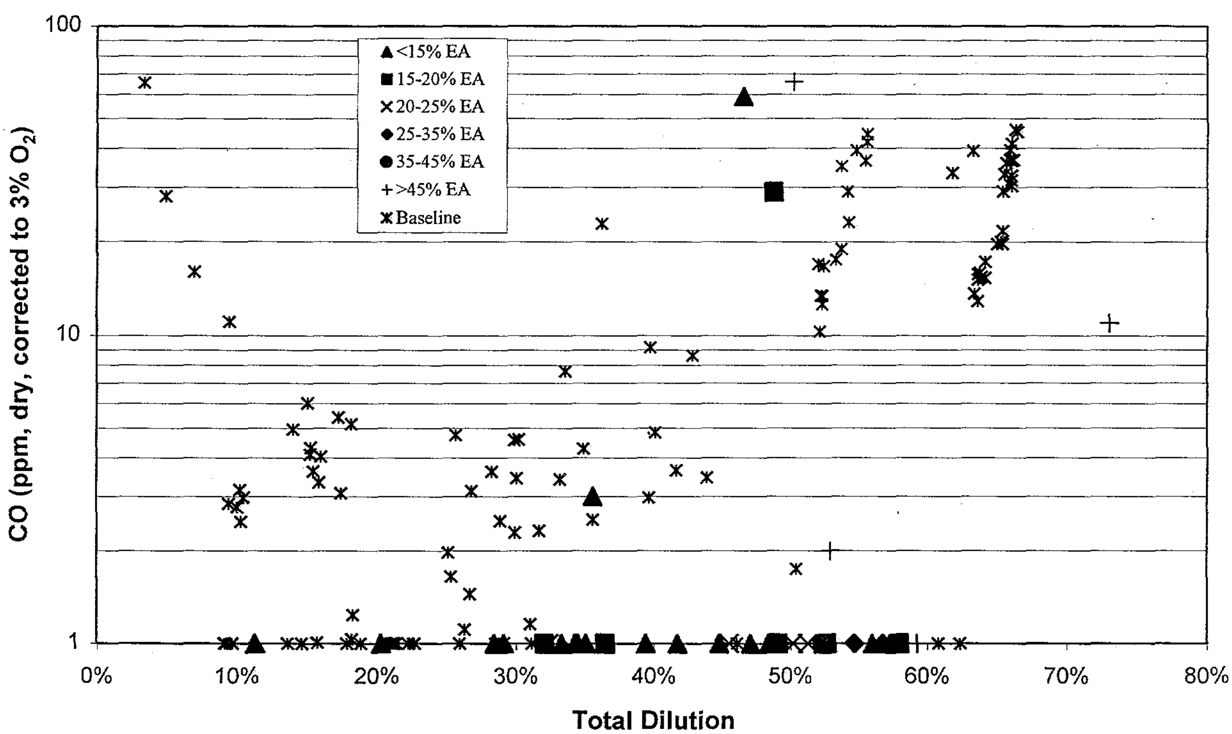

Figure 2-10b. CO Concentration versus Percentage Total Dilution in field test boiler for Varying Levels of Excess Air, with Baseline Data

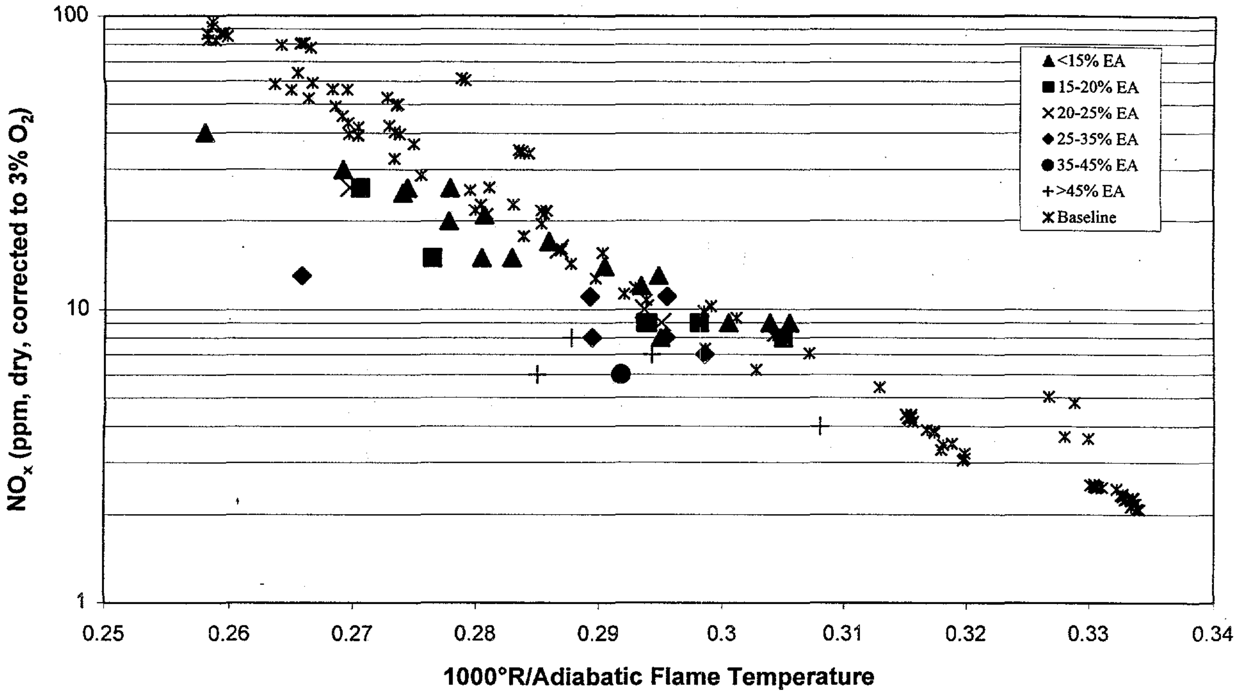

Figure 2-11. NO_x Concentration versus Reciprocal Adiabatic Flame Temperatur in Field Test Boiler for Varying Levels of Excess Air, with Baseline Data

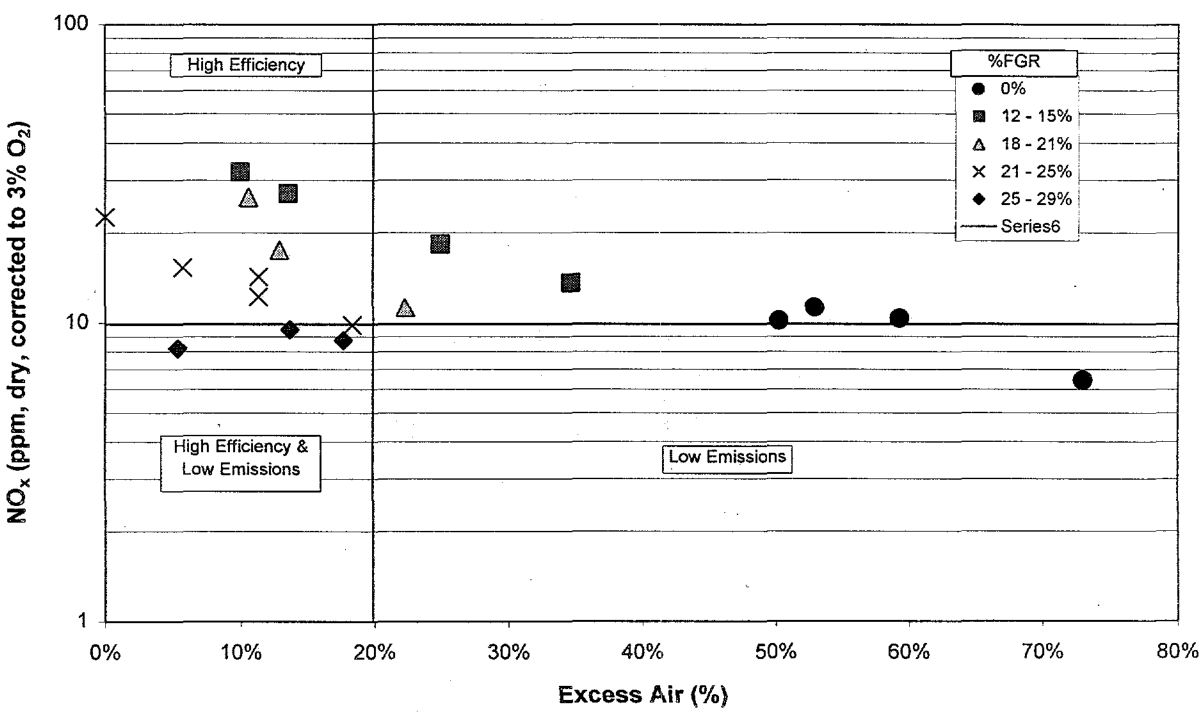

Figure 2-12. NO_x versus Excess Air for various levels of Flue Gas Recirculation in Field Test Boiler

By using Computational Fluid Dynamics (CFD) codes, B&W was able to correlate their model to heat flux and temperature data from Cymric, and also to predictions from Alzeta plug flow and gas phase emissivity models. The B&W modeling was useful in verifying our models, and did provide some insight into the effects of changing boiler firebox dimensions and adding additional heat transfer surface to a boiler. The two-part B&W report is included as Appendix D. A more complete Alzeta test report, including the results of the staging tests is included as Appendix C.

2.3 PHASE 2 PACKAGE BOILER FIELD TEST

During Phase 2 of the project, Alzeta had the opportunity to install a 125 MMBtu/hr CSB in an industrial package boiler in San Francisco. This provided us with the chance to test our ultra-low NO_x control strategies in a package boiler that was required to meet a 30 ppm NO_x performance guarantee. Burner performance could therefore be tested in a package boiler without having to meet a 9 ppm emissions guarantee, allowing for some margin for error between the design NO_x level and the regulatory limit.

2.3.1 <u>Facility Description</u>

Alzeta sold a Pyromat CSB36-5SO-30FS burner for retrofit into a Zurn "O" type Keystone package boiler to S.F. Thermal in San Francisco, California. SF Thermal is a company that sells steam to downtown buildings for general heating and process steam. The boiler has 7926 ft^2 of heating surface and is capable of producing 100,000 lb/hr of steam at 200 psig. The internal dimensions of the radiant section are 267 inches long by 105 inches wide by 77 inches tall. This provides a heat release rate of about 100,000 $Btu/hr/ft^3$, which is comparable to the 3 MMBtu/hr laboratory watertube boiler used in Phase 1 of this project. A multi-pass convective section sits on either side of the radiant section. Figure 2-13 illustrates the tube configuration for the Keystone boiler.

The boiler was equipped with two round viewports in the back wall. It was also equipped with pressure gages on the windbox, in the burner, and inside the furnace to assist in tuning the burner and to understand the flow dynamics. A thermocouple was located in the stack for determining efficiency and a pollutant emissions analyzer was inserted into the stack to verify O_2 measurements and to record real-time NO_x and CO measurements.

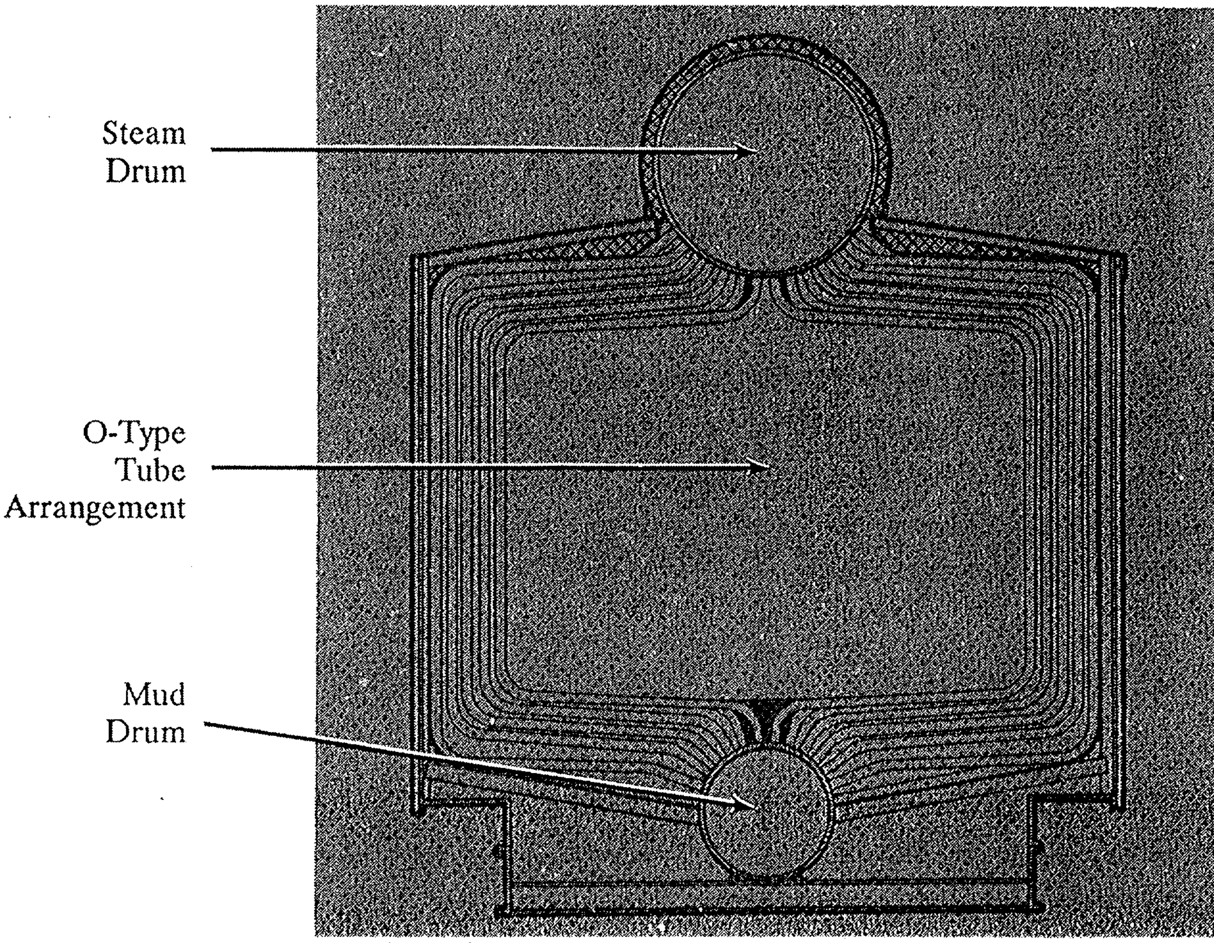

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Figure 2-13. Internal Geometry of "O" Type Boiler

2.3.2 Test Results

Although the burner sold to SF Thermal was intended to use fuel staging for NO_x emissions control, fuel staging tests conducted in this facility were unsuccessful and are presented in Appendix B. The burner currently operates as a sub-30 ppm burner that uses excess combustion air to control NO_x. Data collected from boiler operation are plotted in Figure 2-14. Emissions are consistent with, though somewhat higher, at a fixed excess air level, when compared to data from Cymric.

Since the original laboratory data agreed well with the Cymric data, it was felt prior to the SF Thermal demonstration that data from all facilities would achieve sub-9 ppm NO_x performance at the same dilution level. The high volumetric heat release rate of the package boiler (relative to the Cymric tests), and the much larger furnace volume (relative to the laboratory tests) were believed to lead to the higher NO_x levels. Although we expected similar package boiler performance in the Phase 3 burner retrofit, it is expected that a boiler design that decreases the volume of the boiler firebox will also reduce NO_x emissions at a given level of excess air or dilution by more rapidly cooling the flame.

2.4 SUMMARY OF FUEL STAGING RESULTS

The desire to achieve our NO_x and CO emissions targets at minimum mass flow through the boiler led to a series of fuel staging tests that were conducted during Phase 1 and Phase 2 of the project. Results are summarized briefly in this section. Data from all staging tests are presented in Appendix B. Field test staged combustion data from Cymric are presented and discussed at the conclusion of Appendix C. In general, fuel staging results were found to be more difficult to predict and to control than the high excess air and FGR tests.

Initial tests were conducted in the 3 MMBtu/hr laboratory watertube boiler, with the staged fuel being introduced through manifolds on each side of the planar burner. While our initial tests showed that NO_x emissions were reduced at the lower stack O_2 levels, CO emissions were much higher than the project goal of 50 ppm. See Figure 2-15.

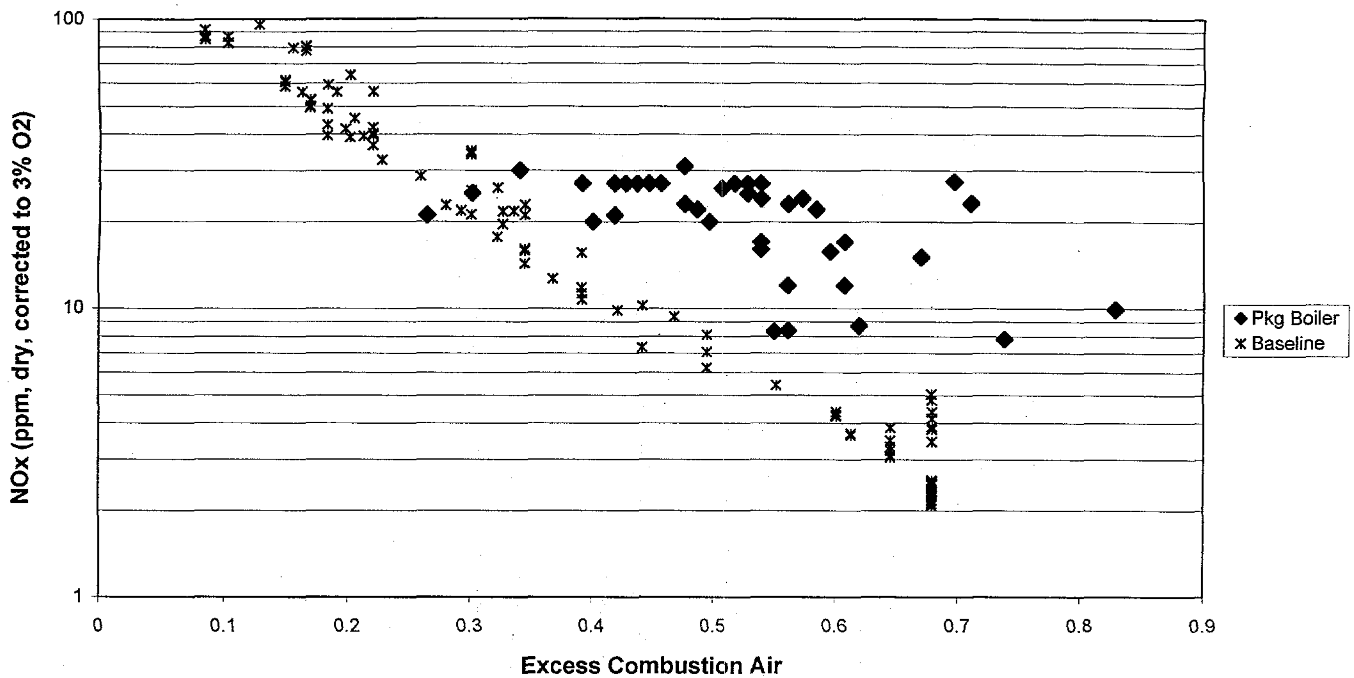

Figure 2-14. NO_x concentration versus excess combustion air from package boiler and baseline tests.

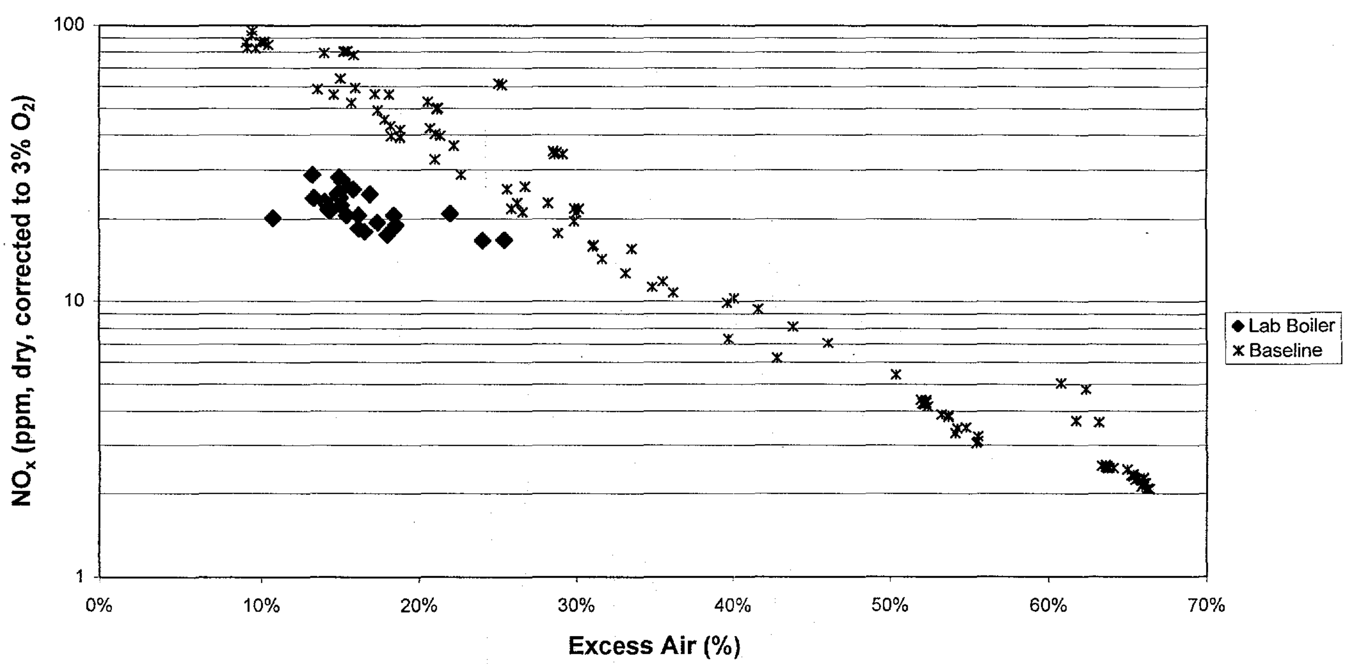

Figure 2-15. NO_x versus excess air for Laboratory Boiler Fuel Staging Tests with Baseline Data

This led to a first series of tests in the larger scale TEOR steam generator. Because we had a limited testing window available in this piece of equipment, we designed a very flexible fuel staging manifold that allowed us to test different fuel injection patterns without changing the hardware. In the oil field steamer, we were able to use the existing Pyromat CSB30-4SO-30 burner, with some modifications, to investigate staging at full scale. The burner was modified to accommodate secondary fuel injection by adding a series of fuel staging manifolds to the end of the last segment. The injectors were supplied by fuel lines inside the burner plenum. Personnel from Alzeta were present to supervise the burner modifications and conduct the tests. The burner was modified and operated by Chevron.

Figure 2-16 presents the emissions results of the TEOR fuel staging tests. The considerable spread in the staged fuel NO_x emissions from 10 ppm to almost 30 ppm is due to variations in fuel fraction (amount of staged fuel), the shape of secondary combustion zone, and steamer load. In general, this scatter demonstrates the difficulty we had in developing a staged burner. It was these difficulties that eventually caused us to focus our further development efforts on the more predictable FGR NO_x control approaches.

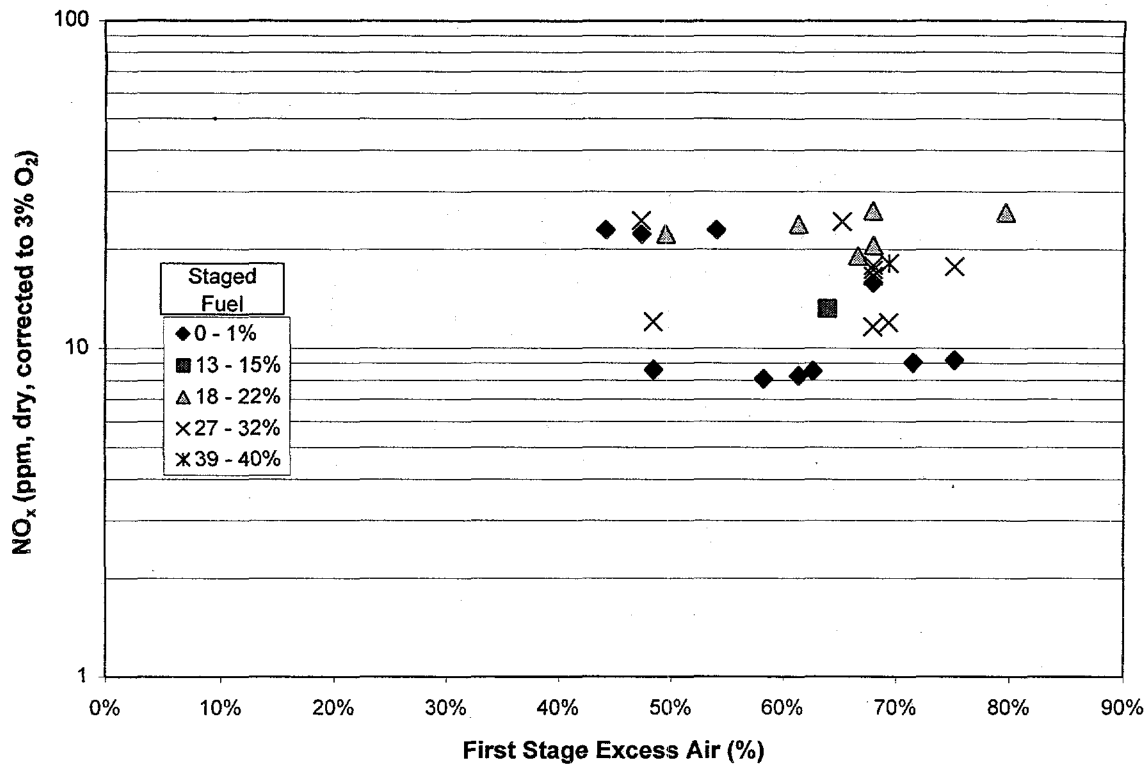

Figure 2-16. NOx versus Excess Air for Industrial Boiler Fuel-Staged Burner

SECTION 3

Optimized Low Emissions Boiler - Burner Package

The laboratory and full scale field test results presented in Section 2 demonstrated that the emissions targets of the project could be met using either of two approaches: FGR or high excess air. While the high excess air approach represents the lowest first cost method, and is also viewed by customers as having the lowest perceived risk, our interest was in meeting the emissions target at a boiler efficiency that was equivalent to or greater than that of today's standard package boiler. Because of this interest, Alzeta focussed on optimizing the performance of the FGR burner in a redesigned package boiler.

3.1 End User Perspective

Historically plant operators have vigorously resisted implementing NO_x controls, even under threat of penalty, because investment in NO_x control equipment yields no financial benefit (and frequently leads to higher operating costs as well as more operational complexity). This behavior has been exhibited repeatedly in various market segments, and leads Alzeta to conclude that new low NO_x technologies will achieve widespread acceptance only when the incremental cost of NO_x control is equal to zero.

This means that the NO_x control equipment will have to pay for itself through reduced operating costs arising from process improvements, improved thermal efficiency, or reduced electric power consumption. Since the end product of a boiler is steam, there is minimal opportunity to increase the "value" of the product. The focus on cost savings in the industrial boiler market must therefore be to maximize thermal efficiency and minimize electric power consumption.

Given the existence of air district programs to buy and sell NO_x emissions credits, the value of emissions offsets that may be produced could also be important. This would likely be of secondary importance to plant operators who are judged on their operating costs, and who can only indirectly benefit from revenue from emissions offsets that would typically be captured elsewhere in the company.

The very promising emissions results presented in Section 2 came at the expense of a significant increase in mass flow through the boiler. This increased mass flow (at fixed heat input) was necessary to dilute the fuel-air mixture in order to reduce the temperature of the flame, and thereby reduce the rate of NO_x formation. While the emissions benefits that result from this simple approach were obvious, the shortcomings of the approach are equally obvious.

Operation with FGR is more thermally efficient than operation at high excess combustion air, and can be implemented in a manner that can match the thermal efficiency of any boiler being sold today. If stack oxygen and stack temperature of the ultra-low NO_x Alzeta system can be matched to the stack oxygen and stack temperature of simple boiler operating at 15 percent excess combustion air, then the ultra-low NO_x system will be operating at equivalent thermal efficiency.

Unfortunately, adding FGR to a system that was not designed to accommodate FGR does have negative consequences, all of which increase the cost of the boiler. The first is that thermal efficiency may decrease as more mass flow is forced through a boiler with a fixed amount of heat transfer surface. The benefit of the preheat energy provided by nominally 400°F flue gas that is re-introduced into the boiler can compensate for some of the decrease heat exchanger effectiveness, but in general there is some efficiency loss associated with FGR. This decrease in efficiency results in increased fuel usage, and ultimately higher operating costs. Efficiency can be matched by increasing the amount of boiler heat transfer surface ("derating" the boiler shell), but this increases capital cost.

A second and usually more significant consequence of increased boiler mass flow is that increased fan power is required to force more mass flow through a boiler of a fixed size. Ultra-low NO_x burners requiring 35 percent FGR have been known to have a combustion air fan horsepower requirement that is 2.5 times that of the "uncontrolled" baseline burner. The requirement for the larger fan adds to both the initial cost and the operating cost of the system.

Given a choice, boiler operators would prefer to operate burners at nominally 15 percent excess combustion air with no FGR, and most boilers in operation today were designed to operate best at that condition. The best 30 ppm burners on the market today can meet that level of performance in certain applications. If the boiler operator's expectations of how an "uncontrolled" boiler should operate could be met in terms of thermal efficiency, fan power requirement, boiler shell size, and at only a small capital cost increment, then the ultra-low NO_x burner-boiler package would be viewed as having minimal incremental cost.

Performance targets for new installations, relative to the current state of the art at 30 ppm in an industrial package boiler, are to provide the end user with:

- Equivalent thermal efficiency
- Equivalent fan power requirement
- Equivalent boiler footprint

Achieving these goals will bring the cost of controlling NO_x emissions to the 9 ppm level down to the level currently associated with NO_x control at the 30 ppm level, and would remove most of the resistance that exists today to meeting ultra-low NO_x emissions levels.

3.2 RSB Performance Advantages in Boiler-Burner Package

In addition to providing the low emissions of NO_x and CO discussed in Section 2, the RSB has been demonstrated to have the following key performance characteristics:

- Distributed flame shape allowing transfer of heat uniformly over a large surface
- Short flame length off of the burner surface, allowing placement of the burner in close proximity to heat transfer surfaces
- Rapid burn out of CO and hydrocarbons, which allows rapid cooling of the flame to minimize NO_x formation, without producing large concentrations of CO or hydrocarbons in the stack.

In Figure 1-1a, it was apparent that the flame zone is maintained in close proximity to the burner surface. This was substantiated with modeling completed by Babcock and Wilcox (B&W) in Phase 2. Results of the B&W modeling are discussed in detail in Appendix D. Recognizing this characteristic of the burner permits modifications to be made to the traditional package boiler that will reduce NO_x emissions and improve thermal performance, but which will only work with a premixed surface combustor such as the RSB.

3.3 New Boiler Design

The conventional package boiler was redesigned to accommodate the high FGR level of the RSB. The new design is shown schematically in Figure 3-1,and is compared to the baseline boiler design in greater detail in Table 3-1. The modified design is based on the results shown in Section 2, which demonstrated that emissions can be reliably controlled to the 9 ppm level by diluting the flame with air or flue gas. The design is also based on the known fact that running high dilution levels through existing boiler designs will result in significant undesirable consequences such as:

- Increased system pressure drop leading to increased electric power consumption
- Reduced thermal efficiency leading to increased fuel usage
- Shell de-rating to combat increases fan power and fuel usage, which will increase capital cost and size of the boiler "footprint" on the factory floor

Figure 3-1a and column 1 of Table 3-1 present the standard, or baseline, package boiler design for a 60,000 lb/hr boiler. This particular boiler (based on an existing English Boiler design) is 13 tubes wide and approximately 60 tubes long. The proposed modifications are made relative to that baseline. This standard boiler is assumed to achieve 30 ppm NO_x emissions at 15 percent excess air and no FGR, at a thermal efficiency of 80 percent and a fan power requirement of 60 hp. Most of the 30 ppm burners on the market today would require some FGR to achieve the 30 ppm NO_x level, so the Alzeta 9 ppm burner will be compared to an "aggressive" baseline.

In Figure 3-1b, the boiler is redesigned to operate at 15 percent excess combustion air and 35 percent FGR. Four boiler tubes are added to the standard design in the cross flow direction, and are added to every tube row along the full length of the boiler. This requires that the mud drum diameter be increased from 24 inch OD to 30 inch OD, but no other changes that would be obvious from outside of the boiler shell are required. The 4 tubes are added to the generating bank, the generating bank is made wider to accommodate the additional tubes, and the firebox is made narrower to maintain the same overall boiler width.

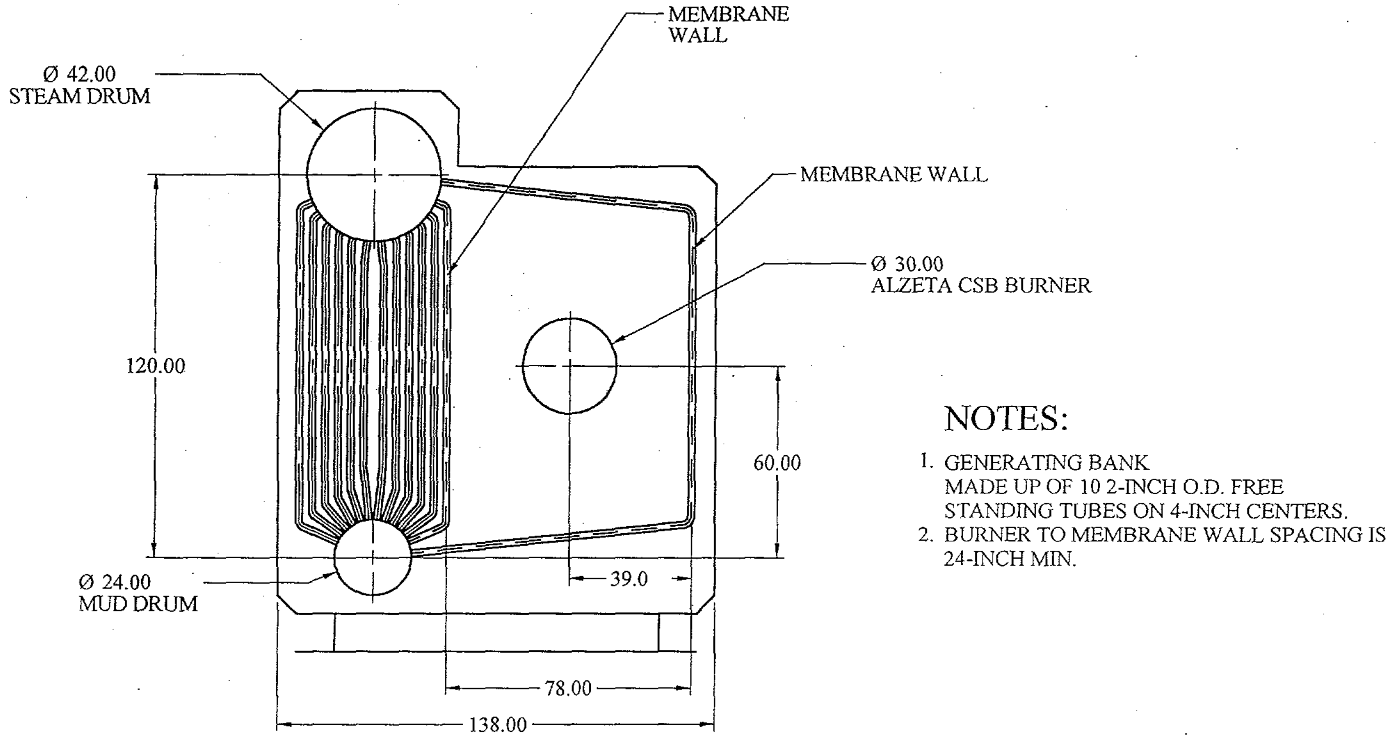

Figure 3-1a. Standard Package Design

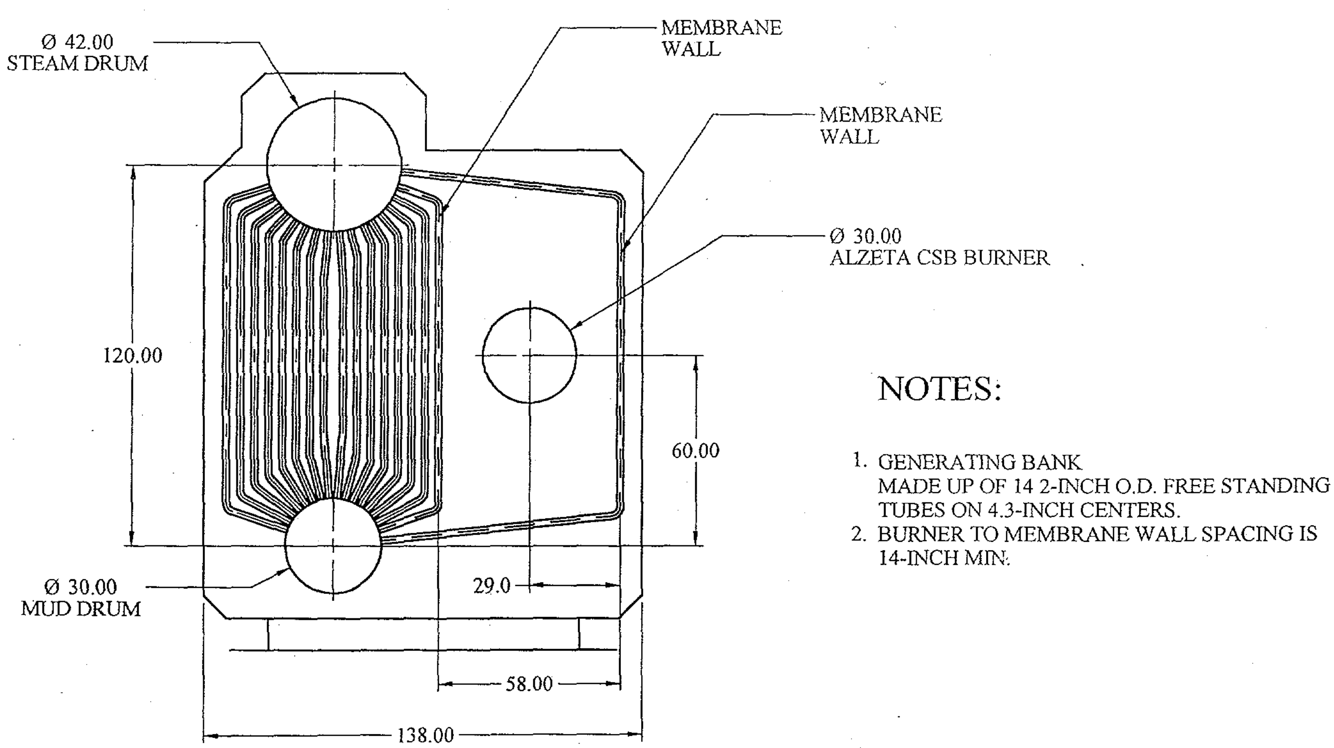

Figure 3-1b. Optimized RSB Boiler-burner Package

Table 3-1. Comparison of Boiler Configurations for 60,000 lb/hr package boiler[1]

Parameter	Baseline 30 ppm NO_x No FGR	Optimized RSB Boiler-Burner Package 9 ppm NO_x
Excess Combustion Air (%)	15	15
FGR (%), Defined as Recirc Flow/Boiler Stack Flow	0	35
Total Boiler "Dilution" Flow (%)[2]	1.15	1.55
Number of Tubes in Cross-Flow Direction	13	17
Freestanding Tubes in Generating Bank	10	14
Tube "spaces" in Generating Bank	11	15
Generating Bank Cross-Flow Tube Spacing (Distance Between Tubes in inches)	2.0	2.3
Boiler Volumetric Flowrate Ratio (Baseline is 1.0)	1.0	1.35
Generating Bank Cross-Sectional Area Ratio (Baseline is 1.0) [3]	1.0	1.57
Relative Velocity, Flow/Cross-Sectional Area (Baseline is 1.0)	1.0	0.86
Fan Power Ratio[4]	1.0	1.0
Fan Power Requirements (hp)[3]	60	60
Overall Heat Transfer Coefficient Ratio (Baseline is 1.0)[5]	1.0	0.91
Boiler Tube Surface Area Ratio, Ignore outside ½ of each wall tube (Baseline is 1.0)	1.0	1.33
Furnace Width (in)	78	58
Minimum Burner-to-Tube Spacing (in)	24	14
Stack Temperature (°F)	490	490
Thermal Efficiency (% of HHV)	80.0	80.0

1. Common to all designs are the following: 60,000 lb/hr capacity at 150 psi design pressure. Boiler shell dimensions are 11 ft 6 inches wide by 20 ft long. Centerline distance between steam and mud drum is 10 ft. Tubes are 2 inch OD, nominally on 4 inch centers in flow and transverse directions. Fired duty to achieve steam capacity is nominally 75 MMBtu/hr at 80 percent HHV thermal efficiency.
2. When defined this way, the relationship between total dilution flow, excess air and FGR is: Total Dilution = (1 + EA) x (1+FGR)
3. Cross-sectional area is defined as minimum flow area in transverse direction in generating bank. This figure is of interest because it has a large effect on system pressure drop.
4. Fan power scales with system pressure drop and flowrate (dp x Q), which scales with velocity^2 x flowrate.
5. Heat transfer is a function of Reynolds number, which is a function of relative velocity, since tube diameter is fixed and the flue gas properties are nominally identical for each case.

As a result of these modifications:

- Tube surface area in the boiler is increased by at least 31 percent by increasing the number of tubes from 13 to 17 (17/13 – 1). The argument could be made that we are increasing heat transfer surface by 33 percent (16/12 – 1) since the outside half of the two side wall tubes do not absorb much energy.
- Minimum flow area in the generating bank (defined as the open area between tubes in the cross-flow direction) is increased by 57 percent [(15 2.3-inch spaces)/(11 2-inch spaces) – 1]
- Burner surface to firebox wall spacing is 18 inches minimum

The benefits of this modified design are readily apparent. The boiler shown in Figure 3-1b can be operated at a mass flow rate that is 35 percent higher than that of a standard boiler and deliver "equivalent" performance. Velocity through the generating bank is maintained at a level that is nearly equal to, but slightly lower than, that of the standard boiler. Since most pressure drop inside of the boiler occurs in the generating bank (as opposed to the firebox), we have reduced the generating bank velocity to reduce boiler pressure drop. This allows us to match the fan power requirement of the boiler even though the mass flow through the fan is higher by 35 percent.

Of equal importance, the convective heat transfer coefficient and surface area of both system can be matched to the baseline to provide equivalent thermal efficiency. Since we have increased the heat transfer area in the boiler to compensate for higher mass flow and a slightly lower convective heat transfer coefficient, the number of transfer units in the boiler remains constant relative to the baseline, and boiler thermal efficiency is also matched. Since the additional tubes are added within the existing boiler shell dimensions, the external dimensions of the boiler remain constant relative to the baseline.

These advantages seem apparent, so a logical question that should be asked is "Why aren't all boilers designed this way now?" Answers to this question include:

- Operation at very high FGR or excess air changes the standard boiler design assumptions. When running a standard boiler at uncontrolled NO_x levels, the objective is to run the burner at 10-15 percent excess air, which results in a much hotter flame. The firebox is sized to transfer heat by gas phase radiation, and to cool the combustion products to a level well below the radiation, and to cool the combustion products to a level well below the adiabatic flame temperature, prior to introduction into the generating bank. Once the decision is made to reduce the NO_x by quenching the flame with 30 percent FGR or more, then these old design assumptions no longer hold. First, the adiabatic flame temperature of the burner operating with 30 percent FGR is already cooler than the firebox exit temperature of the conventional burner, so we have eliminated any concerns of overheating tubes at the entrance of the generating bank. Secondly, quenching the flame has a more significant negative impact on gas phase radiant transfer (which scales with T^4) than it does on convection (which scales linearly with temperature). Therefore, the package boiler becomes more of a convective heat transfer system, and should be designed as such.

- Most low- NO_x burners need the wide firebox in order to operate correctly. Originally, the firebox width was selected to achieve good gas phase heat transfer and good CO burnout. As described above, dilution with FGR reduces gas phase radiation, and it also increases the distance required to complete combustion and to get good CO burnout because combustion reactions are slowed. If anything, non-premixed low NO_x burners probably would operate better with a wider firebox. The fully premixed Alzeta burner, with its short flame length, controlled flame shape, and rapid CO burnout can operate well in a narrow firebox,

3.4 Summary of Boiler-Burner Benefits

By designing the boiler to operate well at high mass flow conditions, then fan power, efficiency, and boiler footprint can all be controlled and optimized. This is particularly true if the firebox width can be reduced, which is the case with the RSB.

The benefits of the boiler design optimized for high mass flow include:

- **Increased boiler capacity**. Capacity is typically limited by the heat transfer surface constrained inside of a fixed boiler shell size. Designs that increase total exposed tube surface area provide the opportunity to increase boiler capacity without increasing boiler footprint. Boiler footprint is often a critical constraint in boiler selection, transport to the site, and installation. Increasing capacity within a fixed boiler footprint leads to increased cost effectiveness.

- **Increased efficiency of the boiler for fixed boiler size.** Increasing tube surface area has the additional benefit of increasing the thermal efficiency of the boiler. This translates directly into a cost saving for the plant operator in terms of reduced fuel usage. Heat transfer analysis of the proposed designs predicts that thermal efficiency at sub-9 ppm NO_x can match the efficiency of a typical 30 ppm boiler.
- **Reduced fan power requirements.** By increasing cross-flow tube spacing, pressure drop of the sub-9 ppm burner can match, or actually be lower than, the drop through a conventional 30 ppm boiler.
- **Further reduction of NO_x. Rapid cooling of the flame is critical in** reducing thermal NO_x formation. In large systems, high temperature gaseous species can block the radiation path from the flame zone to the cold tube surfaces. The narrower firebox introduces the combustion products more quickly into the convective section of the boiler, and the inclusion of watertubes in the firebox will even more quickly cool the flame. Since the premixed Alzeta burner completes CO burnout within approximately 1 foot of the burner surface and controls the flame to an area directly above the burner surface, these compact designs are feasible.

