Stationary Combustion $NO_x$ Control

950R80040

| U.S. Environmental Protection Agency | Electric Power Research Institute | IERL-RTP-1083 October 1980 |
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# Proceedings of the Joint Symposium on Stationary Combustion $NO_x$ Control

## Volume I
## Utility Boiler $NO_x$ Control by Combustion Modification

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IERL-RTP-1083
October 1980

# Proceedings of the Joint Symposium on Stationary Combustion $NO_X$ Control

## Volume I
## Utility Boiler $NO_X$ Control by Combustion Modification

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Program Element No. N130

Prepared for

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## PREFACE

These proceedings document more than 50 presentations given at the Joint Symposium on Stationary Combustion $NO_x$ Control held October 6-9, 1980 at the Stouffer's Denver Inn in Denver, Colorado. The symposium was sponsored by the Combustion Research Branch of the Environmental Protection Agency's (EPA) Industrial Environmental Research Laboratory-Research Triangle Park and the Electric Power Research Institute (EPRI). The presentations emphasized recent developments in $NO_x$ control technology. Cochairmen of the symposium were Robert E. Hall, EPA, and J. Edward Cichanowicz, EPRI. Introductory remarks were made by Kurt E. Yeager, Director, Coal Combustion Systems Division, EPRI, and the welcoming address was given by Roger L. Williams, Regional Administrator, EPA Region VIII. Stephen J. Gage, Assistant Administrator for Research and Development, EPA, was the keynote speaker. The symposium had 11 sessions:

I: $NO_x$ Emissions Issues
Michael J. Miller, EPRI, Session Chairman

II: Manufacturers Update of Commercially Available Combustion Technology
Joshua S. Bowen, EPA, Session Chairman

III: $NO_x$ Emissions Characterization of Full Scale Utility Powerplants
David G. Lachapelle, EPA, Session Chairman

IV: Low $NO_x$ Combustion Development
Michael W. McElroy, EPRI, Session Chairman

Va: Postcombustion $NO_x$ Control
George P. Green, Public Service Company of Colorado, Session Chairman

Vb: Fundamental Combustion Research
Tom W. Lester, EPA, Session Chairman

VI: Status of Flue Gas Treatment for Coal-Fired Boilers
Dan V. Giovanni, EPRI, Session Chairman

VII: Small Industrial, Commercial, and Residential Systems
Robert E. Hall, EPA, Session Chairman

VIII: Large Industrial Boilers
J. David Mobley, EPA, Session Chairman

IX: Environmental Assessment
Robert P. Hangebrauck, EPA, Session Chairman

X: Stationary Engines and Industrial Process Combustion Systems
John H. Wasser, EPA, Session Chairman

XI: Advanced Processes
G. Blair Martin, EPA, Session Chairman

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*See Volume V, Addendum.

*See Volume V, Addendum.

# DEVELOPMENT AND FIELD OPERATION OF THE CONTROLLED FLOW/SPLIT-FLAME BURNER

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ABSTRACT

An advanced low $NO_x$ coal burner has been installed in a 375 MW front-wall fired steam generator. Unstaged $NO_x$ levels below 0.4 lb/million Btu are being consistantly obtained with burners having a maximum liberation rate of 285 million Btu/hr. Prototype tests of this burner, in a 50 million Btu/hr test furnace, have resulted in unstaged $NO_x$ emissions of 0.25 lb/million Btu; when staged using overfire air ports emissions were reduced below 0.20 lb/million Btu.

This high capacity low $NO_x$ burner permits new steam generators to be equipped with the same number of burners and the same type of burner management system as were used prior to the advent of emission regulations.

The Foster Wheeler low $NO_x$ system is also available for retrofit to older steam generators.

This availability is timely in that it provides an option for utilities, which must convert from oil to coal, to use a modern combustion system. This can be of particular importance to those units which were designed to fire "future coal", based on the boiler, firing system and performance coal availability of the 1950's and '60's, but have instead been firing oil. A further advantage may be provided by the large $NO_x$ reductions attainable since these may permit trade-offs within the EPA's "bubble concept". However, the actual $NO_x$ levels attainable for older units would be site-dependent.

## INTRODUCTION

The nearly simultaneous imposition of emission controls and fuel restrictions on the design of power plants has resulted in a significant increase in the quantity of hardware which must be included between the fuel storage area and the stack. Coal, which is currently the only fuel permissible for new utility boilers in the U.S., now requires more extensive particulate and sulfur control equipment. Although this type of equipment is supplied by boiler manufacturers or their subsidiaries, the primary area of responsibility for the steam generator designer is that of $NO_x$ control. Significant $NO_x$ reductions, as compared to levels emitted prior to the advent of $NO_x$ limits, can be attained by proper boiler and combustion system design.

A primary consideration in the design of low $NO_x$ combustion systems should be attainment of minimum $NO_x$ levels simultaneously with minimum increase in system complexity. Clearly, as more components are added to the overall power plant train it is desirable to maximize the availability of each component. Systems of reduced complexity result in lower first cost, decreased maintenance and simpler operation.

Foster Wheeler's method of minimizing boiler and firing system complexity is based upon the use of large capacity (up to 300 million Btu/hr) low $NO_x$ coal burners which minimizes the number of burners required. The burner design and its flexibility and controllability permit a simple common windbox to be retained.

Foster Wheeler's first generation low $NO_x$ burner, the Controlled Flow design, had been retrofitted in 1976 [1] to an older unit. $NO_x$ was reduced about 50% (to 0.42 $lb/10^6$ Btu) without staging and to 0.3 $lb/10^6$ Btu with staging. More recently the advanced Controlled Flow/Split-Flame burner has been achieving unstaged $NO_x$ levels between 0.35 and 0.41 lb/$10^6$ Btu on a 375 MW steam generator to which it had been retrofitted.

If the EPA's research goals [(2)] can be used as a guide then even more stringent limits may be instituted in the future. These research goals are 200 ppm by 1980 and 100 ppm by 1985. Also in some states, units sold prior to 1971 are required to reduce $NO_x$ emissions to below 0.7 lb/$10^6$ Btu.

In 1979, Foster Wheeler's experimental development program achieved $NO_x$ levels below 0.2 lb/$10^6$ Btu, with the Controlled Flow/Split-Flame burner, in a 50 million Btu/hr research furnace. This development program and the field operation of this burner will be presented here.

## $NO_x$ EMISSIONS: EFFECT OF COAL CHARACTERISTICS AND BOILER DESIGN

The $NO_x$ emissions from coal fired steam generators consist of three components:

- Thermal $NO_x$: formed by fixation of molecular nitrogen contained in the combustion air. This quantity is exponentially dependent on flame temperature; below about 2800°F the formation of thermal $NO_x$ is negligible.

- Volatile and Char Fraction Fuel $NO_x$: formed from the atomic nitrogen which is chemically bound within the structure of the coal: nitrogen is contained in both the volatile and char fractions. $NO_x$ formed from the volatile fraction is typically responsible for 75% of the fuel $NO_x$ emission thereby being the largest component in the total emission.

These sources of $NO_x$ can be controlled, to varying degrees, by proper boiler and firing system design. The $NO_x$ level which is ultimately produced is dependent on numerous variables. The following is a discussion of those variables which are of primary consideration:

(a) Burner Zone Liberation Rate (Q/BZS): This is defined as the net heat input to the burner zone divided by the effective projected surface. This quantity has been discussed in detail previsouly [3,4]. Q/BZS affects flame temperature thereby determining the amount of thermal $NO_x$ generated.

The boiler designer is provided with a useful tool for reducing $NO_x$ by increasing burner zone surface (lowering Q/BZS). Reducing Q/BZS from 450,000 to 300,000 Btu/hr-ft$^2$, on units equipped with high turbulent burners, lowers $NO_x$ by about 30%.

(b) Firing Geometry: Opposed or Single Wall: Figure 1 is a summary of the $NO_x$ emissions as a function of Burner Zone Liberation Rate for both single-wall and opposed-fired units. Both plots are composits of full load data from units all utilizing similar high turbulent intervane burners. It can be seen that, for any particular value of Q/BZS, opposed-firing always has lower $NO_x$ emissions than does single-wall firing.

A third curve represents the $NO_x$ variation with Burner Zone Liberation Rate (using the above definition and derived from published emission data [5,6,7])for tangential-fired boilers operated with overfire air ports closed. Although tangential firing has a lower uncontrolled $NO_x$ emission, when compared with wall-fired boilers equipped with high-turbulent pre-NSPS* burners, the sensitivity to heat release rate appears to be greater. This differential is of no consequence when wall-fired units are equipped with modern low $NO_x$ combustion systems.

Although this is useful information, the boiler's firing configuration cannot be dependent on $NO_x$ requirements. The choice of boiler configuration is generally governed by the specified boiler capacity, economic considerations and plant requirements.

(c) Coal Characteristics: That part of the $NO_x$ emission which is formed from the fuel-bound nitrogen is primarily dependent upon the percent fuel nitrogen content, heating value and volatility. The total nitrogen content is a function of both the percent nitrogen and heating value and can be expressed as lb $NO_x$/million Btu. Varying fuel characteristics will shift the curves of Figure 1 in the vertical direction.

*NSPS: NEW SOURCE PERFORMANCE STANDARD

Knowledge of the fuel nitrogen effect is important so that the designer can accurately determine the effect of various $NO_x$ control measures. Foster Wheeler has developed such a technique. The uncontrolled $NO_x$ level produced with the high turbulent intervane burner is determined to provide a baseline against which the effectiveness of $NO_x$ reduction devices can be compared. Figure 2 illustrates the accuracy of the technique for four boilers equipped with intervane burners and staging ports for $NO_x$ control. It can be seen that the baseline prediction method is quite accurate.

This prediction technique was modified in 1976 to incorporate the first generation low $NO_x$ burner as the primary $NO_x$ control method. The effectiveness of the newest low $NO_x$ burner, the Controlled Flow/Split-Flame design, on a 375 MW front-wall fired unit, is shown for comparison.

Coal particle size distribution is also of importance for $NO_x$ control. Good fineness has always been important from a combustion efficiency viewpoint. However, fineness can also have a significant impact on $NO_x$ emission in low $NO_x$ systems.

(d) <u>Burner Characteristics:</u> Flame conditions have a major impact on $NO_x$ emissions. High turbulent burners which provide rapid mixing between the fuel and total combustion air and produce short intense flames will have the highest $NO_x$ emissions. The rapid mixing increases flame temperature while simultaneously permitting the fuel-bound nitrogen to be liberated from the coal particles in an excess oxygen environment, thus promoting a relatively high fraction to be converted to NO.

The most effective means of reducing this conversion rate is to reduce the availability of oxygen to the fuel-found nitrogen. The two most practical means of accomplishing this are:

- Reduce burner air by use of staged combustion

- Controlled mixing of air and fuel at the burner

With a suitably designed burner, staged combustion can be used to provide additional $NO_x$ reduction. However, coal properties must be carefully evaluated for any adverse effect on furnace conditions. Operation at burner stoichiometries below about 96-100% is, in general, not recommended.

## $NO_x$ CONTROLS AND THEIR EFFECTIVENESS

Prior to the advent of $NO_x$ emission regulations the historical trend in burner and boiler design had been toward hot, high turbulent systems. Burners were designed to be as close to the premixed concept as possible in order to maximize flame temperature and minimize unburned carbon carryover. Figure 3 shows a typical 1965 vintage high turbulent intervane burner. A key reason for the excellent flame stability and high carbon burnout of this design is the annular coal nozzle and its tangential coal inlet.

The inlet/nozzle configuration produces a uniform coal distribution around the periphery of the nozzle outlet; there is no roping of the coal. The single register and throat geometry cause the coal/primary air stream to be rapidly entrained by the secondary air flow thereby maximizing the oxidizing regions of the flame. A short, hot flame results which has high thermal and fuel $NO_x$ emissions.

The only operating control used with this type of burner is that which operates the register. In order to minimize the complexity of low $NO_x$ systems, which must have increased numbers of components, it is advantageous to use the same type of control, scanning and ignition systems as were utilized on high turbulent burners.

High turbulent burners are amenable to $NO_x$ reduction by controlling both flame temperature and oxygen availability to the coal.

Flame temperature can be reduced by:

- Increasing cooling surface (reducing Burner Zone Liberation Rate)
- Flue Gas Recirculation to the windbox (ineffective for coal firing)

Figure 1 has shown that $NO_x$ emissions, from units equipped with high turbulent intervane burners, can be reduced by about 30% when Burner Zone Liberation Rate is decreased from 450,000 to 300,000 Btu/hr-ft$^2$.

The combination of reduced Burner Zone Liberation Rates and staged combustion was used as the $NO_x$ control method for meeting the first EPA limits (0.7 lb/MMBTu) on units sold by Foster Wheeler until 1976.

Although effective in reducing $NO_x$ emissions, staged combustion has two primary limitations:

- Tube wastage which occurs with high iron, high sulfur coals can affect unit life and reliability.
- Increased slagging which can affect unit availability.

These prolems tend to occur when the burner zone is operated substoichiometrically so that reducing atmospheres exist along the waterwalls. In order to avoid this situation we have limited burner stoichiometry to 96% minimum and incorporated BOUNDARY AIR ™ to provide an oxidizing atmosphere along the walls in the burner zone. Figure 4 shows the location of the BOUNDARY AIR ports and slots. The locations were arrived at through the combined use of cold flow modeling of the lower burner zone and field experience. BOUNDARY AIR also acts as passive air flow balance technique to minimize slagging potential during load changes, mill out of service or unequal mill load operations.

The operational limits placed on staged combustion, so as to control wastage and slagging, inhibit its usefulness as a $NO_x$ control measure. Consequently, a more flexible primary $NO_x$ control technique was needed. This requirement has resulted in the development of the low $NO_x$ controlled flow family of burners.

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## LOW $NO_x$ BURNER DEVELOPMENT

A low $NO_x$ burner development program was commenced in 1975. The primary goal was to develop a burner which would produce $NO_x$ reductions greater than those attainable with overfire air ports. However, since the burner is only part of the overall system, requirements were also placed on compatability with the steam generator's design. These requirements can be summarized as follows:

- Burner capacity should be the same as that of the pre-NSPS high turbulent intervane burners (up to about 300 million Btu/hr).
- Excess air requirements and unburned carbon levels should be equal, and preferably superior, to those of the intervane burner.
- The common windbox should be retained to minimize secondary air system complexity.
- Combustion system controls and flame scanning should require no additional complexity.

### Low $NO_x$ Concept

Within a flame there is strong competition for $O_2$ between the carbon and nitrogen released from the coal. Under turbulent excess air conditions, substantially all of the carbon is oxidized to $CO_2$ whereas, about 30% of the fuel nitrogen becomes NO, the remainder being emitted as molecular nitrogen (the conversion varies inversely with nitrogen content).