3.5 Status of RSB Boiler-Burner Package

The system design proposed by Alzeta has been validated with in-house thermal modeling by our selected manufacturer, English Boiler of Richmond, Virginia. The boiler modeling was completed by English, and a first system has been designed and quoted for an industrial customer. Although the project was bid in January of 1999, the customer is still awaiting corporate approval for the purchase. Due to this delay, an alternate field demonstration was completed in Phase 3 to validate burner performance. The final field validation of the optimized burner-boiler design will take place after the completion of this project.

SECTION 4
MARKET ASSESSMENT

The initial market for the sub-9 ppm RSB has been identified as industrial package boilers, with the expectation that the RSB will be utilized in other industrial and commercial applications in the near future. The RSB product is defined in Section 4.1 and a summary of the market is presented in Section 4.2. The cost effectiveness of the RSB boiler-burner package is quantified in Section 4.3. Benefits that will be realized in terms of energy savings and emissions reductions are estimated in Section 4.4.

4.1 BURNER PRODUCT DEFINITION

Based on the results of this project, the operating characteristics and performance limits of the RSB are well understood. The burner product that will be sold into industrial applications will have the following product definition:

- Single burner elements scaleable in size from 2 MMBtu/hr to 180 MMBtu/hr
- Multi-burner arrays with undefined total capacity (with larger package boiler and field erected boiler burner arrays topping out at 250-300 MMBtu/hr)
- Operation with excess combustion air can be used to achieve low NO_x in applications that are relatively insensitive to operating costs
- FGR will be used to achieve sub-9 ppm NO_x at 3 percent stack O_2 (15 percent excess air) in new RSB boiler-burner package installations. CO emissions will be below 50 ppm
- RSBs meeting less stringent emissions levels (up to a maximum of 30 ppm NO_x) will be designed to operate at reduced excess air or FGR levels in both new and retrofit boiler applications
- The burner will be fabricated using all metal construction for elements covering the full size range

4.2 SUMMARY OF TARGETED BOILER MARKET

In terms of market timing, the need for the product is immediate. Emissions regulations for industrial boilers are in place at the 9 ppm NO_x level in the major industrial areas of California now. In addition, the concept of "ozone transport" regions appears to now be having an impact on emissions regulations in the major industrial regions of the Midwest and Northeast.

The total market over the next 3 years for low NO_x retrofit burners in industrial boilers is on the order of $50 million to $80 million per year. The total market for new boiler burners requiring sub-9 NO_x emissions is on the order of $10 million to $30 million per year, provided there is a viable sub-9 ppm burner is available that eliminates the need for SCR to achieve sub-9 ppm emissions. A more detailed assessment of the domestic industrial boiler market is presented as Appendix E. That market assessment is summarized here.

- The RSB target market is industrial boilers with steam capacity of 20 to 250 thousand lbs/hr, typically of package boiler design. Operating package watertube boilers in the U.S. in the 20-250 kpph range number from 12,000 to 16,000 boilers.
- Of these boilers, 6000 to 8000 boilers in the U.S. are in the 50-250 kpph size range. This is greater than 60 percent of the 25 kpph and larger boiler population and 46 percent of installed boiler capacity.
- In these boilers, gaseous fuels are the primary energy source, representing approximately 40-50 percent of fuel usage.
- In the Midwest, Gulf States, and all states west of the Mississippi River, gaseous fuels are a larger percentage of total than the 40-50 percent figure.
- Four industries account for 70 percent of the total installed capacity of 1.5 trillion Btu/hr. These industries are paper, chemicals, petroleum, and food processing.
- Installed boilers are relatively old, with two-thirds of boilers (and roughly two-thirds of installed capacity) being greater than 15 years old.
- New boilers sales in the targeted size range are in the order of 400 new boilers per year (2.5 percent of installed base per year) with sales primarily being in package boilers or HRSG's

- The retrofit burner market (for sub-30 ppm burners) is much larger, but is also closely tied to regulations and is on the order of 10 percent of the installed base annually or 1200-1600 boilers per year.
- The estimated capacity of these products is 7-10 billion Btu/hr of installed new boiler capacity per year, and 60-80 billion Btu/hr of retrofit capacity per year.
- The California new boiler market requires typically sub-9 ppm NO_x, and this will be the first region targeted for the RSB.

4.3 COST EFFECTIVENESS OF THE RSB BURNER-BOILER PACKAGE

Benefits of the RSB are quantified in this section with respect to thermal efficiency improvements, boiler and burner capital costs, other O&M costs, and the environmental benefit of reduced NO_x emissions. The benefits quantified below are for industrial package boilers. Additional markets for the RSB in future years will include industrial process heaters, field erected boilers, and commercial-scale boilers. Therefore, the numbers presented in this section are accurate for the near-term target market for the RSB, but underestimate the total market.

An analysis has been performed of the RSB Burner-Boiler Package using the RSB Boiler-Burner configuration presented in Section 3. More radical design modifications were proposed, but this configuration is a conservative design, could be manufactured easily, and is therefore the focus of this cost effectiveness assessment. Numbers are presented for a 60,000 lb/hr package boiler, since that is the unit that was proposed for sale to Hershey Chocolate and Confectionery in Oakdale, CA in early 1999. The basis for the costs presented in the table are summarized in the following paragraphs.

4.3.1 Capital Cost

The capital cost in this table is based on an actual Alzeta burner cost for the high excess air burner currently sold into this market. It is assumed that at the completion of the and DOE funding, the FGR version of the burner can be sold for the same price. We have also included the additional cost to manufacture the modified boiler based on input from several of the manufacturers that we are working with.

TABLE 4-1. COST EFFECTIVENESS SUMMARY FOR 60,000 LB/HR BOILER

Parameter	Optimized RSB Cost Relative to 30 ppm burner	Optimized RSB Cost Relative to 9 ppm burner operating at 20% EA, 35% FGR
Incremental Capital Cost (Burner + Boiler Modifications for 60,000 lb/hr Boiler)	$95,000	$20,000
Annual Fuel Usage Differential (Assume $3/MMBtu fuel cost)	$0	-$12,320
Annual Electric Cost Differential (Assume $.06 per kWh)	$0	-$35,300
Non-Energy O&M	$2,400	$2,400
Annualized Cost (Capital Amortized using factor of 0.1624 per EPA guidelines)	$17,830	-$41,970
NO_x Reduced (Relative to 30 ppm baseline) in Tons/yr	8.28	NA
Cost Effectiveness ($/ton)	$2,150/ton	NA

4.3.2 Fuel Usage

Our objective in laying out Configuration 1 in Section 3 was to match the thermal efficiency of the baseline boiler, which was assumed to be a 30 ppm staged-combustion burner that could operate at 15 percent excess air and no FGR. The 9 ppm ultra-low NO_x burner that was used as the 9 ppm comparison was assumed to use 35 percent FGR to achieve ultra-low emissions at 15 percent excess air.

4.3.3 Electric Power Consumption

Based on the Section 3 boiler-burner design, power consumption was matched to the baseline 30 ppm system. The additional fan power required for the comparable 9 ppm burner was based on the observation of systems now operating in the field, where the required fan horsepower is greater by a factor of 2 to 2.5 over the 30 ppm baseline case.

4.3.4 Non-Energy Operating and Maintenance

The only incremental O&M specific to the Alzeta system is believed to be maintenance of the burner surface. We have conservatively estimated burner pad life at 5 years. We have annualized the cost of the 5 year pad service into the annual O&M

estimate. We have also conservatively assumed that the Alzeta O&M cost will also be higher than the O&M cost of the competing 9 ppm system by the same amount. In reality, we would assume maintenance for that high FGR system to be significant due to the complexity of the controls and FGR ducting.

4.3.5 Cost Effectiveness Calculation

Cost effectiveness calculations for the 9 ppm Alzeta boiler and burner relative to the 30 ppm baseline and the 9 ppm baseline are presented. As noted above, single percent changes in thermal efficiency can have a significant affect on the cost effectiveness number, so there is some uncertainty in this calculation. However, based on the calculations presented here, our goal of matching the operating costs of today's sub-30 ppm boiler and burner with the 9 ppm Alzeta product is feasible.

Although the calculations above, using the EPA cost effectiveness methodology, show a $2,150 per ton cost relative to a 30 ppm burner, several other points should be made. The typical plant operator would like to see a 1 to 2 year payback on capital investments, so amortization over 10 years under estimates the true value that the end user places on capital. The high capital cost of NO_x control equipment, while providing no benefits to the end user beyond NO_x compliance, has been an impediment to the implementation of NO_x control equipment. The proposed Burner-Boiler Package provides benefits beyond NO_x compliance, namely lower pressure drop and increased heat transfer surface in a fixed boiler size, that will benefit users and speed the acceptance of this product in the market.

4.4 CUMULATIVE BENEFIT TO THE ENVIRONMENT

4.4.1 NO_x Emissions Reduction

Consider the subset of industrial boilers that are prospective candidates for gas-fired retrofits. Alzeta and B&W identified approximately 12 thousand units nationally as prospective candidates sized at 25-320 MMBtu/hr firing rate, with one thousand of these units being in California. Uncontrolled gas-fired boilers, correctly tuned, typically emit 80-100 ppm of NO_x (corrected to 3 percent oxygen). The new Alzeta burner is targeted to operate below 9 ppm, also corrected to 3 percent oxygen, yielding a conservative savings of nominally 70 ppm, or about 0.085 pounds of NO_x per MMBtu input. Applying this to the inventory of package boilers that will eventually be replace with the 9 ppm product yields the following calculation for annual NO_x reduction (Assuming an average boiler capacity of 125 MMBtu/hr, 50 percent of the installed base to be replaced, and 50 percent capacity factor using the same assumptions as used above):

(12,000 boilers)x(125 MMBtu/hr)x(0.50 retrofit)x(0.50 capacity factor)x

(0.0852 lbs NO_x/MMBtu)x(8760 hrs/yr)/(2000 lbs/ton) = **140,000 tons/year nationally and 11,700 tons/yr in California. The reduction per 125 MMBtu/hr boiler is 11.7 tons/yr.**

Applied to the "addressable" market of all suitable boiler and heater designs, this would provide a significantly larger NO_x savings (on the order of 2 to 3 times larger), but one which is difficult to quantify as accurately.

4.4.2 Energy Savings

Energy savings as a result of implementation of the RSB Boiler-Burner design will result from both reduced fuel usage and reduced electric power consumption. The reduced fuel usage is difficult to quantify. Since almost all boilers can be equipped with additional heat transfer surface to increase efficiency, the claim of increased energy efficiency resulting from the use of one boiler and burner design relative to another must include other assumptions regarding downstream heat recovery equipment.

In section 3.3 a 0.5% increase in efficiency was assumed (80.0 percent for the RSB boiler-burner package and 79.5 percent for a high FGR 9 ppm burner in a standard boiler shell). From a cost effectiveness standpoint, these numbers were justified. From a energy savings standpoint, either system could recover a significant amount of energy by adding a economizer to the basic system, with the economizer adding possibly a 5 percent increase to the thermal efficiency of both systems. From an energy savings standpoint, we will make no claim of fuel savings for the RSB, but we will make the claim that low emissions will be achieved without sacrificing thermal efficiency.

The savings in electric power usage resulting from the use of the RSB boiler-burner package when compared to competing 9 ppm burners is much more significant. In addition, these savings are not application specific (as were the fuel savings estimates), and are benefits that result specifically from the use of the RSB in the new boiler design.

The most common 9 ppm industrial burner on the market today uses approximately 35 percent FGR to control NO_x to the 9 ppm level. When installed in a conventional boiler shell, the fan power required to force this additional mass through the boiler shell increases significantly. It is common to see a burner of this type equipped with a combustion air fan motor that is 2.5 times larger than the fan would be if the burner was operating at 15 percent excess air with no FGR.

A typical boiler with a capacity of 125 MMBtu/hr would require a 100 hp combustion air fan motor when operated at 15 percent excess combustion air. The RSB boiler-burner package is designed as a low pressure drop system that will require the same fan power requirement. As discussed above, the high FGR burner installed in the conventional boiler shell (the approach commonly used today) would require a 250 hp fan motor, or an increased fan power requirement of 150 hp per boiler. Using the same assumptions of market size used for the environmental calculation results in the following:

(12,000 boilers)(150 hp)(.746 kW/hp)(0.50 retrofit)(0.50 capacity factor)(8760 hrs/yr) = 2.9 billion kwh of electricity per year.

Assuming that this electricity is generated from fossil fuels in a plant with a conversation efficiency of 40 percent, the fossil fuel energy that is saved by using the RSB is calculated to be 25.1×10^{12} Btu/hr. Applied to the "addressable" market of all suitable boiler and heater designs, this would provide a significantly larger energy savings (on the order of 2 to 3 times larger), but one which is difficult to quantify as accurately.

SECTION 5
FIELD DEMONSTRATION

In July of 1999, the RSB field demonstration was completed at the Cribari Winery in Fresno, California. The field demonstration boiler was an industrial package boiler with a required capacity of 50 thousand pounds per hour of steam. A description of field demonstration partners and a discussion of how the selection of the RSB was made is presented as Section 5.1. Specifications for the burner and boiler, and a comparison to the performance of a low-NO_x 30 ppm burner are presented in Section 5.2. Installation and startup are described in Section 5.3. Source test and thermal efficiency test results are presented in Section 5.4.

5.1 OBTAINING THE FIELD TEST COMMITMENT

The Cribari Winery in Fresno, California is owned by Canandaigua Wine Company of Canandaigua, New York. Cribari required additional steam capacity, and made the decision to purchase a new boiler in early 1999. The Cribari site is located in the San Joaquin Valley Air Pollution Control District (SJVAPCD). This air district is responsible for air quality in the California Central Valley from approximately Stockton south to Bakersfield. In the Spring of 1999, the Air District lowered the required NO_x emissions level for industrial boilers with capacity of 20 MMBtu/hr or greater to 9 ppm.

Cribari solicited competitive bids to provide 50 thousand lb/hr of steam capacity. Primary concerns expressed by the customer, in addition to meeting the required 9 ppm NO_x emissions level, were:

- Minimizing technical risk and operational complexity
- Meeting a relatively tight schedule to have the boiler installed and operational by the summer of 1999.
- Providing the above at low cost

The Alzeta RSB was bid to the customer by Nationwide Boiler or Fremont, California. Competition included the Todd RMB 9 ppm burner, as well as two stack treatment technologies, Selective Catalytic Reduction and Low Temperature Oxidation. Nationwide Boiler was awarded the contract to supply the RSB to the customer packaged in a used Nebraska rental boiler. Nationwide Boiler was the supplier to the customer. Alzeta Corporation supplied the RSB to Nationwide to install in the boiler. Nationwide also had responsibility for boiler installation, but installation and startup support was provided by Alzeta and the Northern California sales representative, California Power Equipment of Modesto, California as part of the DOE project.

5.2 BOILER AND BURNER SPECIFICATION

The boiler furnished to the customer by NBI was manufactured by Nebraska Boiler Company of Lincoln, Nebraska. The boiler was of the industrial package boiler '"O" configuration, and had a nameplate capacity of 60,000 lb/hr. Previous operating data for an identical boiler at NBI equipped with a 30 ppm burner provided the baseline comparison for the field demonstration.

Specifications for the Nebraska Boiler when operated with natural gas were as follows:

Capacity:	60,000 lb/hr steam
Steam Pressure:	100 psig
Saturated Steam Temperature:	337°F
Feed Water Supply Temperature:	212°F
Fuel Input:	76.9 MMBtu/hr
Excess Air at Capacity:	10%
Combustion Air Temperature:	80°F
Stack Temperature:	505°F
Thermal Efficiency (HHV):	78.92%

Although the boiler was designed to have a capacity of 60,000 lb/hr, the customer required only 50,000 lb/hr of steam, and the boiler was sold as such to the customer. NBI had the 60,000 lb/hr boiler available to sell, had previous experience with a 30 ppm burner that had difficulty providing 40,000 lb/hr in the identical Nebraska Boiler shell, and therefore was willing to sell the boiler as a de-rated unit.

Alzeta burner specifications are presented as Appendix E and summarized below:

Model Number:	CSB30-3SO-30/30/EC
Windbox Size:	Re-use existing Nebraska Boiler Windbox
Heat Input:	64.0 MMBtu/hr
Fuel:	Natural Gas
Turndown:	6:1
Burner Pressure Drop (100°F):	8 in. w.c.
Air Flow Required at Full Load:	17,600 scfm
Emissions Guarantee:	
NO_x	9 ppm at 3% O_2 dry
CO	50 ppm at 3% O_2 dry
VOC	10 ppm at 3% O_2 dry
Excess Air	65%
FD Fan:	Chicago PFD 4014-1904 100 hp
Damper Type:	Parallel plane exit damper
Air Filter:	Maxiflow 3000

5.3 BASELINE BURNER COMPARISON

No source test data were available for the Nebraska boiler sold to the Cribari Winery, and at the time that the sale was made there was not a working burner installed in the boiler. Fortunately, NBI had an identical boiler in their fleet and they were able to provide the results of the 30 ppm source test from the identical system.

The boiler was a Nebraska Boiler, Model O, and was equipped with a Nebraska Mark I natural gas fired burner rated at 83 MMBtu/hr. The burner was equipped with FGR to achieve the 30 ppm NO_x level. Emissions results for the Mark 1 burner in the Nebraska Boiler were as follows:

Source Test Results - 30 ppm NO_x Baseline Burner

Operating Point	NO_x ppm @3% O_2	CO ppm @3% O_2	NO_x Limit ppm	CO Limit ppm
Normal	22.4	4.5	30	400
Maximum	25.0	67.5	30	400
Minimum	25.7	88.7	30	400

Although the results met the regulatory requirements that existed at the time, it has been reported by NBU that the burner could not operate at greater than approximately 40,000 lb/hr capacity, and therefore was derated significantly to meet the 30 ppm NO_x level.

5.4 INSTALLATION AND STARTUP, SOURCE TEST, EFFICIENCY TEST

The burner was installed at NBI in Fremont prior to shipment to the job site. In July, 1999 the boiler was set in place. Burner light-off and a boil out of the system were competed on July 26, and burner tuning was scheduled for the following day. A photograph of the boiler being installed is shown as Figure 5-1. The burner during operation at the 9 ppm NO_x level is shown as Figure 5-2.

On July 27, the burner was tuned to the 9 ppm NO_x emissions level over a 4:1 turndown range, with the burner achieving a higher turndown as required by the performance guarantee. Note that burner turndown is 6:1 and emissions are guaranteed over a 4:1 range. Tuning was completed in one day, and operation of the boiler was turned over to the customer.

The source test was scheduled for September 28, and NBI, Alzeta, and CPE personnel were present. The district required that 3 separate tests of 30 minute duration be completed, and then the results averaged to determine the operating level. A copy of the emissions report is contained in Appendix F. Results for the RSB were as follows:

Source Test Results - Alzeta RSB 9 ppm Burner

Test Point	NO_x ppm @3% O_2	CO ppm @3% O_2	O_2 %
1	4.8	<1.5	9.07
2	5.1	<1.5	8.93
3	5.3	<1.5	8.83
Average	5.1	<1.5	8.95

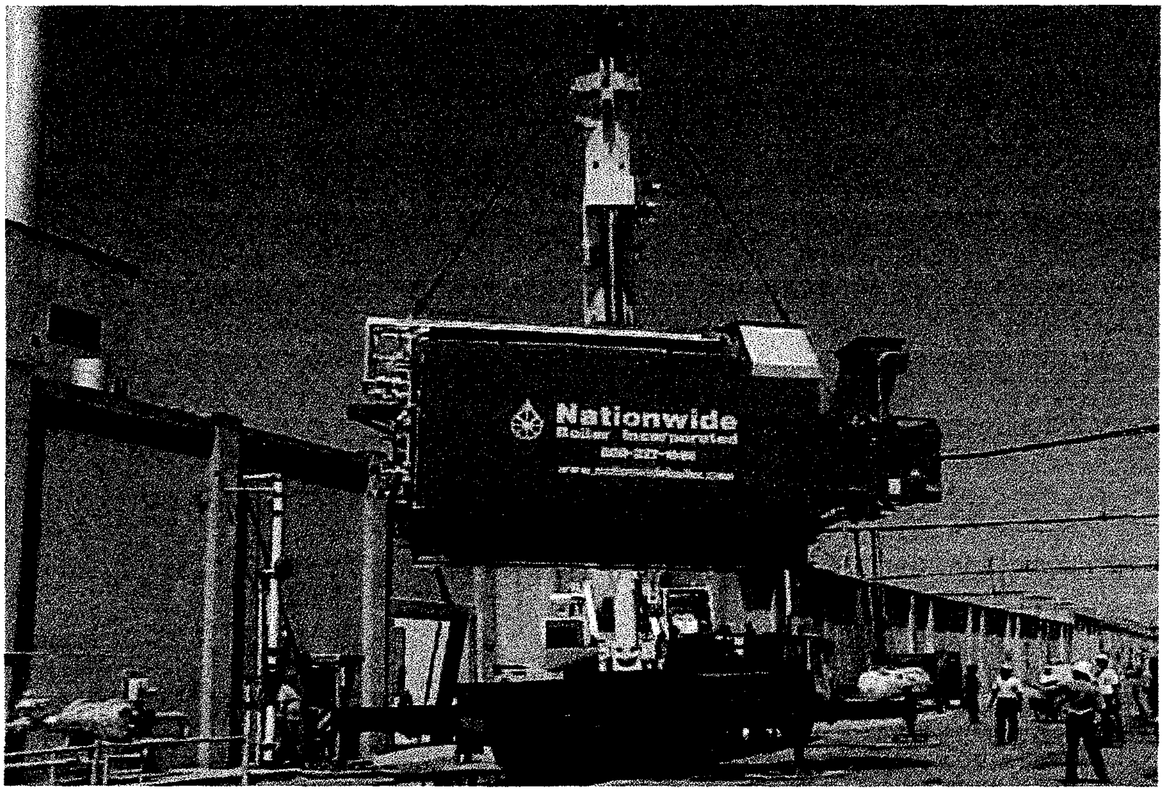

Figure 5-1. Boiler installation at Cribari Winery.

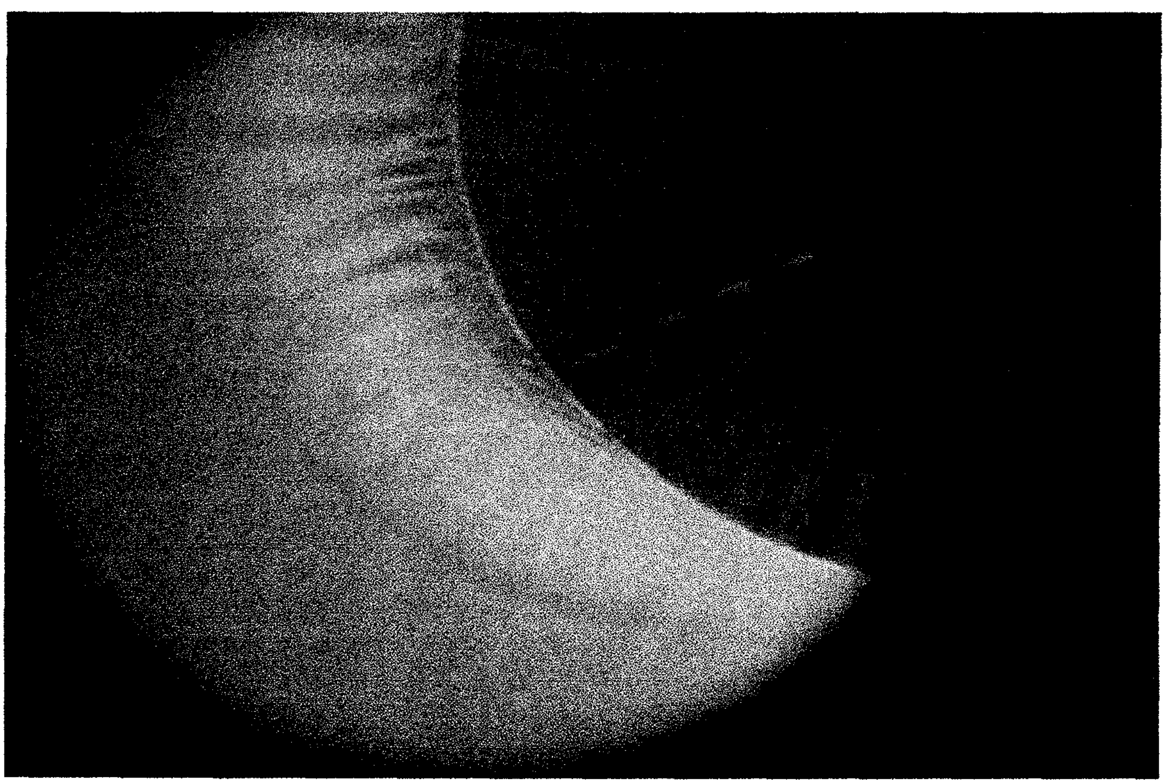

Figure 5-2. The Cribari Winery burner producing 9 ppm NO_x.

The SJVAPCD does not require that efficiency be calculated as part of the source test. Therefore, additional boiler measurements were taken by Alzeta personnel to fill out an ASME short form. The results showed that boiler efficiency was 80.9% based on HHV, which exceeded the Alzeta and NBI target of 80 percent. A copy of the ASME short form is also presented in Appendix F.

5.5 Startup was completed in one day, a rare occurrence in the boiler industry for a 9 ppm burner.

- NO_x emissions as measured in the source test were actually 5.1 ppm, which his well below the 9 ppm guarantee. CO emissions were less than 1.5 ppm.
- Efficiency of 80.9% with a moderately sized economizer shows that the simple Alzeta system (simple controls, no FGR, passive components such as the economizer) can provide a good balance of low first cost and high efficiency.
- The customer has now been operating the boiler continuously since the startup date, which was in July of 1999.

SECTION 6

SUMMARY OF RESULTS AND CONCLUSIONS

A summary of the most significant results of the DOE-funded RSB development and demonstration effort are discussed below. Conclusions based on these results are also summarized, including recommendations of areas where additional work should be performed.

6.1 GENERAL OVERVIEW

Prior to the development of the RSB, porous surface radiant burners found only limited use in industrial applications due primarily to the low surface heat release rate of existing burner designs. Fragility of very large porous ceramic burners was also a concern, as was the high cost, on a "per Btu" basis, of sintered metal burners.

By increasing the surface heat release rate of the RSB by approximately a factor of ten over the earlier fully radiant designs, the RSB made possible the use of single burner elements in applications with capacities of up to 180 MMBtu/hr. The RSB can therefore be retrofit into existing industrial package boiler designs, and can also be incorporated into more advanced designs that take advantage of the unique operation of the RSB.

6.2 LABORATORY AND FIELD TEST RESULTS

The RSB can be operated as a fully-premixed burner using excess combustion air and gas, or in more elaborate designs, by premixing flue gas with the combustion air-gas mixture prior to combustion. Tests were completed with and without FGR, and with and without combustion air preheat. In the fully premixed mode, it was demonstrated that NO_x emissions can be accurately modeled as a function of adiabatic flame temperature over the full range of test conditions. Emissions are relatively unaffected by burner load and boiler design, making the RSB fairly easy to model over its full range of operation.

In the absence of combustion air preheat, the 9 ppm NO_x emissions level was achieved at a total dilution level of 50 to 60 percent. Combustion air preheat of 500°F to 600°F was shown to increase the amount of total dilution required to achieve a specific

NO_x level. Therefore, combustion air preheat is not viewed as a good method of improving thermal efficiency of the RSB. The addition of combustion air preheat to improve thermal efficiency will require that additional mass flow be added to the burner to reduce the adiabatic flame temperature, which would offset most of the advantage gained by preheat. The use of an economizer to transfer additional flue gas energy to the water side of the boiler was shown to provide a greater performance advantage.

Combustion air preheat is rare in the industrial boiler industry. The use of an economizer to preheat boiler feed water is much more common. Although there is some sensible heat in the flue gas used in an FGR system, the total increase in temperature of the mixed FGR-air stream is on the order of 100°F. Therefore, in most instances total dilution with flue gas and air is sufficient to predict the emissions performance of a burner.

The RSB has been demonstrated to have very low emissions of CO simultaneously with sub-9 ppm NO_x emissions. Single digit CO emissions are typical. In laboratory testing, an unburned hydrocarbon (UHC) analyzer was used during emissions tests. Emissions of UHCs were typically less that 1-2 ppm.

A considerable amount of effort during the project was directed toward the investigation of fuel staging with the RSB as a means of minimizing boiler mass flow, while still achieving low NO_x emissions. The basic approach was to operate the RSB as an ultra-lean first stage combustor, and then stage additional fuel downstream of the burner. Some promising data were recorded, but in general fuel staging was found to be much more difficult to predict and to control than was fully-premixed burner operation. After considerable effort, the decision was made to re-focus the burner development effort on fully premixed operating modes, which include operation with and without FGR, and which can include combustion air preheat.

6.3 OPTIMIZED BURNER-BOILER DESIGN

Having settled on operation with a high level of FGR as the most promising approach to achieving ultra-low emissions and high efficiency, methods of improving upon the basic design of the package boiler were investigated. Characteristics of the RSB that lend themselves well to boiler redesign include the controlled and relatively short flame above the RSB surface and the rapid burnout of CO and hydrocarbons above the burner. These characteristics allowed us to decrease the dimensions of the boiler furnace, which allowed for additional convective heat transfer surface to be added to the package boiler without increasing the boiler footprint.

Only minor changes in package boiler layout were therefore required to achieve very significant improvements in burner performance. These minor changes made it possible for English Boiler of Richmond, Virginia to predict the performance of the new boiler design using an existing boiler code. The design of the first optimized RSB burner-boiler package has been designed and bid to a customer. If performance is as predicted, the customer will be able to achieve sub-9 ppm NO_x emissions at an operating cost that is equivalent to that of today's 30 ppm burner.

6.4 FIELD DEMONSTRATION

The first field demonstration of the 9 ppm RSB was completed in Phase 3 of this project. The field test site was a 50,000 lb/hr package boiler at the Cribari Winery in Fresno, California. The burner was sold to Nationwide Boiler, Incorporated (NBI) of Fremont, CA. NBI installed the burner in a Nebraska package boiler, which was then shipped to the customer site for startup. Boiler tuning to the 9 ppm NO_x level was completed in one day. Third party source test results demonstrated NO_x emissions to be well below the 9 ppm target (5.1 ppm corrected). CO emissions were less than 1.5 ppm, and thermal efficiency was over 80 percent based on fuel higher heating value. All field demonstration objectives were met.

Alzeta has bid a job with a boiler from English Boiler of Richmond, Virginia to supply the modified RSB burner-boiler package to a customer in the California Central Valley. The project is currently under review. This project, if awarded to Alzeta, would provide the first opportunity to demonstrate the full benefits of the RSB product developed in this project, but would be completed outside of the scope of the DOE project. By modifying the package boiler around the RSB, the 9 ppm NO_x emissions level can be achieved without sacrificing thermal efficiency or combustion fan electric power usage.

Completing this sale would allow Alzeta to achieve the stated goal of our DOE effort which was to *"Demonstrate sub-9 ppm NOx and sub 50 ppm CO emissions while operating with thermal efficiency, electric power usage, and a boiler footprint consistent with the current state-of-the-art in 30 ppm burner technology."*

6.5 RECOMMENDATIONS FOR FUTURE WORK

Further RSB development would focus on the following areas:

- Additional testing with FGR and combustion air preheat should be conducted to better understand differences in performance in the sub-5 ppm to sub-9 ppm NO_x emissions range. Although it was believed that high excess air operation would produce less prompt NO_x (and therefore less total NO_x) than high FGR operation, this result was not observed in our tests. Given the current interest in controlling emissions to the 5 ppm level, further study should be conducted using the existing Alzeta facilities.
- Although dilution with air or flue gas works well as a NO_x control technique, it would still be advantageous to achieve the 9 ppm emissions level at 15 percent excess combustion air without FGR. Fuel staging tests conducted in this project were not successful, and the approach that was investigated has been abandoned. Future staging work by Alzeta with the RSB would focus on the utilization of a fully premixed first and second stage. Concepts for achieving this have been proposed to DOE.
- A commercially viable RSB product at the 9 ppm level was developed in the DOE project. Although the Cribari boiler had only been installed for 6 months at the time of this report, approximately five additional sales have been completed in industrial applications with the 9 ppm NO_x emissions guarantee. Future enhancements to the exiting commercial product will focus on improved fuel-air control, reduced costs, and more rugged burner design.

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3. Wilhelm, D.J., Johnson, H.E., and Karp, A.D., "The Potential Cost and Environmental Benefits of Very low Emissions Burners for NO_x Control," Final Report prepared by SFA Pacific, Inc. Mountain View, CA for U.S. Department of Energy, Contract DE-AC01-94FE63260, July 1995.

APPENDIX A

EXCESS AIR DATA

UNILUX BASELINE

DATE	TRIAL	GAS NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc.) %	NOx ppm	Corr. NOx ppm	CO ppm	Corr. CO ppm	UHC ppm	Corr. UHC ppm
06/29/95	1	3.95	3.1	1680.836	54%	870.900	2.8	3.14	17.0%	15.7%	51.9	52.3	1.0	1.0	0.0	0.0
06/29/95	2	5.8	4.4	1960.976	63%	1016.050	3	3.42	18.4%	17.4%	48.0	49.1	3.0	3.1	0.0	0.0
06/29/95	3	4.6	3.6	1800.000	58%	932.642	3	3.42	18.4%	17.4%	48.0	49.1	3.0	3.1	0.0	0.0
06/29/95	4	2.3	2	1293.298	42%	670.102	2.7	2.95	16.3%	14.6%	56.2	56.0	1.0	1.0	0.0	0.0
06/29/95	5	0.9	1	856.838	28%	443.958	3.3	3.49	20.6%	17.8%	44.3	45.5	0.0	0.0	0.0	0.0
06/29/95	6	0.7	1	810.756	26%	420.081	3.2	3.65	19.9%	18.8%	40.2	41.7	0.0	0.0	0.0	0.0
06/29/95	7	6.9	5.2	2172.973	70%	1125.893	3	3.18	18.4%	16.0%	58.6	59.2	4.0	4.0	0.0	0.0
															0.0	0.0
06/30/95	1	4	3.3	1690.654	55%	875.987	3	3.55	18.4%	18.2%	41.8	43.1	1.0	1.0	0.0	0.0
06/30/95	2	7.6	5.7	2319.231	75%	1201.674	2.6	2.84	15.6%	14.0%	80.0	79.3	5.0	5.0	0.0	0.0
06/30/95	3	9.5	7	2499.482	81%	1295.068	3.1	3.54	19.1%	18.1%	54.4	56.1	5.0	5.2	0.0	0.0
06/30/95	4	9	6.8	2275.472	73%	1179.001	4.8	5.3	32.7%	30.2%	18.9	21.7	4.0	4.6	0.0	0.0
06/30/95	5	6.4	5	1914.286	62%	991.858	5	5.28	34.5%	30.0%	18.4	21.1	3.0	3.4	0.0	0.0
06/30/95	6	3.6	3	1484.308	48%	769.071	5	5.41	34.5%	31.0%	13.7	15.8	1.0	1.2	0.0	0.0
06/30/95	7	5.1	4.1	1741.516	56%	902.340	4.8	5.26	32.7%	29.9%	17.1	19.6	2.0	2.3	0.0	0.0
06/30/95	8	1	1.2	841.885	27%	436.210	5.5	6.05	39.2%	36.2%	8.9	10.7	19.0	22.9	6.0	7.2
06/30/95	9	7.6	5.9	2106.550	68%	1091.477	4.9	5.26	33.6%	29.9%	19.0	21.7	4.0	4.6	0.0	0.0
06/30/95	10	1.8	1.8	1064.901	34%	551.762	5	5.49	34.5%	31.7%	12.3	14.3	2.0	2.3	0.0	0.0
09/15/95	1a	9.3	5.8	1814.668	59%	866.440	8	8.92	68.0%	66.0%	1.5	2.3	21.9	32.6	8.1	12.1
09/15/95	1b	9.3	5.8	1814.668	59%	866.440	8	8.92	68.0%	66.0%	1.5	2.3	20.3	30.2	7.9	11.8
09/15/95	1c	9.3	5.8	1814.668	59%	866.440	8	8.92	68.0%	66.0%	1.5	2.2	21.2	31.6	9.9	14.8
09/15/95	1d	9.3	5.8	1814.668	59%	866.440	8	8.93	68.0%	66.2%	1.5	2.2	24.6	36.7	10.0	14.9
09/15/95	2a	9.3	5.8	1818.153	59%	868.104	8	8.92	68.0%	66.0%	1.5	2.2	27.8	41.4	10.0	14.9
09/15/95	2b	9.3	5.8	1818.153	59%	868.104	8	8.91	68.0%	65.9%	1.5	2.2	26.5	39.5	9.1	13.5
09/15/95	2c	9.3	5.8	1818.153	59%	868.104	8	8.89	68.0%	65.7%	1.5	2.3	24.1	35.8	8.0	11.9
09/15/95	2d	9.3	5.8	1818.153	59%	868.104	8	8.88	68.0%	65.5%	1.5	2.2	22.2	33.0	7.8	11.6
09/15/95	2e	9.3	5.8	1818.153	59%	868.104	8	8.87	68.0%	65.4%	1.6	2.3	19.6	29.1	8.0	11.9
09/15/95	3a	9.3	5.8	1819.202	59%	868.605	8	8.92	68.0%	66.0%	1.5	2.2	24.5	36.5	10.0	14.9
09/15/95	3b	9.3	5.8	1819.202	59%	868.605	8	8.91	68.0%	65.9%	1.4	2.1	24.7	36.8	11.5	17.1
09/15/95	3c	9.3	5.8	1819.202	59%	868.605	8	8.95	68.0%	66.4%	1.4	2.1	30.3	45.3	11.0	16.4
09/15/95	3d	9.3	5.8	1819.202	59%	868.605	8	8.94	68.0%	66.3%	1.4	2.1	30.8	46.0	11.0	16.4
09/15/95	4a	9.3	5.8	1804.290	58%	861.485	8	8.84	68.0%	65.0%	1.7	2.4	13.3	19.7	3.8	5.6
09/15/95	4b	9.3	5.8	1804.290	58%	861.485	8	8.86	68.0%	65.3%	1.6	2.3	13.5	20.0	4.7	7.0
09/15/95	4c	9.3	5.8	1804.290	58%	861.485	8	8.87	68.0%	65.4%	1.6	2.3	13.3	19.7	4.5	6.7
09/15/95	4d	9.3	5.8	1804.290	58%	861.485	8	8.87	68.0%	65.4%	1.6	2.3	14.6	21.7	4.5	6.7
09/15/95	5a	9.3	5.85	1799.080	58%	858.997	8	8.71	68.0%	63.4%	1.7	2.5	9.3	13.6	2.2	3.2
09/15/95	5b	9.3	5.85	1799.080	58%	858.997	8	8.73	68.0%	63.6%	1.7	2.5	10.7	15.7	2.8	4.0
09/15/95	5c	9.3	5.85	1799.080	58%	858.997	8	8.73	68.0%	63.6%	1.7	2.5	10.3	15.1	2.3	3.4
09/15/95	5d	9.3	5.85	1799.080	58%	858.997	8	8.73	68.0%	63.6%	1.7	2.5	8.8	12.9	2.4	3.5
09/15/95	5e	9.3	5.85	1799.080	58%	858.997	8	8.74	68.0%	63.8%	1.7	2.5	10.4	15.3	2.5	3.7
09/15/95	6a	9.25	5.8	1785.186	58%	852.363	8	8.77	68.0%	64.1%	1.7	2.5	11.7	17.2	2.9	4.3
09/15/95	6b	9.25	5.8	1785.186	58%	852.363	8	8.74	68.0%	63.8%	1.7	2.5	10.8	15.9	2.6	3.8
09/15/95	6c	9.25	5.8	1785.186	58%	852.363	8	8.75	68.0%	63.9%	1.7	2.5	10.5	15.4	2.3	3.4
09/15/95	6d	9.25	5.8	1785.186	58%	852.363	8	8.77	68.0%	64.1%	1.7	2.5	10.4	15.3	2.3	3.4
09/15/95	8a	0.3	0.6	517.763	17%	247.214	8	7.72	68.0%	52.0%	3.2	4.4	12.5	16.9	4.0	5.4
09/15/95	8b	0.3	0.6	517.763	17%	247.214	8	7.76	68.0%	52.4%	3.1	4.1	12.3	16.7	5.0	6.8
09/15/95	8c	0.3	0.6	517.763	17%	247.214	8	7.84	68.0%	53.3%	2.8	3.9	12.8	17.5	5.4	7.4
09/15/95	8d	0.3	0.6	517.763	17%	247.214	8	7.88	68.0%	53.7%	2.8	3.8	13.8	18.9	6.2	8.5

UNILUX BASELINE

DATE	TRIAL	GAS NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc.) %	NOx ppm	Corr. NOx ppm	CO ppm	Corr. CO ppm	UHC ppm	Corr. UHC ppm
09/15/95	8e	0.3	0.6	517.763	17%	247.214	8	7.93	68.0%	54.3%	2.5	3.5	16.8	23.1	7.3	10.1
09/15/95	9a	0.35	0.65	552.354	18%	263.729	7.75	7.92	64.6%	54.2%	2.4	3.3	21.1	29.0	10.0	13.8
09/15/95	9b	0.35	0.65	552.354	18%	263.729	7.75	8.04	64.6%	55.5%	2.2	3.1	26.3	36.5	12.0	16.7
09/15/95	9c	0.35	0.65	552.354	18%	263.729	7.75	8.05	64.6%	55.6%	2.2	3.1	32.0	44.5	11.0	15.3
09/15/95	9d	0.35	0.65	552.354	18%	263.729	7.75	8.05	64.6%	55.6%	2.3	3.2	30.2	42.0	10.5	14.6
09/15/95	9e	0.35	0.65	552.354	18%	263.729	7.75	7.98	64.6%	54.8%	2.5	3.5	28.5	39.4	8.0	11.1
09/15/95	9f	0.35	0.65	552.354	18%	263.729	7.75	7.88	64.6%	53.7%	2.8	3.9	25.5	35.0	7.2	9.9
09/15/95	11a	0.4	0.6	555.295	18%	265.134	7.4	7.75	60.1%	52.3%	3.2	4.3	9.9	13.4	3.0	4.1
09/15/95	11b	0.4	0.6	555.295	18%	265.134	7.4	7.74	60.1%	52.2%	3.1	4.2	9.9	13.4	3.0	4.1
09/15/95	11c	0.4	0.6	555.295	18%	265.134	7.4	7.75	60.1%	52.3%	3.2	4.4	9.3	12.6	2.5	3.4
09/15/95	11d	0.4	0.6	555.295	18%	265.134	7.4	7.73	60.1%	52.1%	3.1	4.3	7.6	10.3	2.8	3.8
09/18/95	1a	0.65	0.8	815.492	26%	389.369	1.8	1.94	10.4%	9.1%	91.8	86.7	0.0	0.0	0.0	0.0
09/18/95	1b	0.65	0.8	815.492	26%	389.369	1.8	1.95	10.4%	9.2%	87.5	82.7	0.0	0.0	0.0	0.0
09/18/95	1c	0.65	0.8	815.492	26%	389.369	1.8	2.05	10.4%	9.7%	86.8	82.4	0.0	0.0	0.0	0.0
09/18/95	2a	2.2	1.6	1183.815	38%	565.230	3.5	4.18	22.1%	22.2%	34.2	36.6	0.0	0.0	0.0	0.0
09/18/95	2b	2.2	1.6	1183.815	38%	565.230	3.5	4.05	22.1%	21.4%	37.3	39.6	0.0	0.0	0.0	0.0
09/18/95	2c	2.2	1.6	1183.815	38%	565.230	3.5	4	22.1%	21.0%	38.0	40.2	0.0	0.0	0.0	0.0
09/18/95	2d	2.2	1.6	1183.815	38%	565.230	3.5	3.95	22.1%	20.7%	40.0	42.2	0.0	0.0	0.0	0.0
09/18/95	3a	8.15	4.7	2261.498	73%	1079.786	2.75	3.16	16.6%	15.8%	77.1	77.8	3.3	3.3	0.0	0.0
09/18/95	3b	8.15	4.7	2261.498	73%	1079.786	2.75	3.09	16.6%	15.4%	80.1	80.5	3.6	3.6	0.0	0.0
09/18/95	3c	8.15	4.7	2261.498	73%	1079.786	2.75	3.06	16.6%	15.3%	80.1	80.4	4.3	4.3	0.0	0.0
09/18/95	3d	8.15	4.7	2261.498	73%	1079.786	2.75	3.05	16.6%	15.2%	79.9	80.1	4.1	4.1	0.0	0.0
09/18/95	4a	5.4	3.3	1873.034	60%	894.308	1.5	2.2	8.5%	10.5%	88.7	84.9	3.1	3.0	0.0	0.0
09/18/95	4b	5.4	3.3	1873.034	60%	894.308	1.5	2.16	8.5%	10.3%	90.8	86.8	2.6	2.5	0.0	0.0
09/18/95	4c	5.4	3.3	1873.034	60%	894.308	1.5	2.15	8.5%	10.2%	91.2	87.1	3.3	3.2	0.0	0.0
09/18/95	4d	5.4	3.3	1873.034	60%	894.308	1.5	2.11	8.5%	10.0%	91.3	87.0	2.9	2.8	0.0	0.0
09/18/95	4e	5.4	3.3	1873.034	60%	894.308	1.5	2	8.5%	9.4%	96.7	91.6	3.0	2.8	0.0	0.0
09/18/95	5a	7.6	4.6	1956.345	63%	934.086	4.5	5.16	30.1%	29.1%	30.0	34.1	0.6	0.7	0.0	0.0
09/18/95	5b	7.6	4.6	1956.345	63%	934.086	4.5	5.11	30.1%	28.8%	30.5	34.6	0.3	0.3	0.0	0.0
09/18/95	5c	7.6	4.6	1956.345	63%	934.086	4.5	5.08	30.1%	28.5%	30.9	34.9	0.2	0.2	0.0	0.0
09/18/95	5d	7.6	4.6	1956.345	63%	934.086	4.5	5.09	30.1%	28.6%	30.2	34.2	0.2	0.2	0.0	0.0
09/18/95	6	8	5	1754.426	57%	837.676	8	8.63	68.0%	62.4%	3.3	4.8	0.1	0.1	0.0	0.0
09/18/95	7	8.1	5.1	1774.689	57%	847.352	8	8.5	68.0%	60.8%	3.5	5.0	0.0	0.0	0.0	0.0
09/18/95	9	0.6	0.8	584.195	19%	278.932	7.5	8.7	61.4%	63.3%	2.5	3.6	26.8	39.2	5.2	7.6
09/18/95	10	0.6	0.8	704.299	23%	336.278	7.5	8.58	61.4%	61.8%	2.5	3.7	23.0	33.3	6.1	8.8
09/25/95	1a	10.4	5.65	2432.467	78%	1161.417	2.5	4.63	14.9%	25.3%	55.1	60.6	1.5	1.6	0.5	0.5
09/25/95	1b	10.4	5.65	2432.467	78%	1161.417	2.5	4.6	14.9%	25.1%	56.0	61.5	1.8	2.0	0.5	0.5
09/25/95	2a	0.4	0.6	655.583	21%	313.018	2.8	4.02	17.0%	21.2%	47.1	49.9	0.0	0.0	0.2	0.2
09/25/95	2b	0.4	0.6	655.583	21%	313.018	2.8	4.02	17.0%	21.2%	46.8	49.6	0.0	0.0	0.3	0.3
09/25/95	2c	0.4	0.6	655.583	21%	313.018	2.8	4.03	17.0%	21.2%	47.2	50.1	0.4	0.4	0.3	0.3
09/25/95	2d	0.4	0.6	655.583	21%	313.018	2.8	3.93	17.0%	20.6%	50.0	52.7	0.5	0.5	0.3	0.3
08/11/95	1	1.1	1.05	900.057	29%	466.351	4.25	4.77	28.0%	26.3%	20.5	22.7	1	1.1	0	0.0
08/11/95	2	1.1	1.05	900.057	29%	466.351	4.75	5.12	32.3%	28.8%	15.6	17.7	2.2	2.5	0	0.0
08/11/95	3	1.1	1.1	900.057	29%	466.351	5.25	5.68	36.8%	33.2%	10.8	12.7	2.9	3.4	0	0.0
08/11/95	4	1.1	1.1	900.057	29%	466.351	5.5	5.89	39.2%	34.9%	9.4	11.2	3.6	4.3	0	0.0
08/11/95	5	1.1	1.1	900.057	29%	466.351	6.5	6.8	49.5%	42.8%	4.9	6.2	6.8	8.6	1	1.3