When the early phase of combustion occurs under reducing conditions, with sufficient residence time, the formation of NO is significantly reduced. In particular, when fuel devolatilization takes place in a reducing environment, volatile-fraction fuel $NO_x$ will be minimized. If the residence time in the reducing zone, or low excess air zone, is of sufficient duration, the char-fraction fuel $NO_x$ will also be decreased. Also if the local flame stoichiometry is below about 95% theoretical air, the flame temperature will be depressed thereby reducing the formation of thermal $NO_x$. The reduction in flame temperature will also depend on the available cooling surface; a high Burner Zone Liberation Rate will prevent minimum $NO_x$ levels from being obtained. The sensitivity of fuel $NO_x$ to available oxygen level and mixing rates can be used advantageously to control $NO_x$ via burner modifications.

## Low $NO_x$ Burner Functional Description

The test program has resulted in the successful development and field demonstration of two low $NO_x$ burners: The Controlled Flow and the Controlled Flow/Split-Flame designs. As shown by Figure 5, the two burners are similar; the coal nozzle being the major difference. The burners operate in the following manner:

- Secondary Air Control

  A series register arrangement, common to both designs, allows simple burner controls to be used. The inner register, which regulates the degree of swirl around the coal nozzle, is controlled by a manual drive since continuous adjustment is not required.

  The outer register is controlled by a standard electric drive for operation at "closed", "ignite" and "Operate" positions. The register arrangement divides the secondary air into two concentric streams which independently vary swirl. The secondary air flows axially into the furnace with almost no component directed radially inward, toward the burner centerline. Two registers permit the mixing rate between the primary and secondary air streams, and the rate of entrainment of furnace gases, to be controlled.

  Note that both registers are well shaded from direct furnace radiation so that parts operate cooler and the tendency to warp or bind is minimized.

- Secondary Air Balancing

In order to maintain low levels of excess air while minimizing CO, unburned carbon and slag formation it is advantageous to attain a balanced secondary air flow to all burners. Foster Wheeler achieves this by measuring the pressure drop across the perforated plate air hood thereby obtaining an index of the secondary air flow to each burner. The flows are then balanced by positioning the axially movable sleeves which optimizes the secondary air distribution, both vertically and horizontally, in the windbox. The air hood also improves secondary air distribution around the periphery of the burner to minimize unwanted turbulence.

- Split-Flame Coal Nozzle

Coal is injected into the furnace through an annular nozzle which has been modified to separate the coal into concentrated streams, each of which forms an individual flame. Four streams are indicated in Figure 5 but the number is a design variable.

The split-flame nozzle minimizes mixing between the coal and the primary air. The combination of the concentrated coal streams and the staged secondary air produces near throat flame stoichiometries in the 60-70% range up to about two throat diameters into the furnace. At that point, the swirling secondary stream from the outer annulus, containing the remainder of the combustion air, combines the flames and provides sufficient mixing to ensure adequate carbon-burnout.

Uniform distribution of coal about the periphery of the annular passageway is attained, as with pre-NSPS burners, by use of the tangential coal inlet. There is no undersirable roping of the coal.

The basic Controlled Flow burner employs a tapered annular nozzle instead of a split-flame nozzle. The innner sleeve tip is axially movable thereby providing a means for varying the primary air velocity while primary air flow is maintained constant. The velocity adjustment is used to optimize the primary air/secondary air velocity ratio which minimizes shear-induced turbulence.

The primary air velocity adjustment has also been incorporated into the Controlled Flow/Split-Flame burner.

The flows from both the Controlled Flow and the Controlled Flow/Split-Flame burners are axial and symmetrical about the burner axis. The only flow-induced turbulence is that which is deliberately provided by register swirl setting. This produces early staging of the flames with a minimum of unintentional mixing between the fuel particles and the combustion air.

## Similarity to the Pre-NSPS Burner

After the low $NO_x$ burners three manual adjustments are made(inner register setting, coal nozzle velocity and air hood sleeve) the respective mechanisms are locked. The burners then operate in precisely the fashion as would a pre-NSPS intervane burner. No additional controls are required, beyond the outer register drive. There are no feedback systems interlocked with the pulverizers and no continuous air flow controllers. Mills are taken in and out of service in exacly the same manner as on pre-NSPS boilers.

## $NO_x$ Emission Test Data

Development testing of our low $NO_x$ combustion systems has been performed on a four-burner, 125,000 lb/hr steam generator that has been previously described in detail [1, 4]. More recently, additional testing has been performed on a 50 million Btu/hr single burner test facility [8, 9].

To summarize here:

The original Controlled Flow burner design achieved 35-40% $NO_x$ reductions on the four-burner unit. The design was then modified, scaled-up and tested on a utility steam generator.

This first field installation was a retrofit of a 265 MW opposed-fired unit in Japan. The work was performed by Foster Wheeler's Japanese licensee, Ishikawajima-Harima Heavey Industries Co. (IHI), in 1976. Figure 6 summarizes the $NO_x$ results obtained: 45-50% $NO_x$ reduction with overfire air ports closed, 65-70% with overfire air ports open (at a burner stoichiometry of 96%). Similar results were obtained in the sister unit when it was retrofitted in 1977.

It should be noted that, prior to installation of the Controlled Flow burner, these units had slagging problems which were made worse by staging for $NO_x$ control. When the low $NO_x$ burners were installed, Boundary Air was simultaneously added. The combination of the cooler flames produced by the Controlled Flow burner and the oxidizing atmosphere maintained along the lower furnace walls by Boundary Air has significantly alleviated the slagging problem. The units can now operate continuously with overfire air ports open.

It is interesting to note that overfire air is still effective in combination with the low $NO_x$ burner. This is however, as expected, since the two stage effect, with the burners operated at approximately the stoichiometric ratio, permits most of the char to burn out in a low excess air environment. Consequently, as nitrogen is released from the char it has a greater tendency to form $N_2$ than NO. The greater the separation between the overfire air ports and the burner zone, the greater the residence time at low $O_2$ and the lower the $NO_x$ level will be.

All low $NO_x$ burners developed by Foster Wheeler, including the most advanced designs, can still be used in conjunction with overfire air ports. $NO_x$ can be reduced an additional 25-30% when burner stoichiometry, at 20% excess air, is reduced from 120% theoretical air to about 100%. For this reason overfire air ports may still be considered on a case-by-case basis, as a supplementary $NO_x$ control measure as required by coal characteristics and emission limits. However, it must be reiterated that the degree of staging is generally limited because of its potentially adverse effect on slagging and tube wastage.

The Controlled Flow burner produces a flame shape which is similar to, although slightly longer than, that of the high turbulent intervane burner. The similarity of flame shapes and simplicity of design permits the Controlled Flow burner to be retrofitted to many pre-NSPS steam generators on a plug-in basis.

This is confirmed by the success of the retrofit installations of this burner in Japan; the units there being 10 years old at the time of the retrofit.

Functionally the Controlled Flow burner reduces $NO_x$ by minimizing turbulence and mixing between the primary air/coal stream and the secondary air. Although only sufficient turbulence is generated to maintain flame stability, the initial mixing between primary air and coal and the inner secondary air flow results in near-throat flame stoichiometry of about 85-90%. This is sufficient to yield 40-50% $NO_x$ reductions and is equivalent to operating a high turbulent burner, at the same stoichiometry, in conjunction with overfire air ports.

Figure 7 compares the $NO_x$ reduction attainable from the intervane burner, when staged, to the Controlled Flow burner unstaged and staged, as a function of near throat burner stoichiometry. It can be seen that as the Controlled Flow burners' stoichiometry is reduced by staging (with overfire air ports) from 120% to 96%, the attainable $NO_x$ reduction is increased from about 50% to about 65-70%.

In order to attain greater $NO_x$ reductions, it is therefore desirable to reduce the near-throat flame stoichiometry. Since the Controlled Flow burner is a dual register type which two-stages the secondary air, it does not control the mixing or the distribution of the primary air and coal. If the coal can be substantially separated from the primary air and concentrated (i.e., fuel-side staging) then the Controlled Flow burner will be essentially triple-staged. Near-throat flame stoichiometries of about 60-70% should thus be attainable and would provide $NO_x$ reductions of at least 65%.

The split-flame coal nozzle is one method of achieving this goal and has been successfully developed by Foster Wheeler. Development of the initial design concept [1] on the 125,000 lb/hr industrial steam generator and initial field operation [8, 9] have been discussed in detail previously. This design is effective, functionally, in reducing $NO_x$ 55-60% as shown by Figure 8 for the development tests and Figure 9 for the early field tests.

Figures 10 and 11 are photographs the flames developed on the test boiler and the utility boiler respectively.

The original split-flame design did not incorporate a mechanism for primary air velocity control. The new design, which is now in use commercially and whose operation was described above, now contains this control.

The new burner, which is best described as the Controlled Flow/Variable Velocity Split-flame (CF/SV) design, has been prototype tested on a 50 million Btu/hr test facility and has been successfully scaled-up to full size utility scale. In order to evaluate the performance of the CF/SV design on the test furnace the two earlier burner designs, the Controlled Flow and original Controlled Flow/Split-Flame design, were also tested. These burners provided a basis against which the CF/SV design was compared.

The results of these tests are summarized in Figure 12. It can be seen that the original split-flame design reduces $NO_x$ 35% below the Controlled Flow burner with annular nozzle; the new nozzle design incorporating the variable velocity feature reduces $NO_x$ 50% below the Controlled Flow burner.

For comparison, three full load data points from the 125,000 lb/hr four-burner boiler are also included in Figure 12. They represent the $NO_x$ levels attained by the intervane burner, the Controlled Flow Burner and the Controlled Flow/Split-Flame (original design) burner. Agreement between the single burner test facility and the four-burner industrial boiler is excellent.

Figure 13 is a photograph of the flames produced by the Split-Flame nozzle and Figure 14 is a photo of the flames from the Variable Velocity Split-Flame nozzle. The new design produces more distinct flames with a greater included angle. Furnace observations indicate the flame's length is somewhat shorter than with the original Split-Flame design. This represents an improvement on an already good situation since there was no flame impingement on the rear wall of the actual utility boiler tested.

## FIELD DEMONSTRATION OF THE SPLIT-GLAME CONCEPT

The utility boiler referred to above is the San Juan #1 unit of Public Service Co. of New Mexico. The original split-flame design was retrofitted to this unit in November 1978; the new Controlled Flow/Split-Flame (CF/SV) burner was retrofitted in November 1979 and has been performing satisfactorily, and meeting all design and performance goals, since then.

The boiler is a front-wall fired unit with 16 burners, each of which has a maximum capacity of 285 million Btu/hr, arranged in a 4 x 4 matrix. Four Foster Wheeler medium speed MB pulverizers are used. The boiler can achieve full load with any three pulverizers in service. The fuel used is a high has New Mexico sub-bituminous coal, with heating value typically in the 9,000-10,000 Btu/lb range; although coal with heating value as low as 8,000 Btu/lb has been fired successfully.

Figure 15 compares the emissions attained on San Juan #1 with the results achieved on the test furnace. A reduction over 65% is being achieved in the field, which is quite similar to the reduction achieved on the prototype. This indicates that the scale-up parameters developed (scale-up ratio is 6:1) are accurate.

The Controlled Flow/Split-Flame concept produces significantly greater $NO_x$ reductions than does a dual register type of burner when there is no staging of the throat. However, when the burner is staged, $NO_x$ can be reduced an additional 25% to 30%.

On the test furnace, $NO_x$ is reduced to 0.185 lb/$10^6$ Btu when overfire air ports are open with the Controlled Flow burner and the new Variable Velocity Split-Flame nozzle; with CO increasing to about 125 ppm. This is a 65% reduction from the level measured with the Controlled Flow burner, and 77% from the pre-NSPS intervane burner level. But, as shown on Figure 15, the asymptotic decrease in the attainable $NO_x$ levels may imply that a practical floor is being approached.

Figure 16 summarizes and compares the results of the low $NO_x$ burner conversions on the 265 MW opposed-fired unit and the 375 MW front-wall fired San Juan unit. Although there is a differential of about 0.25 $lb/10^6$ Btu between the uncontrolled $NO_x$ levels, the low $NO_x$ burners reduce the differential to less than 0.1 $lb/10^6$ Btu. Note also that the primary reason that the San Juan emission is higher than the boiler in Japan is that the former is single-wall fired and the latter is opposed fired. Other variables,such as Burner Zone Liberation Rate and coal characteristics, are important but secondary in influence.

Figure 16 also contains the test results from the 50 million Btu/hr test furance from which the burner in use at San Juan #1 was scaled. This data comparison clearly shows the advantages of the Controlled Flow/Split-Flame concept.

The effectiveness of the air hood and sleeve is demonstrated in Figure 17 which shows the necessity for horizontal adjustment of the air distribution in the windbox. With all burners adjusted equally (all air hoods and swirl vanes at the same settings), CO stratified along the sidewalls while $O_2$ and $NO_x$ peaked in the center of the furnace where CO was zero. After balancing the secondary air, by adjusting the air hoods' sleeves to obtain equal pressure drops across all air hoods, a nearly uniform gas distribution was obtained across the furnace. This permitted the unit to operate at lower exess air with reductions in both $NO_x$ and CO.

## THE LARGE CAPACITY BURNER'S SIGNIFICANCE

### New Equipment Design

The large capacity Controlled Flow/Split-Flame low $NO_x$ burner, which emits $NO_x$ levels at least 60% below those of high turbulent burners, increases the flexibility of the steam generator designer. The design constraints and added costs imposed by a large number of small burners are alleviated.

Figure 18 summarizes the low $NO_x$ combustion system for a typical 600 MW coal-fired steam generator. The following enumerates the advantages provided by the large capacity Controlled Flow/Split-Flame low $NO_x$ burner design.

1. A simple common windbox can be retained because the secondary air flow to each burner can be measured and controlled. It is not necessary to modulate the air hood sleeves when pulverizers are taken in and out of service or operated unequally loaded or when load is changed.

2. Lower furnace geometry can be made less dependent on the requirements of the burner. The economics of size, arrangement of heat absorbing area and $NO_x$ requirements can be more advantageously balanced.

3. Standard flame sensing, ignition and control equipment can be used: one electric register drive per burner with no auxiliary controls required. The combustion control system is the same as that for a pre-NSPS boiler.

4. Only two sets of movable vanes per burner: 600 MWe boiler would have 24 - 250 MMBtu/hr burners (48 sets of vanes) versus 48 to 60 small burners (96-120 ets of vanes, assuming only two sets of movable vanes per burner).

5. Burner design is such that no secondary air control vanes receive direct radiation from the flame: parts operate cooler and are less likely to overheat and bind.

6. Pulverizer controls and conduit designs are greatly simplified due to the reduced number of burners. Therefore, there are fewer areas subject to erosion which results in reduced maintenance requirements over the unit's life.

7. The BOUNDARY AIR system provides a passive means of maintaining an oxidizing atmosphere along the sidewalls and in the hopper: during unit operation it is not necessary to modulate any dampers as load changes or as mills are taken out of service. This system is now standard on all Foster Wheeler units, even those where slagging is not expected to be a problem, since it also reduces CO formation during low $NO_x$ operation.

8. Although slightly longer than the high turbulent flame produced by the pre-NSPS intervane burner, the relatively short flame produced by the high capacity Controlled Flow/Split-Flame burner permits this low $NO_x$ design to be amenable to further $NO_x$ reduction via the use of overfire air ports. However, the use of overfire air must be considered on a case-by-case basis since fuel quality and properties must be carefully evaluated.

## Retrofit Capability to Older Boilers

The Controlled Flow and Controlled Flow/Split-Flame burners can be designed over the capacity range of pre-NSPS equipment; up to a maximum burner liberation of 300 million Btu/hr. Since these burners are identical, except for the design of the coal nozzle and their resultant $NO_x$ capabilities, and require no special windbox, structural modifications or additional controls, they can be installed on a plug-in basis in most units equipped with circular burners. Units equipped with other types of burners may require pressure part changes.

The retrofit capability of these burners is due both to the flexibility and controllability designed into them and to their relatively short flame lengths. The flame envelope of the Controlled Flow design is nearly identical to that of the pre-NSPS Intervane burner; that of the split-flame design is slightly longer. Flame envelope and length can be modified by adjusting register settings and primary air velocity.

Other advantages of this system, which combines a modern low $NO_x$ burner with BOUNDARY AIR and is essentially the same as that which is now offered for new equipment, exclusive of low $NO_x$ are:

1. Cooler, less turbulent, flames.
2. Improved balance of secondary flows to yield less variation in burner-to-burner stoichiometries.

These should permit:

- Lower excess air operation for improved efficiency.
- Decreased slagging for improved availability.

The degree of improvements in operation which could be afforded to older equipment would obviously depend on the situation of the individual unit concerned.

SUMMARY

A prototype advanced low $NO_x$ burner, the Controlled Flow/Split-Flame design, has demonstrated $NO_x$ reduction of 65% without staging (to a level of 0.25 lb/million Btu) and up to 77% with staging (to a level of 0.185 lb/million Btu). This burner has been successfully scaled-up and retrofitted to a 375 MW front-wall fired steam generator where $NO_x$ emissions below 0.4 lb/million Btu, also representing a 65% reduction, have been consistently obtained without the use of overfire air. This design is now the standard offering for new Foster Wheeler steam generators.

The Controlled Flow/Split-Flame burner, and the earlier Controlled Flow design, are capable of being retrofitted to older steam generators. Both are in successful field operation in retrofitted units.

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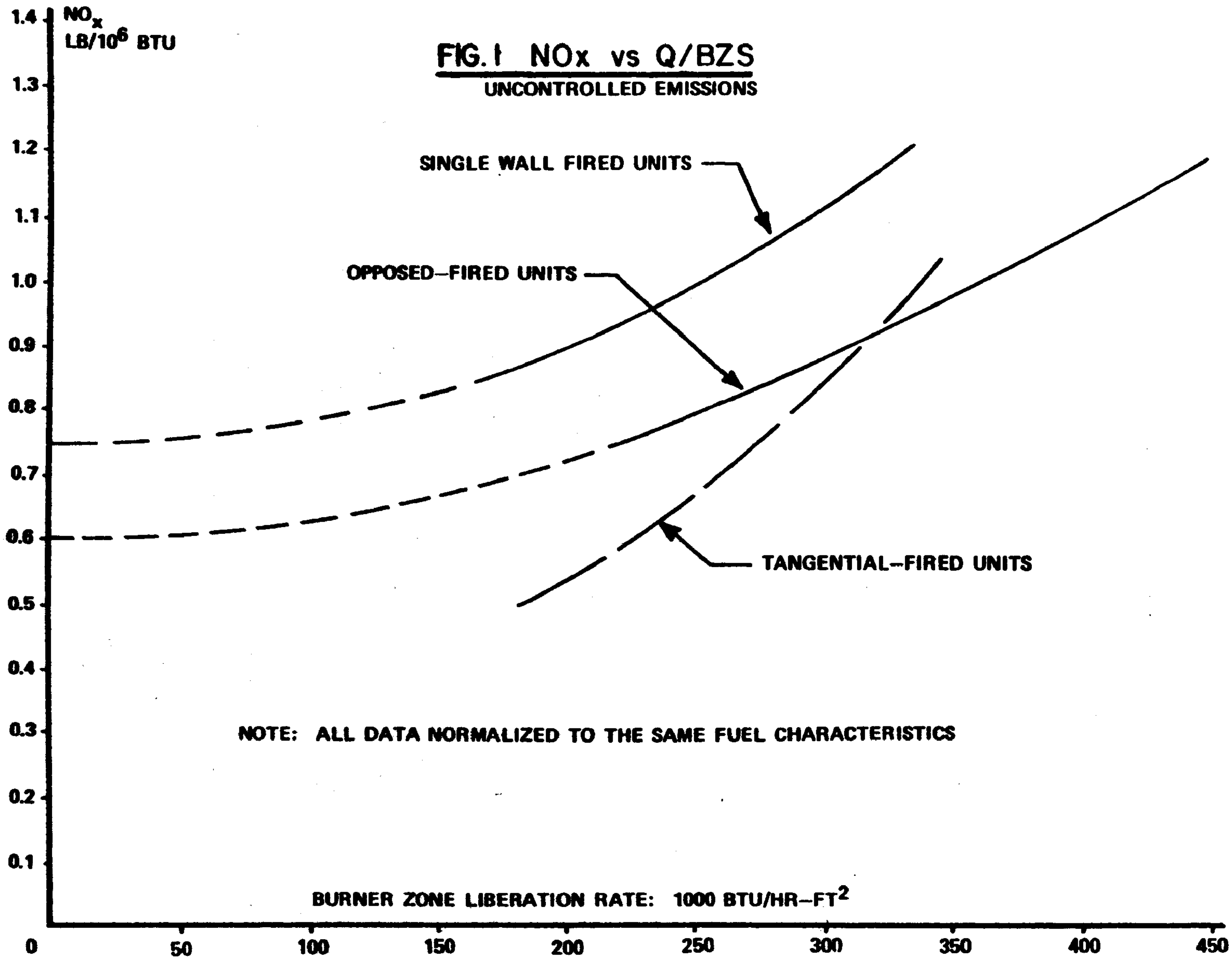
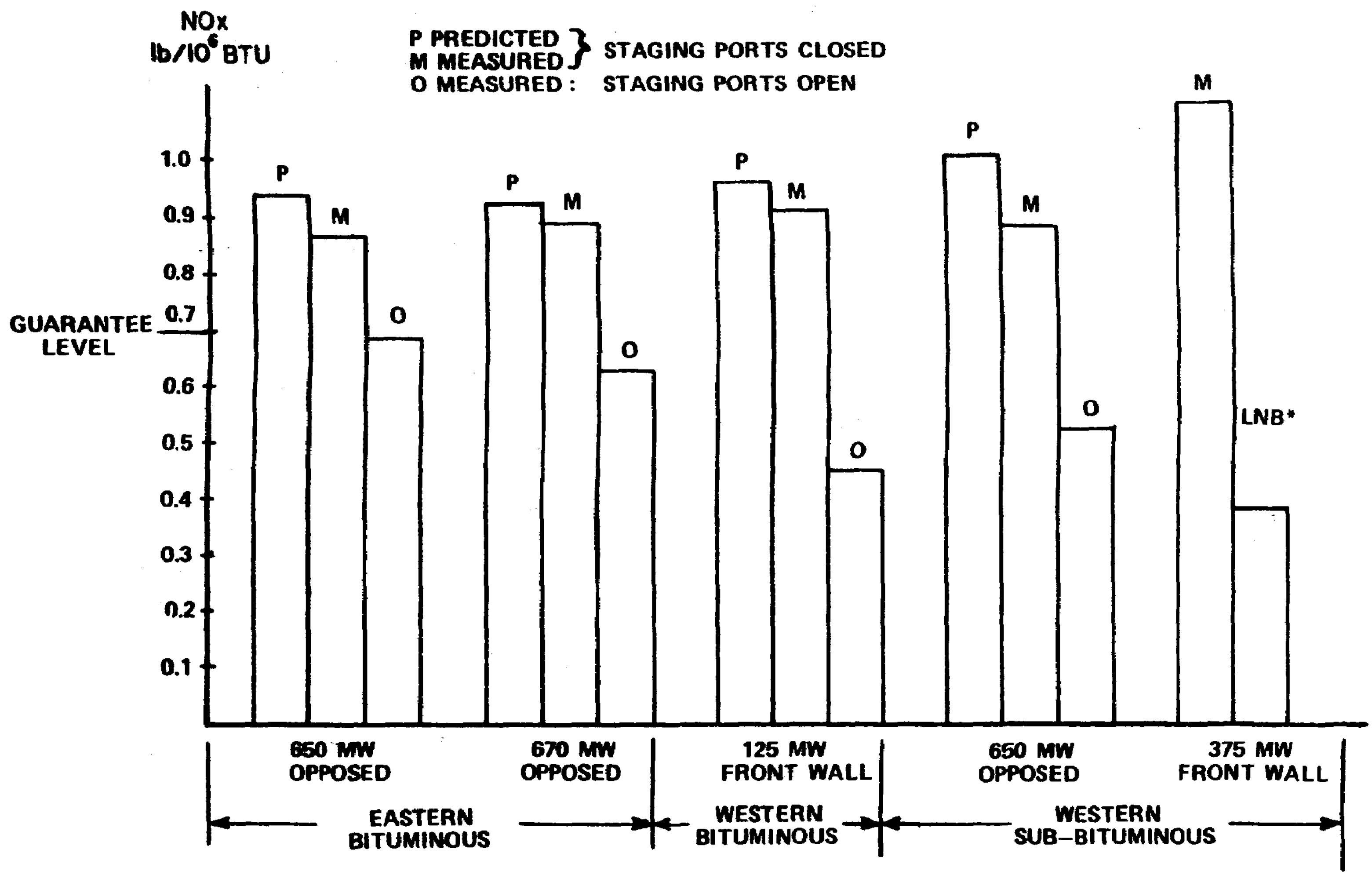
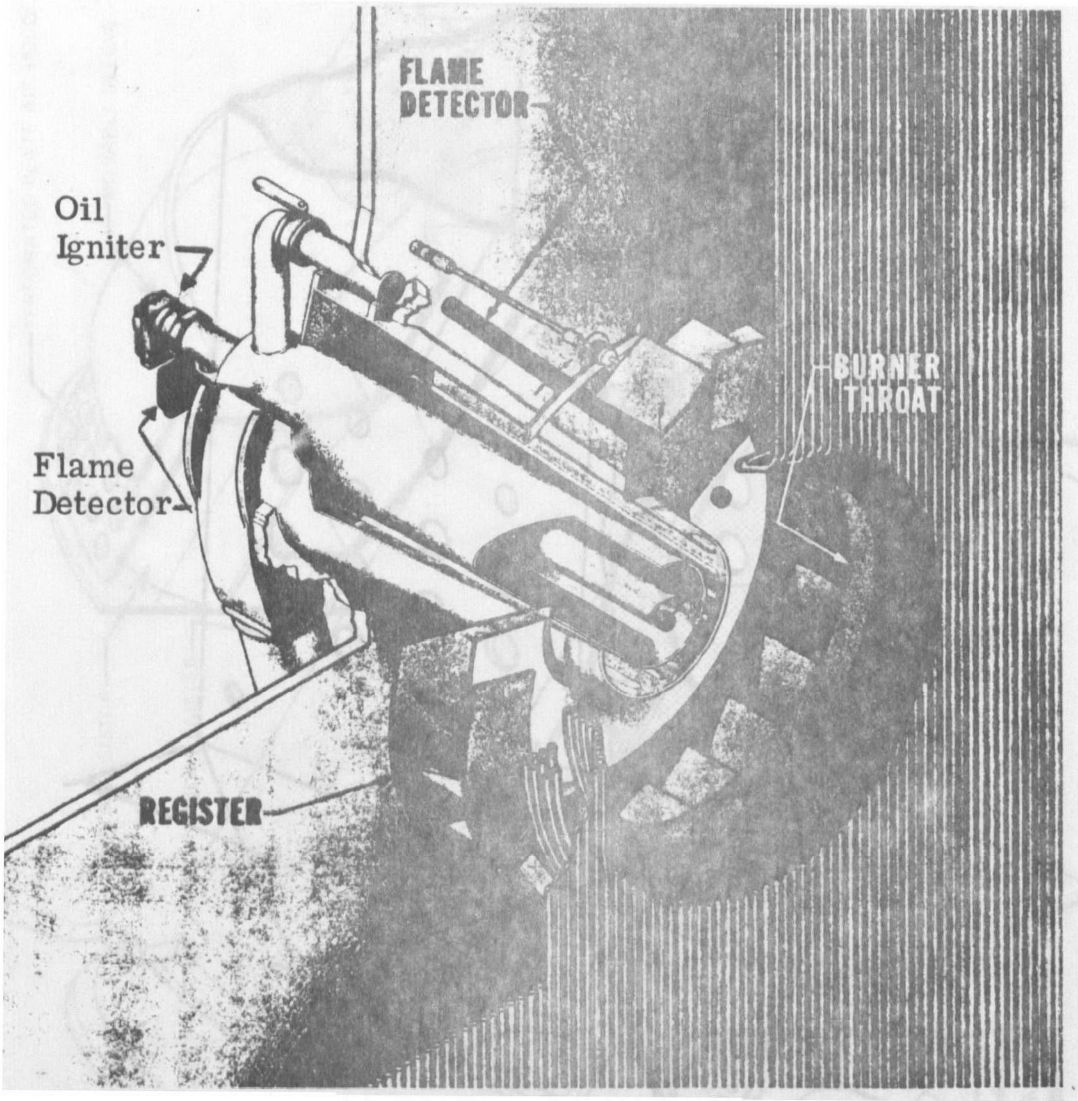