UNILUX BASELINE

DATE	TRIAL	GAS NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc.) %	NOx ppm	Corr. NOx ppm	CO ppm	Corr. CO ppm	UHC ppm	Corr. UHC ppm
08/11/95	6	1.1	1.1	900.057	29%	466.351	6	6.46	44.2%	39.7%	5.9	7.3	7.4	9.2	1	1.2
08/11/95	7	1.1	1	900.057	29%	466.351	2.5	2.77	14.9%	13.6%	59.3	58.6	0.3	0.3	0	0.0
08/11/95	8	1.1	1.05	900.057	29%	466.351	3.4	3.65	21.3%	18.8%	37.9	39.3	0	0.0	0	0.0
08/11/95	9	1.1	1.05	900.057	29%	466.351	3.6	4	22.9%	21.0%	30.8	32.6	0	0.0	0	0.0
08/11/95	10	1.1	1.05	900.057	29%	466.351	4	4.25	26.0%	22.7%	26.7	28.7	0	0.0	0	0.0
08/11/95	11	1.1	1.05	900.057	29%	466.351	4.5	4.82	30.1%	26.6%	19.0	21.1	1.3	1.4	0	0.0
08/11/95	12	5	3.1	1813.455	58%	939.614	3.25	3.65	20.2%	18.8%	37.6	39.0	0.6	0.6	0	0.0
08/11/95	13	5	3.15	1813.455	58%	939.614	4.4	4.72	29.3%	25.9%	19.7	21.8	0.1	0.1	0	0.0
08/11/95	14	5	3.2	1813.455	58%	939.614	5	5.42	34.5%	31.1%	13.9	16.1	0	0.0	0	0.0
08/11/95	15	5	3.2	1813.455	58%	939.614	5.5	5.97	39.2%	35.5%	9.9	11.8	2.1	2.5	0	0.0
08/14/95	1	5	3.2	1813.455	58%	939.614	6.5	7.14	49.5%	46.1%	5.4	7.1	0	0.0	1.4	1.8
08/14/95	2	5	3.2	1813.455	58%	939.614	5.8	6.45	42.1%	39.7%	8.0	9.8	2.4	3.0	0.5	0.6
08/14/95	3	5	3.05	1813.455	58%	939.614	3	3.56	18.4%	18.3%	38.3	39.5	1.2	1.2	0	0.0
08/14/95	4	8.5	4.9	2258.786	73%	1170.356	5	5.04	34.5%	28.2%	20.2	22.8	3.2	3.6	0	0.0
08/14/95	5	8.5	4.9	2258.786	73%	1170.356	4.5	4.68	30.1%	25.7%	23.1	25.5	4.3	4.7	0	0.0
08/14/95	6	8.5	4.7	2258.786	73%	1170.356	3.25	3.02	20.2%	15.0%	63.8	63.9	6	6.0	0	0.0
08/14/95	7	8.5	4.75	2258.786	73%	1170.356	3.5	3.39	22.1%	17.2%	55.0	56.2	5.3	5.4	0	0.0
08/14/95	8	8.5	4.65	2258.786	73%	1170.356	2.2	2.01	12.9%	9.5%	100.7	95.5	11.7	11.1	0	0.0
08/14/95	9	8.5	4.65	2258.786	73%	1170.356	1.75	1.52	10.0%	7.0%	117.0	108.1	17.3	16.0	0	0.0
08/14/95	10	8.5	4.6	2258.786	73%	1170.356	1.35	1.1	7.6%	4.9%	133.0	120.3	31	28.0	0	0.0
08/14/95	11	8.5	4.55	2258.786	73%	1170.356	1	0.77	5.5%	3.4%	141.0	125.5	73.6	65.5	0	0.0
08/14/95	12	8.5	4.45	2258.786	73%	1170.356	0.1	0.11	0.5%	0.5%	137.0	118.0	2503	2156.7	0	0.0
08/14/95	13	8.5	4.95	2258.786	73%	1170.356	4.75	4.84	32.3%	26.8%	23.4	26.1	2.8	3.1	0	0.0
08/14/95	14	8.5	5.05	2258.786	73%	1170.356	5.5	5.73	39.2%	33.6%	13.2	15.6	6.5	7.7	0.8	0.9
08/14/95	15	8.5	5.1	2258.786	73%	1170.356	6	6.5	44.2%	40.1%	8.2	10.2	3.9	4.8	0	0.0
08/14/95	16	8.5	5.1	2258.786	73%	1170.356	6.25	6.67	46.8%	41.6%	7.4	9.3	2.9	3.6	0	0.0
08/14/95	17	8.5	5.2	2258.786	73%	1170.356	7	7.57	55.2%	50.4%	4.0	5.4	1.3	1.7	0	0.0
08/14/95	18	8.5	5.5	2258.786	73%	1170.356	6.5	6.91	49.5%	43.9%	6.4	8.1	2.7	3.4	0	0.0

UNILUX FGR

DATE	TRIAL	NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	INLET OXYGEN %	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc. %	Exhaust Mass Basis		Corrected EA+ FGR %	Diluted NOx ppm	Corr. NOx ppm	Diluted CO ppm	Corr. CO ppm	Diluted UHC ppm	Corr. UHC ppm
												FGR RATE %	EA+ FGR %							
07/06/95	1	1.1	1	900.057	34%	466.351	20.9	1.9	2	11.0%	9.4%	0%	11.0%	9.4%	82.0	78.1	0.0	0.0	0.0	0.0
07/06/95	2	10	5.8	2341.230	89%	1213.073	20.9	4.3	5.1	28.4%	28.7%	0%	28.4%	28.7%	23.2	26.4	5.0	5.7	0.0	0.0
07/06/95	3	9	5	2293.495	88%	1188.339	18.5	1.9	2.05	11.0%	9.7%	14%	27.2%	25.5%	46.3	44.2	9.0	8.5	0.0	0.0
07/06/95	4	1.7	1.4	1069.201	41%	553.990	19.5	5	5.3	34.5%	30.2%	10%	47.8%	42.8%	5.7	6.6	1.0	1.1	0.0	0.0
07/13/95	1	0.55	0.7	735.866	28%	381.278	20.9	2.1	2.42	12.3%	11.7%	0%	12.3%	11.7%	75.7	73.7	0.0	0.0	0.0	0.0
07/13/95	2	0.5	0.6	720.506	23%	373.319	19.2	2	2.5	11.6%	12.1%	10%	23.4%	23.5%	19.3	18.9	0.0	0.0	0.0	0.0
07/13/95	3	0.6	0.75	751.154	24%	389.199	18.2	2.1	2.05	12.3%	9.7%	17%	31.2%	28.3%	23.7	22.6	8.0	7.6	0.0	0.0
07/13/95	4	0.55	0.7	735.866	24%	381.278	18.0	1.9	2.45	11.0%	11.8%	18%	31.5%	31.8%	14.2	13.9	14.5	14.1	3.0	2.9
07/13/95	5	0.5	0.7	720.506	23%	373.319	17.3	2.1	2.78	12.3%	13.6%	24%	40.6%	41.0%	8.9	8.8	18.0	17.8	7.0	6.9
07/14/95	1	9	4.9	2293.495	74%	1188.339	20.9	2	2.19	11.6%	10.4%	0%	11.6%	10.4%	100.0	96.2	10.0	9.6	0.0	0.0
07/14/95	2	9	5	2293.495	74%	1188.339	19.4	2.1	2.61	12.3%	12.7%	9%	22.5%	22.6%	50.4	49.6	6.0	5.9	0.0	0.0
07/14/95	3	9	5.3	2293.495	74%	1188.339	18.3	2.2	2.59	12.9%	12.6%	16%	31.6%	30.8%	26.1	25.7	4.0	3.9	0.0	0.0
07/14/95	4	8.7	5.4	2273.537	73%	1177.998	17.9	2.1	2.4	12.3%	11.5%	19%	34.0%	32.7%	17.6	17.1	2.0	1.9	0.0	0.0
07/14/95	5	8.7	5.3	2273.537	73%	1177.998	17.3	0.9	1.54	4.9%	7.1%	22%	28.7%	30.4%	24.4	22.7	13.5	12.5	0.0	0.0
07/14/95	6	8.6	5.2	2266.306	73%	1174.252	17.8	2.2	3	12.9%	14.9%	20%	37.0%	38.2%	13.3	13.4	1.0	1.0	0.0	0.0
07/28/95	1	0.55	0.65	735.866	24%	381.278	20.9	0.6	0.84	3.2%	3.7%	0%	3.2%	3.7%	109.4	98.2	3.0	2.7	0.0	0.0
07/28/95	2	9.5	5	2320.976	75%	1202.578	20.9	2	1.77	11.6%	8.2%	0%	11.6%	8.2%	115.5	108.7	12.0	11.2	0.0	0.0
07/28/95	3	9.4	5.3	2316.058	75%	1200.030	19.0	1.7	2.13	9.7%	10.1%	11%	21.9%	22.0%	44.1	42.3	10.0	9.5	0.0	0.0
07/28/95	4	9.5	5.3	2320.976	75%	1202.578	19.1	1.2	1.76	6.7%	8.2%	10%	17.8%	19.1%	52.4	49.3	13.0	12.2	0.0	0.0
07/28/95	5	0.55	0.65	735.866	24%	381.278	19.4	1.9	2.26	11.0%	10.8%	9%	20.9%	20.5%	40.2	38.8	0.0	0.0	0.0	0.0
07/28/95	6	0.45	0.6	705.074	23%	365.323	19.1	2.1	2.45	12.3%	11.8%	11%	24.4%	23.7%	31.2	30.4	0.0	0.0	0.0	0.0
07/28/95	7	0.45	0.6	705.074	23%	365.323	18.7	1.8	2.26	10.4%	10.8%	13%	25.5%	25.6%	27.4	26.5	2.0	1.9	0.0	0.0
07/28/95	8	0.4	0.6	689.569	22%	357.290	18.1	2.1	2.4	12.3%	11.5%	18%	32.7%	31.5%	23.4	22.8	3.0	2.9	0.0	0.0
07/31/95	1	0.55	0.7	735.866	24%	381.278	17.9	0.75	1.02	4.1%	4.6%	17%	22.6%	22.9%	34.9	31.4	50.0	45.0	2.0	1.8
07/31/95	2	0.45	0.7	705.074	23%	365.323	16.6		1.51		6.9%	26%	28.3%	34.4%			12.0	11.1	3.0	2.8
07/31/95	3	8.9	5.2	2287.131	74%	1185.042	17.5	0.8	1.46	4.4%	6.7%	21%	26.9%	28.8%	31.2	28.7	17.0	15.7	0.0	0.0
07/31/95	4	8.4	5.2	2250.977	73%	1166.309	17.0	2	2.72	11.6%	13.3%	26%	42.4%	43.0%	14.9	14.7	1.0	1.0	0.0	0.0
07/31/95	5	9		2293.495	74%	1188.339	19.2	1.05	1.28	5.8%	5.8%	9%	15.7%	15.6%			18.0	16.4	0.0	0.0
07/31/95	6	8.7	5	2273.537	73%	1177.998	18.0	0.8	1	4.4%	4.5%	17%	22.5%	22.4%	48.6	43.7	30.0	27.0	4.0	3.6

DATE	TRIAL	GAS NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	INLET OXYGEN %	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc.) %	Preheat Inlet Temperature F	Preheat Enthalpy h Btu/lb	Adiabatic Flame Temperature (°F)	NOx ppm	Corr. NOx ppm	CO ppm	Corr. CO ppm	UHC ppm	Corr. UHC ppm
10/04/95	1a	1	1.1	862.19	28%	411.67	25.0	5	5.6	34.5%	32.5%	289	55.63	3139	22.3	26.1	12.7	0	0.4	0
10/04/95	2a	over 10	7.2	2712.82	88%	1295.28	25.0	4.25	5.47	28.0%	31.5%	227	40.48	3116	29.5	34.2	1.1	0	0.4	0
10/04/95	3a	over 10	7.2	2684.87	87%	1281.93	25.0	2.5	3.13	14.9%	15.7%	227	40.48	3380	104.0	104.8	5.1	0	0.4	0
10/04/95	4a	over 10	7.2	2330.33	75%	1112.65	25.0	5	5.87	34.5%	34.7%	227	40.48	3066	23.0	27.4	0.6	0	0.4	0
10/04/95	4b	over 10	7.2	2330.33	75%	1112.65	25.0	5	5.82	34.5%	34.3%	227	40.48	3072	23.6	28.0	0.3	0	0.3	0
10/04/95	5a	over 10	7.2	2601.89	84%	1242.31	25.0	3.1	3.75	19.1%	19.4%	228	40.73	3317	80.5	84.0	3.1	0	0.5	0
10/04/95	5b	over 10	7.2	2601.89	84%	1242.31	25.0	3.1	3.75	19.1%	19.4%	228	40.73	3317	79.9	83.4	2.8	0	0.4	0
10/04/95	5c	over 10	7.2	2601.89	84%	1242.31	25.0	3.1	3.77	19.1%	19.6%	228	40.73	3314	79.4	82.9	4.0	0	0.4	0
10/04/95	6a	over 10	7.2	2093.52	68%	999.58	25.0	6.5	7.6	49.5%	50.7%	228	40.73	2837	7.2	9.7	0.2	0	0.3	0
10/04/95	6b	over 10	7.2	2093.52	68%	999.58	25.0	6.5	7.6	49.5%	50.7%	228	40.73	2837	7.2	9.6	0.2	0	0.2	0
10/04/95	6c	over 10	7.2	2093.52	68%	999.58	25.0	6.5	7.61	49.5%	50.8%	228	40.73	2836	7.0	9.4	0.0	0	0.2	0
10/04/95	7a	over 10	7.1	2262.28	73%	1080.16	25.0	5.25	6.35	36.8%	38.7%	228	40.73	3006	17.1	21.0	0.7	0	0.0	0
10/04/95	7b	over 10	7.1	2262.28	73%	1080.16	25.0	5.25	6.32	36.8%	38.5%	228	40.73	3009	17.0	20.8	0.2	0	0.0	0
10/04/95	7c	over 10	7.1	2262.28	73%	1080.16	25.0	5.25	6.33	36.8%	38.6%	228	40.73	3008	16.8	20.6	0.2	0	0.0	0
10/04/95	8a	over 10	7.5	2303.44	74%	1099.81	25.0	4.4	4.99	29.3%	27.8%	350	70.61	3250	49.8	56.0	1.6	0	13.0	15
10/04/95	8b	over 10	7.5	2303.44	74%	1099.81	25.0	4.4	4.96	29.3%	27.6%	350	70.61	3253	49.9	56.0	1.1	0	11.0	12
10/04/95	8c	over 10	7.5	2303.44	74%	1099.81	25.0	4.4	4.95	29.3%	27.6%	350	70.61	3253	50.0	56.1	0.6	0	12.0	13
10/04/95	9a	over 10	7.6	2501.03	81%	1194.15	25.0	2.5	3.01	14.9%	15.0%	360	73.07	3462	126.0	126.1	4.4	0	0.3	0
10/04/95	9b	over 10	7.6	2501.03	81%	1194.15	25.0	2.5	3	14.9%	14.9%	360	73.07	3464	127.0	127.0	4.2	0	0.5	1
10/04/95	10a	over 10	7.6	2020.43	65%	964.68	25.0	6.25	7.06	46.8%	45.2%	361	73.32	3000	14.5	18.7	0.1	0	0.0	0
10/04/95	10b	over 10	7.6	2020.43	65%	964.68	25.0	6.25	7.02	46.8%	44.9%	361	73.32	3003	14.4	18.5	0.1	0	0.0	0
10/04/95	10c	over 10	7.6	2020.43	65%	964.68	25.0	6.25	6.99	46.8%	44.6%	361	73.32	3008	14.5	18.6	0.0	0	0.0	0
10/04/95	11a	over 10	7.6	2385.75	77%	1139.11	25.0	3.5	4.06	22.1%	21.4%	357	72.33	3357	80.9	86.0	2.7	0	4.0	4
10/04/95	11b	over 10	7.6	2385.75	77%	1139.11	25.0	3.5	4.02	22.1%	21.2%	357	72.33	3360	82.7	87.7	2.1	0	3.4	4
10/04/95	11c	over 10	7.6	2385.75	77%	1139.11	25.0	3.5	4	22.1%	21.0%	357	72.33	3363	82.5	87.4	2.7	0	3.6	4
10/04/95	13a	over 10	7.8	2400.59	77%	1146.20	25.0	2.75	3.07	16.6%	15.3%	447	94.58	3503	131.0	131.5	4.0	0	0.0	0
10/04/95	13b	over 10	7.8	2400.59	77%	1146.20	25.0	2.75	3.13	16.6%	15.7%	447	94.58	3497	132.0	133.0	4.9	0	0.0	0
10/04/95	13c	over 10	7.8	2400.59	77%	1146.20	25.0	2.75	3.14	16.6%	15.7%	447	94.58	3497	132.0	133.0	4.5	0	0.0	0
10/04/95	14a	over 10	7.9	1920.47	62%	916.96	25.0	6.25	7.14	46.8%	46.0%	449	95.07	3047	16.1	20.9	0.0	0	4.0	5
10/04/95	14b	over 10	7.9	1920.47	62%	916.96	25.0	6.25	7.14	46.8%	46.0%	449	95.07	3047	15.9	20.6	0.0	0	3.4	4
10/04/95	14c	over 10	7.9	1920.47	62%	916.96	25.0	6.25	7.12	46.8%	45.8%	449	95.07	3049	16.1	20.9	0.0	0	3.6	5
10/04/95	15a	over 10	7.8	2299.68	74%	1098.02	25.0	3.5	3.86	22.1%	20.1%	456	96.81	3433	102.3	107.4	2.6	0	0.0	0
10/04/95	15b	over 10	7.8	2299.68	74%	1098.02	25.0	3.5	3.79	22.1%	19.7%	456	96.81	3439	102.4	107.1	3.2	0	0.0	0
10/04/95	15c	over 10	7.8	2299.68	74%	1098.02	25.0	3.5	3.8	22.1%	19.7%	456	96.81	3439	102.5	107.3	4.0	0	0.0	0
10/04/95	16a	over 10	7.8	2108.72	68%	1006.84	25.0	5	5.45	34.5%	31.3%	458	97.31	3261	43.3	50.1	0.4	0	4.0	5
10/04/95	16b	over 10	7.8	2108.72	68%	1006.84	25.0	5	5.48	34.5%	31.5%	458	97.31	3258	42.7	49.5	0.1	0	3.4	4
10/04/95	16c	over 10	7.8	2108.72	68%	1006.84	25.0	5	5.49	34.5%	31.6%	458	97.31	3257	42.7	49.6	0.6	0	3.6	4
10/04/95	17a	over 10	7.8	1662.67	54%	793.87	25.0	8.4	9.23	73.6%	70.1%	450	95.32	2758	3.7	5.6	1.5	2	13.0	20
10/04/95	17b	over 10	7.8	1662.67	54%	793.87	25.0	8.4	9.19	73.6%	69.5%	450	95.32	2764	3.7	5.6	2.3	4	11.0	17
10/04/95	17c	over 10	7.8	1662.67	54%	793.87	25.0	8.4	9.15	73.6%	69.0%	450	95.32	2769	3.7	5.6	1.6	2	12.0	18
10/04/95	17d	over 10	7.8	1662.67	54%	793.87	25.0	8.4	9.14	73.6%	68.8%	450	95.32	2772	3.7	5.6	0.8	1	13.0	20
10/04/95	17e	over 10	7.8	1662.67	54%	793.87	25.0	8.4	9.16	73.6%	69.1%	450	95.32	2768	3.6	5.4	0.8	1	13.0	20
10/04/95	18a	over 10	7.8	1584.78	51%	756.68	25.0	9	9.76	82.8%	77.6%	455	96.56	2683	2.3	3.6	12.9	21	4.0	6
10/04/95	18b	over 10	7.8	1584.78	51%	756.68	25.0	9	9.78	82.8%	77.9%	455	96.56	2680	2.2	3.5	12.5	20	3.4	5
10/04/95	18c	over 10	7.8	1584.78	51%	756.68	25.0	9	9.77	82.8%	77.7%	455	96.56	2682	2.2	3.5	13.0	21	3.6	6
10/12/95	1a	15.5	7.2	2393.41	77%	1142.77	25.0	3.1	3.75	19.1%	19.4%	499	107.51	3467	80.5	84.0	3.1	0	0.5	0
10/12/95	1b	15.5	7.2	2393.41	77%	1142.77	25.0	3.1	3.75	19.1%	19.4%	499	107.51	3467	79.9	83.4	2.8	0	0.4	0
10/12/95	1c	15.5	7.2	2393.41	77%	1142.77	25.0	3.1	3.77	19.1%	19.6%	499	107.51	3464	79.4	82.9	4.0	0	0.4	0
10/12/95	2a	16.5	7.2	2802.65	90%	1338.17	25.0	6.5	7.6	49.5%	50.7%	500	107.76	3019	7.2	9.7	0.2	0	0.3	0
10/12/95	2b	16.5	7.2	2802.65	90%	1338.17	25.0	6.5	7.6	49.5%	50.7%	500	107.76	3019	7.2	9.6	0.2	0	0.2	0
10/12/95	2c	16.5	7.2	2802.65	90%	1338.17	25.0	6.5	7.61	49.5%	50.8%	500	107.76	3018	7.0	9.4	0.0	0	0.2	0
10/12/95	3a	16.25	7.1	2688.77	87%	1283.79	25.0	5.25	6.35	36.8%	38.7%	500	107.76	3180	17.1	21.0	0.7	0	0.0	0
10/12/95	3b	16.25	7.1	2688.77	87%	1283.79	25.0	5.25	6.32	36.8%	38.5%	500	107.76	3182	17.0	20.8	0.2	0	0.0	0
10/12/95	3c	16.25	7.1	2688.77	87%	1283.79	25.0	5.25	6.33	36.8%	38.6%	500	107.76	3181	16.8	20.6	0.2	0	0.0	0
10/12/95	4a	15.5	7.5	2235.95	72%	1067.59	25.0	4.4	4.99	29.3%	27.8%	499	107.51	3339	49.8	56.0	1.6	0	13.0	15
10/12/95	4b	15.5	7.5	2235.95	72%	1067.59	25.0	4.4	4.96	29.3%	27.6%	499	107.51	3342	49.9	56.0	1.1	0	11.0	12
10/12/95	4c	15.5	7.5	2235.95	72%	1067.59	25.0	4.4	4.95	29.3%	27.6%	499	107.51	3342	50.0	56.1	0.6	0	12.0	13
10/12/95	5a	15.5	7.2	2155.22	70%	1029.04	25.0	3.1	3.75	19.1%	19.4%	498	107.26	3467	80.5	84.0	3.1	0	0.5	0
10/12/95	5b	15.5	7.2	2155.22	70%	1029.04	25.0	3.1	3.75	19.1%	19.4%	498	107.26	3467	79.9	83.4	2.8	0	0.4	0
10/12/95	5c	15.5	7.2	2155.22	70%	1029.04	25.0	3.1	3.77	19.1%	19.6%	498	107.26	3464	79.4	82.9	4.0	0	0.4	0
10/12/95	6a	15.5	7.2	1998.90	64%	954.40	25.0	6.5	7.6	49.5%	50.7%	499	107.51	3018	7.2	9.7	0.2	0	0.3	0
10/12/95	6b	15.5	7.2	1998.90	64%	954.40	25.0	6.5	7.6	49.5%	50.7%	499	107.51	3018	7.2	9.6	0.2	0	0.2	0
10/12/95	6c	15.5	7.2	1998.90	64%	954.40	25.0	6.5	7.61	49.5%	50.8%	499	107.51	3017	7.0	9.4	0.0	0	0.2	0

												Exhaust Mass Basis												
DATE	TRIAL	NOZZLE PRESS. in wc	BURNER PRESS. in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	INLET OXYGEN %	PREMIX OXYGEN %	STACK OXYGEN %	Excess Air (Premix Calc.) %	Excess Air (Stack Calc.) %	FGR RATE %	Premix EA+ FGR %	Stack EA+ FGR %	Preheat Inlet Temperature F	Preheat Enthalpy h Btu/lb	Adiabatic Flame Temperature (°F)	Diluted NOx ppm	Corr. NOx ppm	Diluted CO ppm	Corr. CO ppm	Diluted UHC ppm	Corr. UHC ppm
10/09/95	1*	14	8.2	2223.18	78%	1061.49	20.5	2.6%	4.38%	15.6%	23.6%	2.2%	18.2%	26.3%	463	193	3340.8	57	62	1.4	2	0.0	0
10/09/95	2*	14	8.25	1988.18	71%	949.29	20.5	4.0%	6.45%	26.0%	39.7%	2.0%	28.5%	42.4%	471	199	3115.0	18.7	23	0.0	0	0.0	0
10/09/95	3*	14	8.2	2137.07	75%	1020.37	20.5	3.0%	5.18%	18.4%	29.3%	2.0%	20.7%	31.8%	474	199	3265.5	39.5	45	0.0	0	0.0	0
10/09/95	4*	14	8.3	2087.14	74%	996.53	20.5	3.5%	5.59%	22.1%	32.4%	2.2%	24.8%	35.4%	473	199	3214.0	31	36	1.0	1	0.0	0
10/09/95	5*	14	8.2	2017.15	72%	963.12	20.5	3.8%	6.29%	24.0%	38.2%	1.8%	26.3%	40.8%	477	203	3140.4	21	26	0.4	0	0.5	1
10/09/95	6*	13.75	8	1902.70	68%	908.47	19.7	3.3%	5.51%	20.2%	31.8%	6.4%	27.9%	40.2%	495	190	3165.8	16.2	19	0.6	1	0.1	0
10/09/95	7*	13.75	8.1	1902.70	67%	908.47	19.8	2.8%	5.19%	17.0%	29.4%	5.8%	23.8%	36.9%	499	189	3211.9	21.3	24	0.2	0	0.0	0
10/09/95	8*	13.75	8.1	2053.72	72%	980.58	19.5	2.0%	3.98%	11.6%	20.9%	7.2%	19.7%	29.6%	500	191	3311.3	36.7	39	0.9	1	0.0	0
10/09/95	9*	13.75	7.8	1992.48	70%	951.34	18.5	0.5%	3.16%	2.7%	15.8%	13.3%	16.4%	31.3%	517	184	3287.9	26.2	26	1.7	2	0.0	0
10/09/95	10A*	13.25	7.8	1955.17	69%	933.53	18.2	1.3%	3.31%	7.0%	16.7%	15.2%	23.2%	34.5%	539	191	3257.3	27.5	28	1.5	2	0.0	0
10/09/95	10B*	13.25	7.8	1955.17	69%	933.53	17.4	1.0%	3.31%	5.5%	16.7%	20.3%	27.0%	40.5%	539	191	3174.9	27.5	28	1.5	2	0.0	0
10/09/95	11*	13	7.9	1896.20	67%	905.37	18.0	1.6%	3.83%	9.1%	20.0%	16.0%	26.6%	39.1%	521	183	3189.6	19.7	21	2.1	2	0.0	0
10/09/95	12*	13	7.8	2043.67	72%	975.78	18.5	0.0%	1.98%	0.0%	9.3%	13.1%	13.1%	23.7%	520	180	3382.4	38.9	37	4.2	4	0.0	0
10/09/95	13*	13	7.8	1918.26	68%	915.90	18.6	1.3%	3.50%	7.0%	17.9%	12.5%	20.4%	32.7%	520	182	3274.0	23.5	24	1.2	1	0.0	0
10/10/95	1	14.25	8.65	2257.75	80%	1078.00	18.2	2.4%	1.33%	14.3%	6.0%	15.2%	31.6%	22.1%	566	212	3412.8	58.9	54	5.1	5	0.0	0
10/10/95	2	14.25	8.6	2203.02	78%	1051.87	18.1	2.2%	1.32%	12.9%	6.0%	15.6%	30.6%	22.6%	567	207	3405.7	46.8	43	6.4	6	0.0	0
10/10/95	3	14.25	8.55	2133.28	75%	1018.56	18.1	3.0%	1.85%	18.4%	8.6%	15.5%	36.8%	25.5%	563	204	3373.9	40.7	38	3.4	3	0.0	0
10/10/95	4	14	8.6	2045.27	73%	976.55	18.2	4.0%	2.76%	26.0%	13.5%	15.2%	45.1%	30.8%	562	204	3314.3	31.4	31	1.3	1	0.0	0
10/10/95	5	14	8.6	1968.52	70%	939.90	18.0	4.6%	3.33%	31.0%	16.9%	16.0%	51.9%	35.5%	566	204	3258.8	23.1	24	0.4	0	0.0	0
10/10/95	6	13.75	8.3	1882.24	67%	898.70	17.2	4.1%	2.74%	26.6%	13.4%	21.5%	53.9%	37.9%	576	193	3221.1	17.8	18	2.2	2	0.0	0
10/10/95	7	13.75	8.3	1963.90	69%	937.69	17.0	3.3%	1.68%	20.2%	7.8%	23.0%	47.8%	32.5%	573	190	3266.3	23.5	22	3.5	3	0.0	0
10/10/95	8A	13.75	8.3	2036.38	72%	972.30	17.0	2.3%	0.86%	13.6%	3.8%	23.3%	40.1%	28.0%	574	190	3304.7	27.7	25	120.5	108	0.4	0
10/10/95	8B	13.75	8.3	2036.38	72%	972.30	17.0	2.3%	0.87%	13.6%	3.9%	23.3%	40.1%	28.1%	574	190	3304.2	26.9	24	61.8	55	0.8	1
10/12/95	7	13.5	7.9	1857.35	66%	886.82	17.1	2.8%	2.84%	17.0%	14.0%	22.3%	43.0%	39.4%	572	190	3200.4	15.3	15	1.1	1	0.0	0
10/12/95	8	13.75	8.2	1808.24	64%	863.37	16.4	2.0%	2.20%	11.6%	10.5%	27.9%	42.7%	41.3%	577	181	3160.9	13.3	13	12.8	12	7.1	7
10/12/95	9	13.75	8.05	1951.31	69%	931.68	15.9	0.5%	0.41%	2.7%	1.8%	31.5%	35.0%	33.8%	583	182	3198.5	19.6	17	420.0	367	2.0	2
10/12/95	10	13.25	8.2	1779.73	63%	849.76	16.4	1.3%	2.61%	7.0%	12.7%	27.3%	36.2%	43.4%	576	181	3142.7	11.2	11	14.8	14	10.0	10
10/12/95	11	13.75	8.2	1895.54	67%	905.05	16.1	1.6%	1.10%	9.1%	4.9%	30.0%	41.9%	36.5%	576	180	3188.4	18.7	17	18.6	17	3.3	3
10/12/95	13	13.5	8.1	1734.74	62%	828.28	15.5	1.3%	1.54%	7.0%	7.1%	35.3%	44.8%	44.9%	593	174	3099.1	12	11	37.1	34	25.0	23
10/12/95	14	13.5	8	1687.92	60%	805.92	15.9	1.6%	2.49%	9.1%	12.0%	31.9%	43.9%	47.8%	591	176	3093.2	8.63	8	54.4	53	44.0	43
10/12/95	15	13.5	8	1635.65	58%	780.97	15.8	0.0%	3.12%	0.0%	15.6%	32.1%	32.1%	52.8%	586	174	3047.3	6.6	7	108.8	110	74.0	74
10/12/95	16	13.5	8	1623.47	58%	775.15	15.8	1.3%	2.95%	7.0%	14.6%	32.3%	41.6%	51.7%	586	171	3055.4	6.59	7	129.2	129	96.0	96
10/12/95	17	13.5	7.9	1613.23	57%	770.26	15.2	0.0%	2.32%	0.0%	11.1%	37.8%	37.8%	53.1%	595	168	3025.1	7.46	7	150.1	145	110.0	106
10/12/95	18	13.5	7.8	1704.82	60%	813.99	14.9	1.3%	1.05%	7.0%	4.7%	40.5%	50.4%	47.1%	594	167	3048.8	11.5	10	155.4	140	80.0	72

*Data not included in plots

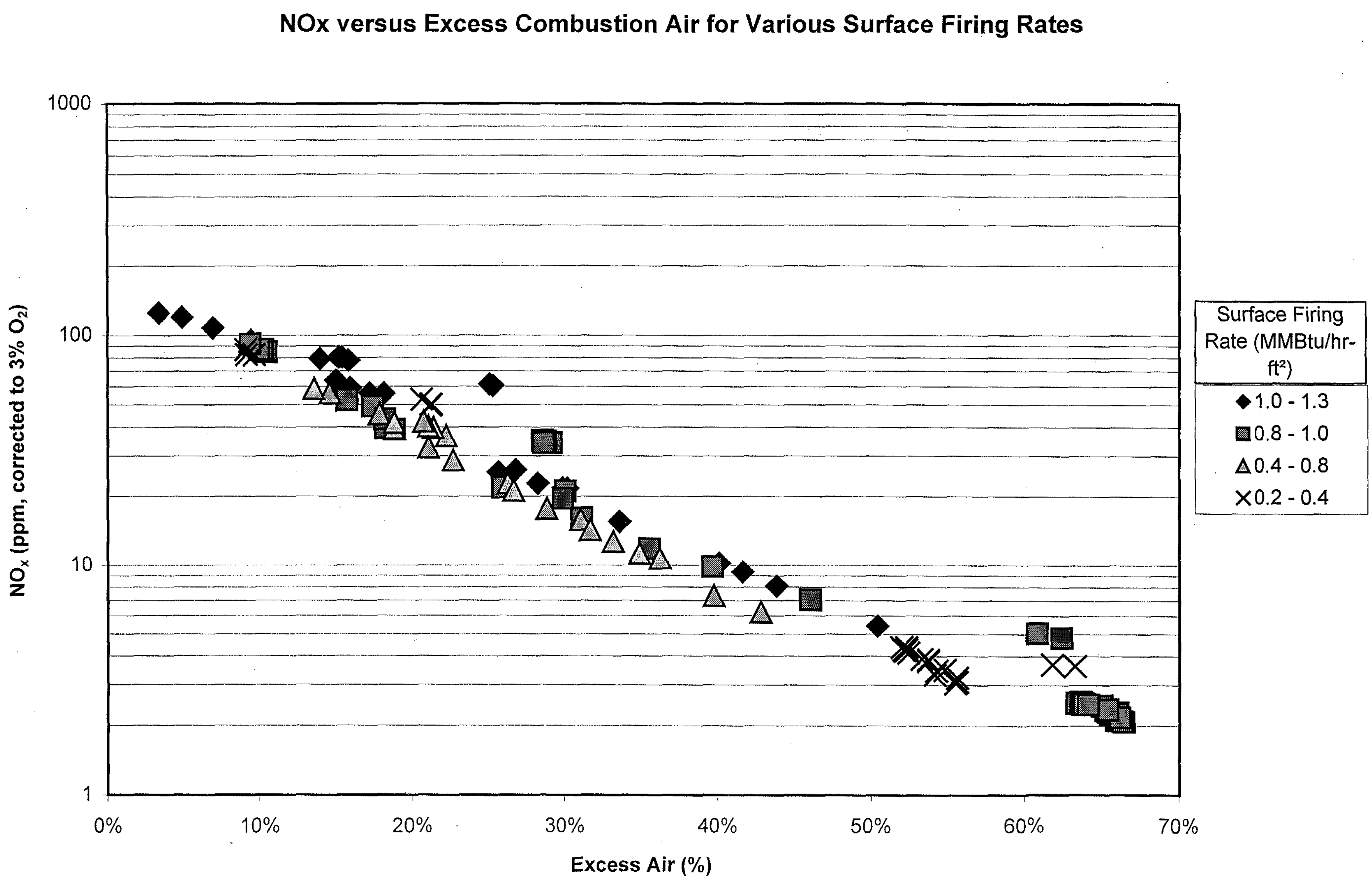
1997 CYMRIC

Date	Time	Point	Total Fired Duty (MMBtu/hr)	Total Excess Air (scfm)	Mix O2 Dry (%)	Excess Air Wet (%)	FGD Wet (%)	FGR Wet (%)	Excess Air Dry (%)	FGD Dry (%)	FGR Dry (%)	Total Dil Wet (%)	Total Dil Dry (%)	Thermox Wet O2 (%)	Stack Dry O2 (%)	CO Corr. To 3% (ppm)	NOx Corr. To 3% O2 (ppm)	CO2 %	Mix O2 dry, %
Excess Air Points																			
06/24/97	-	2	11.9	2071	21.0%	52.8%	0.0%	0.0%	50.2%	0.0%	0.0%	52.8%	50.2%	6.8%	8.6%	96.0	10.2	7.1%	21.0%
06/24/97	-	3	33.7	7909	21.0%	58.7%	0.0%	0.0%	73.0%	0.0%	0.0%	58.7%	73.0%	7.3%	9.8%	17.7	6.5	6.2%	21.0%
06/24/97	14:05	4	33.7	6471	21.2%	39.1%	0.0%	0.0%	59.3%	0.0%	0.0%	39.1%	59.3%	5.5%	8.8%	1.5	10.4	6.8%	21.2%
06/25/97	9:10	A	42.3	7219	21.0%	56.4%	0.0%	0.0%	52.9%	0.0%	0.0%	56.4%	52.9%	7.1%	8.2%	2.8	11.3	7.1%	21.0%
FGR Points																			
06/25/97	13:10	B	33.7	3903	19.3%	----	----	----	34.7%	20.0%	12.9%	----	54.7%	----	6.5%	0.0	13.7	8.0%	19.3%
06/25/97	13:30	C	33.7	2877	19.0%	14.9%	17.3%	13.1%	24.9%	20.6%	14.1%	32.2%	45.5%	2.5%	5.3%	0.0	18.4	8.6%	19.0%
06/25/97	13:50	D	32.0	1322	18.1%	0.0%	19.8%	16.6%	10.6%	24.5%	18.1%	19.8%	35.0%	0.0%	3.2%	0.0	26.3	9.9%	18.1%
07/07/97	10:15	A	29.3	1940	17.6%	25.9%	39.4%	23.8%	18.3%	34.3%	22.5%	65.3%	52.7%	4.0%	4.5%	0.0	9.8	9.2%	17.6%
07/07/97	11:30	B	29.9	1327	17.1%	20.5%	42.5%	26.1%	11.4%	35.7%	24.3%	63.0%	47.0%	3.3%	3.4%	0.0	12.3	9.8%	17.1%
07/07/97	13:20	C	31.2	1580	18.7%	3.2%	16.3%	13.6%	13.5%	19.8%	14.8%	19.5%	33.3%	0.6%	3.7%	0.0	27.1	9.5%	18.7%
07/07/97	13:45	D	31.2	1522	17.8%	14.9%	29.9%	20.7%	12.9%	28.8%	20.3%	44.8%	41.7%	2.5%	3.6%	0.0	17.6	9.7%	17.8%
07/07/97	14:10	E	31.2	2430	18.3%	3.0%	19.4%	15.9%	22.3%	27.9%	18.6%	22.4%	50.2%	4.5%	5.0%	0.0	11.3	8.9%	18.3%
07/07/97	14:30	F	33.8	262	17.0%	8.5%	34.8%	24.3%	0.0%	29.1%	22.5%	43.3%	29.1%	1.5%	1.1%	0.0	22.6	11.0%	17.0%
07/07/97	14:40	G	29.9	1327	17.3%	18.4%	38.2%	24.4%	11.4%	33.4%	23.1%	56.6%	44.8%	3.0%	3.4%	0.0	14.3	9.8%	17.3%
07/07/97	14:55	H	26.0	1697	17.1%	23.6%	45.0%	26.7%	17.7%	40.3%	25.5%	68.6%	58.0%	3.7%	4.5%	0.0	8.7	9.2%	17.1%
07/07/97	15:10	I	26.0	1375	16.7%	18.4%	46.5%	28.2%	13.7%	42.3%	27.1%	64.9%	56.0%	3.0%	3.9%	0.0	9.5	9.5%	16.7%
07/07/97	15:25	J	26.0	1375	16.6%	20.5%	49.9%	29.3%	13.7%	43.6%	27.7%	70.4%	57.3%	3.3%	3.9%	0.0	9.5	9.5%	16.6%
07/08/97	9:25	A	15.0	533	17.3%	13.6%	34.9%	23.5%	5.7%	29.8%	22.0%	48.5%	35.6%	2.3%	3.4%	3.1	15.3	9.8%	17.3%
07/08/97	9:55	B	15.0	734	18.7%	14.9%	20.3%	15.0%	9.9%	18.5%	14.4%	35.2%	28.4%	2.5%	4.1%	0.0	32.0	9.5%	18.7%
07/08/97	10:10	C	15.0	524	16.2%	14.9%	50.3%	30.4%	5.3%	41.2%	28.1%	65.2%	46.5%	2.5%	3.4%	60.3	8.2	9.8%	16.2%
Scratch Points																			
07/07/97	-	1	31.2	3352	21.1%	30.0%	0.0%	0.0%	31.8%	0.0%	0.0%	30.0%	31.8%	4.5%	7.6%	0.0	17.5	----	21.1%
07/07/97	-	2	29.3	3125	19.4%	22.0%	15.3%	11.1%	31.4%	17.8%	11.9%	37.3%	49.2%	3.5%	6.2%	0.0	9.7	----	19.4%
07/07/97	-	3	29.3	1876	17.8%	18.4%	31.9%	21.2%	17.6%	31.5%	21.1%	50.3%	49.1%	3.0%	4.4%	0.0	9.8	----	17.8%
07/07/97	-	4	29.9	3701	19.7%	25.9%	13.0%	9.4%	37.0%	15.4%	10.1%	38.9%	52.4%	4.0%	6.8%	0.0	7.6	----	19.7%
07/07/97	-	5	29.9	3359	19.0%	23.6%	20.1%	14.0%	33.3%	23.5%	15.0%	43.7%	56.8%	3.7%	6.4%	0.0	8.6	----	19.0%
07/07/97	-	6	29.9	2738	18.6%	18.4%	22.7%	16.1%	26.6%	26.1%	17.1%	41.1%	52.6%	3.0%	5.6%	0.0	9.4	----	18.6%
07/07/97	-	7	31.2	2502	20.0%	14.9%	8.2%	6.6%	23.0%	9.4%	7.1%	23.1%	32.4%	2.5%	5.1%	0.0	29.5	----	20.0%
07/07/97	-	8	31.2	2155	19.6%	10.3%	10.8%	8.9%	19.4%	12.6%	9.6%	21.1%	32.0%	1.8%	4.6%	0.0	28.6	----	19.6%
07/07/97	-	9	31.2	3188	19.3%	18.4%	15.4%	11.5%	30.1%	18.6%	12.5%	33.8%	48.7%	3.0%	6.0%	0.0	13.2	----	19.3%
07/07/97	-	10	31.2	1517	18.0%	14.2%	27.3%	19.3%	12.8%	26.6%	19.1%	41.5%	39.4%	2.4%	3.6%	0.0	15.5	----	18.0%
07/07/97	-	11	31.2	2425	18.2%	30.0%	33.2%	20.3%	22.2%	29.1%	19.2%	63.2%	51.3%	4.5%	5.0%	0.0	10.1	----	18.2%
07/07/97	-	12	32.5	1169	17.9%	17.0%	29.9%	20.4%	8.8%	25.6%	19.1%	46.9%	34.5%	2.8%	2.9%	0.0	19.9	----	17.9%
07/07/97	-	13	28.0	1330	17.1%	18.4%	40.9%	25.7%	12.1%	36.2%	24.4%	59.3%	48.4%	3.0%	3.6%	0.0	13.5	----	17.1%
07/07/97	-	14	29.9	359	16.6%	8.5%	39.3%	26.6%	0.9%	33.4%	24.9%	47.8%	34.3%	1.5%	1.5%	0.0	19.4	----	16.6%
07/07/97	-	15	29.9	1757	16.0%	2.7%	41.0%	28.6%	16.0%	54.3%	31.9%	43.7%	70.3%	0.5%	0.5%	0.9	19.3	----	16.0%
07/07/97	-	16	26.0	1113	16.5%	17.7%	48.7%	29.3%	10.3%	42.0%	27.6%	66.4%	52.4%	2.9%	3.4%	0.0	9.2	----	16.5%
07/08/97	-	1	24.7	1143	21.2%	18.4%	0.0%	0.0%	11.3%	0.0%	0.0%	18.4%	11.3%	3.0%	3.6%	0.0	127.3	----	21.2%