FIG. 1 NOx vs Q/BZS
UNCONTROLLED EMISSIONS

FIGURE 2 PREDICTED VS. MEASURED $NO_x$




* LNB = LOW $NO_x$ BURNER




INTERVANE BURNER

FIG. 3

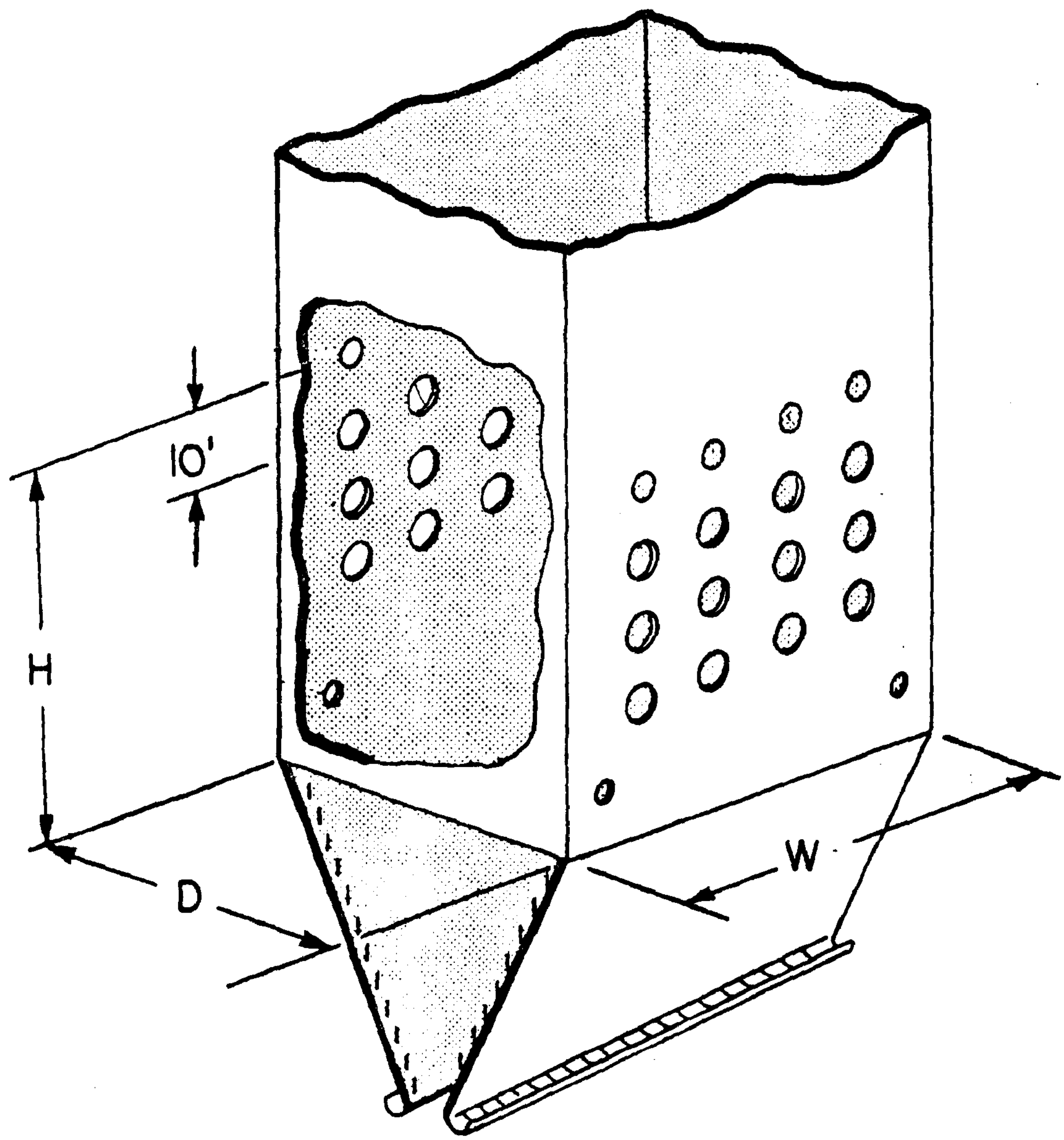



FIG. 4 FLAME BASKET OF TYPICAL LARGE BOILER-BURNER ZONE SURFACE DEFINED BY H. D. AND W.

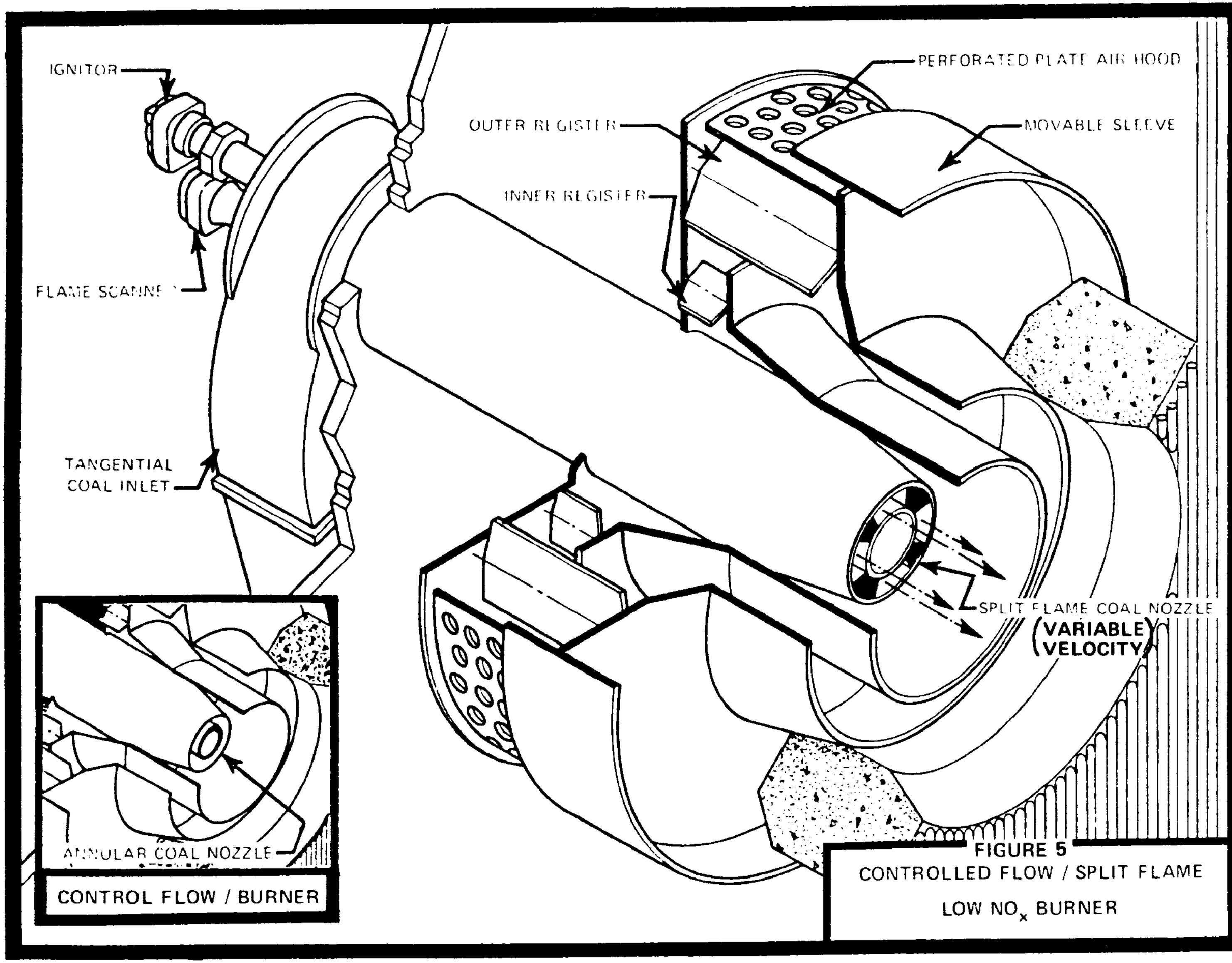



FIGURE 5
CONTROLLED FLOW / SPLIT FLAME
LOW $NO_x$ BURNER

FIG. 6: $NO_x$ EMISSIONS

265 $MW_e$ UTILITY BOILER

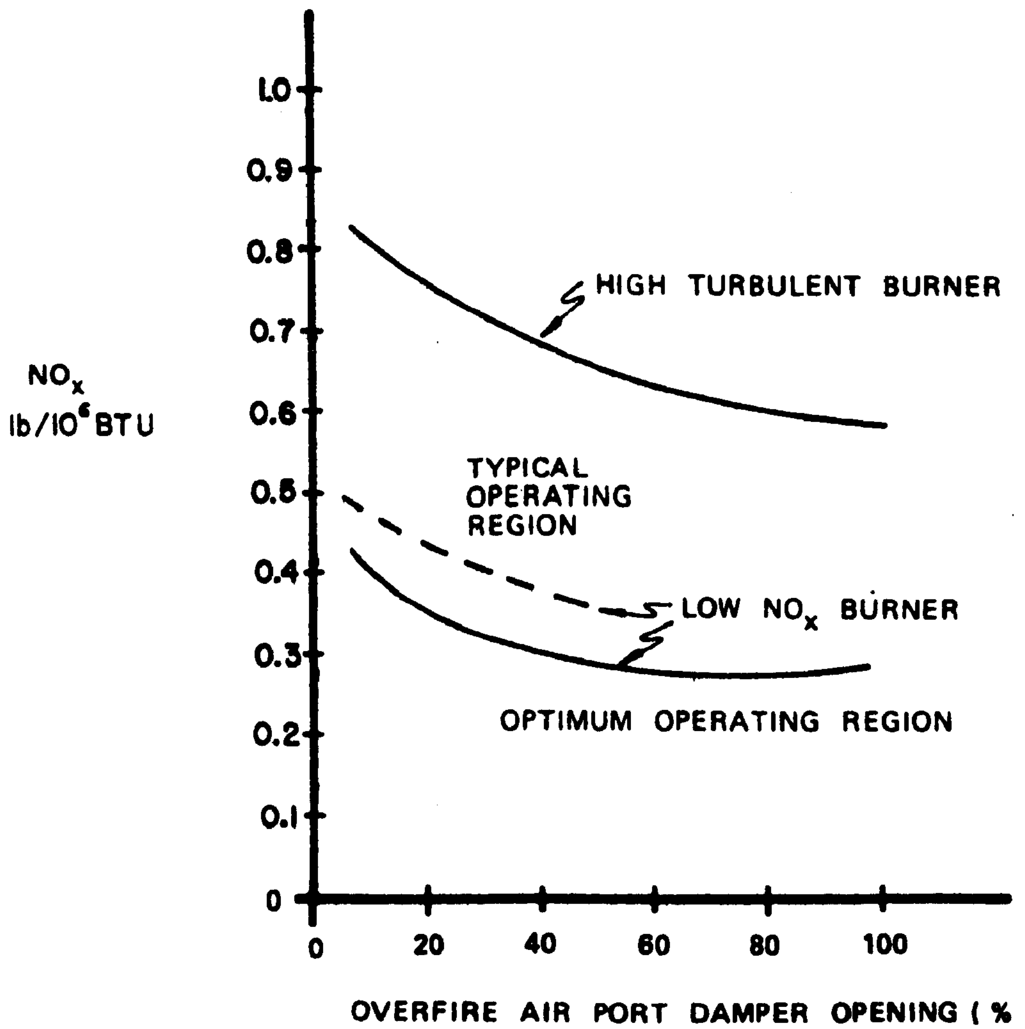


FIG. 7 NOx REDUCTION WITH STAGING

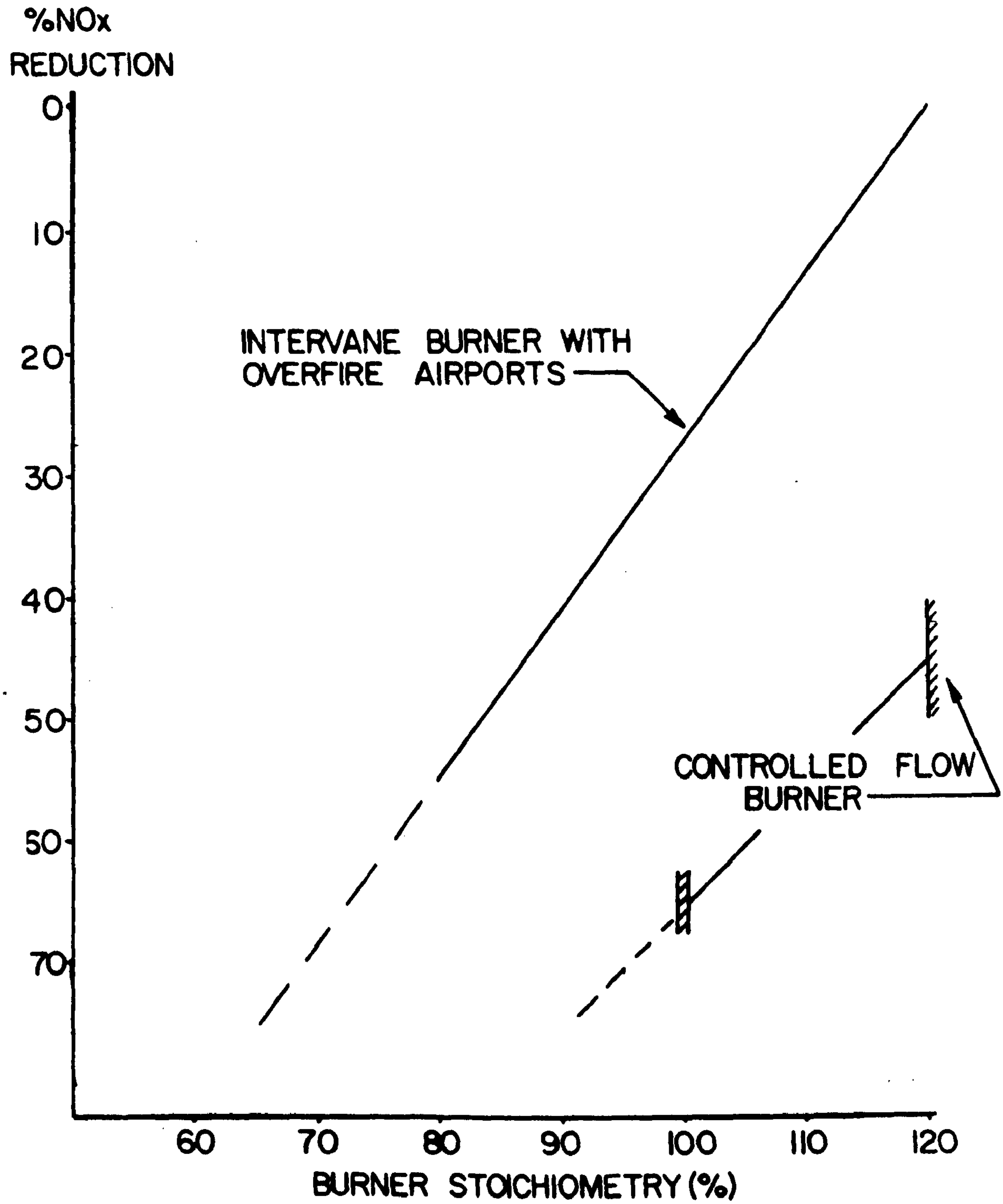


FIG. 8 : NOx vs LOAD

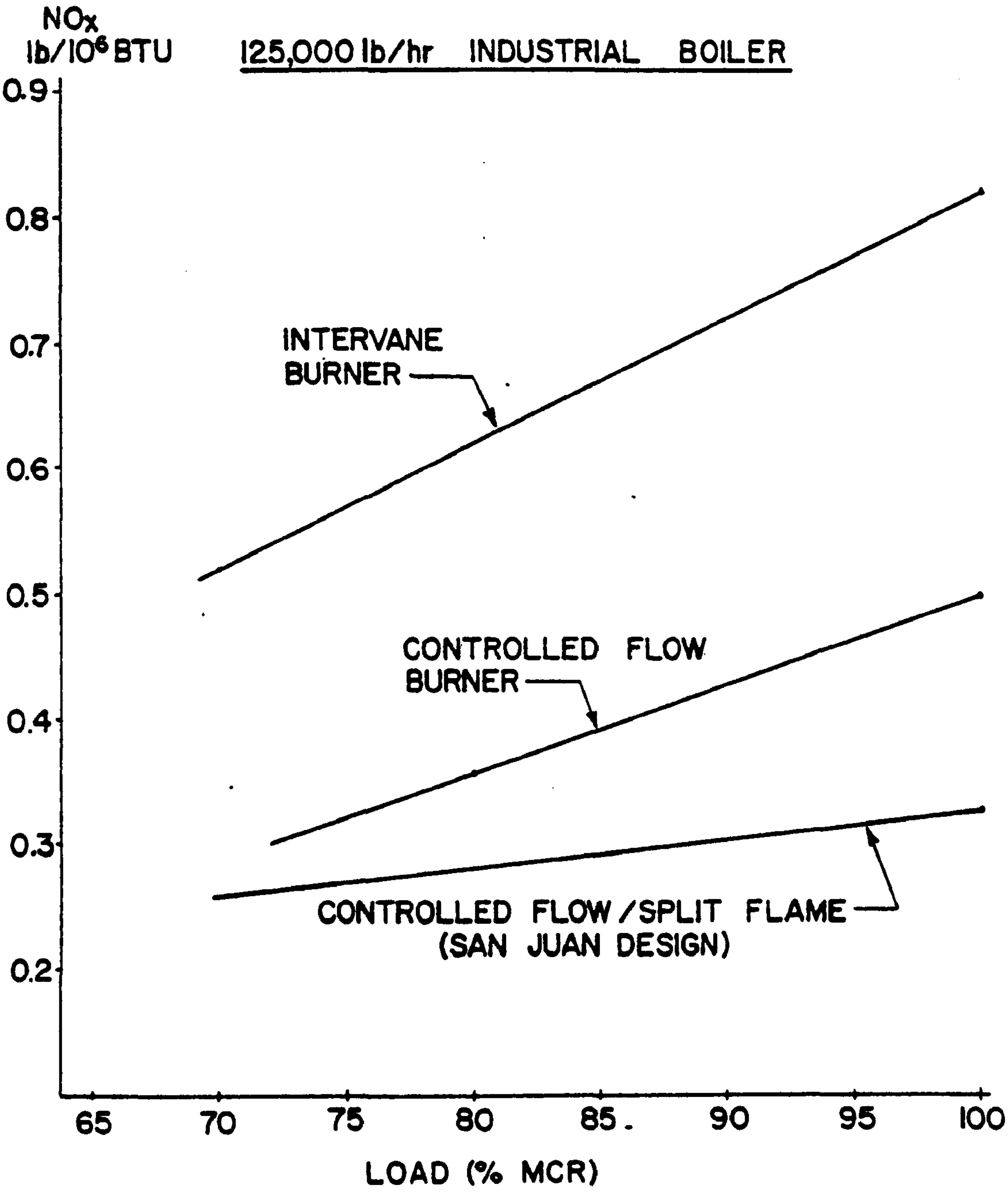
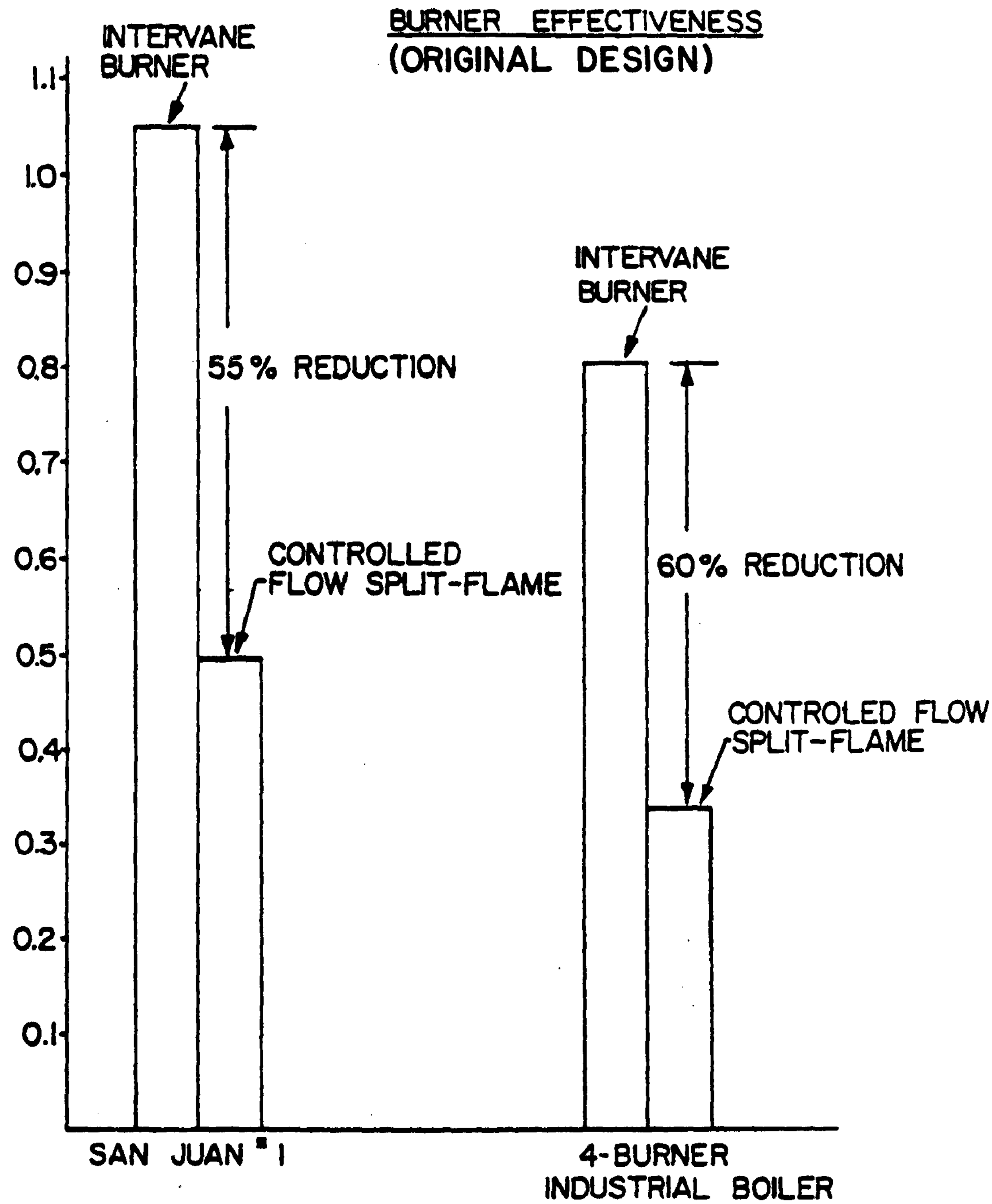