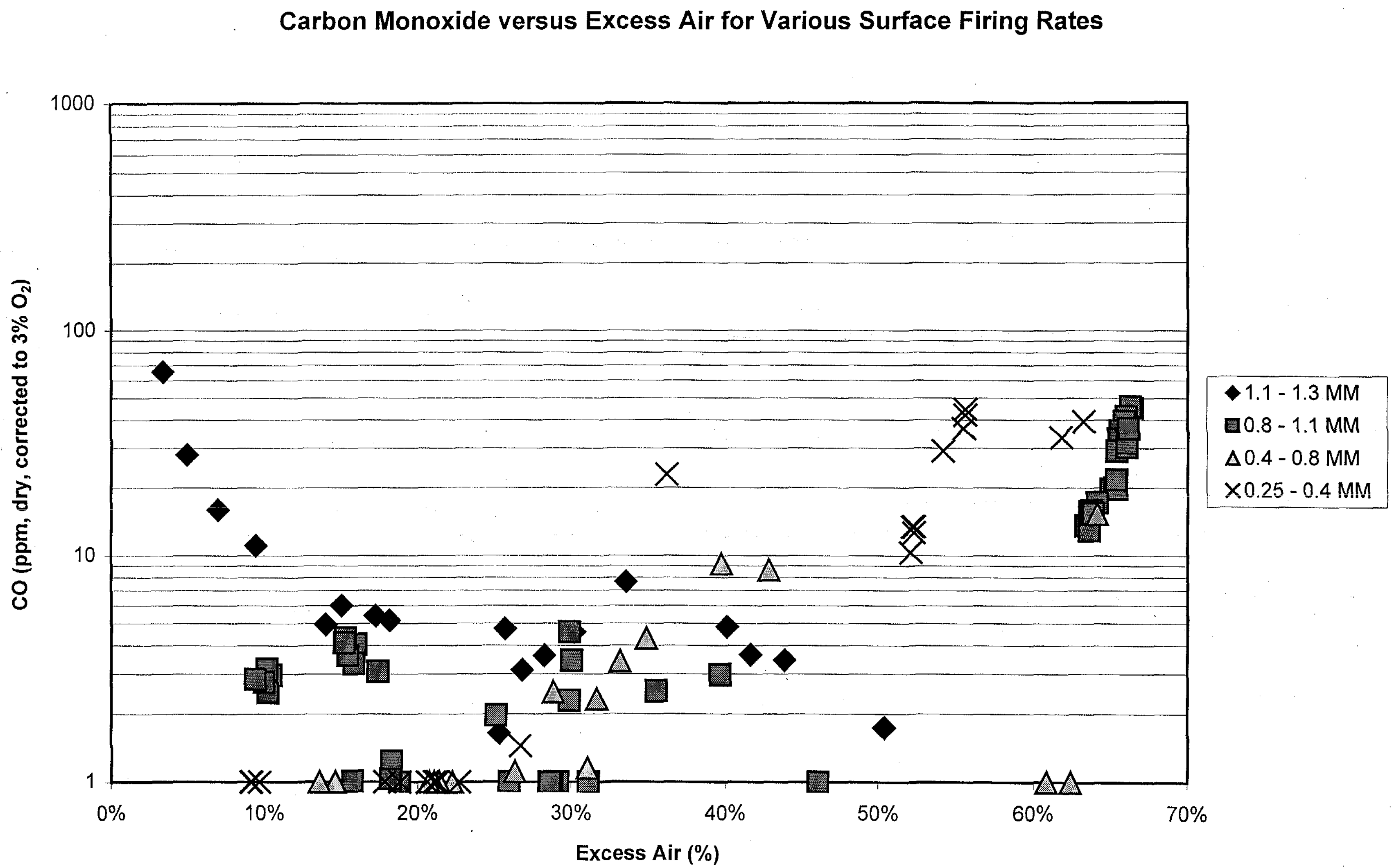
SF THERMAL

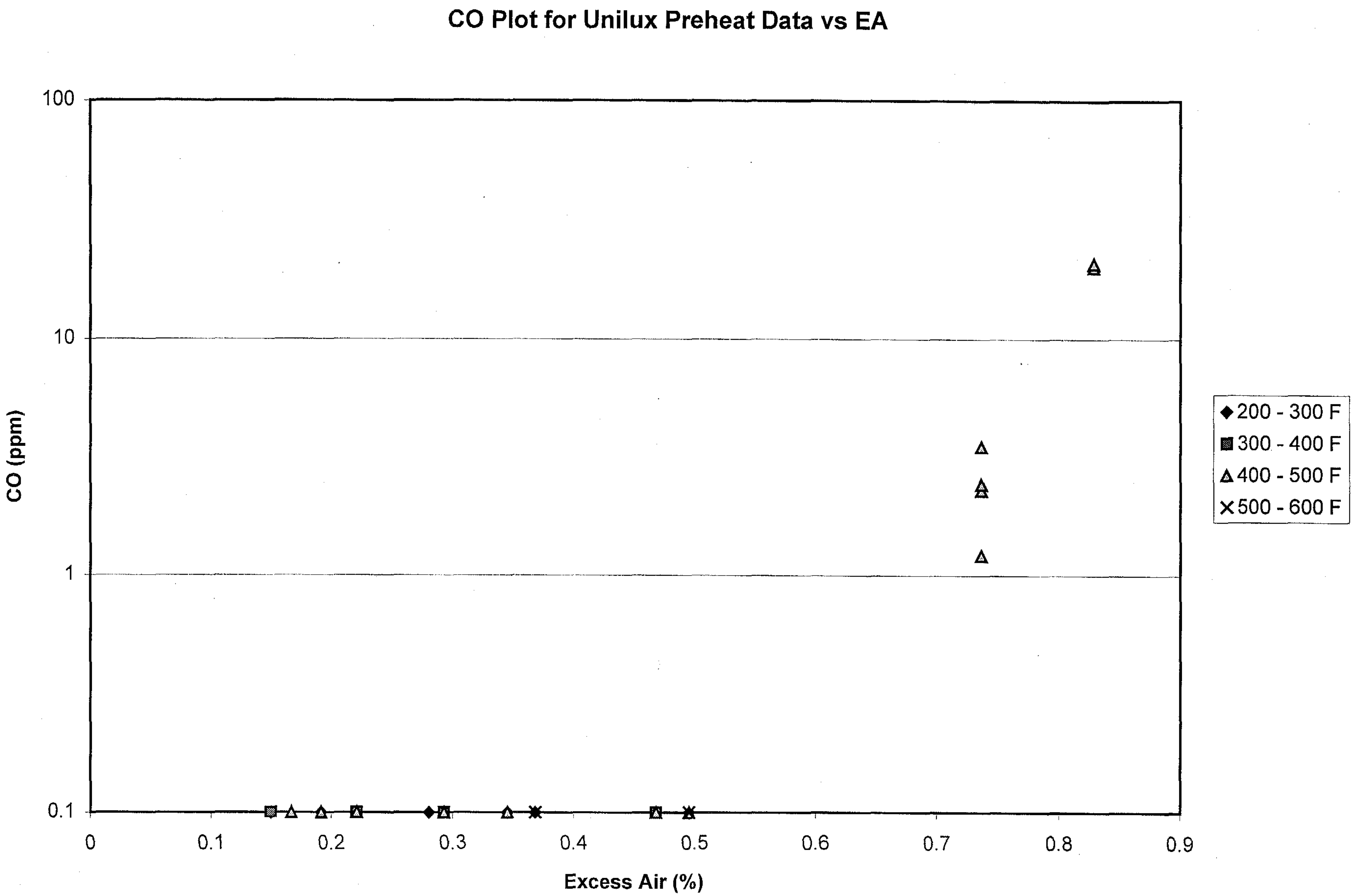
Date	Trial	Firing Rate MMBtu/hr	Surface Firing Rate MBtu/hr-ft2	Stack Temp Deg F	Stack O2 (Dry) %	Excess Air Dry Calc %	NOx corr to 3 % ppm	CO corr to 3% ppm	comments
10/7/96	1	19.62	0.21	-	8.0	55.0%	8	0	Poor Mixing at all firing rates
10/7/96	2	25.98	0.27	-	8.6	62.0%	9	30	Air in secondary
10/7/96	3	36.90	0.39	393.0	8.4	59.6%	16	11	
10/7/96	4	45.12	0.47	411.0	10.1	82.9%	10	239	
10/7/96	5	46.46	0.49	411.0	9.5	73.9%	8	128	
10/7/96	6	59.28	0.62	433.5	9.0	67.1%	15	93	
10/7/96	7	65.92	0.69	446.4	9.3	71.1%	23	180	
10/7/96	8	74.01	0.78	459.0	9.2	69.7%	27	131	
After Modifications									
10/31/96	1	95.70	1.01	493.80	8.1	56.2%	8	0	Analyzer seems off
10/31/96	2	108.10	1.14	507.50	6.7	41.9%	27	0	
10/31/96	3	104.10	1.09	500.00	6.8	42.8%	27	4	
10/31/96	4	100.60	1.06	494.30	6.9	43.8%	27	4	
10/31/96	5	98.71	1.04	490.50	6.9	43.8%	27	4	
10/31/96	6	90.70	0.95	479.00	7.1	45.7%	27	4	
10/31/96	7	80.70	0.85	462.80	7.0	44.7%	27	4	
10/31/96	8	66.40	0.70	439.50	7.4	48.7%	22	4	
10/31/96	9	49.80	0.52	413.70	7.9	53.9%	16	0	
10/31/96	10	36.46	0.38	392.60	8.1	56.2%	12	5	
10/31/96	11	18.67	0.20	363.10	8.5	60.8%	12	5	

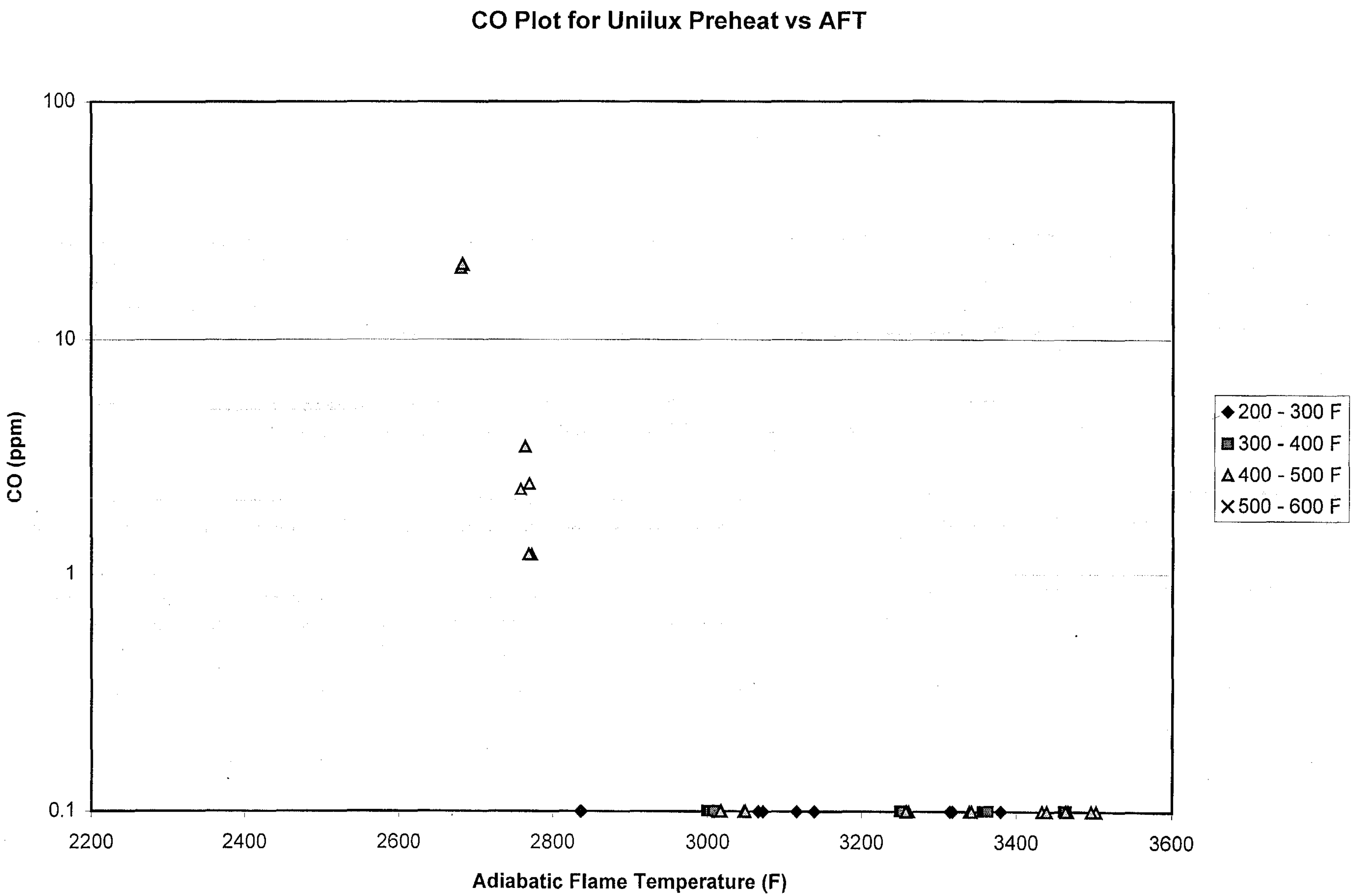
1000 Btu/ft^3 gross heat value was used for calculation in this table



NOx versus Excess Combustion Air for Various Surface Firing Rates
1000
100
10
1
0%
10%
20%
30%
40%
50%
60%
70%
Excess Air (%)
NO_x (ppm, corrected to 3% O_2)
Surface Firing Rate (MMBtu/hr-ft²)
1.0 - 1.3
0.8 - 1.0
0.4 - 0.8
0.2 - 0.4


Carbon Monoxide versus Excess Air for Various Surface Firing Rates
1000
100
10
1
CO (ppm, dry, corrected to 3% O2)
0%
10%
20%
30%
40%
50%
60%
70%
Excess Air (%)
1.1 - 1.3 MM
0.8 - 1.1 MM
0.4 - 0.8 MM
0.25 - 0.4 MM


CO Plot for Unilux Preheat Data vs EA
100
10
1
0.1
CO (ppm)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Excess Air (%)
200 - 300 F
300 - 400 F
400 - 500 F
500 - 600 F


CO Plot for Unilux Preheat vs AFT
100
10
1
0.1
CO (ppm)
2200
2400
2600
2800
3000
3200
3400
3600
Adiabatic Flame Temperature (F)
200 - 300 F
300 - 400 F
400 - 500 F
500 - 600 F

APPENDIX B

STAGING DATA

1995 PYROMAT CSB TESTING AT CYMRIC STEAMER 36W-#60
CSB30-3SC-30 WITH 3 FUEL RINGS ON END CAP

Date	Time	Point	Total Fired Duty (MBtu/hr)	First Stage Fired Duty (MBtu/hr)	Ring #1 Firing Rate (MBtu/hr)	Ring #2 Firing Rate (MBtu/hr)	Ring #3 Firing Rate (MBtu/hr)	Total Second Stage Fired Duty (MBtu/hr)	Surface Firing Rate ($MBtu/hr\text{-}ft^2$)	Percent Staged Fuel (Staged/Total)	Premix O_2 (% O_2)	First Stage Excess Air (%)	Stack O_2 (% O_2)	Excess Air (%)	NO_x Corr. To 3% O_2 (ppm)	CO Corr. To 3% O_2 (ppm)
11/2/95																
	2:37 PM	* 1		31193.53	0.00	0.00	0.00	0.00	650		7.2%	58%	8.4%	60%	8.6	4.3
11/3/95		* 2														
	2:22 PM	* 3	47983.45	45769.13	0.00	0.00	0.00	0.00	954	0.0%	8.0%	68%	7.3%	48%	15.8	3.9
	3:15 PM	* 4	36766.54	38211.09	0.00	0.00	0.00	0.00	796	0.0%	7.3%	58%	7.6%	51%	8.1	4.0
	3:39 PM	* 5	42374.99	38211.09	0.00	8615.34	0.00	8615.34	796	20.3%	N/M	N/M		0%		0.0
	4:21 PM	* 6	23056.98	22753.80	0.00	0.00	0.00	0.00	474	0.0%	7.8%	65%		0%		0.0
11/15/95																
	11:45 AM	* 1	42998.16	44151.72	0.00	0.00	0.00	0.00	920	0.0%	6.3%	47%	6.4%	39%	22.2	3.7
	12:45 AM	* 2	42998.16	44489.71	0.00	0.00	0.00	0.00	927	0.0%	6.9%	54%	6.8%	43%	22.9	7.6
	1:15 PM	* 3	42998.16	44489.71	0.00	0.00	0.00	0.00	927	0.0%	2.9%	18%	3.0%	15%	179.0	6.0
	1:31 PM	* 4	42998.16	44151.72	0.00	0.00	0.00	0.00	920	0.0%	7.6%	63%	8.3%	58%	8.5	8.5
	1:52 PM	* 5	33339.15	34375.20	0.00	0.00	0.00	0.00	716	0.0%	7.5%	61%	7.9%	54%	8.3	8.3
	2:00 PM	6	42374.99	35377.71	8109.57	0.00	0.00	8109.57	737	19.1%	8.0%	68%	5.2%	29%	26.2	6.8
	2:04 PM	6A	42374.99	35377.71	8109.57	0.00	0.00	8109.57	737	19.1%	8.0%	68%	5.2%	29%	20.5	6.8
	2:12 PM	7	44244.48	35377.71	8615.34	0.00	0.00	8615.34	737	19.5%	8.8%	80%	5.0%	28%	25.9	3.4
	2:22 PM	8	44244.48	34375.20	8615.34	4924.06	0.00	13539.40	716	30.6%	7.8%	65%	3.9%	20%	24.2	6.3
	2:37 PM	8A	44867.64	32817.02	8615.34	5254.25	0.00	13869.59	684	30.9%	8.5%	75%	3.7%	19%	17.7	25.0
	2:55 PM	9	44244.48	35377.71	0.00	8262.05	0.00	8262.05	737	18.7%	7.5%	61%	3.6%	18%	23.8	3.1
11/16/95																
	8:55 AM	*1	19984.15	18000.62	0.00	0.00	0.00	0.00	375	0.0%	6.0%	44%	6.8%	43%	22.9	0.0
	9:10 AM	2	23852.05	18000.62	7596.61	0.00	0.00	7596.61	375	31.8%	6.3%	47%	3.3%	17%	24.4	17.3
	9:38 AM	*3	19017.18	18000.62	0.00	0.00	0.00	0.00	375	0.0%	8.5%	75%	9.2%	70%	9.2	4.6
	10:03 AM	4	27075.30	18000.62	7493.15	0.00	0.00	7493.15	375	27.7%	8.0%	68%	3.8%	20%	17.8	16.7
	10:06 AM	4A	27075.30	18000.62	7493.15	0.00	0.00	7493.15	375	27.7%	8.0%	68%	3.3%	17%	17.3	32.5
	10:24 AM	5	27257.95	18000.62	0.00	8312.74	0.00	8312.74	375	30.5%	8.0%	68%	2.4%	12%	11.6	59.0
	10:26 AM	5A	27257.95	18000.62	0.00	8312.74	0.00	8312.74	375	30.5%	8.0%	68%	2.5%	12%	16.5	46.7
	11:37 AM	6	42686.57	34375.20	9113.94	0.00	0.00	9113.94	716	21.4%	6.5%	50%	2.4%	12%	22.3	10.6
	11:56 AM	7	41168.96	31741.95	0.00	8615.34	0.00	8615.34	661	20.9%	7.9%	67%	4.0%	21%	19.1	8.5
	12:15 PM	8	39259.19	31193.53	0.00	0.00	5419.85	5419.85	650	13.8%	7.7%	64%	4.6%	25%	13.2	35.1
	2:03 PM	*9	14182.30	12891.89	0.00	0.00	0.00	0.00	269	0.0%	6.4%	48%	8.4%	60%	8.6	27.2
	2:24 PM	10	22374.73	12891.89	7076.46	0.00	0.00	7076.46	269	31.6%	6.4%	48%	3.0%	15%	12.0	111.0
11/17/95																
	11:08 AM	*1	20776.53	19394.95	0.00	0.00	0.00	0.00	404	0.0%	8.3%	71%	9.0%	67%	9.0	4.5
	12:46 PM	2	28665.44	19394.95	6655.18	4702.50	0.00	11357.67	404	39.6%	8.1%	69%	3.1%	15%	18.1	30.2
	1:03 PM	3	29288.60	20081.23	0.00	8413.89	0.00	8413.89	418	28.7%	8.1%	69%	2.9%	14%	11.9	138.2

1000 Btu/ft^3 gross heat value was used for calculation in this table

* *Data not included in plots.*

UNILUX STAGING

DATE	TRIAL	NOZZLE PRESSURE in wc	BURNER PRESSURE in wc	FIRING RATE MBtu/hr	BOILER CAPACITY %	SURFACE FIRING RATE MBtu/hr-ft2	PREMIX OXYGEN %	STACK OXYGEN %	(Premix Calc.) EXCESS AIR %	(Stack Calc.) EXCESS AIR %	NOx ppm	Corr. NOx ppm	CO ppm	Corr. CO ppm	UHC ppm	Corr. UHC ppm
08/24/95	1	9.5	5.5	2374.14	77%	1230.12	7.00%	4.65%	55.22%	25.44%	15.2	13.1	391	335.9	36	30.9
08/24/95	2	10	5.6	2495.78	81%	1293.15	6.50%	4.15%	49.51%	22.03%	19.5	16.7	226	194.1	17	14.6
08/24/95	3	10	5.5	2572.23	83%	1332.76	6.50%	3.52%	49.51%	18.01%	17	14.6	1029	883.5	69	59.2
08/24/95	4	10.2	5.6	2595.97	84%	1345.06	5.50%	3.34%	39.19%	16.92%	24	20.6	304	261.0	21	18.0
08/24/95	5	10.2	5.6	2625.37	85%	1360.30	5.50%	3.03%	39.19%	15.08%	22.3	19.1	698	599.2	41.5	35.6
08/24/95	6	9.3	5.3	2418.82	78%	1253.28	6.00%	3.61%	44.18%	18.57%	18.3	15.7	440	377.8	29	24.9
08/24/95	7	8.8	5	2406.48	78%	1246.88	6.00%	3.22%	44.18%	16.20%	18.2	15.6	676	580.3	45	38.6
08/24/95	8	9	5.2	2422.42	78%	1255.14	6.00%	3.28%	44.18%	16.56%	17.7	15.2	717	615.5	50	42.9
08/24/95	9	7.7	4.4	2385.45	77%	1235.98	5.50%	2.26%	39.19%	10.79%	21	18.0	2221	1905.8	160	137.3
08/24/95	11	7.7	4.5	2306.75	74%	1195.21	5.50%	2.73%	39.19%	13.37%	24.1	20.7	447	383.6	32.5	27.9
08/24/95	12	6.4	3.8	2080.24	67%	1077.84	6.00%	3.09%	44.18%	15.43%	20.5	17.6	378	324.5	26	22.3
08/25/95	1	9.8	5.5	2479.98	80%	1284.96	5.00%	3.59%	34.51%	18.45%	19.9	17.1	207	177.7	60	51.5
08/25/95	2	9.5	5.5	2359.50	76%	1222.54	6.25%	4.45%	46.80%	24.05%	15.3	13.1	153.6	131.9	59	50.7
08/25/95	3	9.7	5.6	2491.09	80%	1290.72	5.50%	3.42%	39.19%	17.40%	18.9	16.2	262	224.9	93	79.8
08/25/95	4	9.7	5.6	2495.05	80%	1292.77	5.25%	3.22%	36.82%	16.20%	20.3	17.4	261	224.1	86	73.8
08/25/95	5a	9.8	5.6	2534.33	82%	1313.13	5.00%	2.89%	34.51%	14.28%	21.8	18.7	350	300.4	92	79.0
08/25/95	5b	9.8	5.6	2534.33	82%	1313.13	5.00%	2.91%	34.51%	14.39%	21.5	18.5	317	272.1	94	80.7
08/25/95	6	9.9	5.9	2508.77	81%	1299.88	5.00%	2.85%	34.51%	14.05%	23.1	19.8	360	309.0	83	71.2
08/25/95	7a	9.9	5.6	2486.94	80%	1288.57	5.00%	3.01%	34.51%	14.97%	23.9	20.5	321	275.5	61	52.4
08/25/95	7b	9.9	5.6	2486.94	80%	1288.57	5.00%	3.02%	34.51%	15.03%	23.7	20.3	321	275.5	59	50.6
08/25/95	8	8.9	5.1	2336.67	75%	1210.71	5.00%	3.16%	34.51%	15.84%	25.2	21.6	128.7	110.5	25	21.5
08/25/95	9a	8.9	5.2	2358.77	76%	1222.16	5.00%	3.04%	34.51%	15.14%	27.4	23.5	126.5	108.6	20	17.2
08/25/95	9b	8.9	5.2	2358.77	76%	1222.16	5.00%	3.01%	34.51%	14.97%	28.1	24.1	135.7	116.5	20	17.2
08/25/95	9c	8.9	5.2	2358.77	76%	1222.16	5.00%	3.04%	34.51%	15.14%	27.1	23.3	123.2	105.8	20	17.2
08/25/95	10	6.3	3.9	2021.71	65%	1047.52	4.90%	2.71%	33.61%	13.25%	29.2	25.1	240	206.0	21	18.0
08/25/95	12a	6.1	3.7	1974.66	64%	1023.14	5.10%	3.00%	35.43%	14.91%	24.6	21.1	295	253.2	38	32.6
08/25/95	12b	6.1	3.7	1974.66	64%	1023.14	5.10%	2.99%	35.43%	14.85%	24.4	20.9	286	245.5	39	33.5
08/25/95	12c	6.1	3.7	1974.66	64%	1023.14	5.10%	2.99%	35.43%	14.85%	24.5	21.0	305	261.8	37	31.8

SF THERMAL

Date	Trial	Firing Rate MMBtu/hr	Surface Firing Rate MBtu/hr-ft2	% Staged	Stack Temp Deg F	Stack O2 (Dry) %	Excess Air Dry Calc %	NOx corr to 3 % ppm	CO corr to 3% ppm	comments
10/3/96	1	46.10	0.46	4%	406.8	7.5	49.7%	20	15	Gas Staging Poor Stage Mixing
10/3/96	2	48.46	0.46	9%	408.5	6.7	41.9%	21	31	Soot produced at almost all
10/3/96	3	59.65	0.57	9%	428.8	6.5	40.1%	20	64	Firing rates
10/3/96	4	70.90	0.57	23%	-	4.8	26.5%	21	2000	Lots of soot - CO Overload
10/3/96	5	75.40	0.74	6%	459.8	7.9	53.9%	17	105	Sooty
10/3/96	6	56.16	0.59	0%	429.8	8.5	60.8%	17	24	
10/3/96	7	59.79	0.59	6%	430.7	7.3	47.7%	23	25	GAS-AIR Stage 1:1 - No difference
10/3/96	8	66.80	0.59	16%	433.2	5.3	30.2%	25	1400	GAS-AIR Stage 1:3 - Sooty-No Difference
10/3/96	9	91.46	0.96	0%	484.8	7.3	47.7%	31	28	Final Tuning
10/3/96	10	95.14	0.92	8%	485.7	6.4	39.2%	27	43	
10/3/96	11	99.67	0.92	12%	488.7	5.8	34.1%	30	90	
10/3/96	12	87.68	0.92	0%	483.0	7.9	53.9%	24	44	
10/3/96	13	86.40	0.91	0%	480.5	7.8	52.9%	27	44	
10/3/96	14	84.70	0.89	0%	473.5	7.6	50.7%	26	68	
10/3/96	15	75.50	0.79	0%	460.3	7.9	53.9%	27	48	
10/3/96	16	64.70	0.68	0%	446.7	8.1	56.2%	23	4	
10/3/96	17	57.80	0.61	0%	427.8	7.8	52.9%	25	27	
10/3/96	18	53.67	0.56	0%	417.6	8.3	58.5%	22	30	took boiler to 0% and reset inlet
10/3/96	19	43.37	0.46	0%	412.3	7.9	53.9%	24	18	vanes for lowest firing rate. Came
10/3/96	20	33.02	0.35	0%	386.8	7.7	51.8%	27	18	up to 30% and went back to 0%
10/3/96	21	20.90	0.22	0%	376.4	8.2	57.3%	24	28	

1000 Btu/ft^3 gross heat value was used for calculation in this table

APPENDIX C

CYMRIC TEST REPORT

Emissions and Installation Report for the Use of Flue Gas Dilution with Large Diameter CSB's

Alzeta Project 7097:

Development and Demonstration of the Radiation Stabilized Distributed Flux Burner

Final Report for Cymric Test Results

Prepared by

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Alzeta Corporation
2343 Calle Del Mundo
Santa Clara, CA 95054-1008

Emissions and Installation Report for the Use of Flue Gas Dilution with Large Diameter CSB's

Operating and emissions tests of flue gas recirculation (FGR) were conducted using Alzeta's 30" diameter CSB low NO_x burner installed in a Struthers Steamer at Chevron's Cymric Oil Field. Installation of the Alzeta surface burner was performed by J.E. Construction and T.J Cross Engineering provided design work. Test results demonstrated flame stability over a wide range of firing rates and excess air, and low emissions when operated with dilution (by excess air or flue gas recirculation) of 50% or more (low emissions means under 9 ppm NO_x and less than 50 ppm CO corrected to 3% O_2). These tests confirm that burner performance depends upon total dilution, and not whether the dilution is a result of excess air or flue gas. Therefore, when operated with flue gas recirculation (FGR), the Alzeta burner is a stable, low NO_x, high efficiency burner. Additional comments are made on the fully tabulated data, and the possibility of fuel staging.

Installation

The test burner installation went as smoothly as any commercial site with the help of J.E. Construction. The single difficulty resulted from an older segment connection design. The segments connected from the end cap toward the burner wall, necessitating the use of a support tray during installation. The extra handling on the support tray resulted in a torn pad segment, which had to be replaced. Drawing 1 is an assembly drawing of the burner placed in the 37-ft-long Struthers Steamer, and Drawing 2 is an assembly drawing of the burner segment.

Burner Test Results

Burner Stability

Figure 1 shows the operating envelope for the 60 MMBtu/hr Alzeta CSB inside the Struthers Steamer. The figure shows that the burner is stable over a broad operating envelope of firing rate and total dilution. This operating envelope is bordered by high dilution (65%) above which lean flame-out can occur, and minimum dilution (10%) below which high CO levels may result. Maximum firing rates are determined by total surface area (60 ft^2) and maximum surface firing rates (1.2 MMBtu/hr/ft^2), and minimum firing rates are turndown dependent, set at 6:1.

The borders of the stability curve shown in Figure 1 are derived from previous Alzeta burner tests. The confidence in these limits is high enough that test time at the Cymric site was not used to reconfirm them experimentally.

Burner Emissions

Figure 2 illustrates the expected emissions levels inside the overall stability curve. Shaded bands show expected emissions in three regions, 15-30 ppm NO_x, 9-15 ppm NO_x, and below 9 ppm NO_x. NO_x levels that are independent of firing rate are a characteristic of Alzeta's smaller CSB products (less than 5MMBtu/hr, less than 8" diameter), while the large CSB line shows some emissions increase with increasing firing rate. CO levels in this well-mixed system are consistently below 9 ppm, which is far enough below the 50 ppm DOE project target that no plot is shown.

The six data points shown on Figure 2 are all derived from high efficiency cases, where excess air levels are near 15%, with the remaining dilution the result of flue gas recirculation.

Burner Efficiency

The results from Figures 3, 4 and 5 show that when flue gas recirculation is used in the correct proportions, the low excess air and low stack O_2 give a high efficiency boiler. Figure 3 shows the NO_x emissions as they drop with increasing volumetric dilution. NO_x levels near 30 ppm occur when total dilution reaches 30%, levels near 15 ppm occur with 40% dilution, and levels near 9 ppm occur with 50% dilution. Dilution levels of 60% will guarantee NO_x levels below 9 ppm, corrected to 3% stack O_2. Figure 4 is a compilation of data from Alzeta surface burners of different applications, geometries, and excess air levels. This plot shows the emissions levels perform similarly for similar values of total dilution. Figure 5 shows the NO_x emissions for specific values of excess air. In Figure 5, the region where excess air is below 15% is labeled high efficiency, and the region where NO_x levels are below 9 ppm is labeled low emissions. The intersection of these two regions, shaded in gray, is the high efficiency, low emissions operating region. Thus, the use of flue gas recirculation, combined with the other properties of the Alzeta burner, give a boiler burner that is high-efficiency, low emissions and stable over a wide operating range.

Tabulated Data

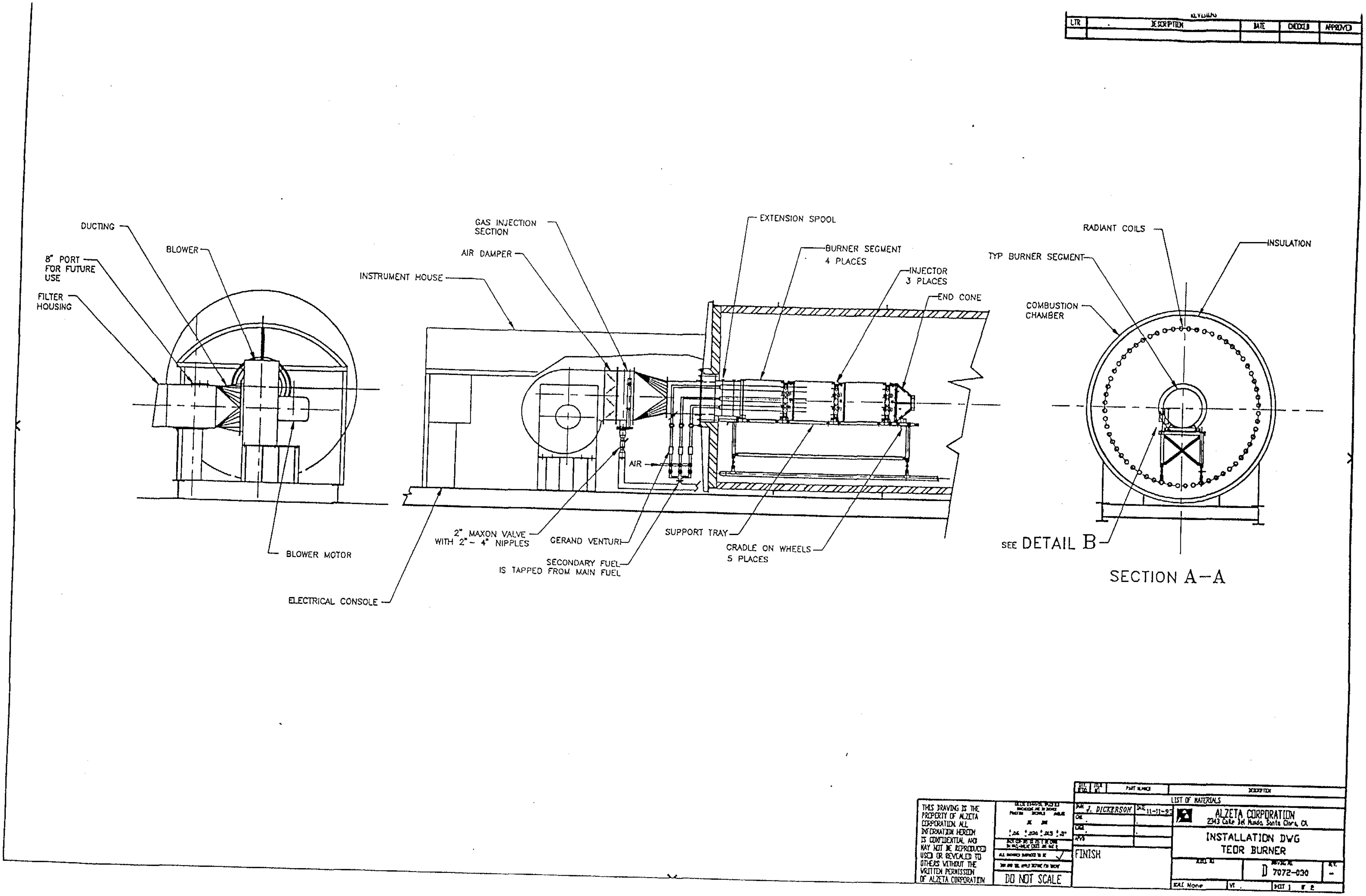
Table 1 and Table 2 contain the full tabulated data for the Cymric tests. The data is broken into excess air data points, where all dilution resulted from air, and FGR points where partial dilution with flue gas was used. Scratch points were recorded for flow rate and emissions data only. Note that the date and point columns provide a unique reference to each data point.

Information on specific columns follows: Total firing rate is given as Tot. Gas in MMBtu/hr. Stack O_2 (dry) is read by an Ecom-AC from the stack of the Struthers Steamer. Mix O_2 is the percent oxygen in the combined flue gas/air stream before gas is mixed. Excess air (EA) is given as the additional percentage of stoichiometric air added to the combustion premix. Flue gas dilution (FGD) is also given as a percentage of stoichiometric air, except this is flue gas that is added to the premix. FGR is the traditional definition of Flue Gas Recirculation, the percentage of the total air and flue gas that is flue gas. Total dilution is the addition of EA and FGD. Stack levels of CO_2, CO, NO, and NO_2 are given. Fuel flow and stoichiometric airflow is given in scfm. A small amount of cooling air is always present through the nozzles (used for different fuel staging tests); thus excess air through the burner, and cooling air flow rates are given.

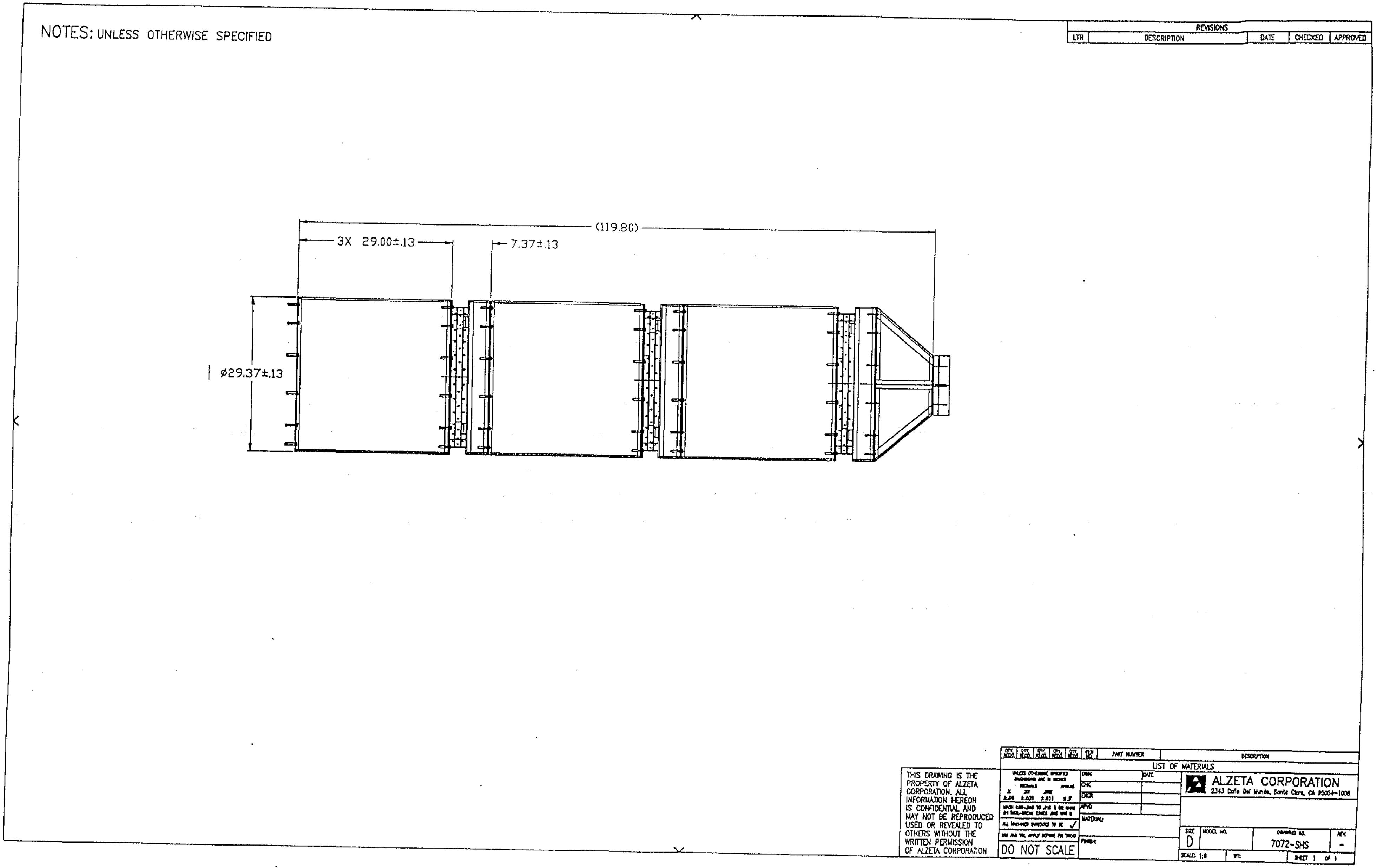
An overview of temperature and heat flux data follows: T1 through T6 are uncorrected thermocouple readings from inside the steamer. (Locations are given as distance from the steamer front wall, and the clockwise angle when viewed from the fan side of the steamer, 0° corresponding to straight up.) T1 (4ft, 90°) and T3 (8ft, 315°) are measure flue temperatures using ceramic coated thermocouples, hanging 2ft radially into the steamer. T2 (8ft, 45°) and T4 (4ft, 270°) measure outer tube wall temperatures, and are covered by generous amounts of refractory coating. T5 (14ft, 0°) and T6 (16ft, 0°) are uncovered thermocouples hanging from the top of the boiler, 3 ft down. The single heat flux gauge (4.5 ft, 90°) is measured at two positions for each data point before its failure. The first position corresponds to 20 inches from the burner surface, the second 40 inches from the surface. Note that the second position is flush with the tube walls. Stack temperature is read by the Ecom-AC at the exhaust. The FGR temperature is the flue gas temperature just before mixing with the air. The burner throat temperature is the premix temperature before combustion. Steam and Tube temperatures are recorded just before the convective section begins. Exhaust temperature is in the stack. St. out, Conv, Coil, and Water in are recorded pressures. All data from 'L Steam' to 'H2O in' is recorded from the steamer's controls.

Fuel Staging Results

Fuel staging results from four tests at three different sites are shown in Figure 6. Changes in site, configuration, and fuel flows result in two broad performance categories, shown in two boxes in Figure 6. Translucent flames that are cleaner burning all have NO_x levels above 30 ppm. Orange flames gave lower NO_x levels due to lower flame temperatures as soot radiates heat energy from the combustion. These lower emission flames are not a low-emission, high-efficiency burner solution because of the soot residue they would leave on the boiler tube walls. In short, fuel staging is not ready for installation at a commercial site.