FIG. 9 : CONTROLLED FLOW/SPLIT-FLAME



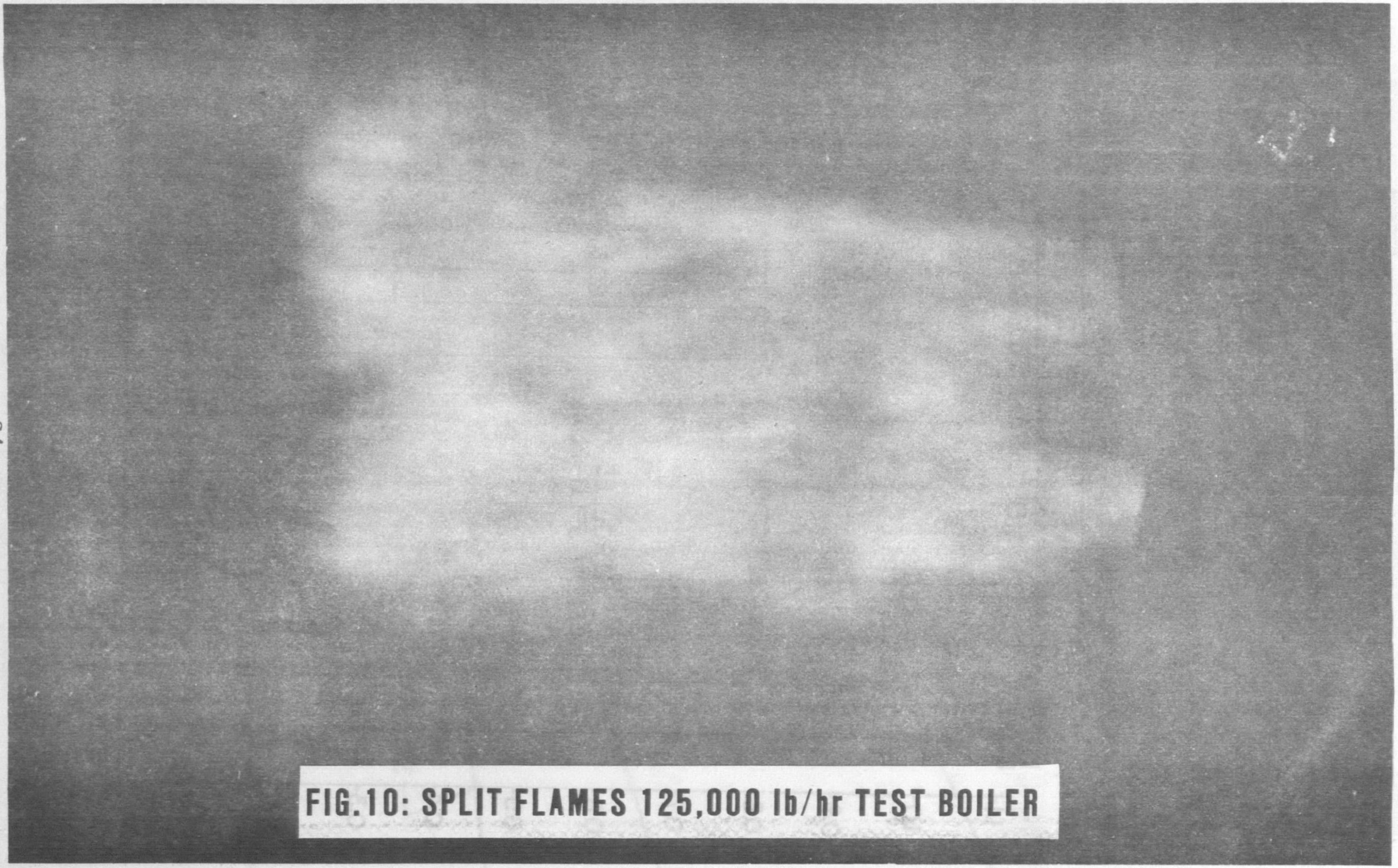


FIG. 10: SPLIT FLAMES 125,000 lb/hr TEST BOILER

FIG. 11: SPLIT FLAMES SAN JUAN #1 BURNER

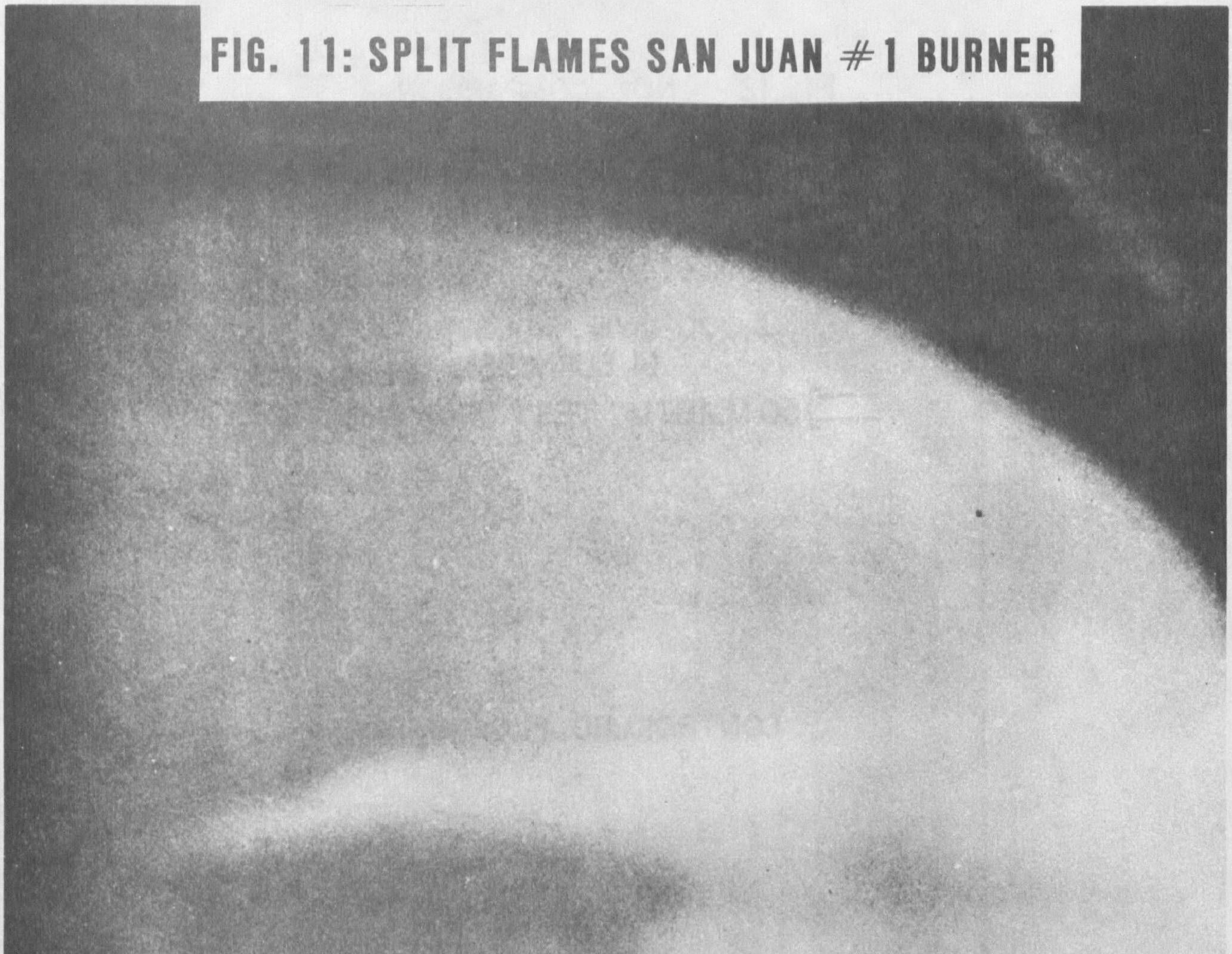
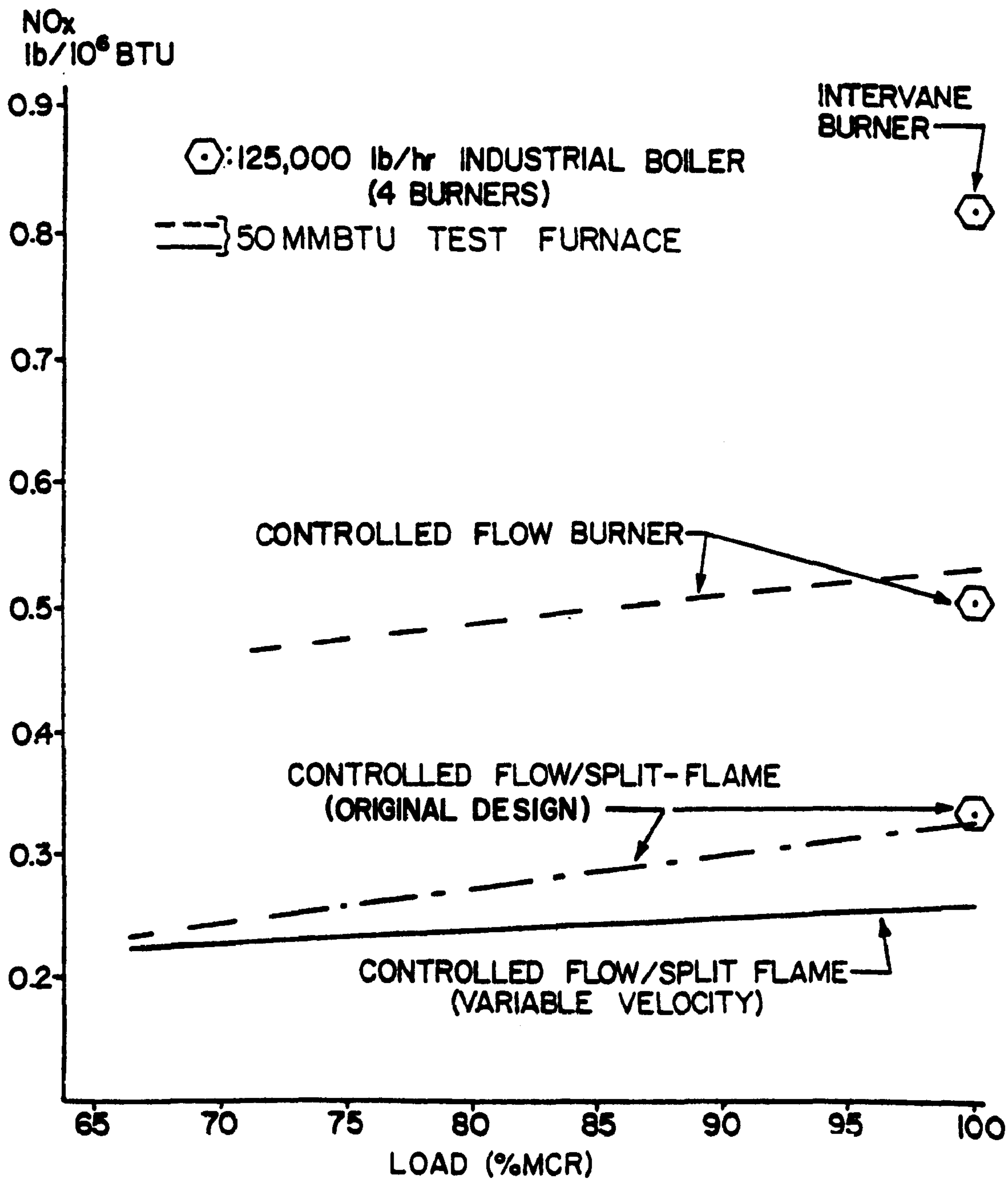


FIG. 12: NOx COMPARISON
SPLIT-FLAME BURNER TIP



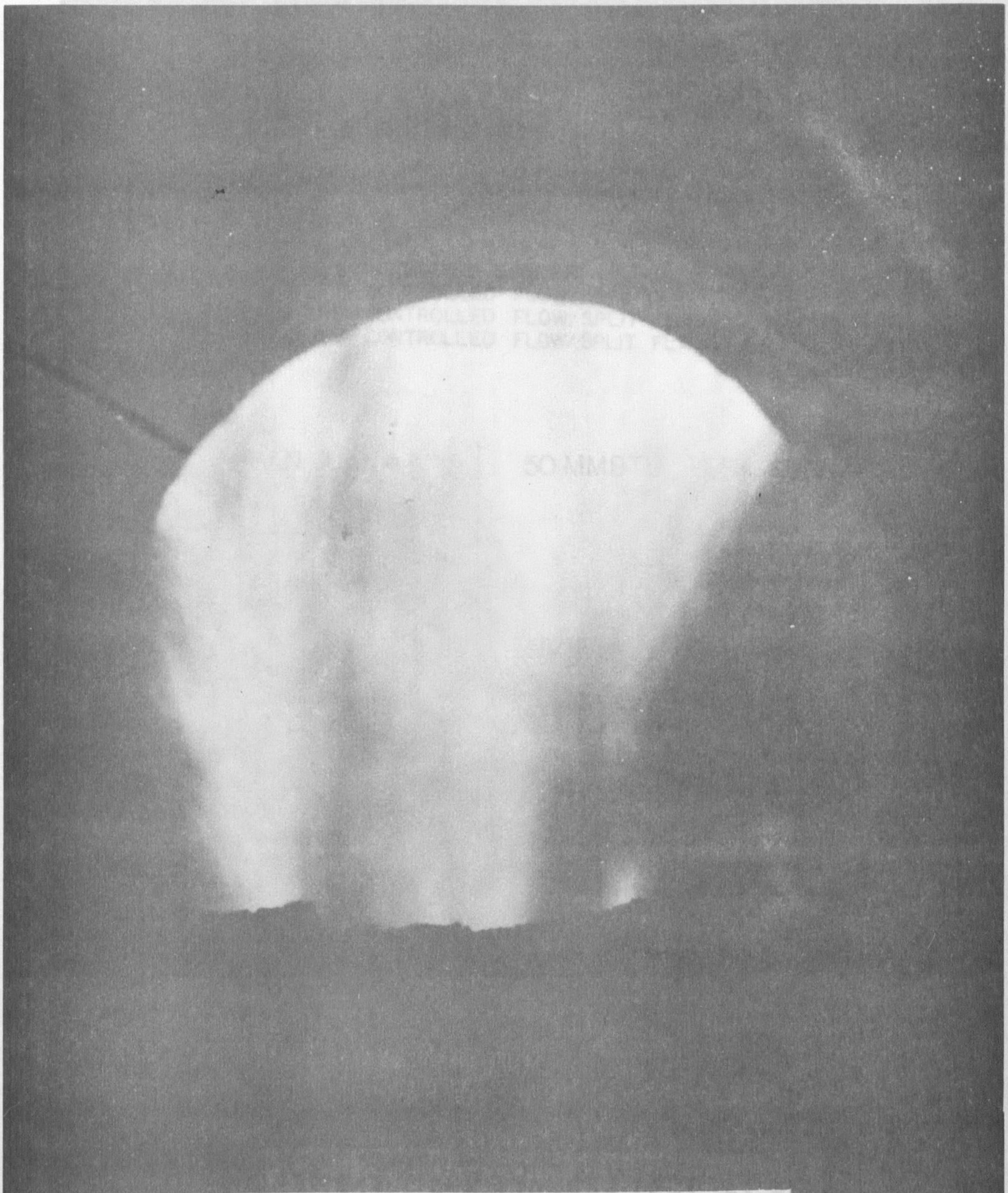


FIG. 13: TEST FURNACE SPLIT-FLAMES
(ORIGINAL DESIGN)

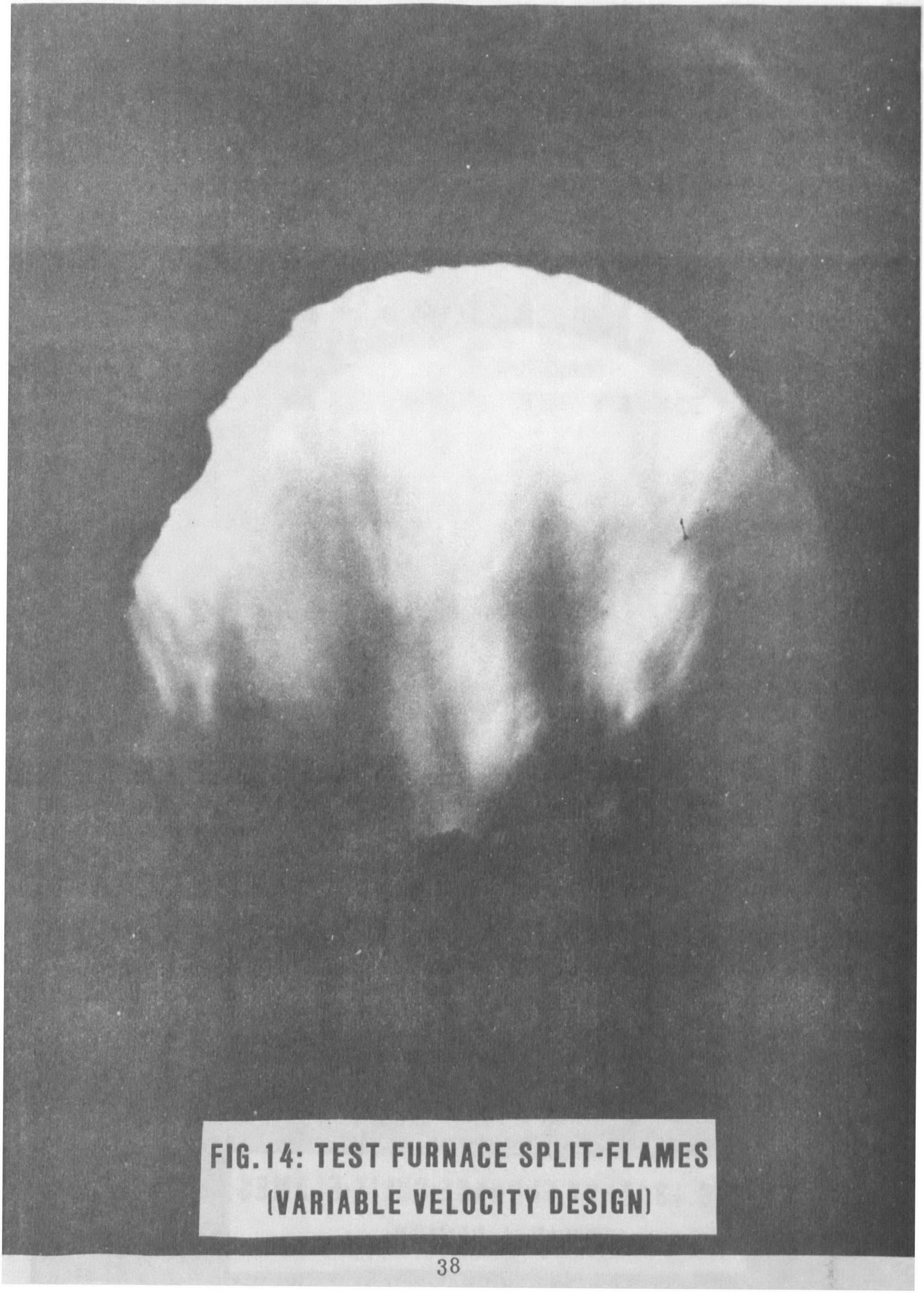


FIG. 14: TEST FURNACE SPLIT-FLAMES
(VARIABLE VELOCITY DESIGN)

## FIG. 15: LOW NOx BURNER NOx COMPARISON

KEY
IV = INTERVANE BURNER
CF = CONTROLLED FLOW
CF/S = CONTROLLED FLOW/SPLIT FLAME
CF/SV = CONTROLLED FLOW/SPLIT FLAME (VARIABLE VELOCITY)