DUCTING
BLOWER
8" PORT FOR FUTURE USE
FILTER HOUSING
BLOWER MOTOR
GAS INJECTION SECTION
AIR DAMPER
INSTRUMENT HOUSE
AIR
2" MAXON VALVE WITH 2" - 4" NIPPLES
GERAND VENTURI
SECONDARY FUEL IS TAPPED FROM MAIN FUEL
ELECTRICAL CONSOLE
EXTENSION SPOOL
BURNER SEGMENT 4 PLACES
INJECTOR 3 PLACES
END CONE
SUPPORT TRAY
CRADLE ON WHEELS 5 PLACES
RADIANT COILS
INSULATION
TYP BURNER SEGMENT
COMBUSTION CHAMBER
SEE DETAIL B
SECTION A-A
LTR
DESCRIPTION
DATE
CHECKED
APPROVED
THIS DRAWING IS THE PROPERTY OF ALZETA CORPORATION. ALL INFORMATION HEREIN IS CONFIDENTIAL AND MAY NOT BE REPRODUCED USED OR REVEALED TO OTHERS WITHOUT THE WRITTEN PERMISSION OF ALZETA CORPORATION
DO NOT SCALE
LIST OF MATERIALS
J. DICKERSON
FINISH
ALZETA CORPORATION
2343 Calle del Mundo, Santa Clara, CA
INSTALLATION DWG
TEOR BURNER
D
7072-030
SCALE None

Drawing 1


NOTES: UNLESS OTHERWISE SPECIFIED
REVISIONS
LTR
DESCRIPTION
DATE
CHECKED
APPROVED
(119.80)
3X 29.00±.13
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LIST OF MATERIALS
THIS DRAWING IS THE PROPERTY OF ALZETA CORPORATION. ALL INFORMATION HEREON IS CONFIDENTIAL AND MAY NOT BE REPRODUCED USED OR REVEALED TO OTHERS WITHOUT THE WRITTEN PERMISSION OF ALZETA CORPORATION
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ALZETA CORPORATION
D
7072-SHS

Drawing 2

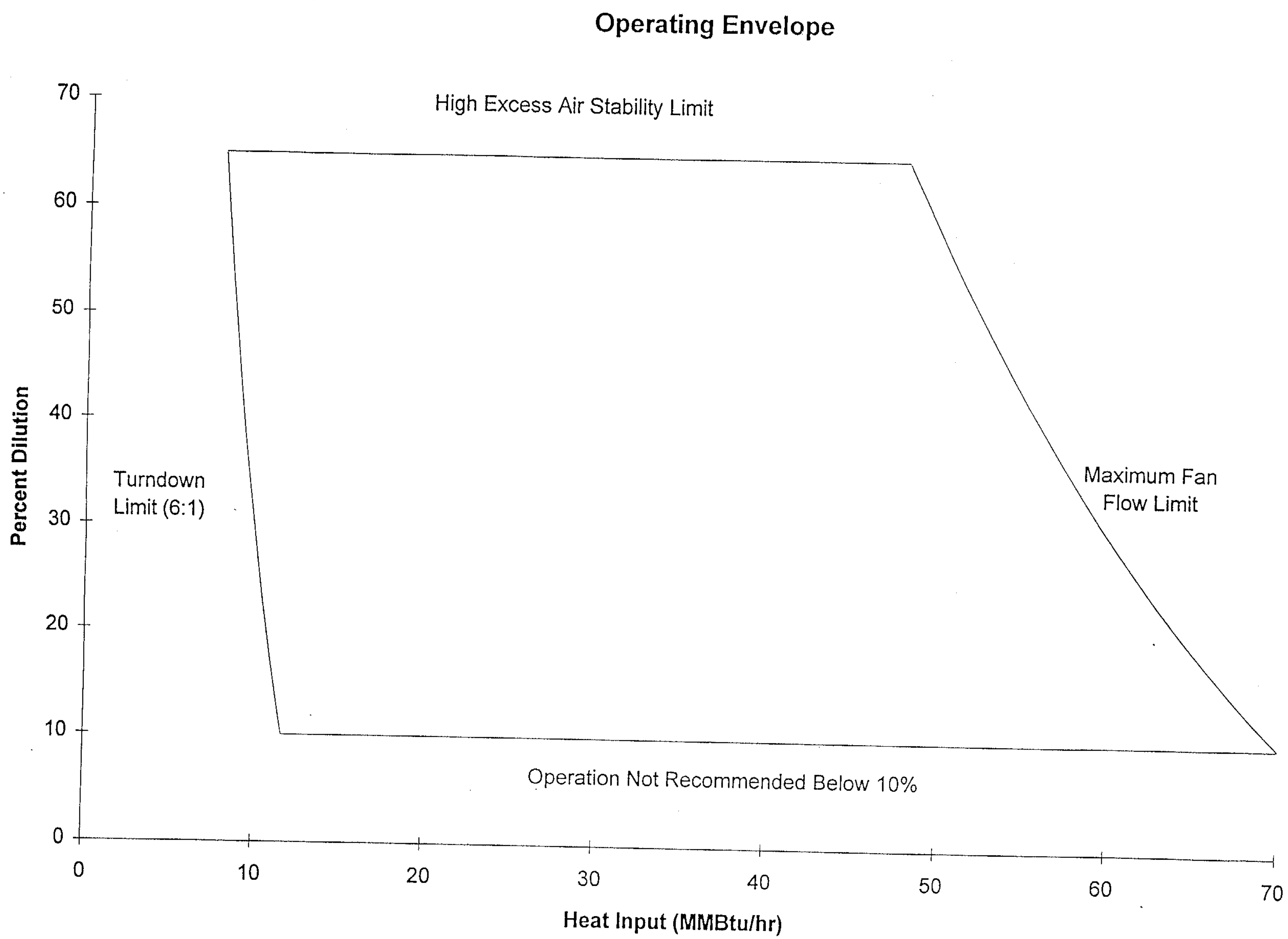
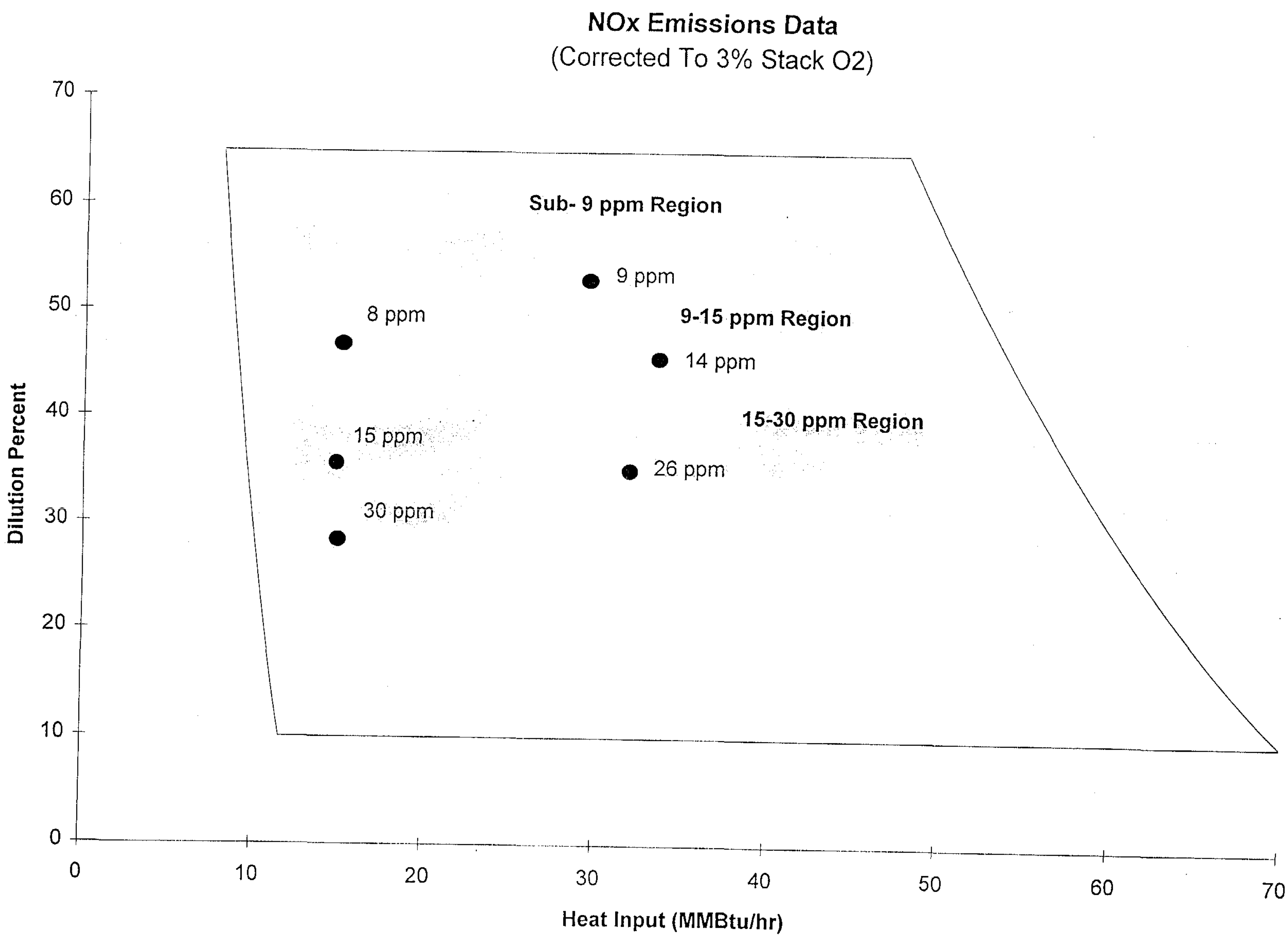
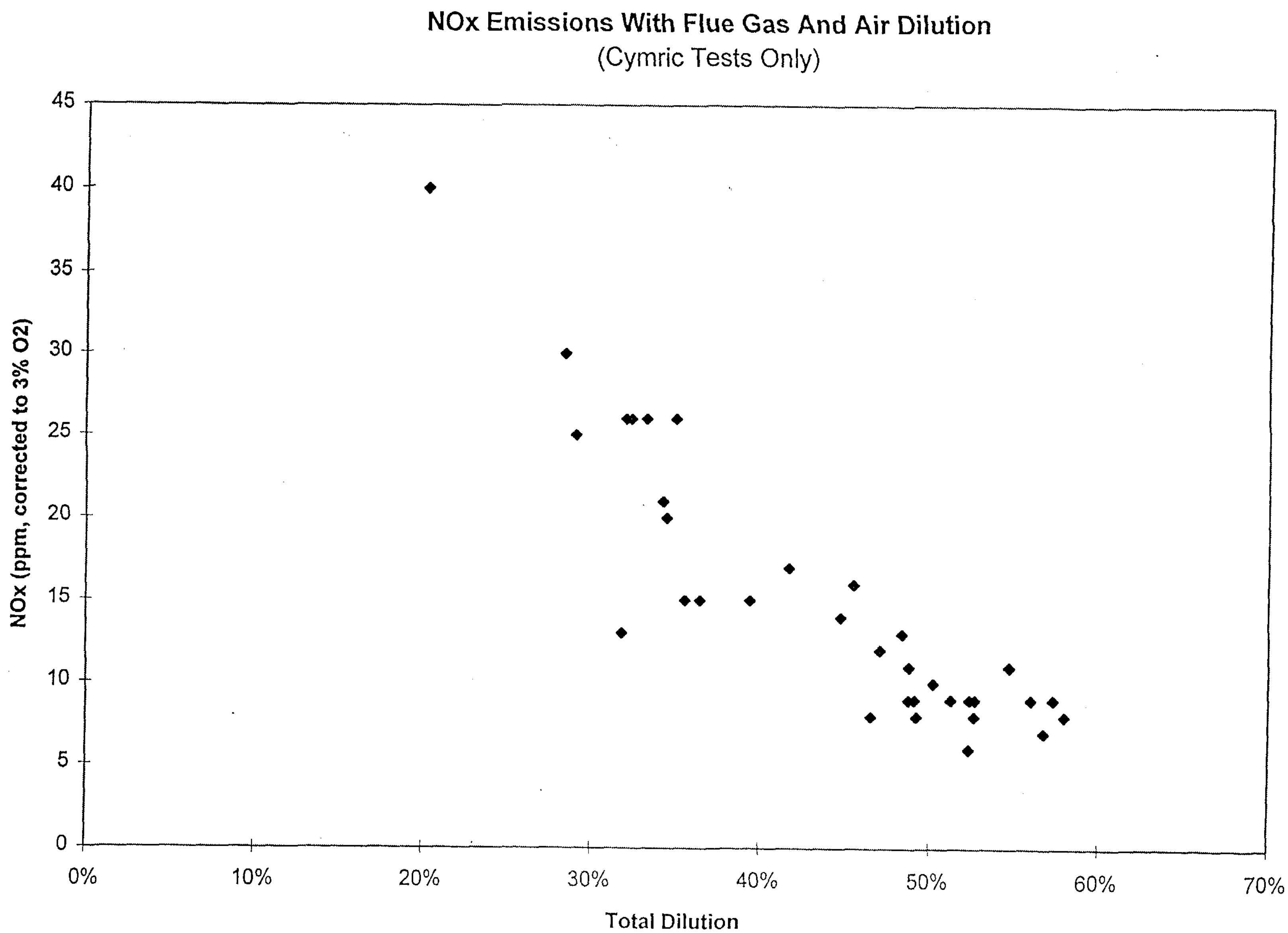

Operating Envelope
High Excess Air Stability Limit
Turndown
Limit (6:1)
Maximum Fan
Flow Limit
Operation Not Recommended Below 10%
Percent Dilution
0
10
20
30
40
50
60
70
Heat Input (MMBtu/hr)

Figure 1



NOx Emissions Data
(Corrected To 3% Stack O2)
Sub- 9 ppm Region
9 ppm
8 ppm
9-15 ppm Region
14 ppm
15-30 ppm Region
15 ppm
26 ppm
30 ppm
Dilution Percent
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
Heat Input (MMBtu/hr)

Figure 2



NOx Emissions With Flue Gas And Air Dilution
(Cymric Tests Only)
NOx (ppm, corrected to 3% O2)
45
40
35
30
25
20
15
10
5
0
0%
10%
20%
30%
40%
50%
60%
70%
Total Dilution

Figure 3

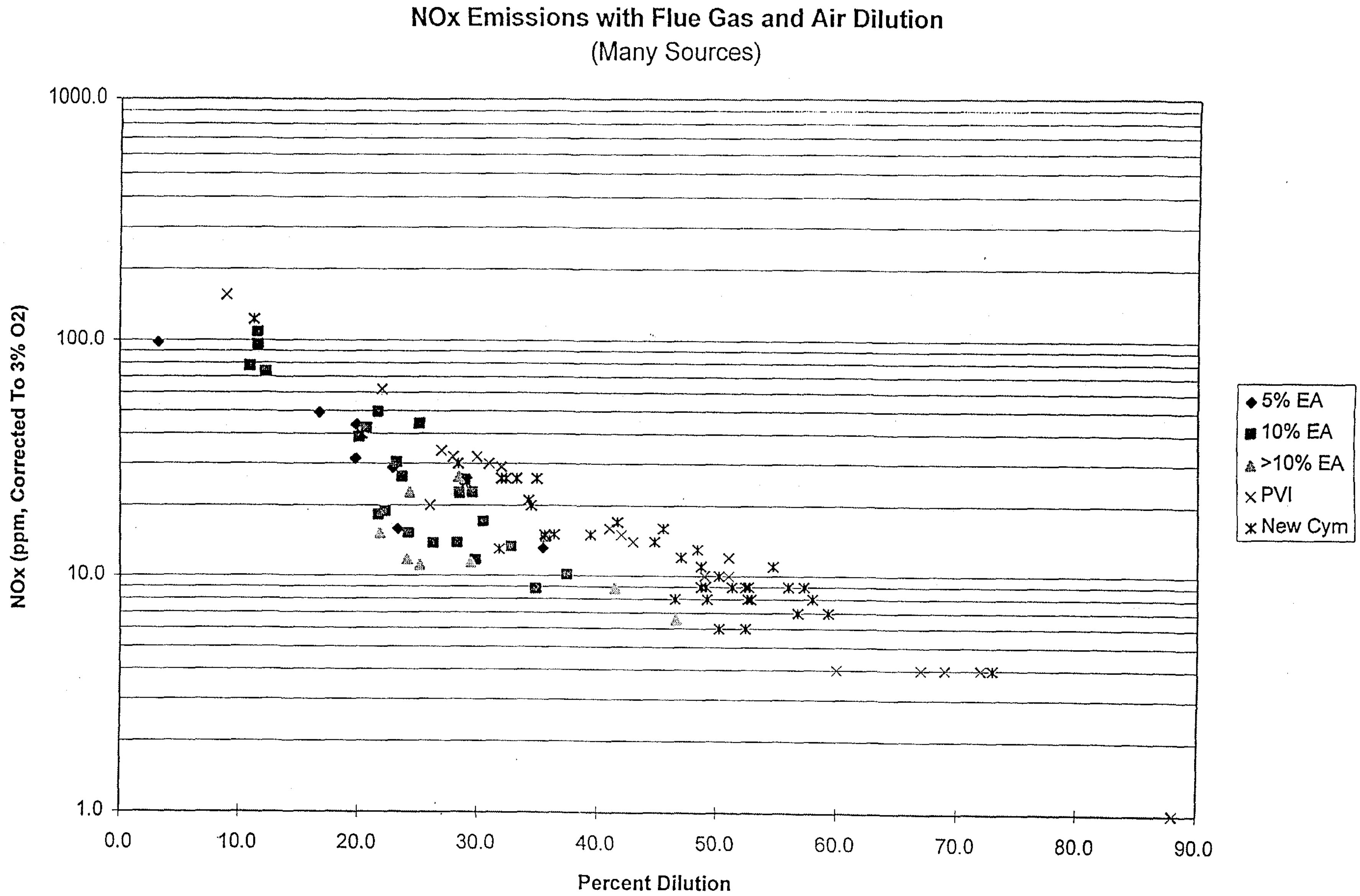

NOx Emissions with Flue Gas and Air Dilution
(Many Sources)
1000.0
100.0
10.0
1.0
NOx (ppm, Corrected To 3% O2)
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
90.0
Percent Dilution
5% EA
10% EA
>10% EA
PVI
New Cym

Figure 4

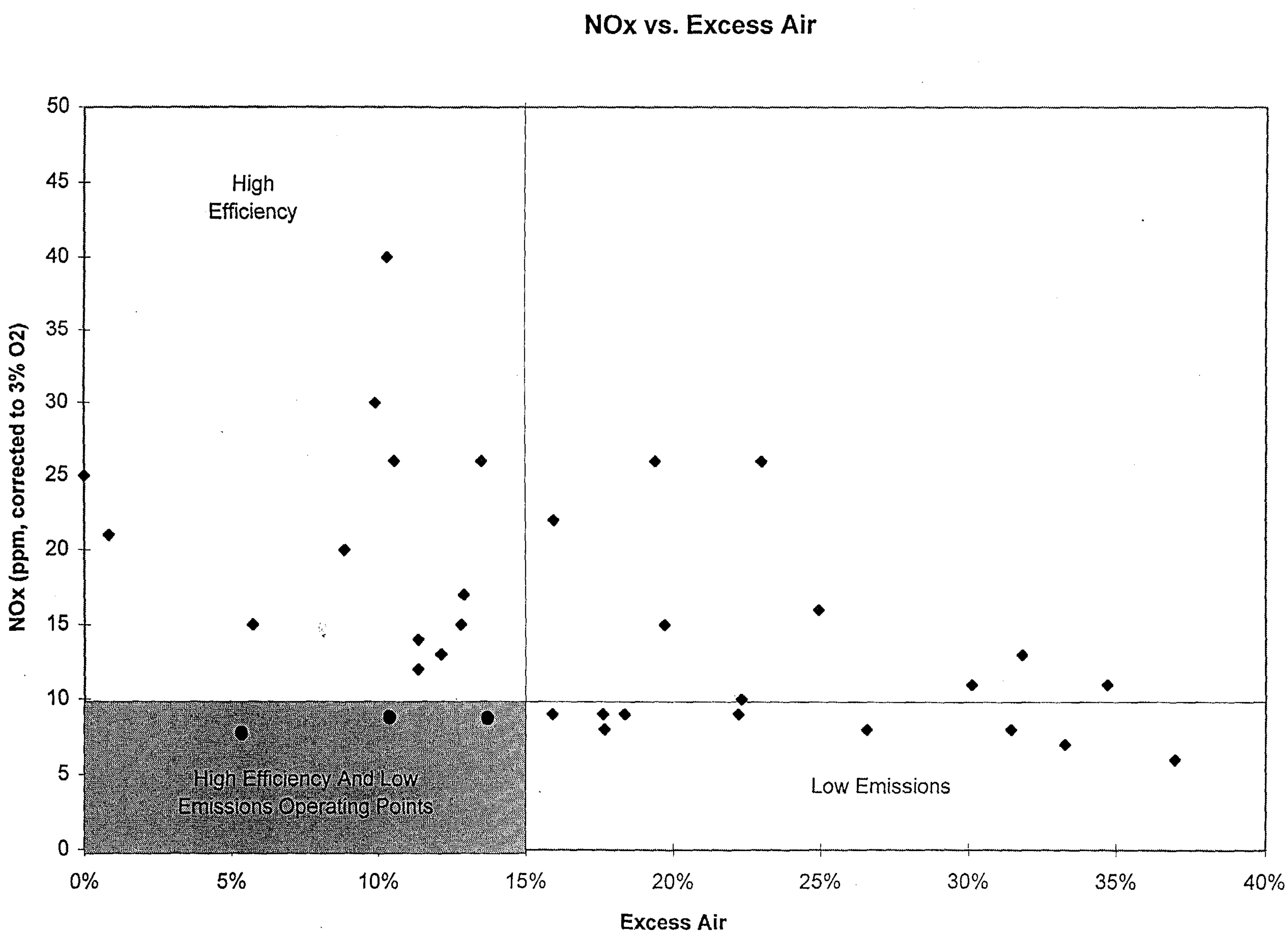

NOx vs. Excess Air
High
Efficiency
High Efficiency And Low
Emissions Operating Points
Low Emissions
NOx (ppm, corrected to 3% O2)
50
45
40
35
30
25
20
15
10
5
0
0%
5%
10%
15%
20%
25%
30%
35%
40%
Excess Air

Figure 5

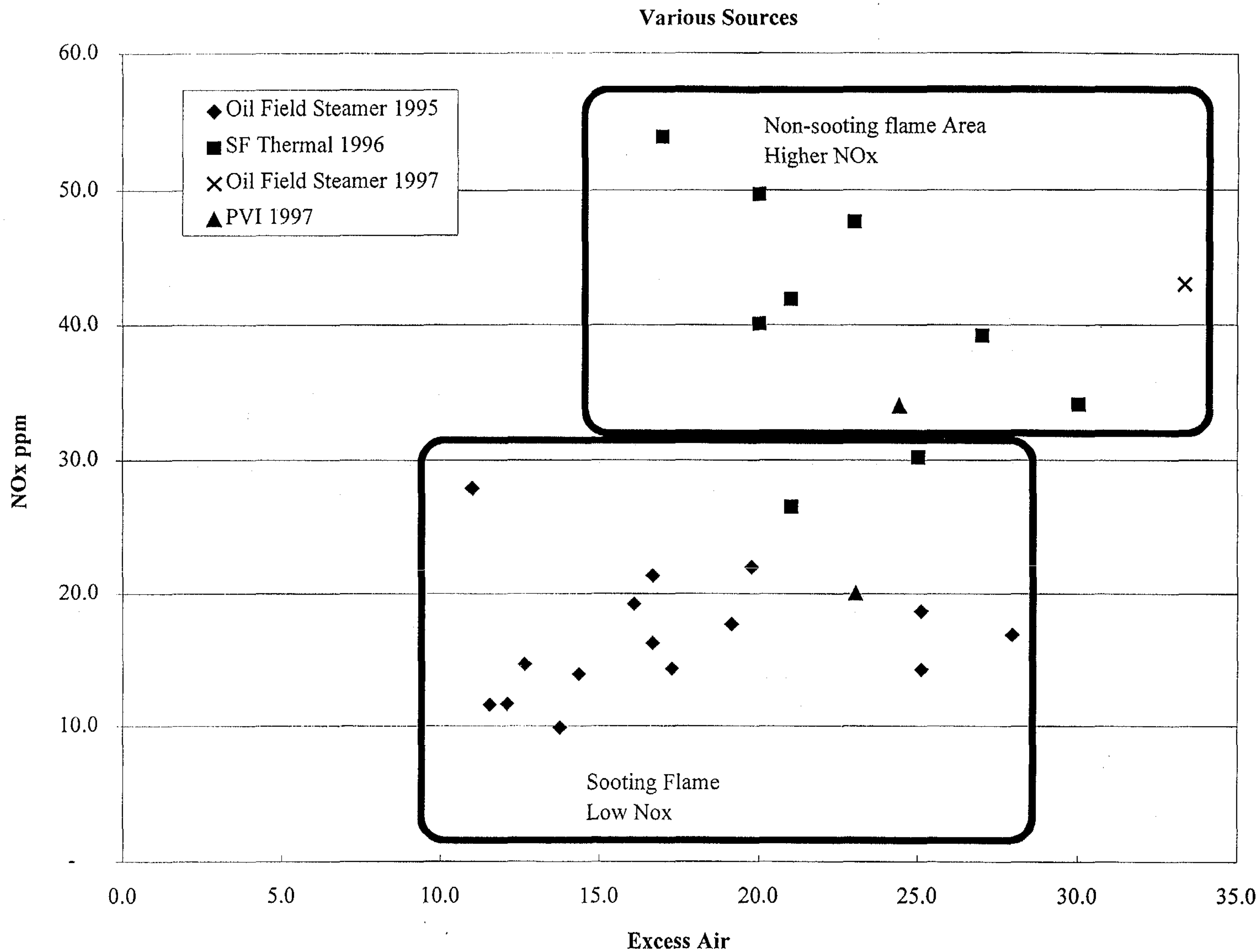


Figure 6. Staging Data

Emissions And Flow Characteristics

Date	Time	Point	Tot. Gas	Stack O2	Mix O2	EA	FGD	FGR	Total Dil	CO2	CO	NO	NO2	Fuel	Sto. Air	EA Burn	Cool Air
			MMBtu/hr	Dry	Dry				Dry	%	ppm	ppm	ppm	scfm	scfm	scfm	scfm
Excess Air Points																	
6/24/97	?	2	11.9	8.6%	21.0%	50.2%	0.0%	0.0%	50.2%	7.1%	66	6	1	194	1842	925	221
6/24/97	?	3	33.7	9.8%	21.0%	73.0%	0.0%	0.0%	73.0%	6.2%	11	4	0	548	5219	3812	285
6/24/97	14:05	4	33.7	8.8%	21.2%	59.3%	0.0%	0.0%	59.3%	6.8%	1	7	0	548	5219	3094	283
6/25/97	9:10	A	42.3	8.2%	21.0%	52.9%	0.0%	0.0%	52.9%	7.1%	2	8	0	688	6550	3466	287
FGR Points																	
6/25/97	13:10	B	33.7	6.5%	19.3%	34.7%	20.0%	12.9%	54.7%	8.0%	0	11	0	548	5219	1810	283
6/25/97	13:30	C	33.7	5.3%	19.0%	24.9%	20.6%	14.1%	45.5%	8.6%	0	16	0	548	5219	1301	275
6/25/97	13:50	D	32.0	3.2%	18.1%	10.6%	24.5%	18.1%	35.0%	9.9%	0	26	----	521	4958	523	275
7/7/97	10:15	A	29.3	4.5%	17.6%	18.3%	34.3%	22.5%	52.7%	9.2%	0	9	0	476	4529	830	279
7/7/97	11:30	B	29.9	3.4%	17.1%	11.4%	35.7%	24.3%	47.0%	9.8%	0	12	0	486	4629	526	275
7/7/97	13:20	C	31.2	3.7%	18.7%	13.5%	19.8%	14.8%	33.3%	9.5%	0	26	0	507	4830	652	275
7/7/97	13:45	D	31.2	3.6%	17.8%	12.9%	28.8%	20.3%	41.7%	9.7%	0	17	0	507	4830	623	275
7/7/97	14:10	E	31.2	5.0%	18.3%	22.3%	27.9%	18.6%	50.2%	8.9%	0	10	0	507	4830	1078	275
7/7/97	14:30	F	33.8	1.1%	17.0%	0.0%	29.1%	22.5%	29.1%	11.0%	0	25	0	550	5233	0	275
7/7/97	14:40	G	29.9	3.4%	17.3%	11.4%	33.4%	23.1%	44.8%	9.8%	0	14	0	486	4629	526	275
7/7/97	14:55	H	26.0	4.5%	17.1%	17.7%	40.3%	25.5%	58.0%	9.2%	0	8	0	423	4025	711	275
7/7/97	15:10	I	26.0	3.9%	16.7%	13.7%	42.3%	27.1%	56.0%	9.5%	0	9	0	423	4025	550	275
7/7/97	15:25	J	26.0	3.9%	16.6%	13.7%	43.6%	27.7%	57.3%	9.5%	0	9	0	423	4025	550	275
7/8/97	9:25	A	15.0	3.4%	17.3%	5.7%	29.8%	22.0%	35.6%	9.8%	3	15	0	243	2315	132	268
7/8/97	9:55	B	15.0	4.1%	18.7%	9.9%	18.5%	14.4%	28.4%	9.5%	0	30	0	243	2315	230	275
7/8/97	10:10	C	15.0	3.4%	16.2%	5.3%	41.2%	28.1%	46.5%	9.8%	59	8	0	243	2315	123	277
Scratch Points																	
7/7/97		1	31.2	7.6%	21.1%	31.8%	0.0%	0.0%	31.8%	----	0	13	----	507	4830	1536	280
7/7/97		2	29.3	6.2%	19.4%	31.4%	17.8%	11.9%	49.2%	----	0	8	----	476	4529	1423	280
7/7/97		3	29.3	4.4%	17.8%	17.6%	31.5%	21.1%	49.1%	----	0	9	----	476	4529	798	280
7/7/97		4	29.9	6.8%	19.7%	37.0%	15.4%	10.1%	52.4%	----	0	6	----	486	4629	1711	280
7/7/97		5	29.9	6.4%	19.0%	33.3%	23.5%	15.0%	56.8%	----	0	7	----	486	4629	1539	280
7/7/97		6	29.9	5.6%	18.6%	26.6%	26.1%	17.1%	52.6%	----	0	8	----	486	4629	1229	280
7/7/97		7	31.2	5.1%	20.0%	23.0%	9.4%	7.1%	32.4%	----	0	26	----	507	4830	1111	280
7/7/97		8	31.2	4.6%	19.6%	19.4%	12.6%	9.6%	32.0%	----	0	26	----	507	4830	937	280
7/7/97		9	31.2	6.0%	19.3%	30.1%	18.6%	12.5%	48.7%	----	0	11	----	507	4830	1454	280
7/7/97		10	31.2	3.6%	18.0%	12.8%	26.6%	19.1%	39.4%	----	0	15	----	507	4830	618	280
7/7/97		11	31.2	5.0%	18.2%	22.2%	29.1%	19.2%	51.3%	----	0	9	----	507	4830	1073	280
7/7/97		12	32.5	2.9%	17.9%	8.8%	25.6%	19.1%	34.5%	----	0	20	----	529	5032	445	280
7/7/97		13	28.0	3.6%	17.1%	12.1%	36.2%	24.4%	48.4%	----	0	13	----	455	4327	525	280
7/7/97		14	29.9	1.5%	16.6%	0.9%	33.4%	24.9%	34.3%	----	0	21	----	486	4629	39	280
7/7/97		15	29.9	0.5%	16.0%	16.0%	54.3%	31.9%	70.3%	----	1	22	----	486	4629	738	280
7/7/97		16	26.0	3.4%	16.5%	10.3%	42.0%	27.6%	52.4%	----	0	9	----	423	4025	416	280
7/8/97		1	24.7	3.6%	21.2%	11.3%	0.0%	0.0%	11.3%	----	----	123	----	402	3824	431	280
7/8/97		2	15.0	5.5%	19.2%	19.7%	16.7%	12.3%	36.4%	----	0	15	----	243	2315	456	280
7/8/97		3	15.0	4.2%	19.7%	10.3%	10.0%	8.3%	20.3%	----	0	40	----	243	2315	238	280
7/8/97		4	15.0	5.0%	17.6%	15.9%	32.8%	22.1%	48.7%	----	29	9	----	243	2315	368	280

Table 1

Date	Time	Point	T1	T2	T3	T4(7)	T5	T6	Flux 20	Flux 20	Flux 40	Flux 40	Stack T	FGR T	Mix T	L Steam	H Tube	H Exh	Burn Thr	St Out	Conv Coil	H2O In
			°F	°F	°F	°F	°F	°F	mV	Btu/ft²/hr	mV	Btu/ft²/hr	°F	°F	°F	°F	°F	°F	°F	psi	psi	psi
Excess Air Points																						
6/24/97	----	2	1093	358	1445	276	1491	1416	----	----	----	----	----	----	----	----	----	----	----	----	----	----
6/24/97	----	3	1550	566	1663	449	1654	1600	----	----	----	----	----	----	----	----	----	----	----	----	----	----
6/24/97	14:05	4	1637	636	1655	526	1686	1624	----	----	----	----	----	----	----	----	----	----	----	----	----	----
6/25/97	9:10	A	1653	657	1817	569	1738	1681	5.4	643464	6.8	810288	405	----	----	520	540	380	----	800	1050	1150
FGR Points																						
6/25/97	13:10	B	1618	638	1629	516	1653	1573	5.3	631548	6.1	726876	333	----	106	520	540	300	130	800	1000	1050
6/25/97	13:30	C	1643	645	1686	523	1653	1574	5.6	667296	5.8	691128	331	----	109	530	540	310	125	800	1050	1100
6/25/97	13:50	D	1687	657	1723	527	1673	1584	6.2	738792	5.2	619632	321	----	115	520	540	300	125	800	1050	1150
7/7/97	10:15	A	1515	645	1642	506	1598	1527	4.8	571968	4.7	560052	321	245	103	120	540	300	135	800	1000	1100
7/7/97	11:30	B	1557	645	1680	521	1632	1557	5.0	595800	5.5	655380	323	248	106	120	540	300	140	800	1000	1100
7/7/97	13:20	C	1665	656	1707	514	1666	1581	----	----	----	----	320	226	106	110	540	300	125	800	1000	1150
7/7/97	13:45	D	1593	651	1696	530	1657	1576	----	----	----	----	334	249	108	110	520	300	140	800	1000	1100
7/7/97	14:10	E	1555	654	1678	529	1632	1560	----	----	----	----	350	261	111	110	540	310	140	800	1050	1150
7/7/97	14:30	F	1646	663	1778	556	1702	1619	----	----	----	----	333	262	110	110	545	310	145	800	1100	1175
7/7/97	14:40	G	1571	650	1681	532	1620	1539	----	----	----	----	330	260	113	----	----	----	----	----	----	----
7/7/97	14:55	H	1493	647	1604	503	1550	1470	----	----	----	----	314	244	114	520	540	300	150	800	1000	1100
7/7/97	15:10	I	1497	642	1604	485	1547	1465	----	----	----	----	308	241	106	520	540	290	150	800	1000	1050
7/7/97	15:25	J	1455	631	1570	464	1519	1437	----	----	----	----	305	236	117	520	530	290	150	800	975	1075
7/8/97	9:25	A	1267	461	1410	323	1337	1228	----	----	----	----	203	156	109	520	420	200	120	800	900	1000
7/8/97	9:55	B	1208	465	1421	322	1343	1238	----	----	----	----	198	153	109	520	420	190	115	800	900	1000
7/8/97	10:10	C	1273	460	1394	323	1321	1209	----	----	----	----	210	165	111	----	----	----	----	----	----	----

Note: Italics indicates data that are averages of data collected with Rustrack.

Note: "Flux 20" indicates heat flow at the tube wall. "Flux 40" indicates the heat flux 1/2 way between the burner surface and the tube wall.

APPENDIX D

BABCOCK & WILCOX REPORTS

Babcock & Wilcox
a McDermott company

Power Generation Group
20 S. Van Buren Avenue
P.O. Box 351
Barberton, OH 44203-0351
(330) 753-4511

December 2, 1997

John Sullivan
Vice President, Engineering
2343 Calle Del Mundo
Santa Clara, CA 95054

Ref: Evaluation of the RSB and In-Furnace
Cooling Surface Using Modeling Techniques
Proposal No. P57-0013

Dear John,

Enclosed herewith are complete sets of the following computer runs:

OPTION 4: Increased Furnace Absorption Utilizing Membrane Wall Construction

MOD. 5: Close Spaced Burner/Wall Arrangement with Constant Resident Time, Reduced Burner Input Rating (per sq-ft), Larger Diameter Furnace & Larger Diameter Burner.

MOD. 6: Close Spaced Burner/Wall Arrangement with Constant Resident Time, Base Burner Input Rating (per sq-ft), & Through a Base Arc Length.

MOD. 8: Close Spaced Burner/Wall Arrangement with Reduced Resident Time, Base Furnace Diameter, Base Burner Input Rating (per sq-ft), & Through a Base Arc Length.

Also attach is a commentary documenting the results of each arrangement and the logic used in selecting the subsequent computer mode.

The results of the modeling thus far indicates that the original hypothesis is not supported. The original concept was that if heat could be absorbed from the combustion process at a higher rate, then the flue gases would be cooler and less thermal NOx would be formed. This is true to a minor extent, but the variations in absorption tested by 1) modeling a membrane wall verses a spaced wall with 50% exposed refractory, or 2) placing the burner heat release surface closer to the water cooled wall, had but a minor effect on furnace temperature. Neither case appreciably lowered the furnace gas temperature, and the effects on thermal NOx was slight. In fact, in the latter case, the NOx production actually went up.

It is estimated that approximately 80 % of the heat released from combustion supports the increase in the flue gas mass temperature, and only approximately 20 % is absorbed by the furnace. By increasing the furnace effectiveness by 12 to 14 % (the shift from OPTION 3 vs. OPTION 4), the shift in heat transfer is but approximately 2 to 3 % of the total. It is estimated that improving the effectiveness of the furnace wall still further with extended surface we could achieve up to 40 % improved heat transfer, resulting in an 8 percent shift of the total. This may result in a furnace temperature drop of an estimated 200 F. If we are close to the thresh hold of thermal NOx this could result in a more significant drop in NOx formation.

We took a closer look at the radiation heat transfer as compared to the convective heat transfer in OPTION 4. This is shown in the 2 plots labeled FURNACE HEAT FLUX; Ratiative & Convective. This incicates that 95 % of the furnace heat transfer is ratidative, and only 5 % is convective.

In the case of the closer spacing of the burner to the furnace wall (MOD. 5), it is concluded that the closer proximity of the burner to the wall didn't really change the overall radiation component, but did improve convection heat transfer slightly due to increased velocities adjacent to the wall. However, changes in the furnace internal recirculation patterns overshadowed this improvement. A far greater effect is seen in the amount of furnace gases entrained in the gas jets. It appears that it may be possible to use this characteristic to a greater extent by using stronger jets (higher pressure drop across the jets), and by arranging their location such that the furnace gases will realize less resistance to reach the root of the jet. Instead of having 1 inch perforation strips on 2 inch centers, perhaps it would work more effectively by doubling the clear space between every other perforation strip. This would result in increasing the clear space by approximately 50%, and increasing the jet velocity by about 50 %.

It is recommended that we extend the modeling program to investigate the above suggested possibilities. I would recommend the following:

1) Reconstructing the burner model to modify the perforation strips. The above arrangement would be one possibility; you may have some other suggestions.

2) Re-run OPTION 4 and MOD. 8 configurations with this modified burner design.

3) Increase the furnace wall heat transfer by adding a large amount of extended surface to the extent that it is even exaggerated to see if this will have a significant effect on Thermal NOx.

4) Repeat test runs 1 and 2 to evaluate relative effectiveness.

The cost of these additional runs is estimated as follows: ITEM	1)-------------	$ 900.00
	2)-------------	$ 900.00
	3)-------------	$1,800.00
	4)-------------	$ 900.00
TOTAL		$4,500.00

Should you have any questions regarding the attached please give me a call.

Regards,

Richard Vetterick

Richard C. Vetterick

Enclosure

cc: D. C. Langley
M. W. Hopkins
M. J. Albrecht

ALZETA BURNER MODELING

SUBSEQUENT COMPARATIVE STUDIES

OPTION 4:

OPTION 4 is identical to OPTION 3 with the exception that the absorption factors for the water cooled wall were increased to represent a membrane wall, as compared to 1 inch tubes on 2 inch centers with kaowool backing. As compared to Option 3, the furnace gas temperatures dropped approximately 44 F at the 8 ft location, and the NOx decreased by an average of 0.2 ppm, or 2.8%.

MOD. 5: Modification 5 is a reconstruction of the model to bring the burner closer to the water cooled furnace walls. This posed somewhat of a problem in that as the burner diameter was increased to bring the fire closer to the wall, the cross sectional flow area decreased dramatically; reducing resident time. It was decided to maintain resident time by increasing the burner diameter and the furnace diameter to the extent that the burner would be half the distance from the wall, but the cross sectional flow area would be the same. This resulted in a 120 inch burner diameter, and a 160 inch furnace diameter, with 20 inch spacing from the burner surface to the water cooled wall. This then posed a second problem, how to set the burner heat release rate. A reduced burner surface heat release rate was chosen, keeping the perforation pattern the same as option 3. This cut the burner heat release rate to one quarter of the previous rate. The absorption characteristic of the furnace wall was kept at the membrane wall factors.

The calculated average furnace temperature at the 4ft. and 8 ft. locations went down slightly (56 F & 30 F respectively), but the NOx went up significantly, from 6.9 ppm to 7.4 (6.9%) and 7.7 (10.4%) respective to the location. This is just opposite from what we expected, and caused us to review our assumptions. Since the burner heat release rate was reduced to one quarter, it was decided to reestablish this to the original values, and to use only a portion of the burner arc for the high input zone, still using the same perforation pattern. This lead to MOD. 6.

MOD. 6: The burner high heat release rate arc in this case returned to 23.6 inches, and the heat release rate returned to that used in OPTION 4. The clearance from the burner surface to the furnace surface was kept at 20 inches. In this case the average calculated furnace temperature at the 4 & 8 ft location dropped down slightly, but the NOx dropped dramatically! The NOx levels dropped from the 6.9 ppm levels in OPTION 3 to 5.4 ppm, some 21.7%. As compared to mod. 5, the drop was 27 % and 30 % respectively at the 4 ft. and 8 ft. locations. Since the heat absorption rates of the furnace wall were not changed, and the clearance from the burner to the furnace wall was not changed, it is concluded that the major contributing factor is the ability, in this arrangement, for the furnace gases to find a flow path back to the root of the burner jets. The velocity vector pattern and relative magnitude (vector length) indicates that there is considerable recirculation within the furnace in this arrangement. The low heat release rate zones on either side of the high heat release rate zone (where the perforations are) provide a flow path for the furnace gases to more easily return to the root of the perforation jets.

MOD. 8: It was decided at this point to return to the original size furnace, to maintain the 20 inch clear space between the burner and the furnace wall, and to maintain the 23.6 inch high heat input burner pattern. This left approximately 31.4 inches on either side of the high heat input burner zone for free flow recirculation patterns (as compared to 35 1/3 in MOD. 6). This produced essentially the same results as MOD. 6.

END

RCV (12/2/97)

Case	Description	Average Furnace Gas Temperature (°F)				Average NO_x (ppm)				Average Heat Flux ($kBTU/hr\text{-}ft^2$) <21ft (<10ft)
		4 feet	8 feet	14 feet	16 feet	4 feet	8 feet	14 feet	16 feet	
Test	Test Point Data	1637	1655	1688	1624	--	--	--	7	?
Alzeta	Spreadsheet Ave Data	2009	2089	1993	1925	--	--	--	--	19.5 (19.8)
Option 3	Model Average Data	2159	2140	1923	1852	7.1	7.1	7.1	7.1	19.0 (19.7)
Option 4	Model Average Data	2120	2096	1857	1780	6.9	6.9	6.9	6.9	21.8 (22.2)
Mod 5	Model Average Data	2064	2069	1745	1646	7.4	7.6	7.7	7.7	12.2 (13.4)
Mod 6	Model Average Data	1931	1956	1672	1578	5.4	5.4	5.4	5.4	13.5 (15.2)
Mod 8	Model Average Data	2172	2188	1909	1807	5.3	5.2	5.2	5.2	18.0 (18.3)

Table: Stage Two Summary Results

ALZETA SUMMARY OF B&W MODELING RESULTS

Attached are the two B&W reports summarizing the modeling of the Alzeta RSB that was done with DOE funds. We view these results as being useful to our effort to develop the RSB for industrial boilers, but additional work is required. Comments on this work are provided on this page as our summary to this Appendix.

The second report, dated December 2, 1997 presents the results of modifications made to the boiler to more quickly cool the flue gas. These modifications were:

- Model the effect of membrane wall construction versus the exposed refractory between tubes as existed at Cymric. Membrane wall construction results in a continuous metal wall surface, with the "membrane" between tubes being welded to the watertubes. The result of this should be slightly higher heat removal in the firebox.

- Model the effect of closer burner-to-wall spacing. Reduced burner-to-wall spacing should result in reduced gas phase radiation (if no other parameters are changed), with the result that NO_x production will increase (as observed by B&W). Reduced burner-to-tube spacing increases heat removal via gas phase radiation only if you split a large gas volume into several small volumes and add heat transfer surface between the small volumes. Reduced burner-to-wall spacing can increase convective transfer, but convection is a small component of total firebox heat transfer.

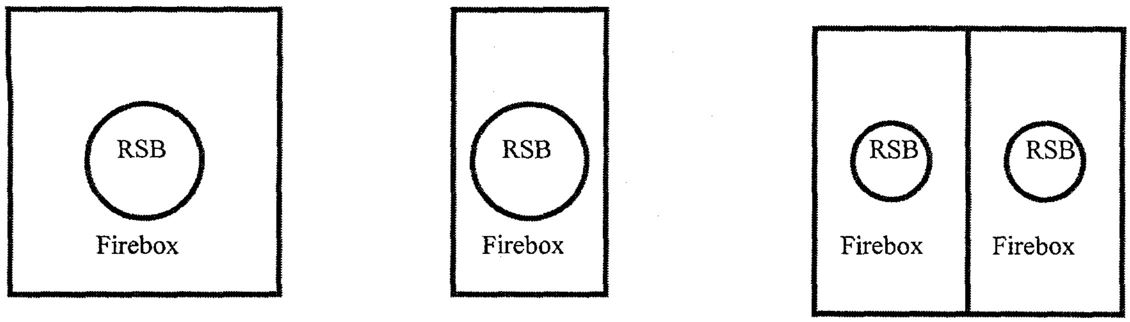
The B&W report concludes that "The results of the modeling thus far indicates that the original hypothesis is not supported." We disagree with this conclusion. **If** heat is absorbed from the combustion process at a higher rate, **then** the flue gases will be cooler and less thermal NO_x will be formed. The modifications modeled by B&W did not significantly increase heat removal, and therefore did not reduce NO_x. The B&W modeling did demonstrate that membrane wall construction and reduced burner-to-wall spacing, by themselves, are not sufficient to significantly increase heat transfer. This is valuable information, since additional modifications to remove heat from the firebox such as an intermediate tube wall in the firebox or extended tube surface will be more expensive to implement.

Other very useful information provided by B&W in the December 2 report is the split of heat absorption between the firebox and convective section, and between radiation and convection mechanisms, in the boiler. Understanding where, and by what mechanism, heat is removed is critical to the design of the sub-9 ppm boiler. In addition, the Alzeta plug flow model was shown to agree closely with the B&W CFD code. In the future we will use the Alzeta code to assess the impact of burner modifications on boiler performance with greater confidence.

The Alzeta conclusions are as follows:

- Splitting a standard firebox into two burner compartments with an intermediate tube wall would have a significant effect on heat removal rate. Gas phase radiation is estimated to be increased by more than 25 percent in the firebox in a typical boiler configuration.

Adding extended tube surface to firebox boiler tubes will increase the heat removal rate, but the magnitude of this increase is still being evaluated. The increase due to increased convection is insignificant. The more significant impact will have to be the result from increased gas phase absorption.



1. End view of Standard Firebox with Alzeta burner

2. Configuration with Reduced Burner-to-Tube Spacing

3. Intermediate Tube Wall Configuration

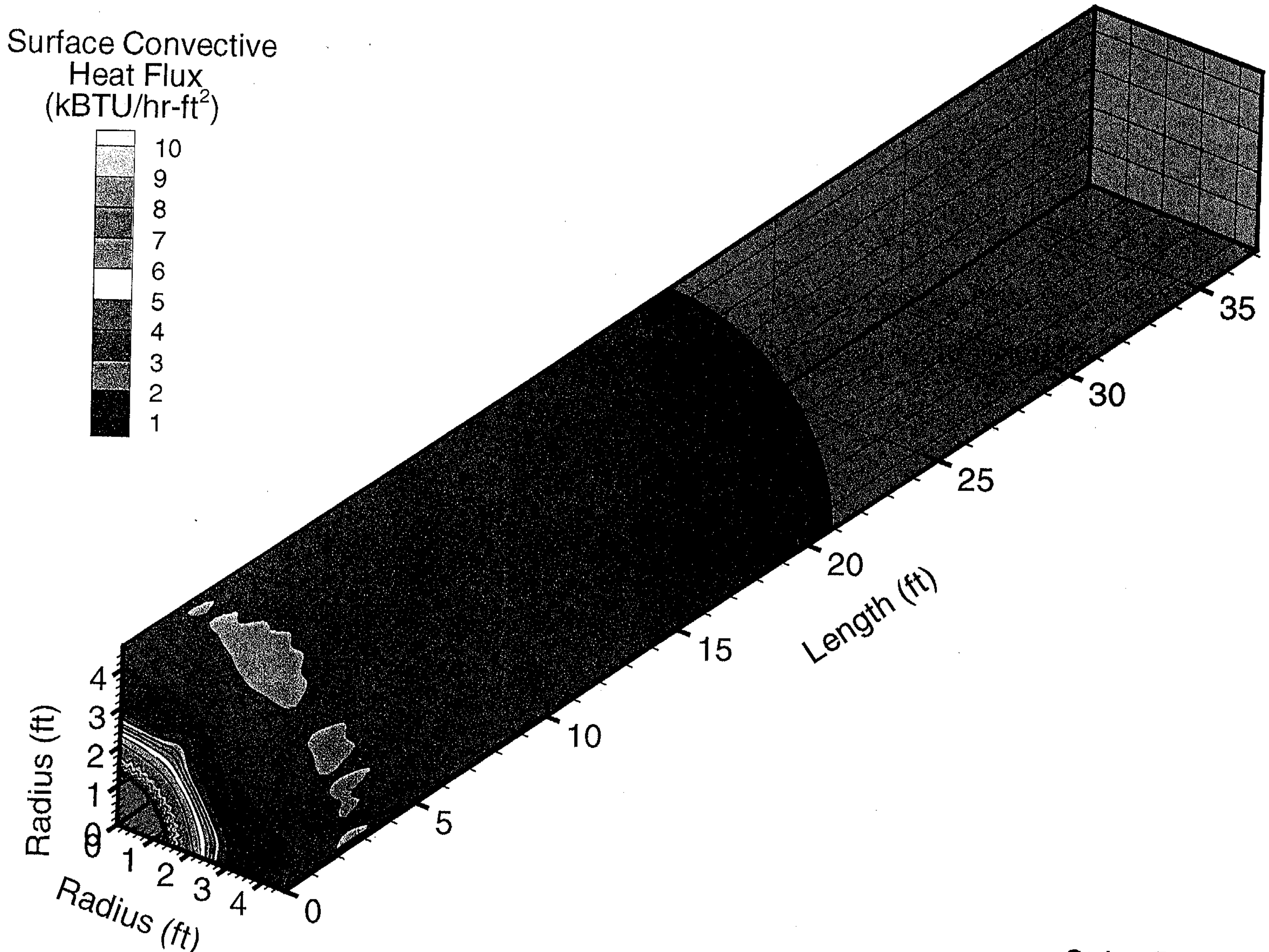
Configuration 1 shows the standard RSB configuration in a package boiler. Note that B&W modeled the cylindrical RSB inside of a cylindrical steam generator, but the same trends will be observed regardless of whether the firebox has a cylindrical or rectangular cross section.

In Configuration 2, the firebox volume is reduced. If the total fired duty of the burner is held constant between Configuration 1 and Configuration 2, then heat absorbed in the firebox is reduced. In the configuration presented, the residence time in the firebox is also reduced. The size of the box and the burner can both be increased to maintain both the Configuration 2 burner-to-tube spacing and the Configuration 1 residence time. In either case, heat absorbed in the firebox is reduced.

In Configuration 3, the firebox volume is equivalent to the Configuration 1 volume. An intermediate tube wall is added, with a burner in each cell. The total fired duty of the two Configuration 3 burners is equivalent to the fired duty of the Configuration 1 burner. Gas phase radiation to each tube wall is less in Configuration 3 relative to Configuration 1, but it is greater than 50 percent of the Configuration 1 flux. Therefore, when the additional tube wall is added to increase the firebox surface area, the result is an increase in total heat removal from the firebox.

Alzeta Burner Project, Cymric Model - Stage 2

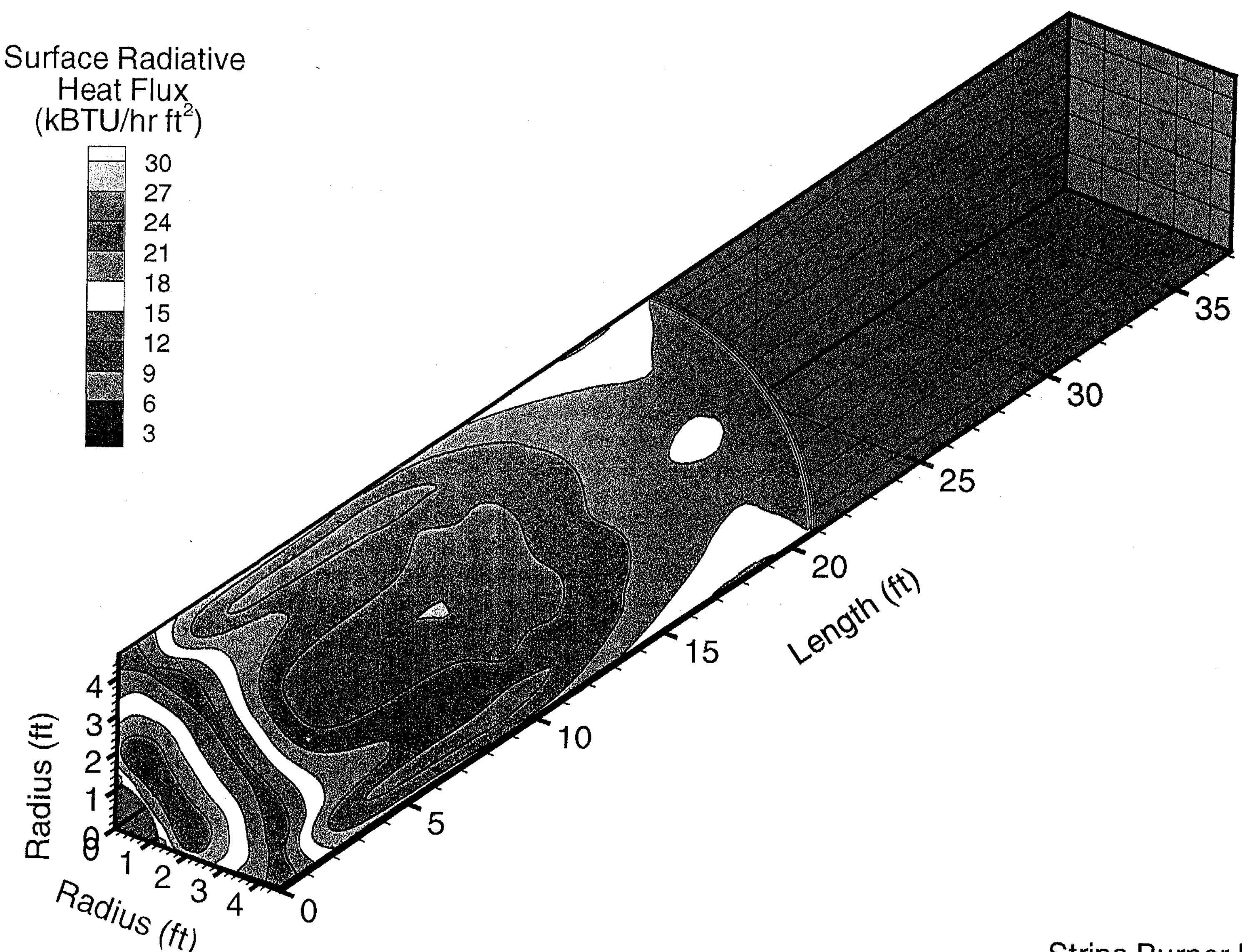
Option 4 - Furnace Heat Flux



Strips Burner Inlet

Alzeta Burner Project, Cymric Model - Stage 2

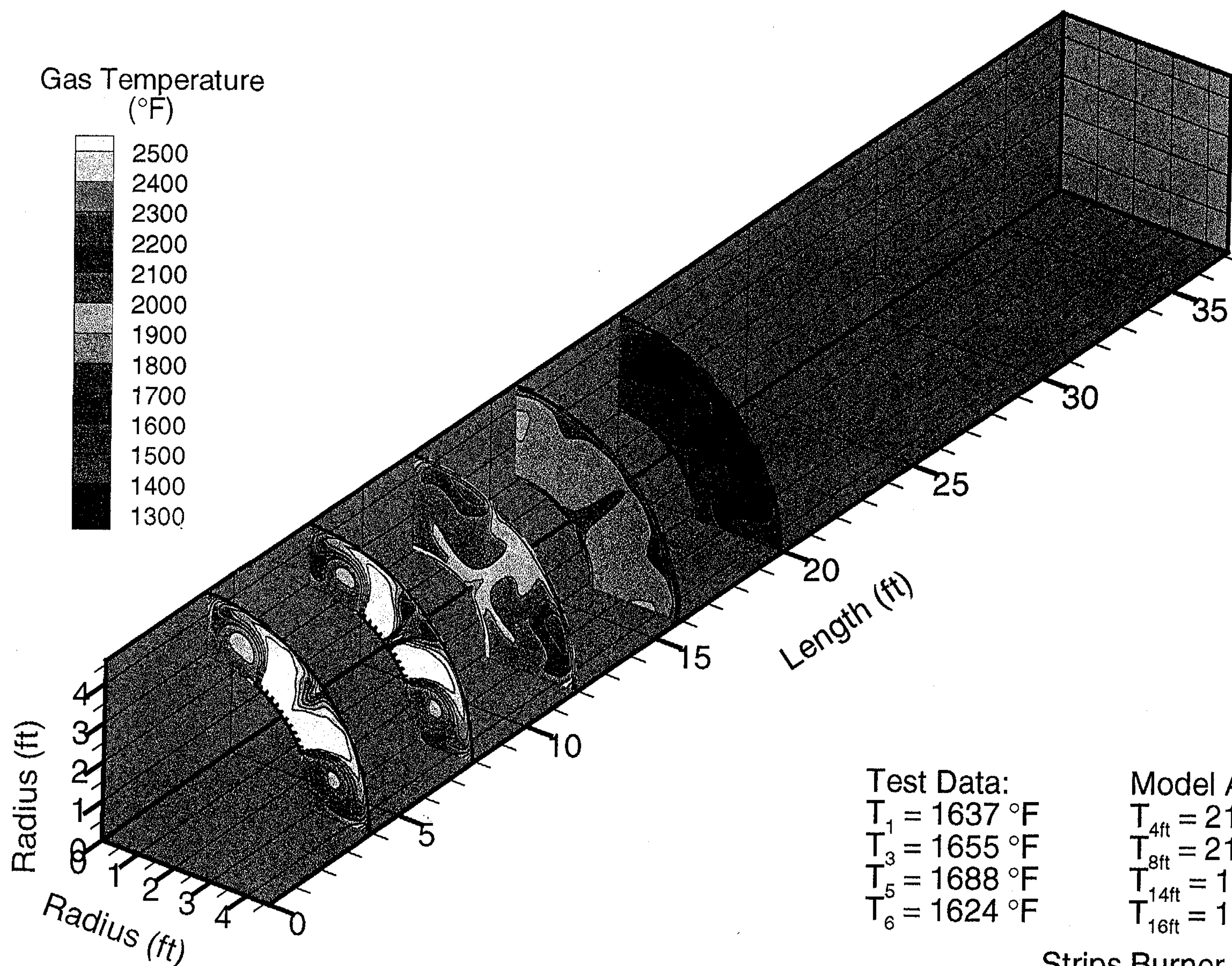
Option 4 - Furnace Heat Flux



Strips Burner Inlet

Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace Gas Temperatures



Test Data:
$T_1 = 1637$ °F
$T_3 = 1655$ °F
$T_5 = 1688$ °F
$T_6 = 1624$ °F

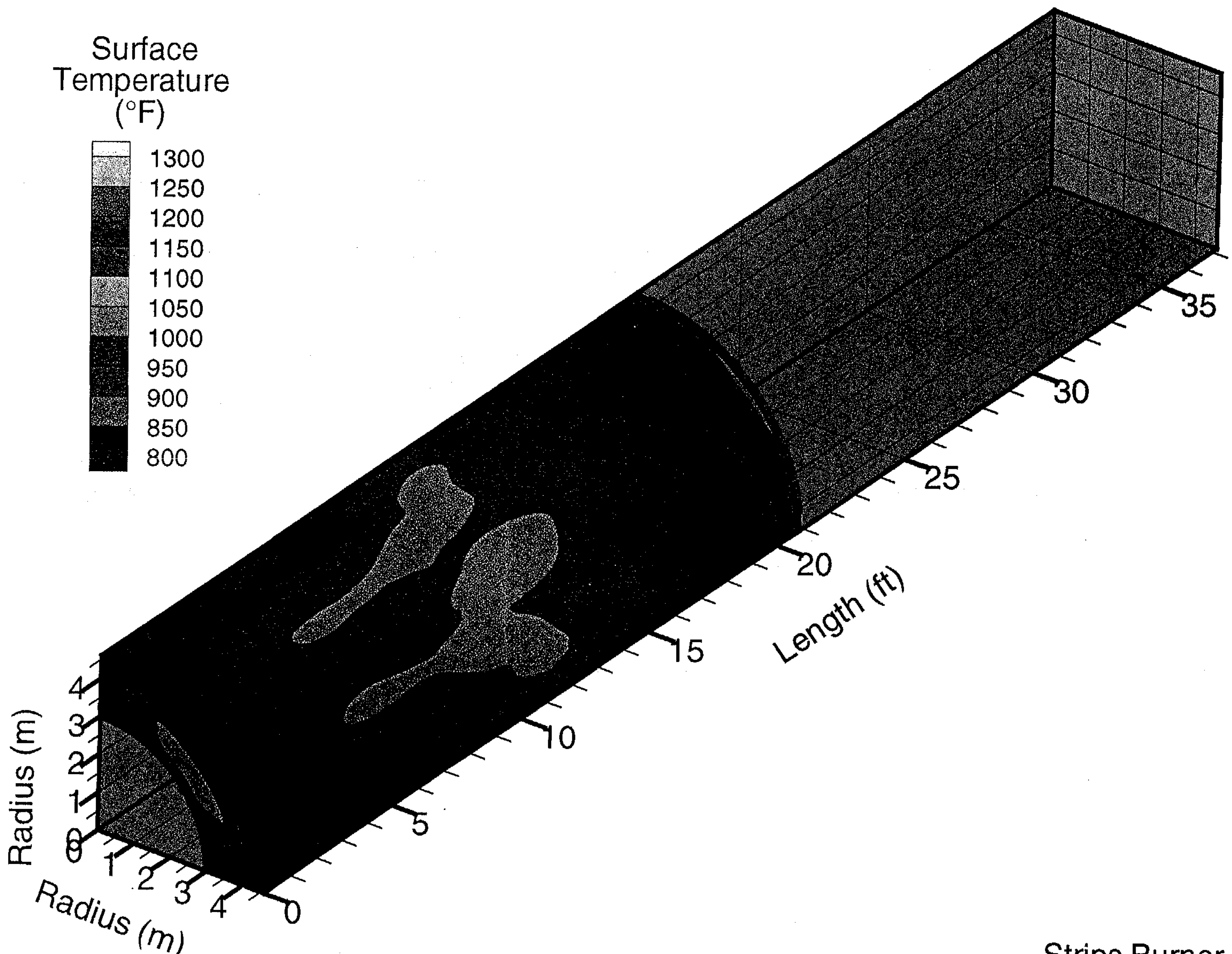
Model Ave:
$T_{4ft} = 2172$ °F
$T_{8ft} = 2188$ °F
$T_{14ft} = 1909$ °F
$T_{16ft} = 1807$ °F

Strips Burner Inlet

a

Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace Surface Temperatures

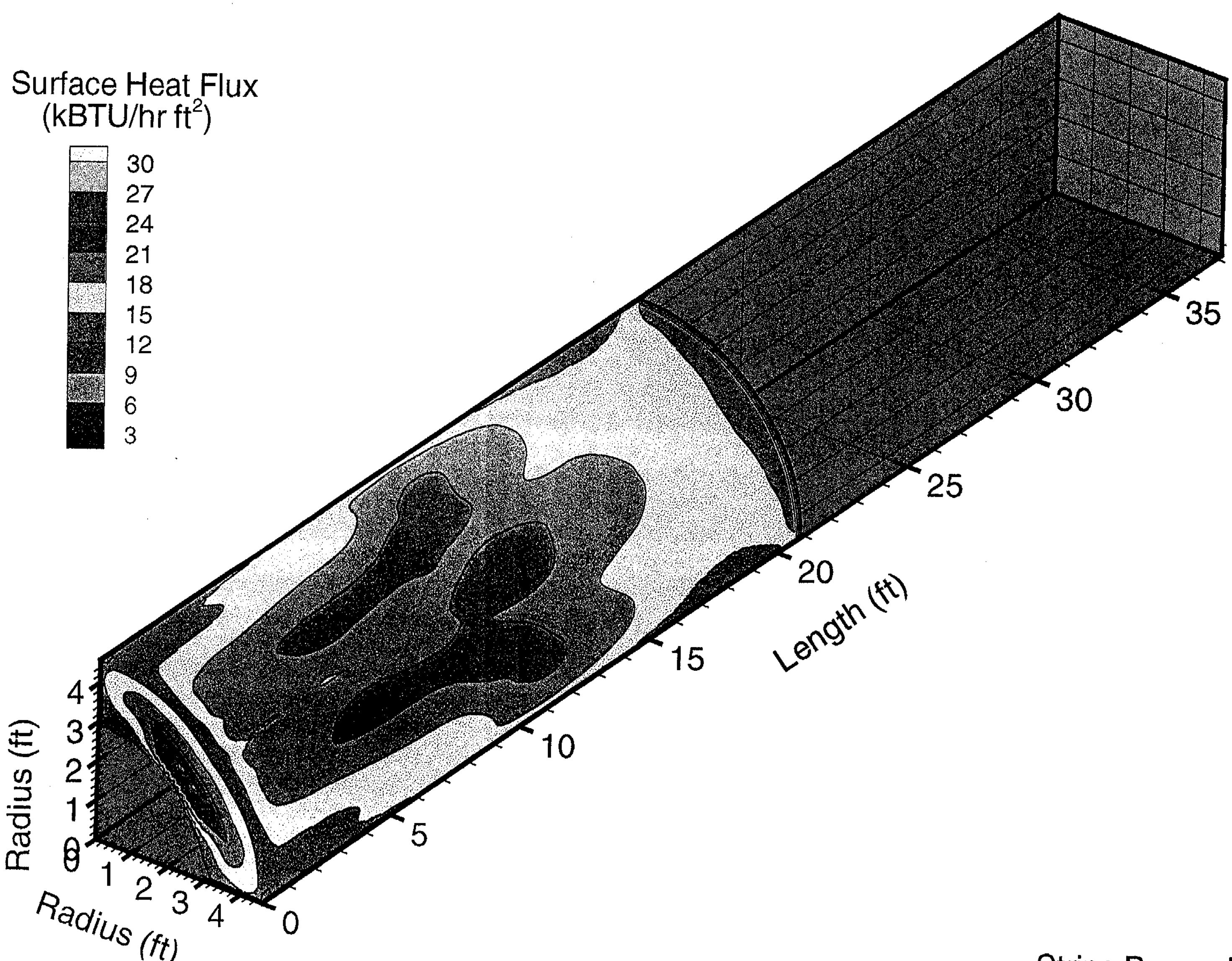


Strips Burner Inlet

b

Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace Heat Flux

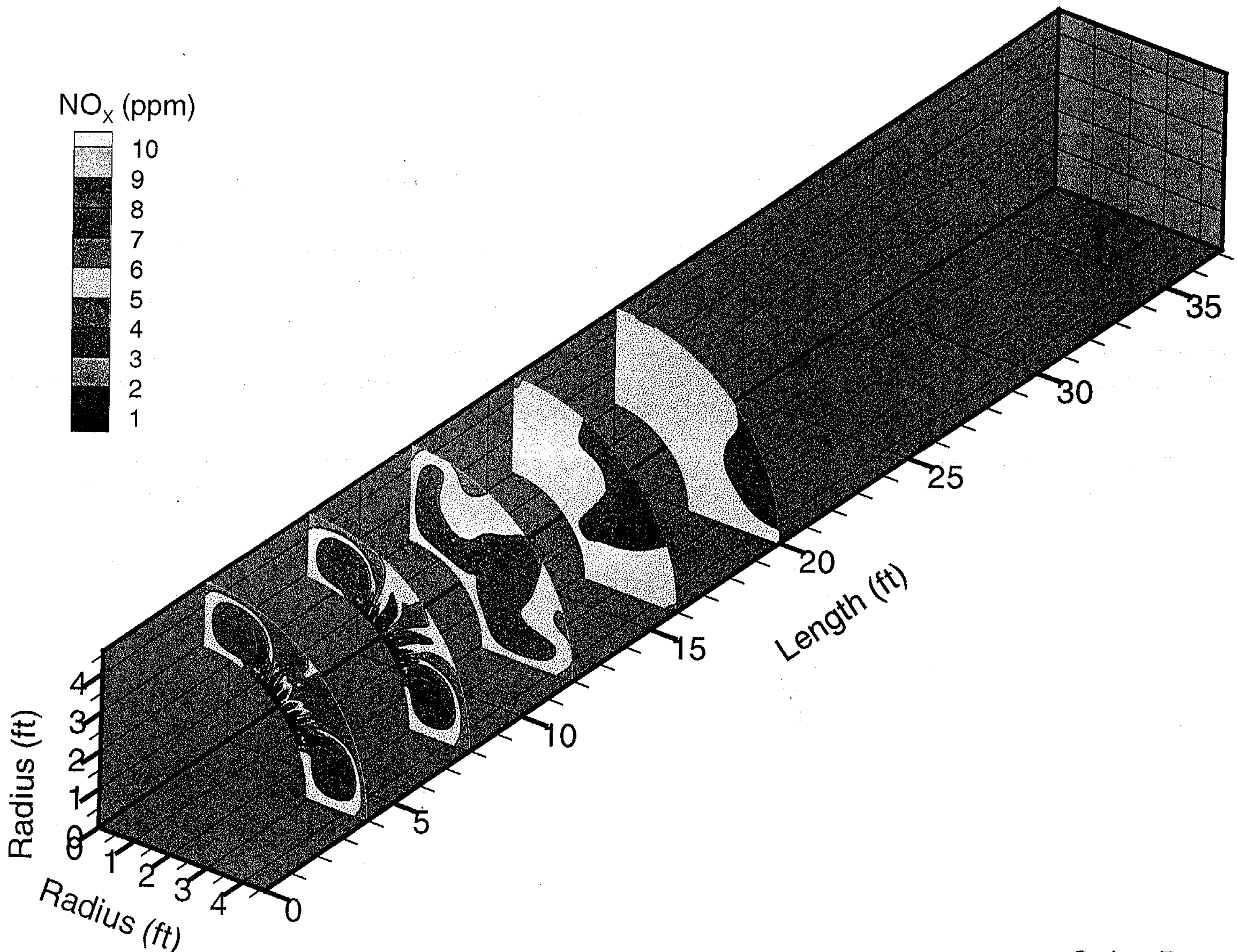


Strips Burner Inlet

c

Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace NO_x Levels

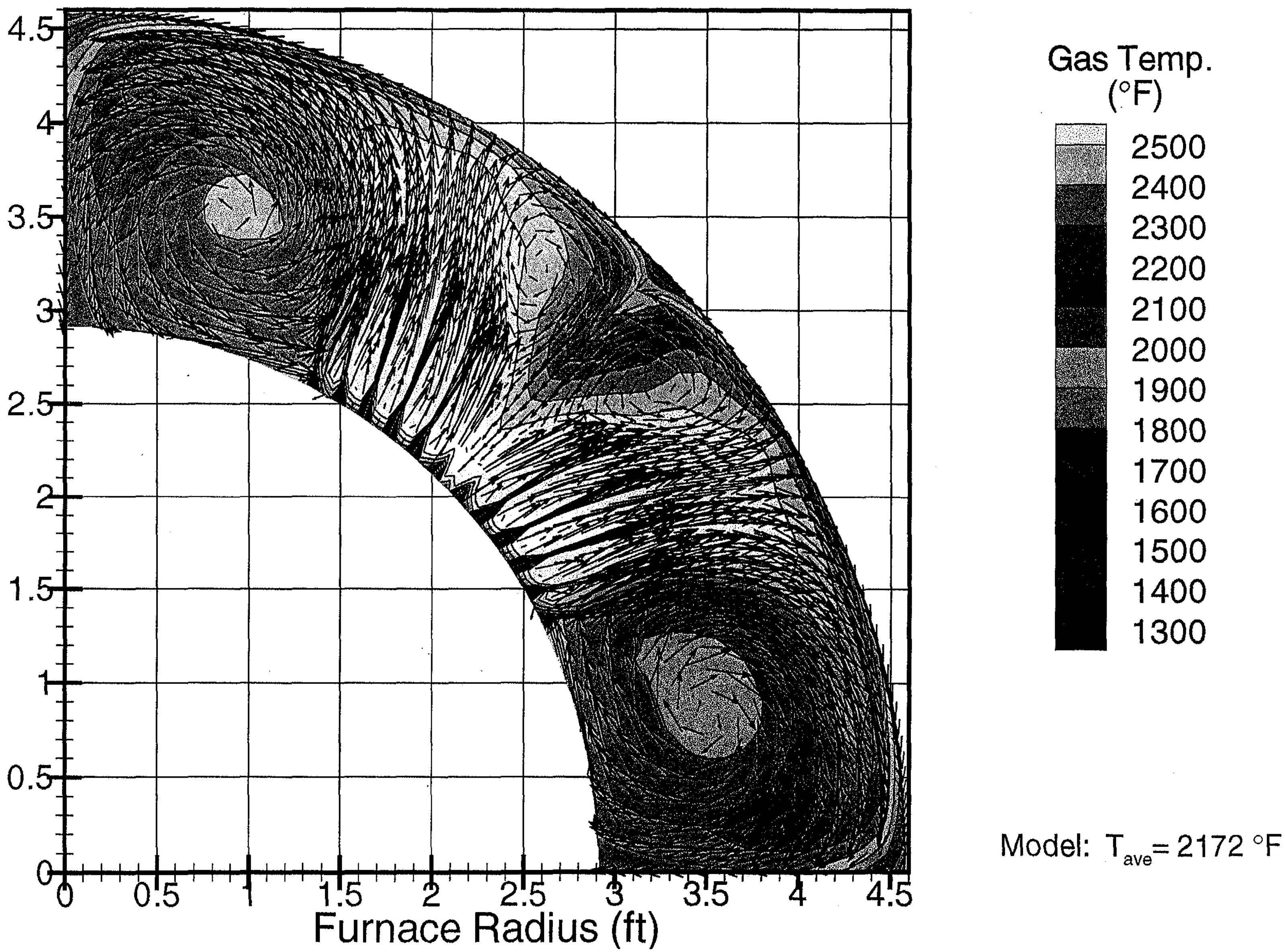


Strips Burner Inlet

d

Alzeta Burner Project, Cymric Model - Stage 2

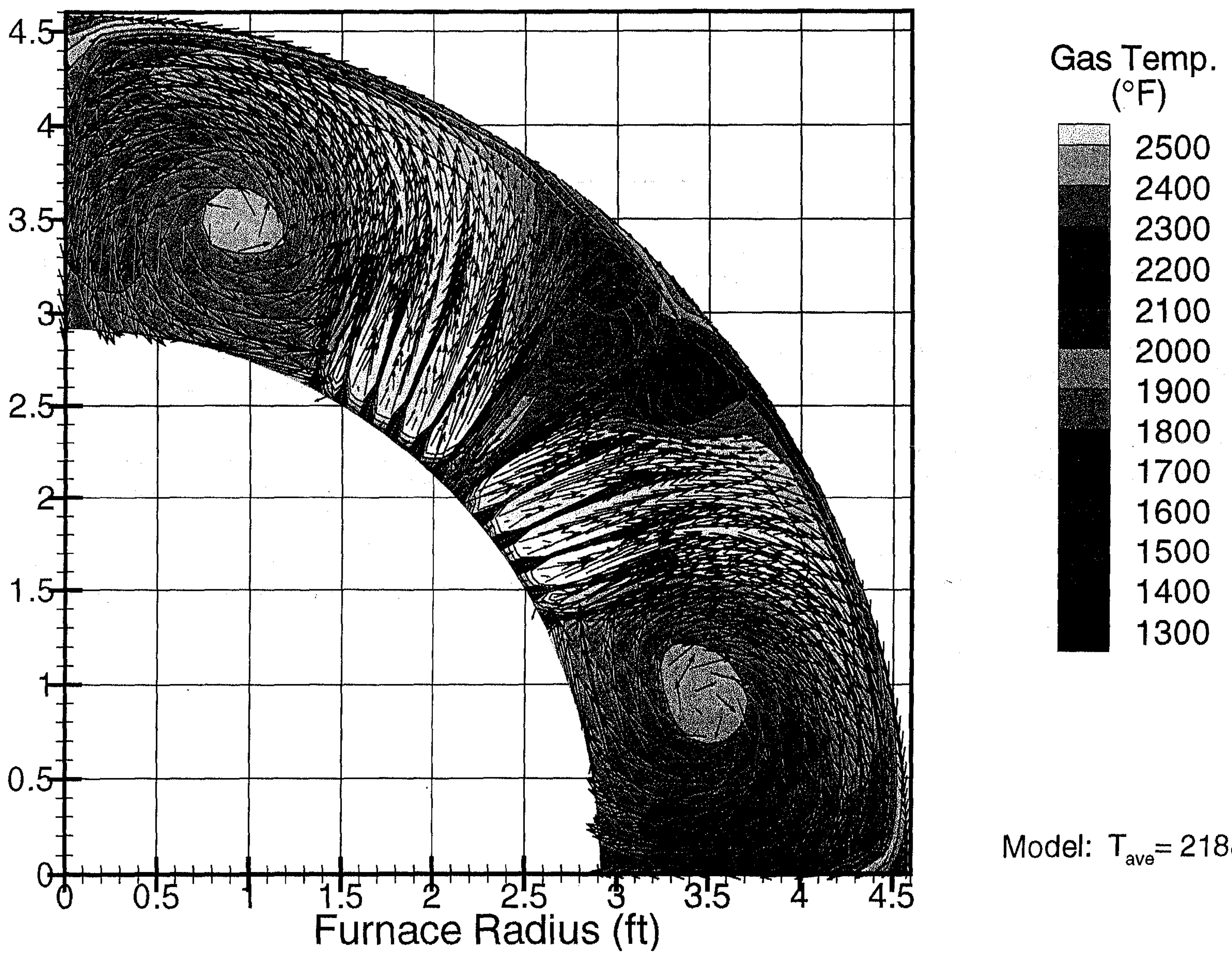
Modification 8 - Furnace Location at 4 feet



e

Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace Location at 8 feet

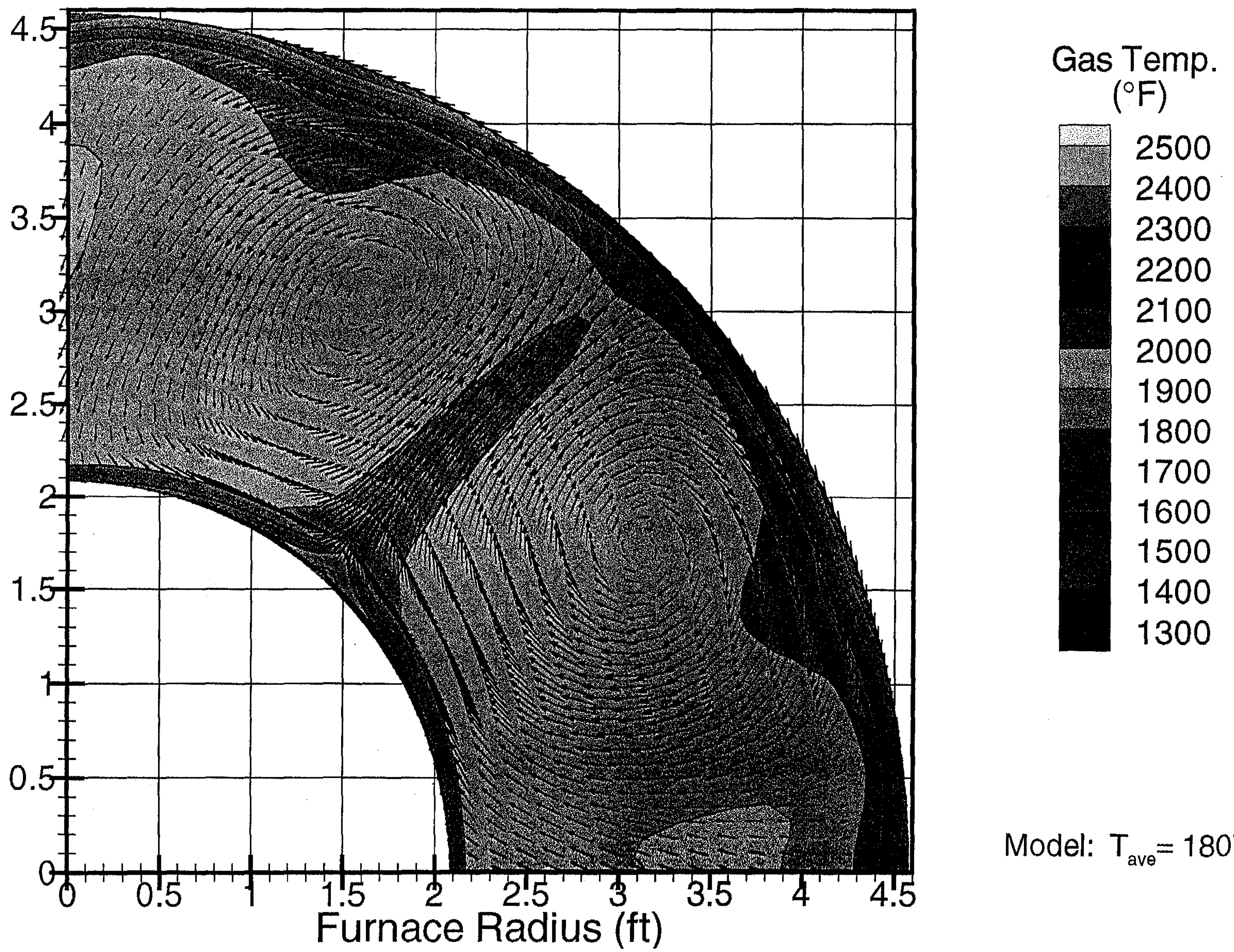


Model: T_{ave}= 2188 °F

f

Alzeta Burner Project, Cymric Model - Stage 2

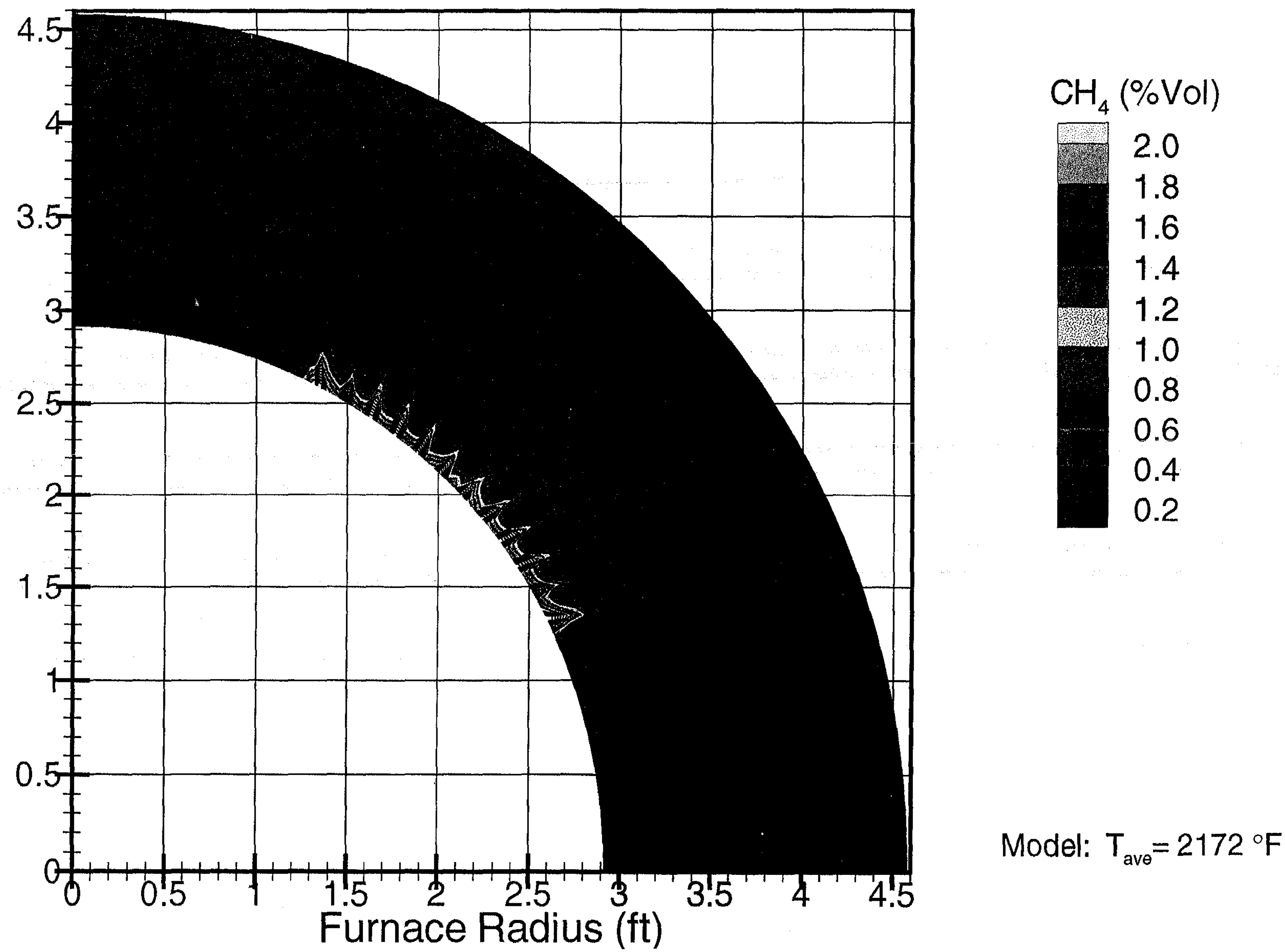
Modification 8 - Furnace Location at 16 feet



Model: T_{ave}= 1807 °F

Alzeta Burner Project, Cymric Model - Stage 2

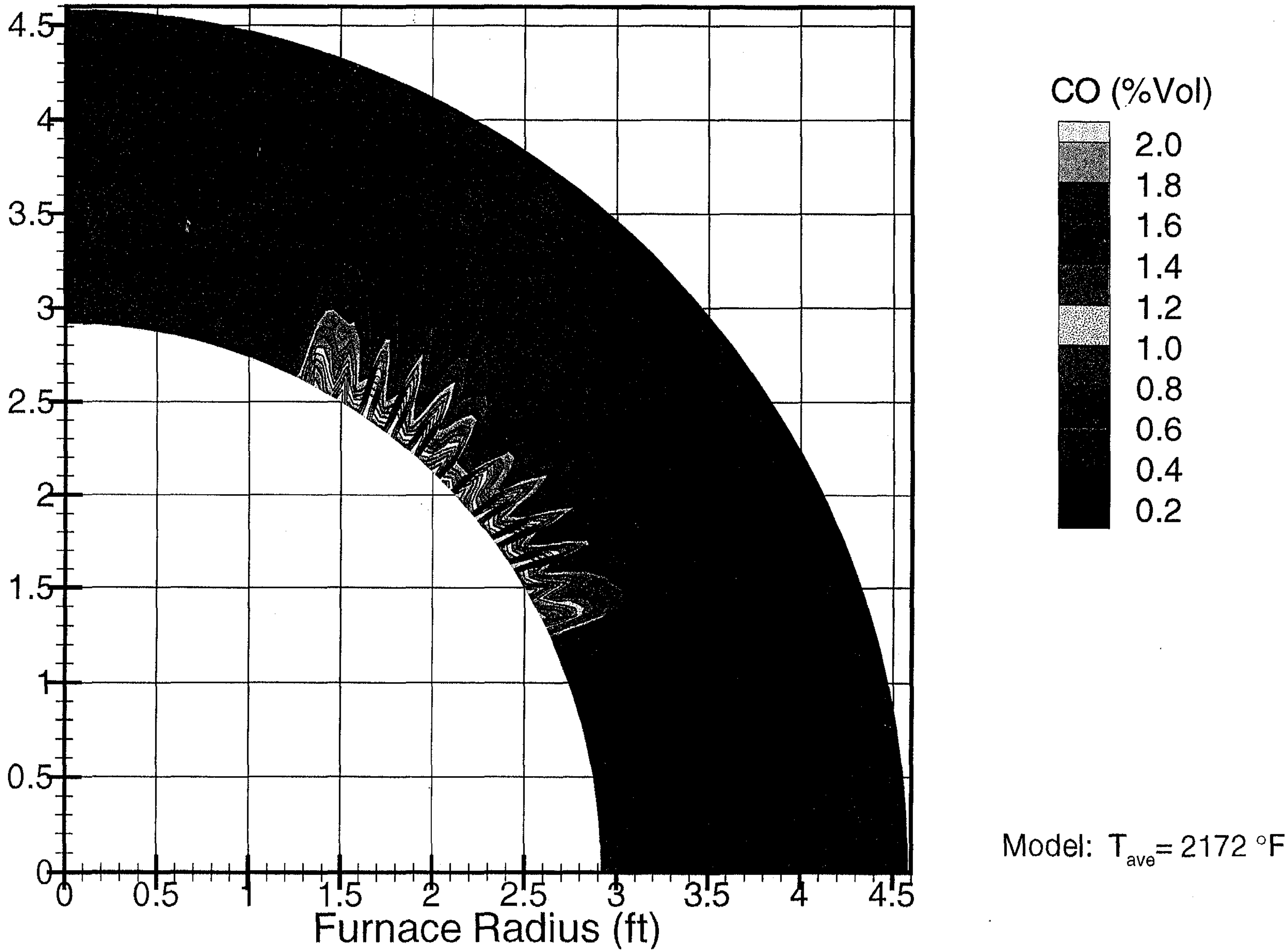
Modification 8 - Furnace Location at 4 feet



h

Alzeta Burner Project, Cymric Model - Stage 2

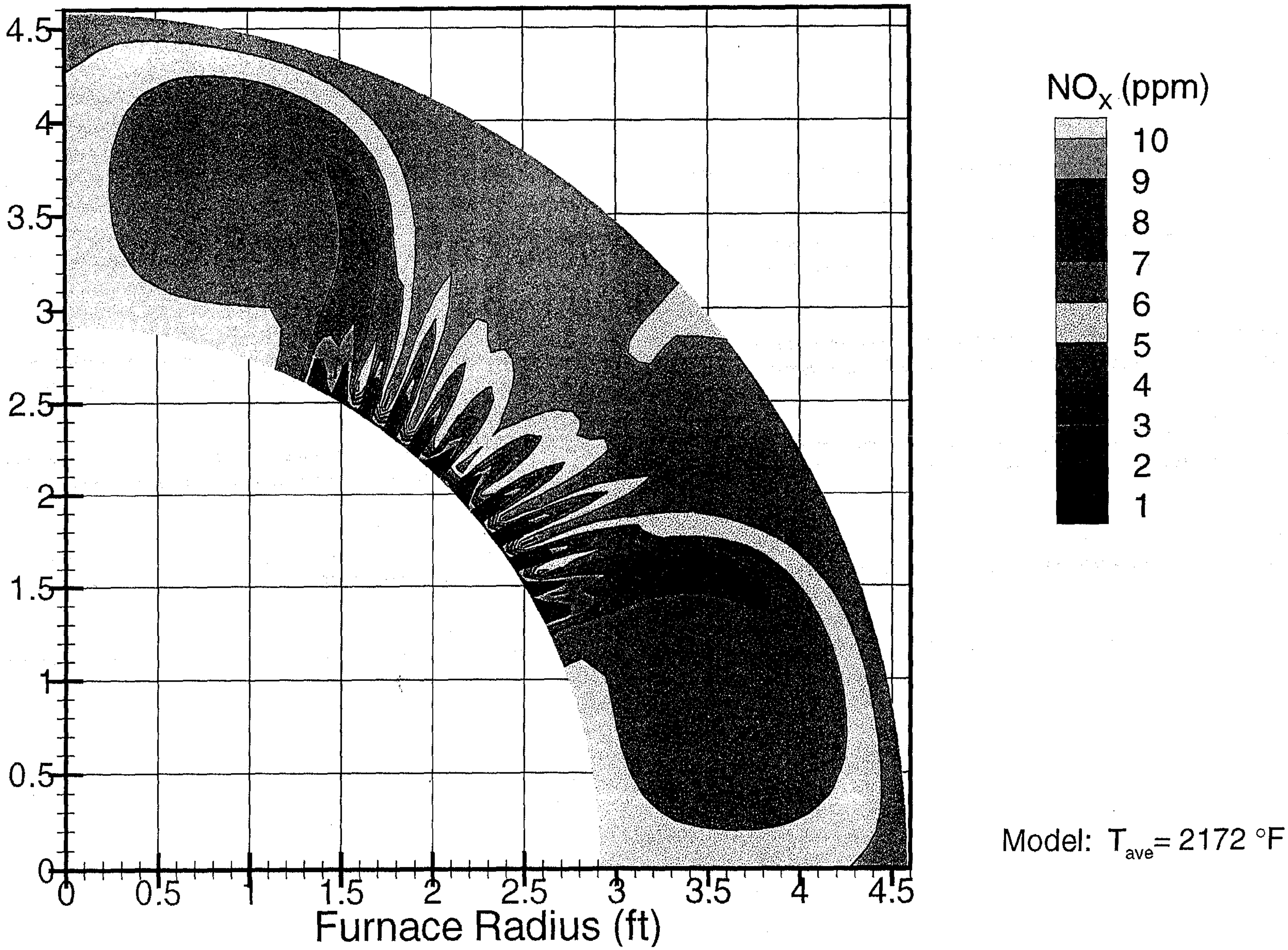
Modification 8 - Furnace Location at 4 feet



2

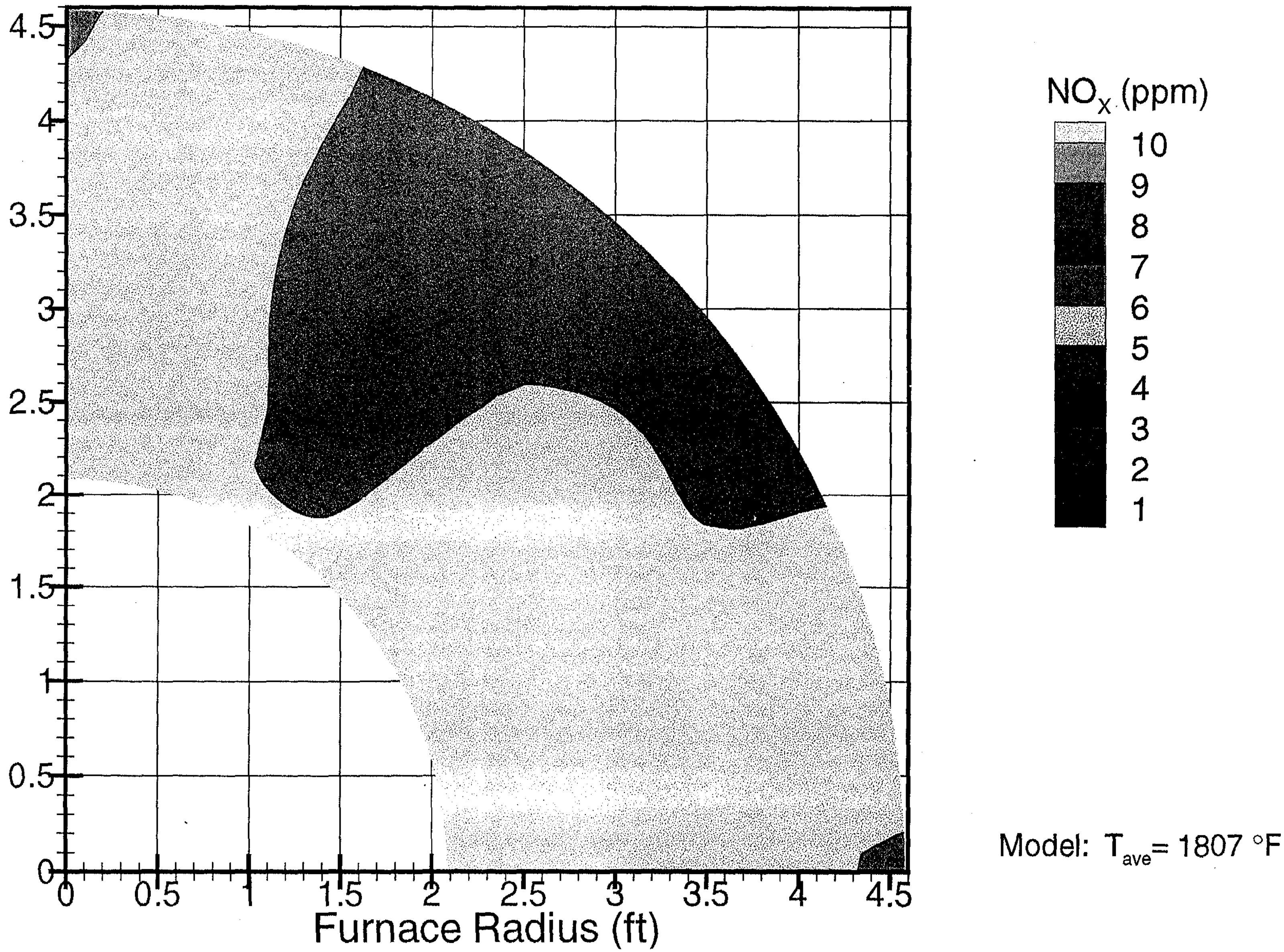
Alzeta Burner Project, Cymric Model - Stage 2

Modification 8 - Furnace Location at 4 feet



k

Alzeta Burner Project, Cymric Model - Stage 2
Modification 8 - Furnace Location at 16 feet



l

APPENDIX E

INDUSTRIAL BOILER MARKET DESCRIPTION

INDUSTRIAL BOILER MARKET DESCRIPTION

Gas Research Institute Market Survey

The Gas Research Institute, through a contract with RCA/Hagler, Bailly, Inc., examined various market aspects of industrial boiler combustion systems (Reference 6). Although this report is approximately 10 years old, more recent data have substantiated results of the GRI survey indicating that many aspects of the industrial boiler market have not changed significantly in the past 10 years. These areas of little or no change include installed capacity, size distribution of industrial boilers, and usage factors. An area of significant change is the shift to natural gas as the primary fuel as the result of lower gas costs and the need to reduce pollutant emissions, but this transition had started at the time of the GRI survey. In addition, this shift should act to increase the advantages of the RSB over competing technologies since the RSB is by design a gaseous fuel burner.