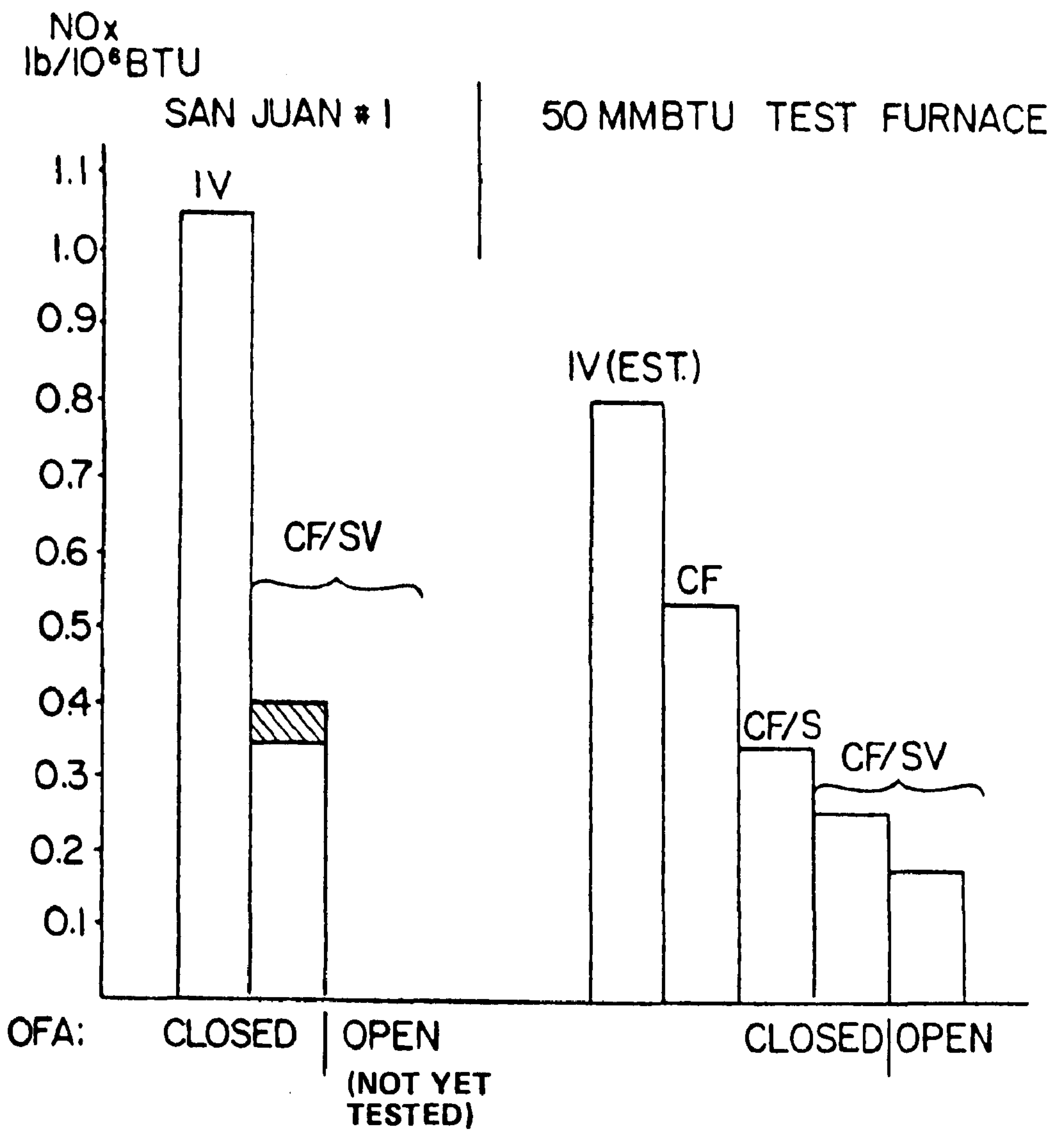
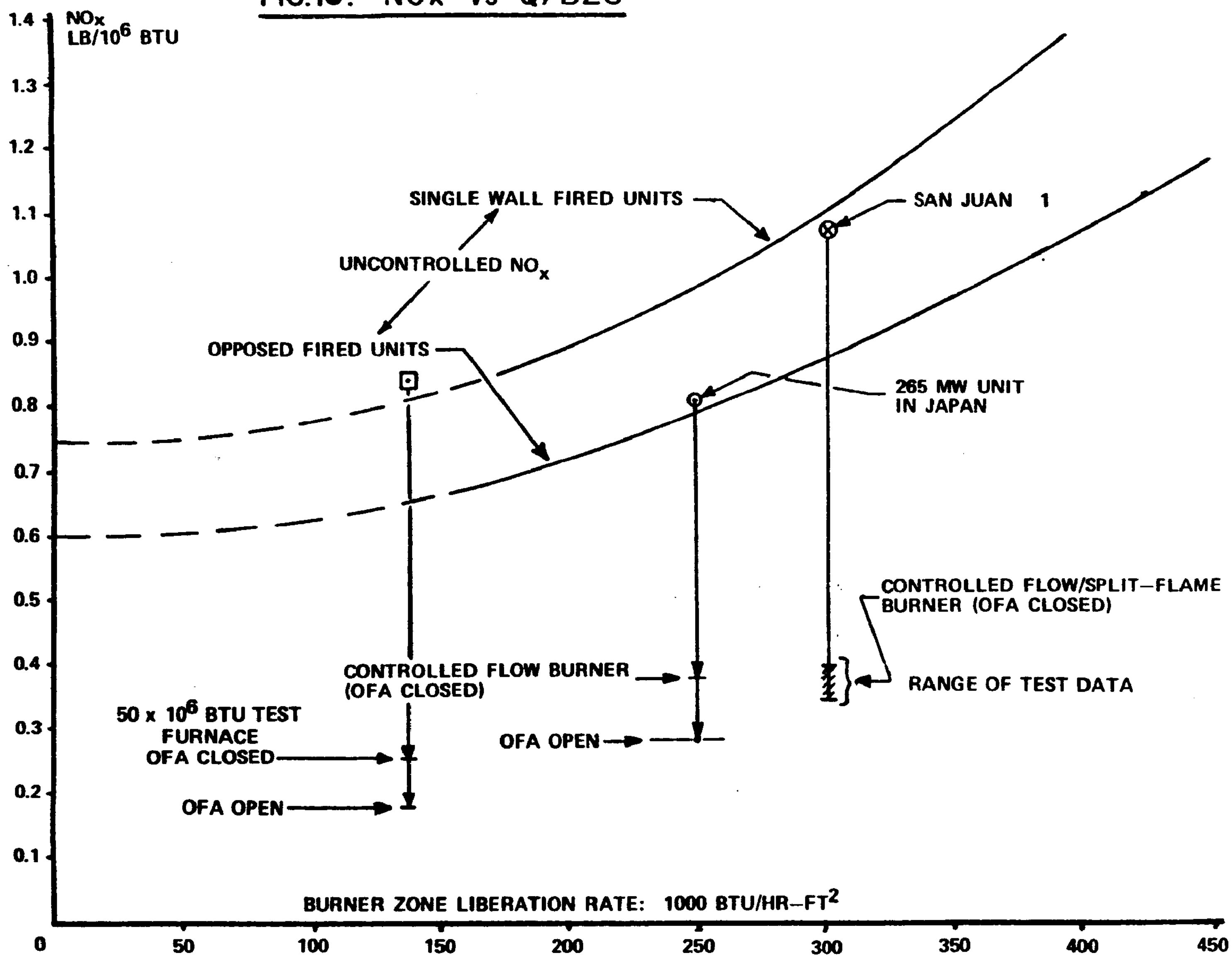


FIG. 16: NOx vs Q/BZS



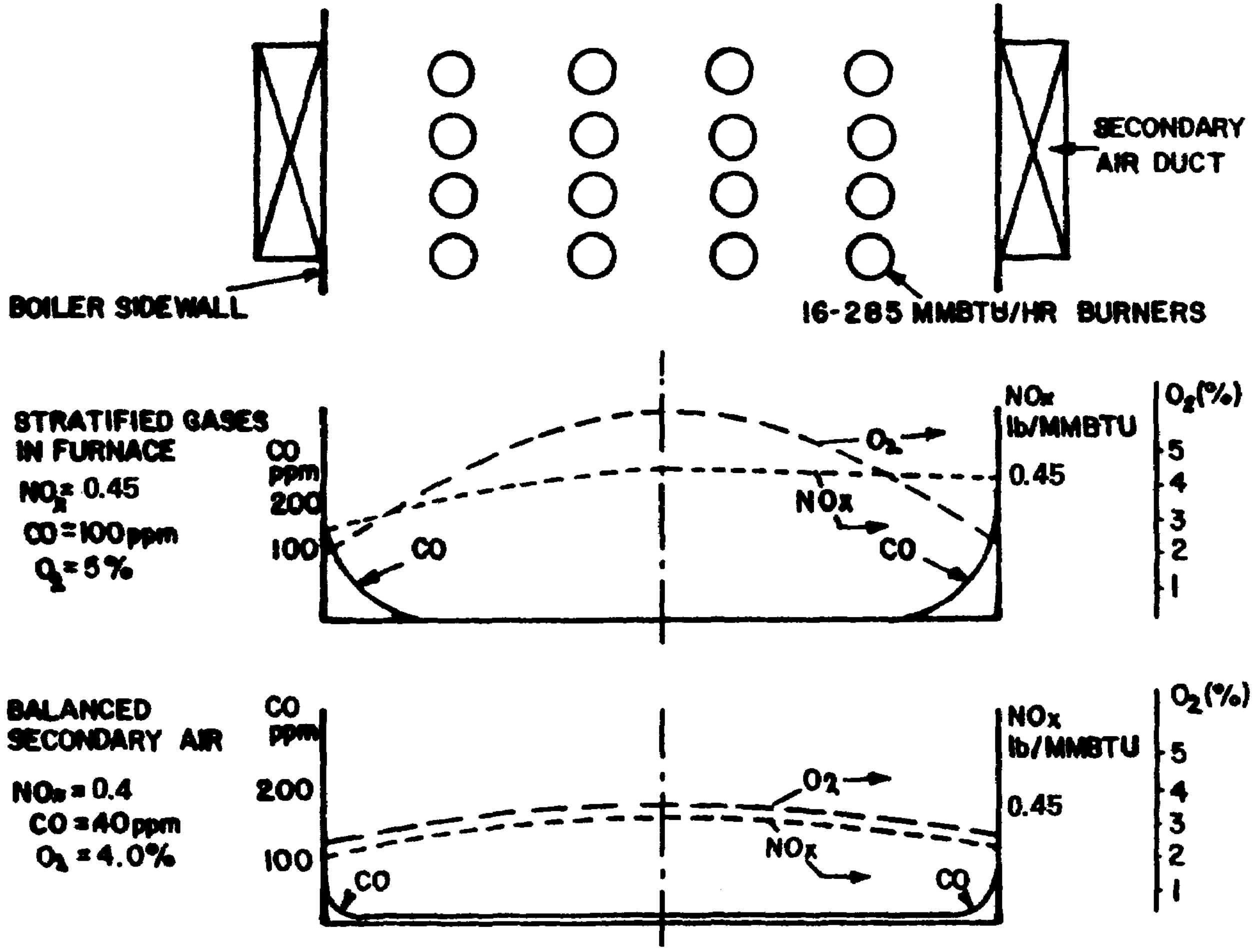
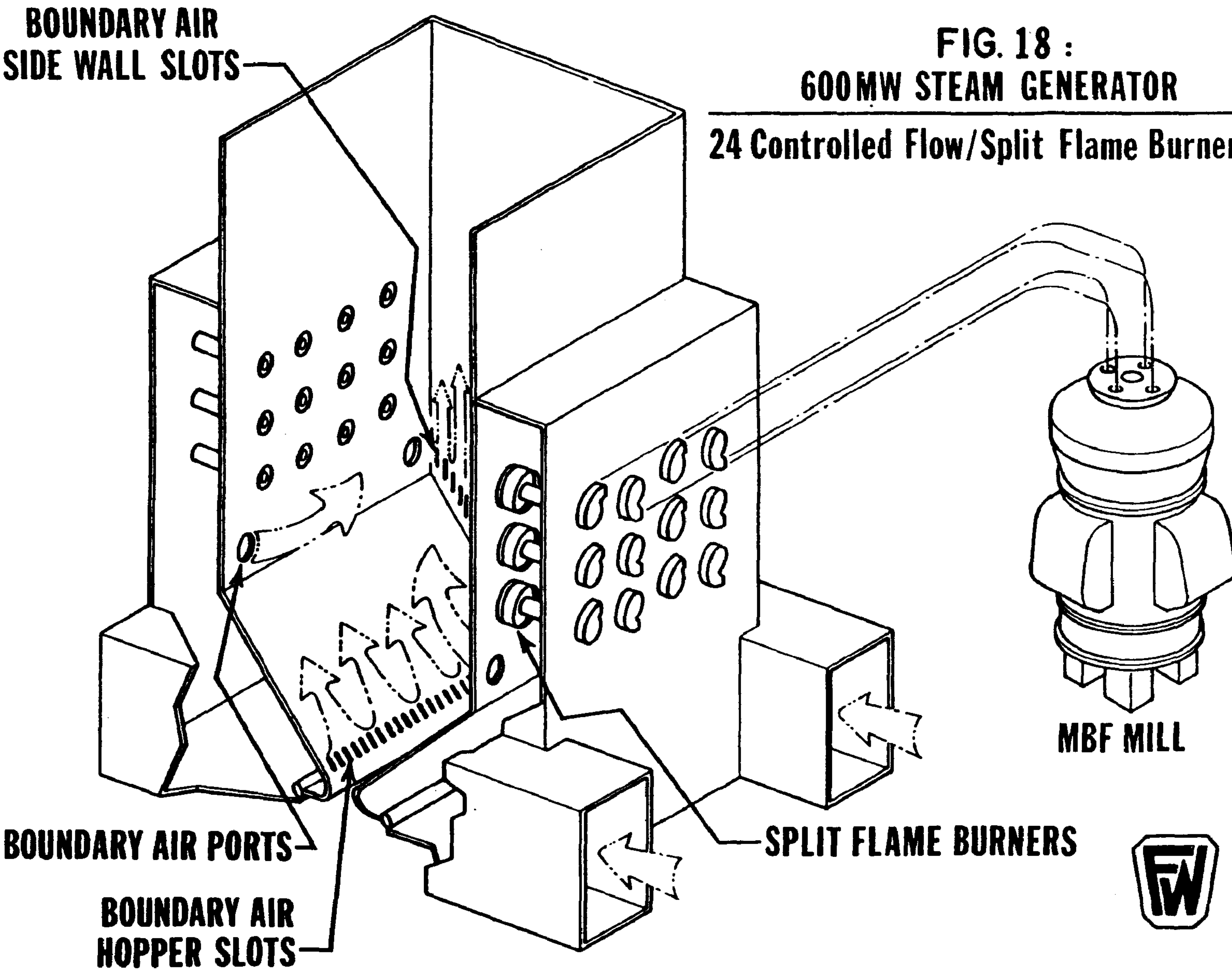



FIG. 17 EFFECTIVENESS OF SECONDARY AIR BALANCING SYSTEM
(375 MWe STEAM GENERATOR)

FIG. 18 :
600MW STEAM GENERATOR

24 Controlled Flow/Split Flame Burners



# FIRESIDE CORROSION AND $NO_x$ EMISSION TESTS ON COAL-FIRED UTILITY BOILERS

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## ABSTRACT

This paper will describe the status of an EPA-sponsored field study of $NO_x$ emissions from coal-fired utility boilers. Previous reports discussed the effectiveness of combustion modification techniques to significantly reduce $NO_x$ emissions. The simultaneous investigation of side effects (e.g., particulate emissions, boiler slagging, boiler performance) did not identify any significant problems. However, one potential side effect -- fireside corrosion of the boiler waterwalls -- was only partially studied. Fireside corrosion rates obtained via probes (short-term exposure) could not be correlated conclusively with actual furnace tube wastage experience. Therefore, a long-term corrosion test was undertaken to obtain representative furnace tube corrosion rate data. Results of this test, conducted on the 500 MW No. 7 pulverized-coal-fired boiler at the Crist Station of the Gulf Power Company, are presented and discussed. Details and a progress update are also given for ongoing corrosion investigations sponsored by EPA on four large coal-fired utility boilers designed to meet NSPS $NO_x$ emission standards. Information is also included on a field test using additives to suppress slag formation in a 330 MW pulverized-coal-fired utility boiler.