The survey, based on 1985 market data, found that the industrial boiler inventory consisted of just under 37,000 systems with a combined steam heat capacity of roughly 1.5 trillion Btu/hr. Small boiler systems, with capacity less than 25 MMBtu/hr, represent the largest number of installed units. However, a typical industrial boiler (used for process steam requirements) is typically between 50 and 250 MMBtu/hr in size. Most industrial capacity is within this size range.

The study found that industrial boilers represent one of the largest components of industrial fuel consumption. Traditionally, industrial boilers have been single-fuel systems, with natural gas-fired systems accounting for a dominant share of the installed base. Natural gas and fuel oil remain the primary boiler fuels (although as mentioned above, the decrease in gas cost and increased pressure for reduced emissions have enlarged natural gas market share significantly). The North Central and South Central regions of the U.S. account for the majority of industry's boiler units and capacity, with these geographic areas defined in Figure E-1. The chemical, food, paper, petroleum and primary metals industries are the largest segments of the industrial market. The vast majority of industrial boilers are fossil-fuel-fired watertube systems and were installed prior to 1970.

While solid-fueled boilers made in-roads in the industrial market in the late 1970's, generally in response to cost-cutting efforts prompted by fuel price surges,

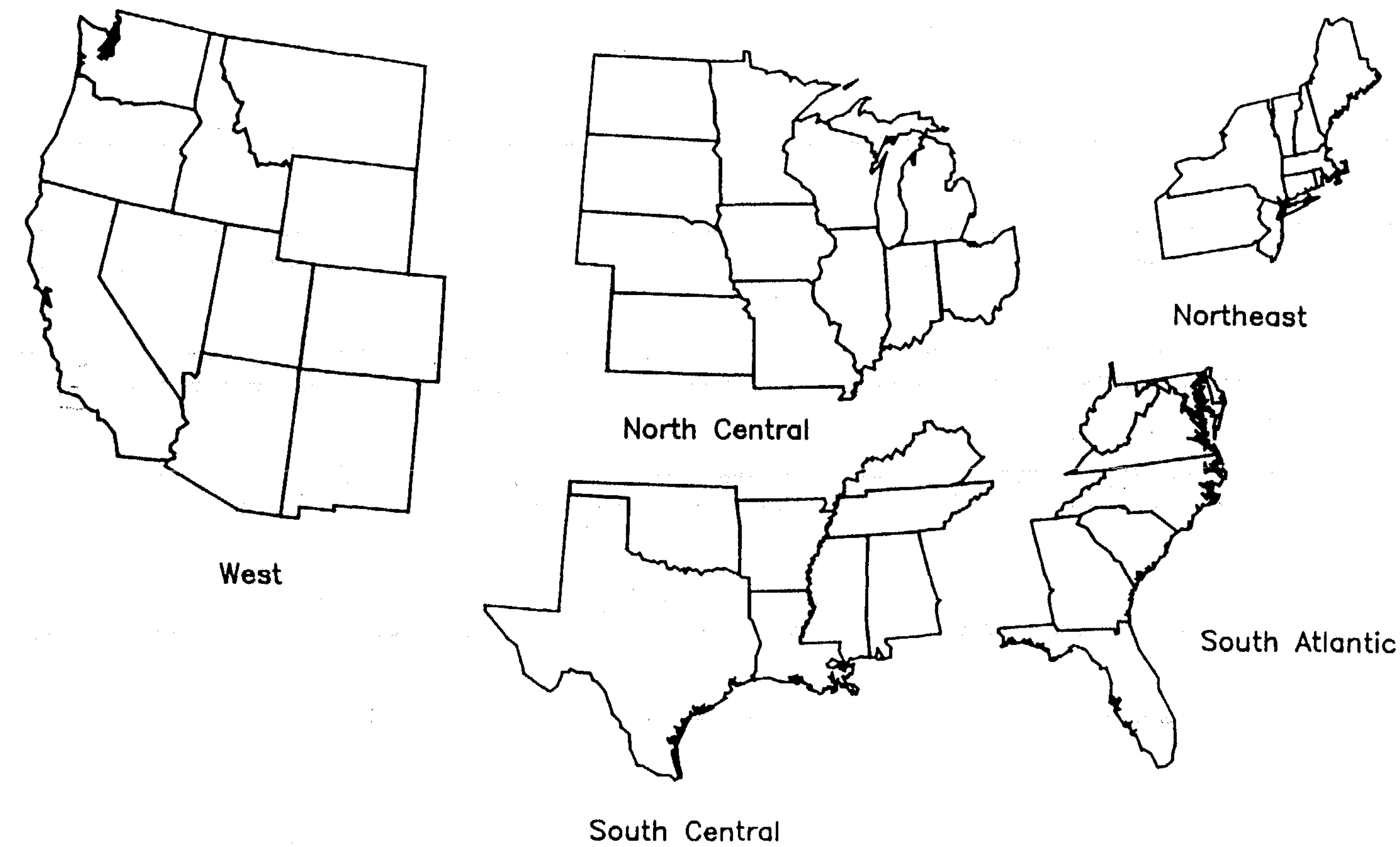


Figure E-1. States Included in Regional Segmentations natural gas has remained the dominant industrial boiler fuel, and gas usage is now displacing solid fuels in many locations, either through substitution or co-firing with solid fuels. Boiler fuel choice tends to be influenced most heavily by the availability and reliability of fuel supplies with emissions restrictions playing a lesser but increasing role now that the effects of 1990 CAAA are being felt at the user level.

As noted above, the 1985 industrial boiler inventory is approximately 37,000 units with capacity of 1.5 trillion Btu/hour. Only about half of this capacity is utilized, however. Annual industrial boiler sales for the past several years have been in the neighborhood of $300-400 million (Reference 7). Major manufacturers include Foster Wheeler, Babcock and Wilcox, and Combustion Engineering (part of ABB), as field erected industrial and utility boiler suppliers. Industrial package boiler suppliers include Nebraska Boiler, B&W, ABCO and Zurn Industries. The chemical industry operates the largest number of industrial boilers, 21 percent, followed by the food and paper industries which use 16 percent and 10 percent of the total, respectively, as shown in Figure E-2.

The largest user of industrial steam is the paper industry which has approximately one-fourth of the installed capacity. The paper industry uses these boilers primarily to provide steam for the paper drying process. Because paper plants tend to operate continuously at near full capacity, boiler utilization factors are high. The chemical and petroleum industries account for 18 percent and 14 percent of installed capacity , as shown in Figure E-3. While the chemical installations tend to be located primarily on the eastern seaboard and Gulf Coast, refineries (particularly heavy energy users) are more widespread with numerous installations also in the West.

Figures E-4 and E-5 show the breakdown of the installed boiler base by primary fuel type in terms of number of installed units and by energy consumption, respectively. Figure E-4 confirms that the majority of boilers are fired on either natural gas or fuel oil. In terms of capacity, natural gas represents one third of the energy consumption expended for industrial steam generation, followed by coal and pulping liquor. (Keep in mind that this is 1985 data, and gas usage has increased since that time.) Approximately half of the installed base is dual-fuel capable, and oil is the dominant secondary fuel. In air pollution-impacted areas, propane is increasingly being used as the back-up fuel. In California, fuel oil is now prohibited as a back-up fuel in several air pollution control districts.

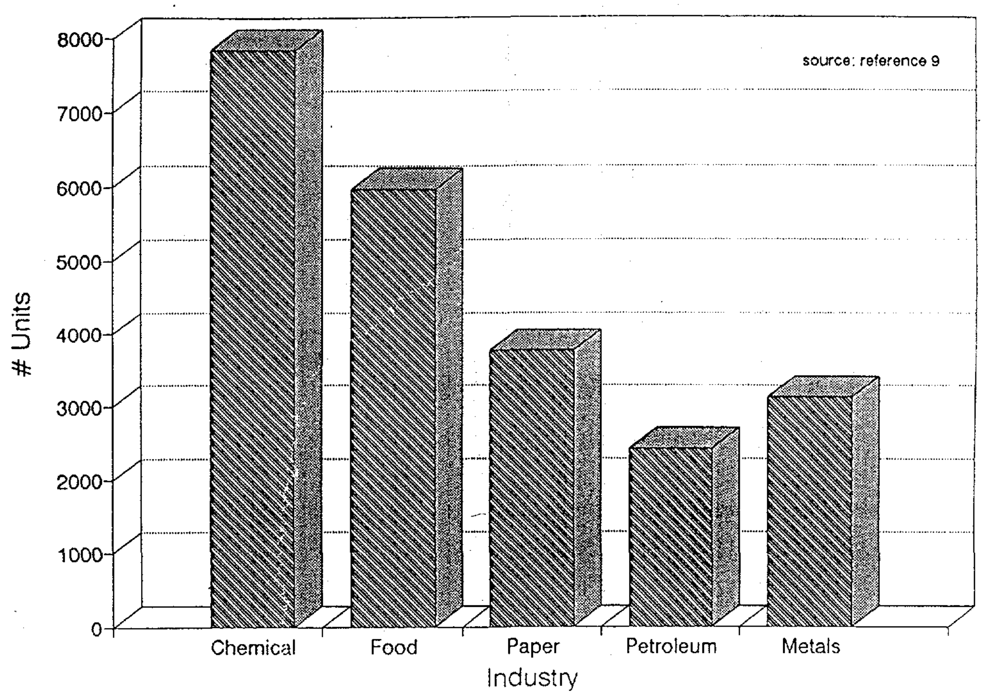


Figure E-2. Industry Boiler Population by Industry for Boilers with Capacity Greater than 10 MMBtu/hr

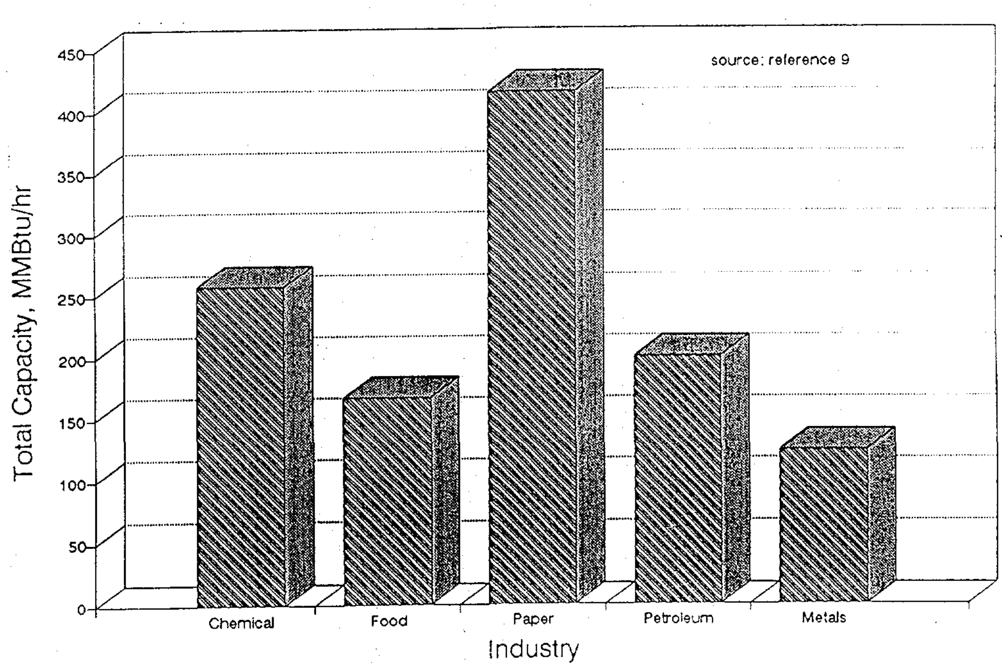


Figure E-3. Industry Boiler Capacity by Industry for Boilers with Capacity Greater than 10 MMBtu/hr

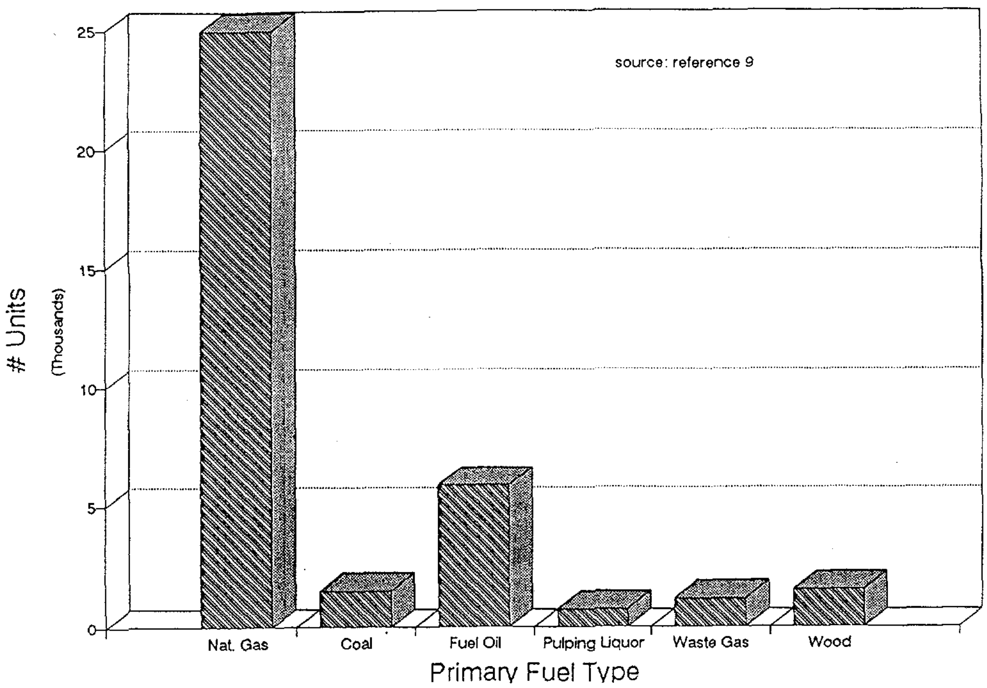


Figure E-4. Industrial Boiler Population by Fuel Type for Boilers with Capacity Greater than 10 MMBtu/hr

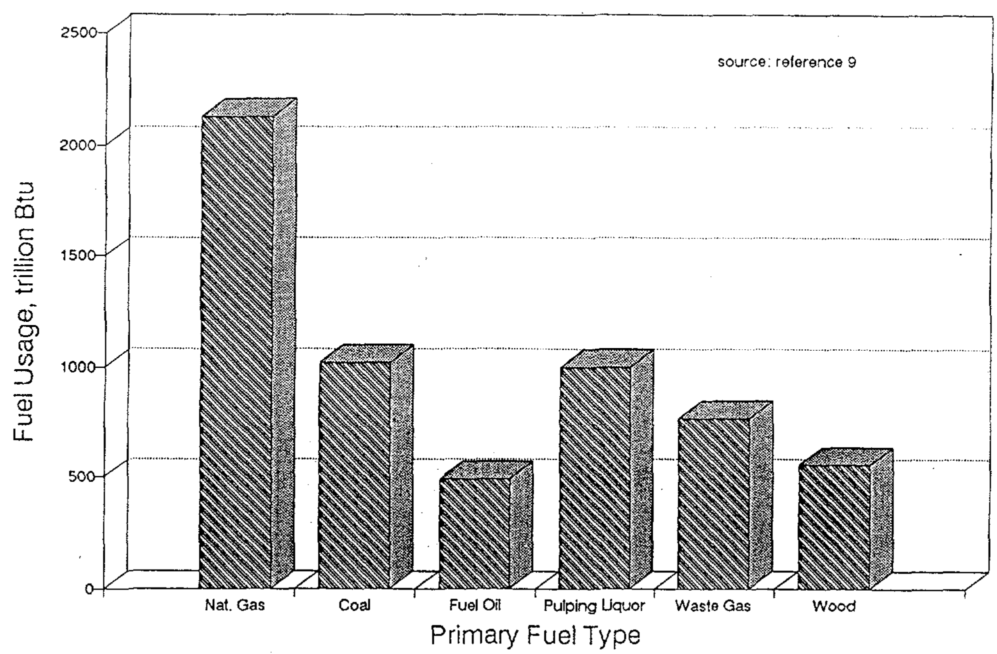


Figure E-5. Industrial Boiler Capacity by Fuel Type for Boilers with Capacity Greater than10 MMBtu/hr

Boilers can be divided into two distinct types, fire tube and watertube. The fire tube boiler has a water-jacketed combustion chamber which surrounds the burner flame. Approximately 53 percent of the installed boiler population meets this description, but these are predominantly smaller, lower pressure boilers with capacities up to about 50 MMBtu/hr, with 10-30 MMBtu/hr being a more typical size. Watertube boilers surround the combustion zone with banks of water-filled tubes, and boilers of this design make up 47 percent of the population. Units below 10 MMBtu/hr are more typically used in commercial applications and are not included in the unit count. Boilers above 50 MMBtu/hr capacity are almost exclusively watertube designs, and they therefore constitute the major share of capacity and fuel use.

Boiler Burners (New vs Retrofit Markets)

The design of burners used in boilers depends more on the dominant fuel rather than the boiler type. Approximately 400 new boilers are installed each year, and a typical unit can be expected to last for at least 30 years (References 6-8). Units are operational today that were installed in the 1930's, and in many cases the plant served by a boiler is decommissioned before the boiler is at the end of its life. Figures E-6 and E-7 present a breakdown of the installed boiler base by installation date in terms of units and capacity, respectively. The decrease in new installations is evident, and can be attributed to decreased need for additional boiler capacity as domestic heavy manufacturing has declined. The bulk of installed units and capacity were installed in the decade of the 1960's. Now the vast majority of new boilers are sold as replacement units.

Unlike the boilers, burners have life expectancies of the order of 15-20 years. Therefore there is a much larger market (in terms of number of units) for retrofit burners than there is for new boiler installations. Retrofitting boiler burners also represents one of the most cost effective ways of reducing NO_x emissions in an industrial plant. Thus, a strategy is emerging in many industrial sectors to "clean up the boiler house" with low NO_x retrofits as a means of reducing overall plant emissions. NO_x reduction is typically more cost effective in boilers than in other types of process equipment. In addition, modifying the boiler runs lower a risk of affecting the process than does modifying burners and heaters elsewhere in the plant. Consequently, much low NO_x burner

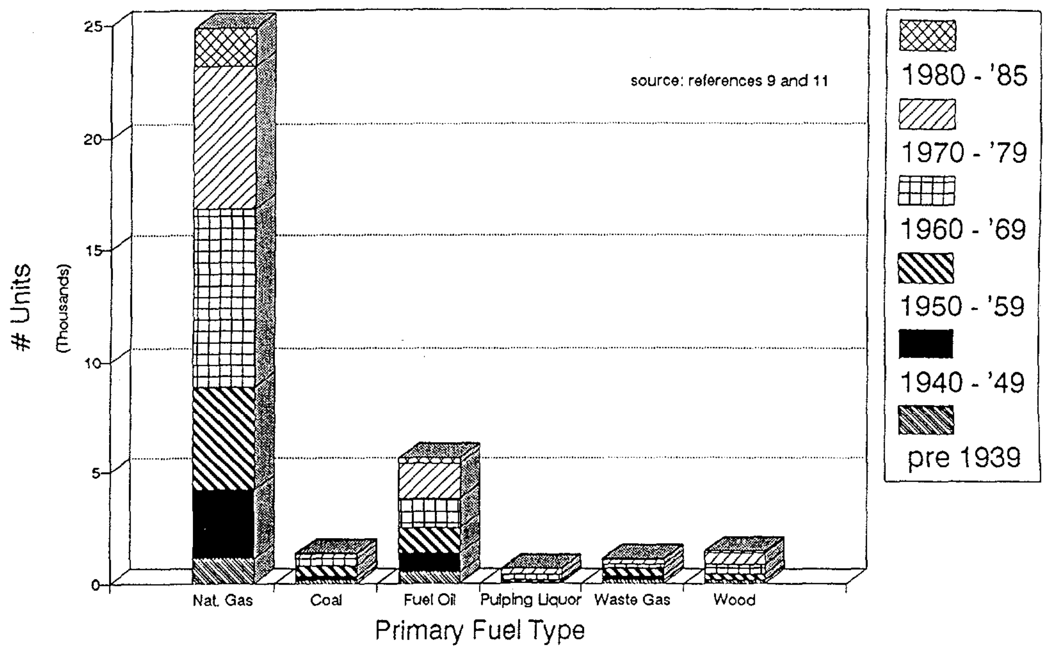


Figure E-6. Industrial Boiler Population by Installation Date for Boilers with Capacity Greater than 10 MMBtu/hr

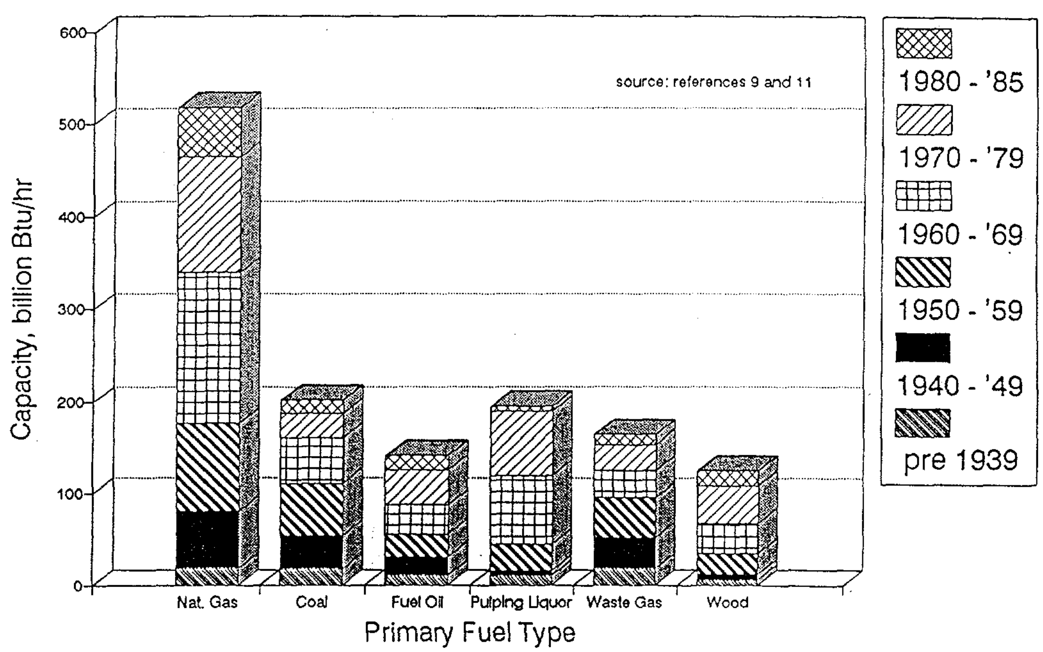


Figure E-7. Industrial Boiler Capacity by Installation Date for Boilers with Capacity Greater than 10 MMBtu/hr activity is expected to be focused on boilers over the next decade. There are approximately 37,000 potential retrofit sites in the U.S., representing a more lucrative market than burners for the 300-400 new boilers sold every year.

Industrial Gas Technology Commercialization Center Market (IGTCC) Update

IGTCC works with the gas industry to develop and implement strategies to promote new natural gas technologies. As part of this work, IGTCC conducts market research, some of which has been used here to update the GRI market survey. Table E-1 summarizes data obtained by Alzeta from IGTCC (Reference 9), and shows that the distribution of energy use and boiler units remains substantially as indicated by the GRI work summarized above. While much of the paper industry capacity is fired with non-fossil fuels, chemicals, petroleum, and food represent the major markets in terms of size of units and fossil fuel consumption. In particular, experience in California and other agricultural areas has been that the population trend to use more prepared foods has led to increased capacity requirements in the food industry. This steam is used to process more of the annual crop into precooked, canned, and frozen meals. This trend is expected to continue, and since much of this agriculture is in California and therefore in pollution impacted areas, the food industry in particular will require low NO_x boiler burners (for both new and retrofit applications) to meet future market demand for its products.

TABLE E-1. IGTCC BOILER DATA (20-250 K lbs/hr)

	Fuel Use 10^{12} Btu/yr	No. Units	Capacity 10^6 lb/hr	Average size K lbs/hr
Paper	1,646	2,423	247	101.9
Chemicals	1,363	3,014	226	75.0
Petroleum	672	1,032	127	123.0
Food	468	584	117	19.9
Primary Metals	328	1,300	57	43.9
Other	748	15,528	219	14.1
Total	5,225	29,131	993 x 10^6 pph	

Price Information

Estimates by SFA Pacific made in 1995 say that burner cost for 30 ppm NO_x technology is about:

- $1.30/pph steam ($1.05/MBtu) at 50 kpph boiler size
- $0.60/pph steam ($0.50/MBtu) at 250 kpph size
- As a point of reference, total package boiler installed cost is $15/pph steam at 50 kpph, and $6/pph steam at 250 kpph
- Sub-9 ppm technology should command a 50 percent premium over the 30 ppm product, or $1.52/MBtu at 50 kpph and $0.75/MBtu at 250 kpph

APPENDIX F

CRIBARI WINERY SOURCE TEST REPORT

Cribari Winery

Source Test Report
Boiler #6

Test Date: September 28, 1999

BEST ENVIRONMENTAL, INC.

15890 Foothill Boulevard
San Leandro, California 94578
Tel: (510) 278-4011
Fax: (510) 278-4018
E-Mail: BESTAIR@PACBELL.NET

BEST ENVIRONMENTAL, INC.
15890 Foothill Boulevard
San Leandro, California 94578
(510) 278-4011 FAX (510) 278-4018

November 22, 1999

Cribari Winery
3223 East Church Avenue
Fresno, CA 93725

Attn.: Frank von Furstenrecht

Subject: Compliance emission test report for a natural gas-fired boiler at Cribari Winery in Fresno, California; Authority to Construct (C-601-7-0).

Test Date: September 28, 1999.

Sampling Location: Sampling was conducted at the exhaust stack of a 68 MMBtu/hr Nebraska boiler, located at the Cribari Winery facility, in Fresno, California. The boiler had one sample port on the outlet stack located ~ 1.5 stack diameters downstream and ~1.5 diameters upstream from any flow disturbances.

Sampling Personnel: Scott Chesnut of BEST ENVIRONMENTAL, Inc. (BEI).

Observing Personnel: Rob Vinson of the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) was present during the test program.

Process Description: Cribari Winery operates the 68 MMBtu/hr natural gas-fired Nebraska boiler (#6) to produce steam used for various processes at the facility. The #6 boiler has been equipped with an Alzeta Low NO_x burner.

Test Program: Triplicate 30-minute tests for nitrogen oxides (NO_x), carbon monoxide (CO) and oxygen (O_2) were performed on the boiler's outlet stack while firing natural gas. Each of the analyzers was first calibrated internally with zero gas, then mid-level calibration gas and finally with high-level calibration gas. Then the analyzers were calibrated through the entire sample system using the mid-level calibration gases. A multi-point probe was used throughout the sampling program.

In order to confirm Rule 4305 Alternative Monitoring compliance, the boiler will be checked with a portable analyzer. The boiler loads were recorded from the boiler's master controller during each test run. The boiler was operated at 60% load throughout the test program.

Sampling Methods: The following source test method was used:

CARB Method 100	NO_x, CO, & O_2 Continuous Monitoring

Instrumentation: The following continuous emissions analyzers were used:

Instrument	Analyte	Principle
TECO Model 10S	NO_x	Chemiluminescence
TECO Model 48	CO	GFC/IR
Siemens Model 5E	O_2	Paramagnetic

Test Results: Tables 1 on the following page summarizes the emission results for the boiler. The compliance parameters are presented in the tables below:

Boiler #6

Parameter	60% Load	Permit Limit
NO_x, ppm @ 3% O_2	5.1	9
CO, ppm @ 3% O_2	<1.5	50

Comments: Calculations, field data sheets, strip chart recordings, calibration gas certifications, stack diagram, Source Test Plan and the Authority to Construct are appended to this report.

If there are any questions concerning this report, please contact Regan Best, Craig Thiry, Scott Brown or me at (510) 278-4011.

Submitted by,

Scott Chesnut
Project Manager

Reviewed by,

Scott Brown
Project Manager

BEST ENVIRONMENTAL, INC. San Leandro, CA 510-278-4011

Table 1

Cribari Winery
Boiler #6

TEST	1	2	3	AVERAGE	LIMIT
Test Condition	Nat. Gas	Nat. Gas	Nat. Gas		
Test Location	Outlet	Outlet	Outlet		
Test Date	9/28/99	9/28/99	9/28/99		
Run Time	10:00 - 10:30	10:58 - 11:28	11:45 - 12:15		
Test Duration (mins)	00:30	00:30	00:30		
Standard Temp., °F	60	60	60		
Load , %	60.0	60.0	60.0	60.0	
O_2, %	9.07	8.93	8.83	8.95	
NOx, ppm	3.2	3.4	3.5	3.4	
NOx, ppm (@3% O_2)	4.8	5.1	5.3	5.1	9
NOx, lbs/MMBtu	0.006	0.006	0.006	0.006	
CO, ppm	<1.0	<1.0	<1.0	<1.0	
CO, ppm (@3% O_2)	<1.5	<1.5	<1.5	<1.5	50
CO, lbs/MMBtu	<0.001	<0.001	<0.001	<0.001	

WHERE:

NOx = Oxides of Nitrogen as NO_2 (MW = 46)
O_2 = Oxygen
CO = Carbon Monoxide (MW = 28)
ppm = Parts Per Million Concentration
DSCFM = Dry Standard Cubic Feet per Minute
lbs/MMBtu = Pounds per Million Btu
Fd = 8710 (EPA F Factor for Natural Gas)
Tstd. = Standard Temp.; °R = °F + 460

CALCULATIONS:

3%O_2 correction = ppm of pollutant * 17.9 / (20.9 - %O_2)
lbs/MMBtu = Fd * MW * ppm * 2.59E-9 * 20.9 / (20.9 - %O_2)

APPENDICES

CALCULATIONS

Standard Abbreviations for Reports

Unit	Abbreviation	Unit	Abbreviation
billion	G	microgram	µg
Brake horsepower	bhp	milligram	mg
Brake horsepower hour	bhp-hr	milliliter	ml
British Thermal Unit	Btu	million	MM
capture efficiency	CE	minute	min
destruction efficiency	DE	Molecular Weight	MW
Dry Standard Cubic Feet	DSCF	nanogram	ng
Dry Standard Cubic Feet per Minute	DSCFM	Parts per Billion	ppb
Dry Standard Cubic Meter	DSCM	Parts per Million	ppm
Dry Standard Cubic Meter per Minute	DSCMM	pennyweight per firkin	pw/fkn
grains per dry standard cubic foot	gr/DSCF	pound	lb
gram	g	pounds per hour	lbs/hr
grams per Brake horsepower hour	g/bhp-hr	pounds per million Btu	lbs/MMBtu
kilowatt	kw	second	sec
liter	l	thousand	k
Megawatts	mw	watt	w
meter	m		

Common Conversions / Calculations / Constants

1 gram = 15.432 grains

1 pound = 7000 grains

grams per pound = 453.6

bhp = 1.34 * Engine kw, (where Engine kw = Generator kw output / 0.95) @ 95% efficiency

g/bhp-hr = lbs/hr * 453.6 / bhp

2.59E-9 = Conversion factor for ppm to lbs/scf; EPA 40CFR60.45

dscf / MMBTU = 8710 for Natural gas; EPA Method 19

Btu/ft^3 = 1040 for Natural Gas; EPA Method 19

lb/hr Part. Emission Rate = 0.00857 * gr/dscf * dscfm; EPA Method 5

lbs/hr = ppm / SV x dscfm x MW * 60; CARB Method 100; where SV = 385E^6 @ 68°F or ≈ 379E^6 @ 60°F.

Correction to 12% CO_2 = gr/dscf * 12% / stack CO_2%; EPA Method 5

Correction to 3% O_2 = ppm * 17.9 / (20.9 - stack O_2 %); CARB Method 100

Correction to 15% O_2 = ppm * 5.9 / (20.9 - stack O_2 %); CARB Method 100

dscfm = Gas Fd * MMBtu/min * 20.9 / (20.9 - stack O_2 %); EPA Method 19

lb/MMBtu = Fd * MW * ppm * 2.59E-9 * 20.9 / (20.9 - stack O_2 %); EPA Method 19

Standard Temperatures by District

EPA	68 °F	NSAPCD - Northern Sonoma	68 °F
CARB	68 °F	PCAPCD - Placer	68 °F
BAAQMD - Bay Area	70 °F	SLOCAPCD - San Luis Obispo	60 °F
SJVUAPCD - San Joaquin	60 °F	SMAQMD - Sacramento	68°F de facto
SCAQMD - South Coast	60 °F	SCAQMD - Shasta County	68 °F
MBUAPCD - Monterey Bay	60 °F	YSAPCD - Yolo-Solano	68 °F

BEST ENVIRONMENTAL, INC. San Leandro, CA (510) 278-4011

DAS CONTINUOUS EMISSIONS MONITORING DATA SHEET

Facility:	Cribari Winery	Run #:	1	Date:	09/28/99
Location:	Boiler #6	Barometric:	29.60	Leak ✓:	OK
Observers:	Robert Vinson	Personnel:	sc	Strat. ✓:	OK
Expected Run Time =	30 min	Std. Temp:	60		

Cylinder #s: O2 = SA18224 CO = SA18224

NOx = CC108117 O2 = CC92841

Analyte		O2		NOx	CO					
Analyzer		5E		RS55	TECO 48					
Range		10		100	100					
Span Value		4.47		44.9	44.0					
Time										Comments:
	10:00									
	10:05	9.20		3.1	0.0					Unit #
	10:10	9.20		3.1	0.0					
	10:15	9.20		3.1	0.0					
	10:20	9.20		3.1	0.0					Operating Conditions
	10:25	9.20		3.2	0.0					
	10:30	9.20		3.2	0.0					
ZERO I	10:47	0.11		0.0	0.0					
SPAN I	10:44	4.57		43.9	43.7					
Average		9.20		3.13	0.00					
ZERO f	13:42	0.29		0.0	0.0					
SPAN f	13:40	4.70		44.3	43.2					
Zero Drift %		1.8%		0.0%	0.0%					
Span Drift %		1.3%		0.4%	-0.5%					
Corr. Avg.		9.07		3.2	0.0					

Corrected Average = [Test Avg. - ((Zi+Zf) / 2)] * Span Gas Value / [((Si+Sf) / 2)-((Zi+Zf) / 2)]

Zero Drift % = 100 * (Zf - Zi)/Instrument Range

Span Drift % = 100 * (Sf - Si)/Instrument Range

01/04/00 TUE 11:42 FAX 510 490 0571 NATIONWIDE BOILER 009

:ST ENVIRONMENTAL, INC. San Leandro, CA (510) 278-4011

DAS CONTINUOUS EMISSIONS MONITORING DATA SHEET

cility:	Cribari Winery	Run #:	2	Date:	09/28/99
cation:	Boiler #6	Barometric:	29.60	Leak ✓:	OK
servers:	Robert Vinson	Personnel:	sc	Strat. ✓:	OK
pected Run Time =	30 min	Std. Temp:	60		

linder #s: O2 = SA18224 CO = SA18224

NOx = CC108117 O2 = CC92841

	Time									Comments:
alyte		O2		NOx	CO					
alyzer		5E		RS55	TECO 48					
nge		10		100	100					
in Value		4.47		44.9	44.0					
	10:58	9.18		3.1	0.0					
	10:59	9.16		3.2	-0.2					Unit #
	11:00	9.12		3.3	-0.1					
	11:01	9.16		3.2	-0.2					
	11:02	9.18		3.2	-0.2					Operating Conditions
	11:03	9.11		3.4	-0.2					
	11:04	9.12		3.3	-0.1					
	11:05	9.18		3.2	-0.2					Fuel
	11:06	9.17		3.3	-0.1					
	11:07	9.19		3.3	-0.2					
	11:08	9.18		3.3	-0.2					
	11:09	9.16		3.4	-0.2					
	11:10	9.09		3.5	-0.2					
	11:11	9.07		3.5	-0.3					
	11:12	9.06		3.5	-0.3					
	11:13	9.16		3.4	-0.2					
	11:14	9.11		3.5	-0.2					
	11:15	9.09		3.5	-0.2					
	11:16	9.09		3.5	-0.2					
	11:17	9.07		3.5	-0.3					
	11:18	9.09		3.5	-0.3					
	11:19	9.11		3.4	-0.2					
	11:20	9.15		3.4	-0.2					
	11:21	9.15		3.3	-0.2					
	11:22	9.13		3.4	-0.3					
	11:23	9.13		3.4	-0.2					
	11:24	9.15		3.4	-0.1					
	11:25	9.12		3.4	-0.3					
	11:26	9.18		3.3	0.0					
	11:27	9.19		3.3	0.0					
RO I	13:42	0.29		0.0	0.0					
AN I	13:40	4.70		44.3	42.1					
Average		9.14		3.4	-0.2					
RO f	11:38	0.30		0.0	0.2					
AN f	11:39	4.74		44.2	43.6					
o Drift %		0.1%		0.0%	0.2%					
an Drift %		0.4%		-0.1%	1.5%					
Corr. Avg.		8.93		3.4	-0.3					

ected Average = [Test Avg. - ((Zi+Zf)/2)] * Span Gas Value / [((Si+Sf)/2)-((Zi+Zf)/2)]

Drift % = 100 * (Zf - Zi)/Instrument Range

Drift % = 100 * (Sf - Si)/Instrument Range

BEST ENVIRONMENTAL, INC. San Leandro, CA (510) 278-4011

DAS CONTINUOUS EMISSIONS MONITORING DATA SHEET

Facility:	Cribari Winery	Run #:	3	Date:	09/28/99
Location:	Boiler #6	Barometric:	29.60	Leak ✓:	OK
Observers:	Robert Vinson	Personnel:	sc	Strat. ✓:	OK
Expected Run Time =	30 min	Std. Temp:	60		

Cylinder #s: O2 = SA18224 CO = SA18224

NOx = CC108117 O2 = CC92841

Analyte		O2		NOx	CO					
Analyzer		5E		RS55	TECO 48					
Range		10		100	100					
Span Value		4.47		44.9	44.0					
Time										Comments:
	11:45	9.11		3.5	-0.3					
	11:46	9.06		3.5	-0.2					Unit #
	11:47	9.05		3.5	-0.3					
	11:48	9.13		3.4	-0.3					
	11:49	9.05		3.6	-0.2					Operating Conditions
	11:50	9.02		3.6	-0.3					
	11:51	9.04		3.6	-0.4					
	11:52	9.08		3.5	-0.3					Fuel
	11:53	9.15		3.4	-0.3					
	11:54	9.13		3.4	-0.2					
	11:55	9.07		3.6	-0.3					
	11:56	9.04		3.6	-0.3					
	11:57	9.14		3.4	-0.3					
	11:58	9.21		3.3	-0.2					
	11:59	9.17		3.3	-0.3					
	12:00	9.15		3.4	-0.3					
	12:01	9.10		3.5	-0.3					
	12:02	9.06		3.6	-0.4					
	12:03	9.06		3.6	-0.3					
	12:04	9.17		3.4	-0.3					
	12:05	9.12		3.5	-0.3					
	12:06	9.13		3.4	-0.3					
	12:07	9.10		3.6	-0.3					
	12:08	9.09		3.6	-0.3					
	12:09	9.07		3.7	-0.3					
	12:10	9.06		3.7	-0.3					
	12:11	9.07		3.7	-0.3					
	12:12	9.07		3.6	-0.4					
	12:13	9.01		3.8	-0.3					
	12:14	9.05		3.7	-0.3					
ZERO I	11:38	0.30		0.6	0.2					
SPAN I	11:39	4.74		44.2	43.6					
Average		9.09		3.5	-0.3					
ZERO f	12:29	0.33		0.1	0.5					
SPAN f	12:30	4.77		43.9	43.0					
Zero Drift %		0.3%		0.1%	0.3%					
Span Drift %		0.3%		-0.3%	-0.6%					
Corr. Avg.		8.85		3.5	-0.7					

Corrected Average = [Test Avg. - ((Zi+Zf) / 2)] * Span Gas Value / [((Si+Sf) / 2)-((Zi+Zf) / 2)]

Zero Drift % = 100 * (Zf - Zi)/Instrument Range

Span Drift % = 100 * (Sf - Si)/Instrument Range

FIELD DATA SHEETS

CEM SYSTEM TEST SUMMARY SHEET

Facility: Cribari Winery Date: 9/28/99 Personnel: (SC)

Location: Boiler #6 Barometric: 29.60 Leak Check: OK

	O_2	CO_2	NOx	CO	THC	SO_2	Comments
Analyzer	5E		10S	48			
Range	10		100	100			
Cal Value (mid)	4.47		44.9	44.0			
Cyl #	CC16847		SA13874	CC16847			
Cal Value (Hi)	8.52		88.0	85.9			
Cyl #	SA20615		SA154562	SA20615			

LINEARITY

zero (int)	-0-		-0-	-0-			
Abs. Difference	-0-		-0-	-0-			
% Linearity	-0-		-0-	-0-			<2%
mid cal (int)	4.47		44.9	44.0			
Abs. Difference	-0-		-0-	-0-			
% Linearity	-0-		-0-	-0-			<2%
high cal (int)	8.51		87.9	87.0			
Abs. Difference	0.01		88.0	1.1			
% Linearity	0.1		0.1	1.1			<2%

SYSTEM BIAS

Zero (int)	-0-		-0-	-0-			
Zero (ext)	0.11		-0-	-0-			
Abs. Difference	0.11		-0-	-0-			
bias, % range	1.1		-0-	-0-			EPA 20/6C/7E (±5%)
Cal (int)	4.47		44.9	44.0			
Cal (ext)	4.57		43.9	43.7			
Abs. Difference	0.10		1.0	0.3			
bias, % range	1.0		1.0	0.3			EPA 20/6C/7E (±5%)

SYSTEM RESPONSE TIME = 1:30

Stack Gas NOx = 2.9

Stack Gas NO_2 = 0.4

% of NO_2 = 14%

If NO_2 > 5% of NOx then run converter test.

NO_2 CONVERTER TEST

Cal value = 54.7	Final Value = 53.5	% Efficiency = 97.8	Cyl # = CAO1333

$$\text{System Calibration Bias (Limit} \pm 5\%) = 100 * \frac{\text{External cal - Internal cal}}{\text{Span Range}}$$

$$\text{\% Linearity (Limit} \pm 2\%) = 100 * \frac{\text{Span Value - Internal cal}}{\text{Span Range}}$$

$$\text{\% Converter Efficiency (Limit } 90\%) = 100 * \frac{\text{Internal cal}}{\text{Span Value}}$$

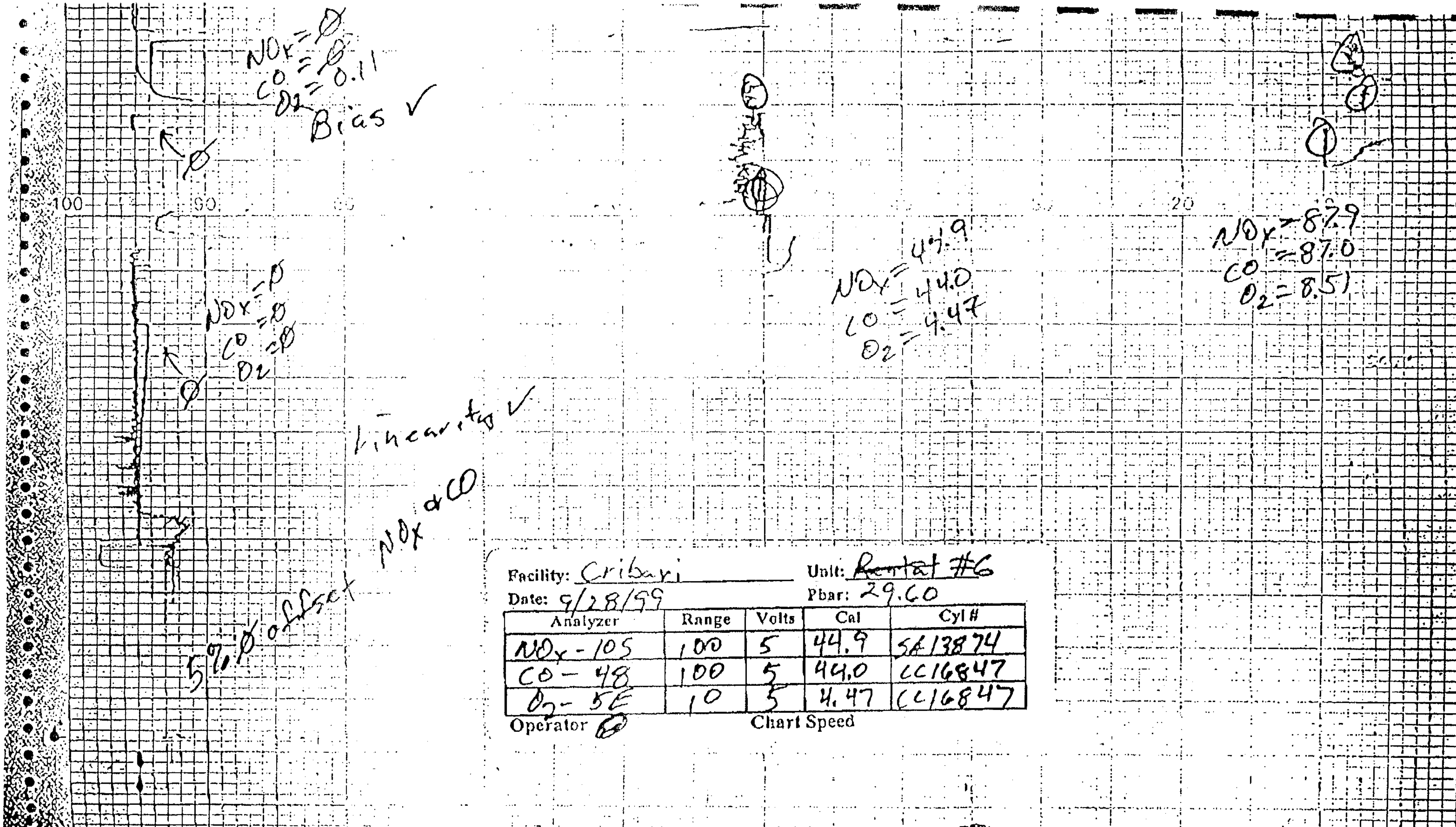
Process Notes

Facility: Cribari Winery
Unit: Boiler #6
Data Recorded By: [illegible]

Date: Sept. 28, 1999
Condition: Normal
Barometric: 29.60

Parameters → Time ↓	Boiler load	Ambient °F	Heated line °F	Knock-out °F		
1010	60%	65	252	36		
1105	60%	67	252	38		
1152	60%	68	252	38		

STRIP CHART RECORDS



Facility: Cribari Unit: ~~Rental~~ #6

Date: 9/28/99 Pbar: 29.60

Analyzer	Range	Volts	Cal	Cyl #
NO_x - 105	100	5	44.9	SA13874
CO - 48	100	5	44.0	CC16847
O_2 - 5E	10	5	4.47	CC16847

Operator Ø Chart Speed

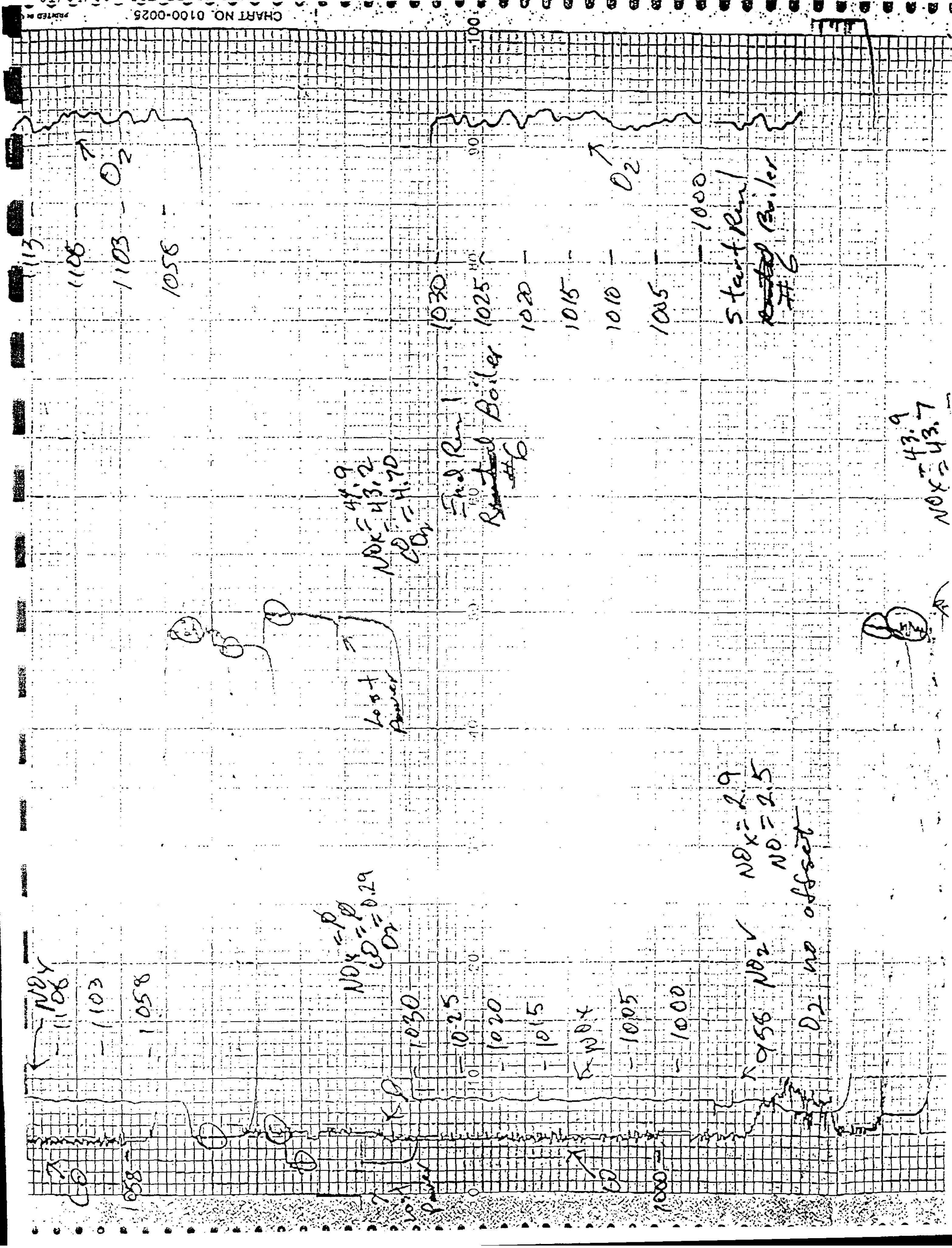
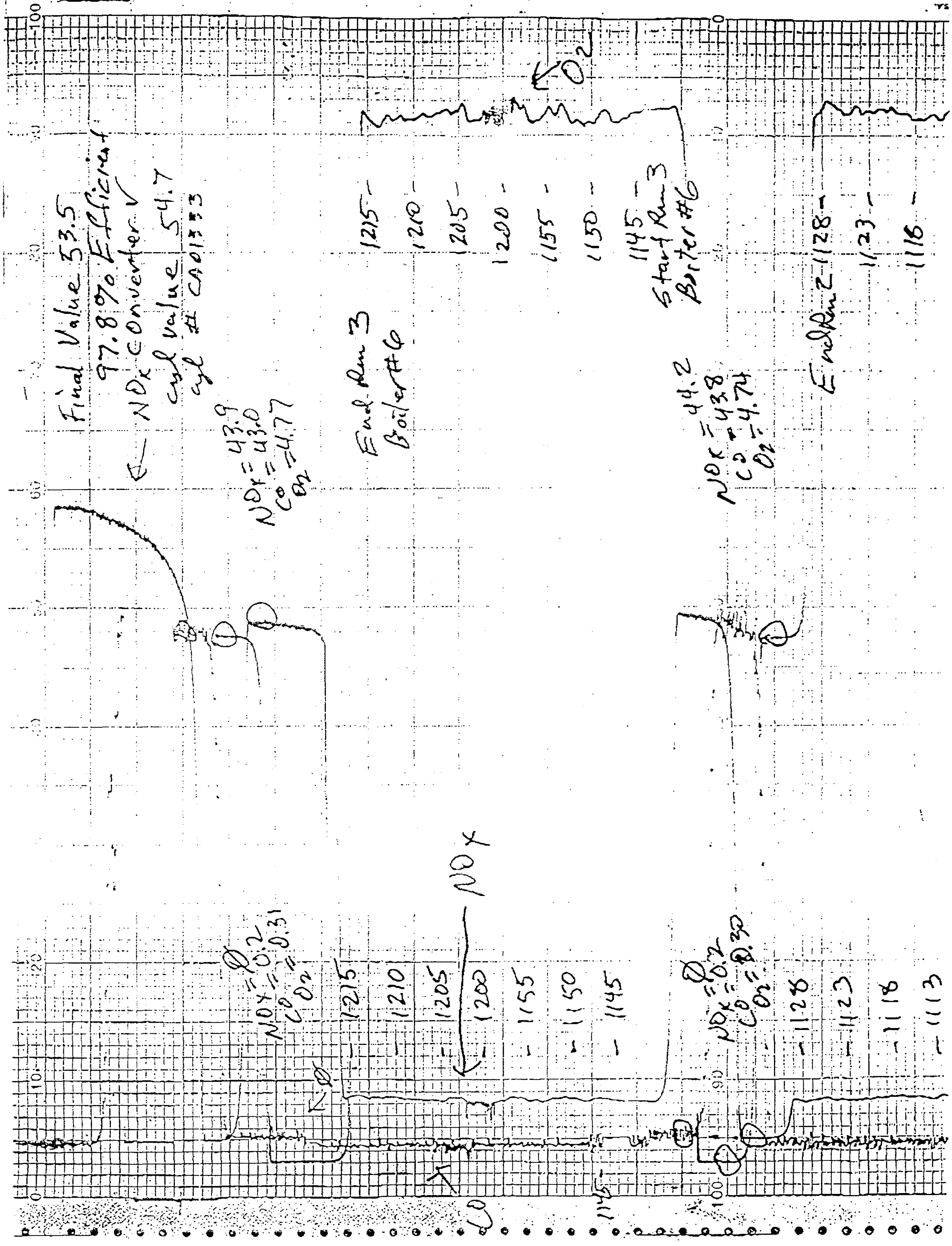
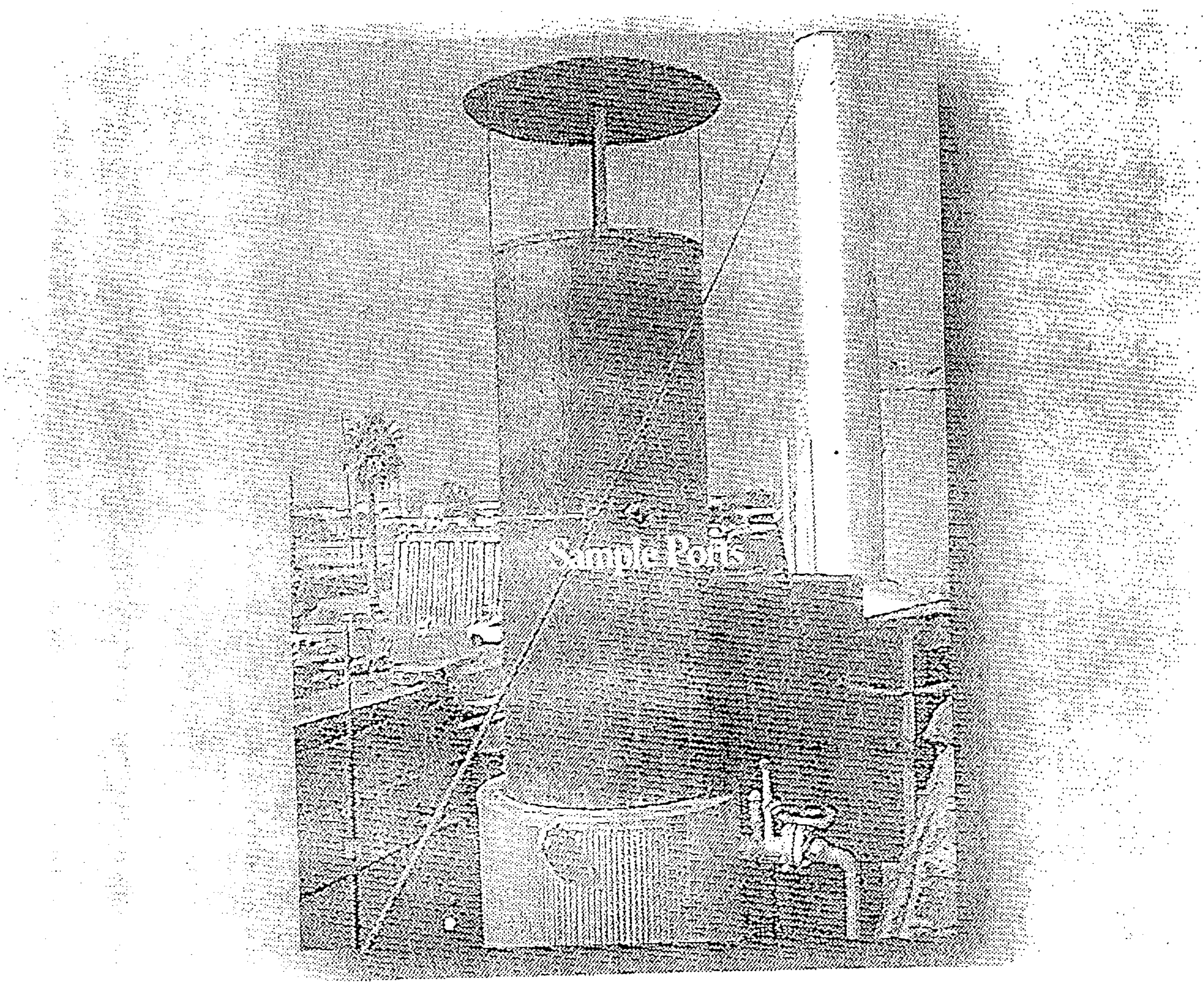


CHART NO. 0100-0025
100
90
80
60
50
40
20
10
0
O2
1113
1108
1103
1056
1030
1025
1020
1015
1010
1005
1000
Start Run 1
Boiler #6
End Run 1
Boiler #6
Lost Power
NOx
1058
NO2
CO
O2 no offset

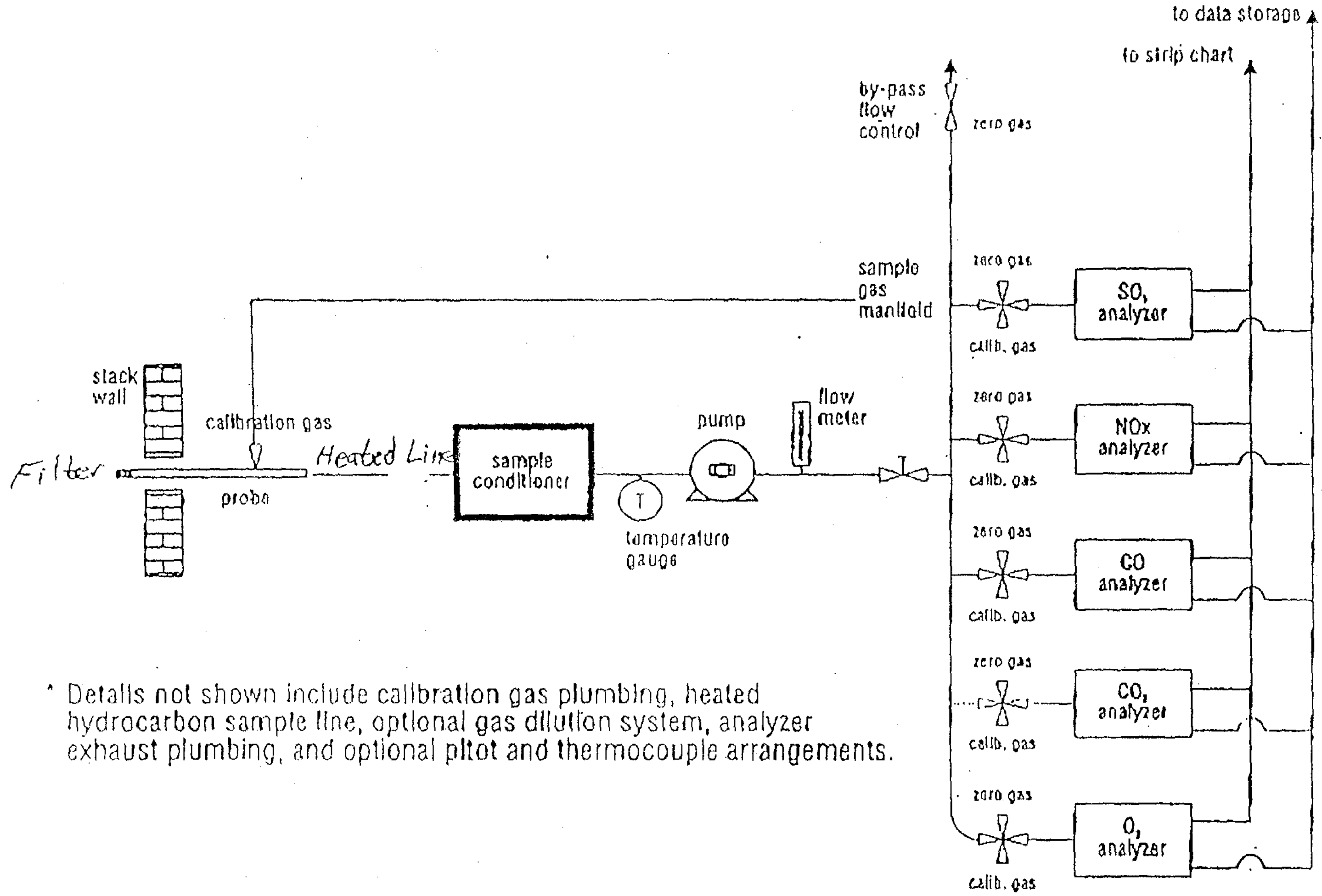

Final Value 53.5
97.8% Efficient
NOx Converter
cyl value 54.7
NOx = 43.9
CO = 43.0
O2 = 4.77
End Run 3
Boiler #6
NOx = 44.2
CO = 43.8
O2 = 4.74
Start Run 3
Boiler #6
End Run 2 1128
O2
NOx
CO
1215
1210
1205
1200
1155
1150
1145
1123
1118
1113

STACK DIAGRAMS


Sample Ports

SAMPLE SYSTEM DIAGRAMS

Method 100 Sample Train Assembly



* Details not shown include calibration gas plumbing, heated hydrocarbon sample line, optional gas dilution system, analyzer exhaust plumbing, and optional pitot and thermocouple arrangements.

CALIBRATION GAS CERTIFICATES

PRAXAIR

Praxair
5700 South Alameda Street
Los Angeles. CA 90058
Telephone: (323) 585-2155
Facsimile: (323) 585-0582

CERTIFICATE OF ANALYSIS / EPA PROTOCOL GAS

CUSTOMER BEST ENV. PO#9494 P.O NUMBER 9494

REFERENCE STANDARD

COMPONENT	NIST SRM NO.	CYLINDER NO.	CONCENTRATION
CARBON MONOXIDE GMIS	vs 1678c	SA 6079	50.3 ppm
OXYGEN GMIS	vs 2658a	SA 11101	5.02%
CARBON DIOXIDE GMIS	vs 1674b	X-990	10.07%

ANALYZER READINGS

R=REFERENCE STANDARD Z=ZERO GAS C=GAS CANDIDATE

1. COMPONENT CARBON MONOXIDE GMIS ANALYZER MAKE-MODEL-S/N Siemens Ultramat 5E S/N A12-729

ANALYTICAL PRINCIPLE NDIR LAST CALIBRATION DATE 07/27/99

FIRST ANALYSIS DATE 08/13/99 SECOND ANALYSIS DATE 08/20/99

Z 0.00	R 50.30	C 44.14	CONC. 44.1	Z 0.00	R 50.40	C 43.85	CONC. 43.8
R 50.30	Z 0.00	C 44.09	CONC. 44.1	R 50.40	Z 0.00	C 43.85	CONC. 43.8
Z 0.00	C 43.99	R 50.30	CONC. 44.0	Z 0.00	C 44.05	R 50.40	CONC. 44.0
U/M ppm		MEAN TEST ASSAY	44.1 ppm	U/M ppm		MEAN TEST ASSAY	43.9 ppm

2. COMPONENT OXYGEN GMIS ANALYZER MAKE-MODEL-S/N Siemens Oxymat 5E S/N A12-839

ANALYTICAL PRINCIPLE Paramagnetic LAST CALIBRATION DATE 08/05/99

FIRST ANALYSIS DATE 08/13/99 SECOND ANALYSIS DATE

Z 0.00	R 5.02	C 4.47	CONC. 4.47	Z	R	C	CONC.
R 5.02	Z 0.00	C 4.47	CONC. 4.47	R	Z	C	CONC.
Z 0.00	C 4.47	R 5.02	CONC. 4.47	Z	C	R	CONC.
U/M %		MEAN TEST ASSAY	4.47 %	U/M %		MEAN TEST ASSAY	

3. COMPONENT CARBON DIOXIDE GMIS ANALYZER MAKE-MODEL-S/N Siemens Ultramat 5E S/N A12-730

ANALYTICAL PRINCIPLE NDIR LAST CALIBRATION DATE 08/05/99

FIRST ANALYSIS DATE 08/13/99 SECOND ANALYSIS DATE

Z 0.00	R 10.07	C 8.22	CONC. 8.22	Z	R	C	CONC.
R 10.09	Z 0.00	C 8.23	CONC. 8.21	R	Z	C	CONC.
Z 0.00	C 8.22	R 10.09	CONC. 8.20	Z	C	R	CONC.
U/M %		MEAN TEST ASSAY	8.21 %	U/M %		MEAN TEST ASSAY	

THIS CYLINDER NO. CC 16847

HAS BEEN CERTIFIED ACCORDING TO SECTION EPA-600/R97/121

OF TRACEABILITY PROTOCOL NO. Rev. 9/97

PROCEDURE G1

CERTIFIED ACCURACY ± 1 % NIST TRACEABLE

CYLINDER PRESSURE 2000 PSIG

CERTIFICATION DATE 08/20/99

EXPIRATION DATE 08/20/02 TERM 36 MONTHS

CERTIFIED CONCENTRATION	
CARBON MONOXIDE	44.0 ppm
OXYGEN	4.47 %
CARBON DIOXIDE	8.21 %
NITROGEN	BALANCE

Values not valid below 150 psig

CO CONC. WAS CORRECTED FOR CO2 INTERFERENCE.

ANALYZED BY JOSEPH CHARLES CERTIFIED BY PHU TIEN NGUYEN

PRAXAIR

Praxair
5700 South Alameda Street
Los Angeles, CA 90058
Telephone: (213) 585-2154
Facsimile: (714) 542-6689

CERTIFICATE OF ANALYSIS / EPA PROTOCOL GAS

CUSTOMER BEST ENVIRONMENTAL P.O NUMBER 9276

REFERENCE STANDARD

COMPONENT	NIST SRM NO.	CYLINDER NO.	CONCENTRATION
CARBON MONOXIDE GMIS	vs 2636a	SA 13656	100.9 ppm
OXYGEN GMIS	vs 2658a	SA 19970	10.04%
CARBON DIOXIDE GMIS	vs 2745	282185	14.01 %

ANALYZER READINGS

R=REFERENCE STANDARD Z=ZERO GAS C=GAS CANDIDATE

1. COMPONENT CARBON MONOXIDE GMIS ANALYZER MAKE-MODEL-S/N Siemens Ultramat 5E S/N A12-729
ANALYTICAL PRINCIPLE NDIR LAST CALIBRATION DATE 10/06/97
FIRST ANALYSIS DATE 10/29/97 SECOND ANALYSIS DATE 11/05/97

Z 0.0	R 100.8	C 86.0	CONC.	86.1 ppm	Z 0.0	R 100.6	C 85.6	CONC.	85.9 ppm
R 100.8	Z 0.0	C 85.8	CONC.	85.9 ppm	R 100.8	Z 0.0	C 85.8	CONC.	85.9 ppm
Z 0.0	C 86.0	R 100.8	CONC.	86.1 ppm	Z 0.0	C 85.8	R 101.0	CONC.	85.7 ppm
U/M ppm		MEAN TEST ASSAY		86.0 ppm	U/M ppm		MEAN TEST ASSAY		85.8 ppm

2. COMPONENT OXYGEN GMIS ANALYZER MAKE-MODEL-S/N Siemens Oxymat 5E S/N A12-839
ANALYTICAL PRINCIPLE Paramagnetic LAST CALIBRATION DATE 10/08/97
FIRST ANALYSIS DATE 10/29/97 SECOND ANALYSIS DATE

Z 0.00	R 10.04	C 8.52	CONC.	8.52 %	Z	R	C	CONC.	
R 10.04	Z 0.00	C 8.52	CONC.	8.52 %	R	Z	C	CONC.	
Z 0.00	C 8.52	R 10.04	CONC.	8.52 %	Z	C	R	CONC.	
U/M %		MEAN TEST ASSAY		8.52 %	U/M %		MEAN TEST ASSAY		

3. COMPONENT CARBON DIOXIDE GMIS ANALYZER MAKE-MODEL-S/N Siemens Ultramat 5E S/N A12-730
ANALYTICAL PRINCIPLE NDIR LAST CALIBRATION DATE 10/08/97
FIRST ANALYSIS DATE 10/29/97 SECOND ANALYSIS DATE

Z 0.00	R 14.01	C 13.00	CONC.	13.00 %	Z	R	C	CONC.	
R 14.02	Z 0.00	C 13.00	CONC.	12.99 %	R	Z	C	CONC.	
Z 0.00	C 13.00	R 14.02	CONC.	12.99 %	Z	C	R	CONC.	
U/M %		MEAN TEST ASSAY		12.99 %	U/M %		MEAN TEST ASSAY		

THIS CYLINDER NO. SA 20615
HAS BEEN CERTIFIED ACCORDING TO SECTION EPA-600/R93/224
OF TRACEABILITY PROTOCOL NO. Rev. 9/93
PROCEDURE G1
CERTIFIED ACCURACY ± 1 % NIST TRACEABLE
CYLINDER PRESSURE 2000 PSIG
CERTIFICATION DATE 11/05/97
EXPIRATION DATE 11/05/00 TERM 36 MONTHS

CERTIFIED CONCENTRATION	
CARBON MONOXIDE	85.9 ppm
OXYGEN	8.52 %
CARBON DIOXIDE	12.99 %
NITROGEN	BALANCE

Values not valid below 150 psig

ANALYZED BY STEVE GUTIERREZ CERTIFIED BY JOSEPH CHARLES

IMPORTANT
Information contained herein has been prepared at your request by qualified experts within Praxair Distribution, Inc. While we believe that the information is accurate within the limits of the analytical methods employed and is complete to the extent of the specific analyses performed, we make no warranty or representation as to the suitability of the use of the information for any particular purpose. The information is offered with the understanding that ...

PRAXAIR

Praxair
5700 South Alameda Street
Los Angeles; CA 90058
Telephone: (323) 585-2154
Facsimile: (714) 542-6689

CERTIFICATE OF ANALYSIS / EPA PROTOCOL GAS

CUSTOMER BEST ENVR. PO#9424 P.O NUMBER 9424

REFERENCE STANDARD

COMPONENT	NIST SRM NO.	CYLINDER NO.	CONCENTRATION
NITRIC OXIDE GMIS	1683b	CC 66572	50.0 ppm

ANALYZER READINGS

R=REFERENCE STANDARD Z=ZERO GAS C=GAS CANDIDATE

1. COMPONENT NITRIC OXIDE GMIS ANALYZER MAKE-MODEL-S/N Thermo Env. 42H S/N 42H-44979-273

ANALYTICAL PRINCIPLE Chemiluminescence LAST CALIBRATION DATE 02/11/99

FIRST ANALYSIS DATE 02/18/99 SECOND ANALYSIS DATE 02/25/99

Z 0	R 50.4	C 44.9	CONC. 44.5 ppm	Z 0	R 49.8	C 44.7	CONC. 44.9 ppm
R 50.2	Z 0	C 44.6	CONC. 44.4 ppm	R 49.8	Z 0	C 44.7	CONC. 44.9 ppm
Z 0	C 44.5	R 50.0	CONC. 44.5 ppm	Z 0	C 44.6	R 49.8	CONC. 44.8 ppm
U/M ppm		MEAN TEST ASSAY	44.5 ppm	U/M ppm		MEAN TEST ASSAY	44.9 ppm

NOx values for reference only.
All values not valid below 150 psig.

THIS CYLINDER NO.	SA 13874	CERTIFIED CONCENTRATION	
HAS BEEN CERTIFIED ACCORDING TO SECTION	EPA-600/R97/121	NITRIC OXIDE	44.7 ppm
OF TRACEABILITY PROTOCOL NO.	Rev. 9/97	NITROGEN	BALANCE
PROCEDURE	G1	NOX	44.9 ppm
CERTIFIED ACCURACY	± 1 % NIST TRACEABLE		
CYLINDER PRESSURE	2000 PSIG		
CERTIFICATION DATE	02/25/99		
EXPIRATION DATE	02/25/01 TERM 24 MONTHS		

ANALYZED BY PHU TIEN NGUYEN CERTIFIED BY JACKSON KONG

PRAXAIR

Praxair
5700 South Alameda Street
Los Angeles, CA 90058
Telephone: (213) 585-2154
Facsimile: (714) 542-6689

CERTIFICATE OF ANALYSIS / EPA PROTOCOL GAS

CUSTOMER BEST ENVIRONMENTAL P.O NUMBER 9319

REFERENCE STANDARD

COMPONENT	NIST SRM NO.	CYLINDER NO.	CONCENTRATION
NITRIC OXIDE GMIS	vs. 1684b	SA 4796	99.1 ppm

ANALYZER READINGS

R=REFERENCE STANDARD Z=ZERO GAS C=GAS CANDIDATE

1. COMPONENT NITRIC OXIDE GMIS ANALYZER MAKE-MODEL-S/N Thermo Env. 42H S/N 42H-44979-273

ANALYTICAL PRINCIPLE Chemiluminescence LAST CALIBRATION DATE 04/08/98

FIRST ANALYSIS DATE 04-28-98 SECOND ANALYSIS DATE 05-06-98

Z 0	R 102.7	C 90.4	CONC.	87.2		Z 0	R 104.3	C 92.0	CONC.	87.4
R 103.3	Z 0	C 91.4	CONC.	87.7		R 104.2	Z 0	C 92.7	CONC.	88.2
Z 0	C 91.4	R 103.3	CONC.	87.7		Z 0	C 92.0	R 104.3	CONC.	87.4
U/M ppm			MEAN TEST ASSAY	87.5		U/M ppm			MEAN TEST ASSAY	87.7

NOx values for reference only.
All values not valid below 150 psig.

THIS CYLINDER NO. SA 15456
HAS BEEN CERTIFIED ACCORDING TO SECTION EPA-600/R97/121
OF TRACEABILITY PROTOCOL NO. Rev. 9/97
PROCEDURE G1
CERTIFIED ACCURACY ± 1 % NIST TRACEABLE
CYLINDER PRESSURE 2000 PSIG
CERTIFICATION DATE 05/06/98
EXPIRATION DATE 05/06/00 TERM 24 MONTHS

CERTIFIED CONCENTRATION	
NITRIC OXIDE	87.6 ppm
NITROGEN	BALANCE
NOx	88.0 ppm

ANALYZED BY PHU TIEN NGUYEN CERTIFIED BY MICHAEL PEREZ

AUTHORITY TO CONSTRUCT
OR
PERMIT TO OPERATE

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT UNIT: C-601-7-0 **ISSUANCE DATE:** 03/30/1999

LEGAL OWNER OR OPERATOR: GUILD WINERIES & DISTILLERIES
MAILING ADDRESS: 3223 E CHURCH AVENUE
FRESNO, CA 93725

LOCATION: 3223 E CHURCH, FRESNO

EQUIPMENT DESCRIPTION
INSTALL NEW 68.0 MMBTU/HR NEBRASKA BOILER, MODEL NOS-2-525 EQUIPPED WITH AN ALZETA LOW NOX BURNER. ADD PRE-APPROVED "A" ALTERNATE MONITORING CONDITIONS, REMOVE FROM SERVICE, BOILERS C-601-2 & C-601-4 AFTER THE INSTALLATION OF THE NEW BOILER.

CONDITIONS

1. Prior to the implementation of this Authority to Construct into a Permit to Operate, the facility shall remove from service, Permits C-601-2 and C-601-4. [District Rule 2201]

2. Authority to Construct C-601-6-2 shall be implemented and enforcable concurrent with, or prior to, startup of the equipment listed above. [District Rule 2201]

3. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

4. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

CONDITIONS CONTINUE ON NEXT PAGE

This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION OF THE EQUIPMENT IS COMPLETED. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

DAVID L. CROW, Executive Director/APCO

SEYED SADREDIN, Director of Permit Services

Central Regional Office • 1990 E. Gettysburg Ave. • Fresno, California 93726 • (559)230-5900 • FAX (559) 230-6061

conditions continued:
C-601-7-0
Page 2

5. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

7. The boiler shall be fired solely on PUC quality natural gas. [District Rule 2201]

8. Natural gas usage rate from this boiler shall not exceed 595,680 MMBtu/yr. [District Rule 2201]

9. Records of the amount of monthly natural gas consumption shall be maintained and retained on the premises for at least two years and made available for District inspection upon request. [District Rule 4305]

10. Emissions shall not exceed 50 ppmv CO @ 3% O2 (equivalent to 0.037 lb CO/MMBtu), 0.0107 lb NOx/MMBtu (or 9 ppmv @ 3% O2), 0.00756 lb PM10/MMBtu, 0.000597 lb SOx/MMBtu, nor 10 ppmv VOC @ 3% O2 (equivalent to 0.004 lb VOC/MMBtu). [District Rule 2201]

11. This unit shall be tested for compliance with the NOx and CO emissions limits within 60 days of start-up and not less than once every 12 months thereafter. After demonstrating compliance on two consecutive annual source tests, the unit shall be tested not less than once every thirty-six months. [District Rule 4305]

12. NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rule 4305]

13. Source testing to measure CO emissions (ppmv) shall be conducted using EPA Method 10 or ARB Method 100. [District Rule 4305]

14. Source testing to measure stack gas oxygen concentration shall be conducted using EPA Method 3 or 3A, or CARB Method 100. [District Rule 4305]

15. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. [District Rule 1081]

16. The results of each source test shall be submitted to the District within 60 days after completion of the test. [District Rule 1081]

17. Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

18. The stack concentration of NOx (as NO2), CO, and O2 shall be measured at least on a monthly basis using District-approved portable exhaust gas analyzers. [District Rule 4305]

19. The permittee shall maintain records of the date and time of NOx, CO, and O2 measurements, the measured NO2 and CO concentrations corrected to 3% O2, and the O2 concentration. The records must also include a description of any corrective action taken to maintain the emissions within the acceptable range. These records shall be retained at the facility for a period of no less than two years and shall be made available for District inspection on request. [District Rule 4305]

CONDITIONS CONTINUE ON NEXT PAGE

FACILITY NAME:GUILD WINERIES & DISTILLERIES
LOCATION:3223 E CHURCH, FRESNO

conditions continued:
C-601-7-0
Page 3

20. If the NOx or CO concentrations, as measured by the portable analyzer, exceed the allowable emissions rate, the permittee shall notify the District and take corrective action within one (1) hour after detection. If the portable analyzer readings continue to exceed the allowable emissions rate, the permittee shall conduct an emissions test within 60 days, utilizing District-approved test methods, to demonstrate compliance with the applicable emissions limits. [District Rule 4305]

21. The portable analyzer shall be calibrated as recommended by the manufacturer. All instrument calibration data shall be kept on file including the date of calibration. The calibration date shall not exceed 6 months prior to the date the stack concentration are measured and recorded. [District Rule 4305]

22. Concentration measurements shall not be taken until the sample acquisition probe has been exposed to the stack gas for at least 150% of the response time. Measurements shall be taken in triplicate. [District Rule 4305]

23. If water vapor is not removed prior to measurement, the absolute humidity in the gas stream must be determined so that the gas concentrations may be reported on a dry basis. [District Rule 4305]

24. If water vapor creates an interference with the measurement of any component, then the water vapor must be removed from the gas stream prior to concentration measurements. [District Rule 4305]

SOURCE TEST PLAN

BEST ENVIRONMENTAL, INC.
15890 Foothill Boulevard
San Leandro, California 94578
(510) 278-4011 FAX (510) 278-4018

September 2, 1999

Attn.: Mr. Robert Vinson
San Joaquin Valley Unified APCD
1990 E Gettysburg Avenue
Fresno, CA 93726

Re: Source Test Plan for compliance emissions monitoring of new 68.0 MMBtu/hr Nebraska boiler (#6) located at Guild Wineries & Distilleries (Canandaigua Wine Co. – Cribari), 3223 E Church Avenue, Fresno, California. The objective of this test program is to assess the boilers compliance per Rule 4305 and ATC #C-601-7-0 (9/50 ppmv NOx/CO @ 3% O2).

Dear Mr. Vinson:

BEST ENVIRONMENTAL, Inc. (BEI) proposes the following methodology to perform the emission testing on the source(s) referenced above:

- Triplicate thirty-minute (plus response time) test runs for NO_x, CO and O_2 will be performed at the boiler outlets using CARB Method 100. This testing will occur with the boiler operating at the load representative of normal operating conditions.
- Additional testing (five-minute emissions check runs) will not need to be performed at other load points (alternate loads), due to the use of a portable analyzer for Rule 4305 Alternate Monitoring System (AMS) compliance. If the analyzer is available during the test program, BEI will record the values from the analyzer during the source testing.
- Load will be determined using EPA Method 19 (fuel consumption), steam flow data or gas valve indicator.
- Three copies of the technical report will be submitted to Cribari Winery within four weeks of test completion. The report will include a test description and tables presenting concentrations (ppm), emission rates (lbs/hr) and emission factors (lbs/MMBtu) for all compliance parameters. All supporting documentation will be included (field data sheets, strip charts, calibrations, calculations, etc.).

Per our conversation, the testing is scheduled for September 28th, 1999, with BEI's arrival time on site of ≈ 10 AM, with testing starting at approximately noon. Mr. Frank M von Furstenrecht is our site contact for this test program and he can be reached at (559) 485-3080. If you have any questions concerning this Source Test Plan, please contact Regan Best, Guy Worthington, or me at (510) 278-4011.

Sincerely

Craig Thiry

Craig Thiry
Operations Manager

cc: Frank M von Furstenrecht, Cribari Winery

Alzeta Corporation
2343 Calle Del Mundo
Santa Clara, CA 95054

Ph (408) 727-8282
Fax (408) 727-9740

Boiler Efficiency Form

Date: November 1999
Location: 3223 E Church Ave, Fresno, CA 93725-1338
Owner of Boiler: Cribari Winery
Type of boiler Nebraska
Size as fired: 68 MMBtu/hr
Fuel type: Natural Gas

	Test #1	Test #2	Test #3
Time (hh:mm: 24hr)	9:15	10:00	10:50
1 Steam Pressure in drum (psia)	149.7	149.7	150.7
9 Steam quality	100%	100%	100%
Steam Temp (°F)	358	358	358
8 Water temp entering Economizer (°F)			
10 Ambient Temp (°F)	57	58	62
11 Combustion air temp (°F)		93.7	
12 Temperature of Natural Gas (°F)			
13 Stack Temp (°F)	230	334	384
15 Enthalpy of Sat liquid			
Pressure of inlet water (psig)			
Temperature of inlet water (°F)			
Flow rate of inlet water			
17 Enthalpy of exit from economiser			
Pressure of economiser (psig)			
Temperature of economiser (°F)			
Flow rate of economiser			
26 Actual water evaporated (lb/hr)			
28 Rate of fuel as fired (BTU/hr)			55.2E+6
28 Rate of fuel as fired (lb/hr)			2.27E+03
Metered amount (ft^3)			500
Pressure (psia)			29.09
Metered time (s)			65.8
Gas HHV (BTU/ft^3) (as supplied by PG&E)	1020	1020	1020
41 Gas HHV (BTU/lb)	24286	24286	24286
Density of premix (lb/ft^3)	0.042	0.042	0.042
30 Enthalpy of blowdown			
Pressure of blowdown (psig)	14.7	14.7	14.7
Temperature of blowdown (°F)	212.7	212.5	212
Flow rate of blowdown			
Flue Gas Analyis			
32 CO2			6.2%
33 O2			9.8%
34 CO			0.0003%
35 N2 (by difference)			84.0%
36 Excess Air			78.3%

Test #3 is high fire and the only test point where Alzeta burner was sole-user of Natural gas supply allowing for gas volume measurement.

25	Dry gas per lb as fired fuel burned	29.61953
	Q fuel (ft^3/hr)	5.41E+04
	mdot fuel (lb/hr)	2.27E+03
	Theo air	1.782501
	Q air (ft^3/hr)	9.26E+05
	mdot air (lb/hr)	6.95E+04
25a	Dry gas per lb as fired fuel burned	3.16E+01
65	heat loss due to dry gas (as fired fuel)	2288.998
65a		2438.737
65	heat loss due to dry gas (%loss)	9.4%
65a		10.0%
	Percent of gross heat input	0.70%
	Total % Heat Loss	10.1%
a		10.7%
72	Total Efficiency %	89.9%
72a	Total Efficiency %	89.3%
73	HHV	80.9%
73a	HHV	80.3%

"a" above is engineering cross-check of air+fuel/fuel.