## ACKNOWLEDGMENTS

The authors wish to acknowledge the constructive participation of Mr. R. E. Hall, EPA Project Officer, in planning the field test programs and providing coordination with boiler operators and manufacturers. The assistance and cooperation of the General Electric Company personnel in helping the selection of gas turbines for testing is also gratefully acknowledged. The helpful cooperation, participation and advice of Babcock and Wilcox, Combustion Engineering and Foster Wheeler were essential in selecting representative boilers for field testing and conducting the program. The voluntary participation of electric utility boiler operators in making their boilers available is gratefully acknowledged. These boiler operators include the East Kentucky Power Cooperative, Inc., Public Service Electric and Gas Company, Louisville Gas and Electric Company, Houston Lighting and Power Company, Public Service Company of Colorado and the Gulf Power Company. The authors also express their appreciation for the extensive coal analyses services provided by Exxon Research's Coal Analysis Laboratory at Baytown, Texas and to Messrs. A. A. Ubbens and E. C. Winegartner for their contributions and advice on coal related matters. The valuable assistance of Messrs. L. W. Blanken, R. W. Schroeder, W. Petuchovas, and Mrs. M. V. Thompson in performing these field studies is also acknowledged.

## SECTION 1

## INTRODUCTION

Exxon Research and Engineering Company (ER&E) under contract to EPA has been conducting field studies since 1970 on combustion modification techniques to control $NO_x$ and other pollutant emissions from utility boilers. In early studies significant reductions of $NO_x$ were achieved in gas and oil-fired boilers under EPA Contract No. CPA 70-90 (1) without optimizing the technology. In a follow up investigation, emphasis shifted to the more difficult task of controlling $NO_x$ emissions in pulverized coal-fired boilers and the assessment of potential side effects. Twelve coal-fired boilers were tested under EPA Contract No. 68-02-0227 (2) in cooperation with boiler owner-operators and boiler manufacturers. In this study reductions in $NO_x$ emissions averaging 39 percent (ranging from 12 to 59%) were achieved with no apparent adverse side-effects. In addition to the optimization of $NO_x$ emissions the study included particulate and unburned combustible measurements, furnace corrosion rate probing, determination of boiler efficiency and observations on changes in boiler operability, i.e., slagging, fouling, flame impingement or instability, etc.

In the current program, presently nearing completion, sponsored by EPA (Contract No. 68-02-1415) and partially by the Electric Power Research Institute (EPRI Project No. 200), five coal-fired and 2 coal, mixed-fuel fired boilers were tested in the Phase I program (3) and four coal-fired boilers, two gas turbines and one oil-fired boiler were tested in the Phase II program now reaching its conclusion. The scope of the program was broadened under these contracts to explore the effectiveness of equipment modifications designed for $NO_x$ control, such as boilers constructed with overfire air ports and use of low $NO_x$ emitting improved burner designs. $NO_x$ emissions in the coal-fired boilers tested were reduced by 34% in the Phase I program and by 38% in Phase II. Potential combustion modification adverse side-effects such as, particulate mass and size distribution, boiler performance and operability, furnace tube corrosion, etc., received increased emphasis and were studied in more detail than previously. Since combustion modifications for $NO_x$ control potentially may cause increased slagging problems in boilers, as a part of this program a series of tests were conducted with promising results using additives to suppress slag formation in a coal-fired boiler.

Furnace tube corrosion, which may be aggravated by low $NO_x$ operation, is a potential major side-effect. Data developed in past programs with corrosion probes, however, could not be conclusively related to actual furnace tube corrosion. The importance of this problem dictated a major effort to specifically address this question. An extensive long-term corrosion study was undertaken to obtain corrosion rates on actual furnace tubes. This program encompassed the use of corrosion probes, exposure of pre-measured furnace tube panels in the furnace and ultrasonic thickness measurement (mapping) of furnace tubes to determine actual corrosion rates.

Under EPA Contract No. 68-02-2696 a major effort is being expended in an on-going program to obtain long-term corrosion data on three additional coal-fired boilers designed to NSPS standards of 0.7 lbs of $NO_x/10^6$ Btu. Two tests are presently in progress. The 3rd is in the active selection stage and will be combined with Combustion Engineering's test of a new firing concept (rich fireball) for tangentially fired boilers. The scope of this program has also been expanded to include level 1 testing, continuous monitoring of pertinent gaseous emissions and extensive pollutant assessment of solid, liquid and gas streams entering or leaving the boilers.

## SECTION 2

## TEST PROGRAM UPDATE

Details of test program designs, gaseous sampling and analysis, particulate, $SO_x$, corrosion rate and boiler performance measurements and calculations have been covered in prior reports (1)(2)(3)(4). This report will update work performed under EPA Contract No. 68-02-1415 which was partially sponsored by the Electric Power Research Institute under EPRI Project No. 200. Field tests conducted under this program were carried out in Phases I and II. Five pulverized coal-fired boilers and two mixed-fuel fired (coal/oil, coal/gas) boilers were tested under Phase I, results of which were reported in EPA Report EPA-600/7-78-036a (NTIS No. PB281078)(3). Phase II, covered by this report, will update the program covering field tests on four coal-fired and one oil-fired boiler with special emphasis on the long term corrosion test conducted on Gulf Power Company's No. 7 boiler at their Crist Station.

### NITROGEN OXIDE EMISSIONS

Field tests conducted in the Phase I program are summarized in Table 1 for record and comparison purposes. Included in the table are details concerning the boiler manufacturer, the type of firing, kind of fuel burned, numbers of burners, test variables, number of tests run, and emission data for baseline and optimum low $NO_x$ operation on each boiler tested. Referring to Table 1 it may be seen that uncontrolled (baseline) emissions ranged from 341 to 1383 ppm with only four out of the seven boilers tested meeting the New Source Performance Standard (NSPS) of 0.7 lbs of $NO_x/10^6$ Btu. Three of these, Barry No. 2, Navajo No. 2 and Comanche No. 1 were equipped with overfire air ports while the 4th, Gaston No. 1, had been retrofitted with B&W's new low $NO_x$ burners. Also note that application of combustion modification techniques successfully reduced emissions below the new NSPS standard of 0.6 lbs $NO_x/10^6$ Btu in all cases but two (Mercer No. 1 and TVA No. 5) and even TVA No. 5 could meet the original (old) standard. $NO_x$ reductions ranged from 22 to 45%, averaging 34 percent commenserate with reductions achieved in prior programs.

Results of field tests conducted during Phase II of the program are tabulated in Table 2. It may be noted from Table 2 that baseline emissions in the four coal-fired boilers tested, ranging from 533 to 827 ppm, did not meet the original NSPS standard of 0.7 lbs of $NO_x/10^6$ Btu. Under low $NO_x$ firing conditions, however, two boilers (Cooper No. 2 and Comanche No. 1) met the new NSPS standard 0.6 lbs of $NO_x/10^6$ Btu. There is little doubt however that Louisville Gas and Electric Company's Mill Creek, No. 1 boiler could have met both NSPS requirements, but low $NO_x$ firing was not applied to this unit during the additive tests due to a lack of time. Average $NO_x$ reductions were 38% in the coal-fired boilers tested, ranging from 22 to 62 percent. This is consistent with $NO_x$ reductions achieved in Phase I and earlier programs.

Emission reductions obtained in boilers representative of the utility boiler population and on various current design configurations complying with recent low $NO_x$ requirements or guarantees have been discussed and published elsewhere (1, 2, 3, 4). $NO_x$ emission reduction and optimization achieved on the No. 7 horizontally opposed fired Foster Wheeler boiler at Gulf Power Company's, Crist Station, which was selected for long-term corrosion testing, will be presented here to illustrate slightly different applications of combustion techniques.

Crist Station Boiler No. 7 is a horizontally opposed fired, dry bottom, single furnace Foster Wheeler boiler rated at 500 MW capacity. This unit was selected for testing because it is a large, pulverized coal burning unit of modern design. It also appeared to have the necessary operating flexibility and management support so that it was a good candidate for the Phase IV, long-term corrosion test program. The furnace measures 52 feet 5 inches wide and 40 feet in depth. Six pulverizers feed 24 burners arranged in three rows of four burners each in the front and rear walls of the furnace.

The operating variables found to have a statistically significant influence on $NO_x$ emission levels were load, excess air level, and firing patterns. Figure 1, "ppm $NO_x$ vs. % Oxygen in Flue Gas," has been constructed to indicate the most important relationships found in analyzing the test data. The numbers within the symbols indicate the run number while the symbols indicate the various firing patterns tested. The lines drawn on Figure 1 are least squares, linear regression lines for ppm $NO_x$ vs. % oxygen calculated for each firing pattern.

The strong influence of excess air level on $NO_x$ emission levels for all firing patterns is indicated by the steep slopes of the lines drawn on Figure 1. Very close agreement was found in the calculated regression coefficients (change in ppm $NO_x$ for a 1% change in oxygen) for the various firing patterns, i.e., 69, 80, 81, 59, and 76 for firing patterns $S_1$, $S_2$, $S_3$, $S_6$, and $S_7$, respectively. Since excess air levels could be reduced by at least 2% to as much as 5% from normal to low excess air operation without violating the 200 ppm CO maximum emission level guideline or increasing stack plume opacity, this represents an important operating variable for $NO_x$ emission control. Thus, $NO_x$ emissions were reduced by 16% in changing from a full load (480-510 MW) baseline operation (4% $O_2$) of 827 ppm to 696 ppm under low excess air (2.1% $O_2$) operation.

Reducing load by 62% from the 480 to 510 MW range to 190 MW under normal excess air firing operation resulted in lowering $NO_x$ emissions by about 37%. Staged firing generally resulted in reduced loads as well as reduced $NO_x$ emission levels. Separating the effect of staged firing on $NO_x$ emission levels from the load effect indicate the following. Staged firing operation, $S_2$, top burners fired lean (by reduced coal flow to top row of burners) and normal excess air (4% $O_2$) resulted in a 12% reduction in $NO_x$ emissions (827 ppm to 728 ppm) with about 5% due to load reduction (496 to 451 MW average) and the remaining 7% due to staged firing. Staged firing operation, $S_3$, (1 top mill on air only) resulted in a 39% reduction in $NO_x$ emissions (to 509 ppm from 827 ppm) with about 12% due to load reduction and 27% due to staged firing. Finally, $S_6$, staged firing with both top mills on air only produced a 72% $NO_x$ emission reduction with about 32% due to reduced load (230 MW vs. 495 MW). Part of the load reduction experienced during the test period, however, was due to abnormal operating difficulties such as partial air heater plugging.

The combined effect of low excess air and staged firing operation resulted in further $NO_x$ emission reductions as would be expected. Thus, the ppm $NO_x$ levels (and % $NO_x$ reduction from the 827 ppm measured under baseline operation) were 451 (-31%), 400 (-52%) and 244 (-70%) for $S_2$, $S_3$ and $S_6$ staged firing patterns, respectively. These results indicate that this boiler has an excellent $NO_x$ reduction capability through modified combustion operation.

## PARTICULATE EMISSIONS AND BOILER PERFORMANCE

Low $NO_x$ combustion modification techniques, especially staging the firing pattern in combination with low excess air firing, results in less intense combustion conditions than conventional firing methods. A tendency toward increased burnout problems, therefore, may occur which, potentially, could increase particulate mass loading as a consequence of increased carbon in the fly ash. In addition, these effects could also result in changes in particulate particle size distribution. Changes in particulate mass loading and particle size distribution could adversely affect collection efficiency in electrostatic precipitators or in other collection devices while an increase in unburned combustibles could have a corresponding adverse effect on boiler efficiency. A further potential adverse side effect of low $NO_x$ operation could be a change in fly ash resistivity which might have a similar adverse affect on precipitator collection efficiency. Measurements of resistivity, however, were beyond the scope of this program.

Low $NO_x$ combustion modification effects on dust loading were investigated using an EPA Method 5 type sampling train incorporating a Brink cascade impactor for particle size determination. Measurements of total mass loading and particle size distribution were made under baseline and optimized low $NO_x$ operating conditions upstream of the electrostatic precipitators. In the latter phase of the contract dust loading measurements were made with EPA's SASS train sampling system. Results of the analyses of the latter tests, however, are not available at this writing.

A summary of particulate emissions and particle size distribution determination results for boilers tested in the Phase II program are tabulated in Tables 3, 4, and 5, respectively. Comparing particulate mass loading data in Table 3 for baseline against low $NO_x$ operation, it may be seen that mass emissions under low $NO_x$ firing conditions, for the tests in the Phase II program, are essentially the same as for baseline operation, requiring little or no change in electrostatic precipitator collection efficiency. Referring to Tables 4 and 5 it again may be seen that low $NO_x$ operation has very little, if any, effect on particle size distribution. Aside from potential changes in resistivity, therefore, it may be concluded from these data, as in the

Phase I and prior programs, that there are no significant differences in particulate mass loading or particle size distribution under low $NO_x$ combustion conditions.

Increases in percent carbon on particulate are noted for low $NO_x$ firing conditions in Table 3 which do not seem to have a corresponding direct effect on mass emissions. Furthermore, the expected decrease in boiler efficiency (Table 6) not only failed to materialize but for the low $NO_x$ conditions efficiency, if anything, is even greater by a small margin leading to the conclusion that low $NO_x$ firing has only insignificant effects on boiler performance.

## SECTION 3

## ANTI-SLAGGING ADDITIVE TESTS

Low $NO_x$ combustion modifications, especially staged firing in combination with low excess air operation, can result in lower net reducing atmospheres in the bottom of the furnace often accompanied by higher temperatures. Under reducing atmospheres, coal ash fusion temperatures generally are about 200°F lower than for oxidizing conditions. This fact, coupled with higher furnace temperatures can affect the character of the slag formations making them more fluid and sticky with potentially greater slagging difficulties. Where boilers may be operating near incipient slagging conditions, the application of $NO_x$ reduction techniques could result in increased slagging problems.

A part of the Phase II program was devoted to investigation of means to control increased slagging if ever this problem should occur when applying $NO_x$ control modifications. The potential use of additives gave promise of being the most cost effective solution to control or ameliorate slagging conditions in coal-fired boilers. Accordingly, arrangements were made with Basic Chemicals and the Louisville Gas and Electric Company to conduct Cooperative tests on LG&E's No. 1 boiler at the Mill Creek Station. Rated output of the No. 1 boiler is 325 MW but LG&E had arbitrarily derated the unit to 300 MW in order to keep slagging conditions within mangeable bounds.

A series of eight tests were run during June, 1979; four without additive injection to develop "baseline" operating information and four while injecting Basic Chemicals UltraMag additive, an ultra fine (<2 microns) dispersion of MgO in heating oil. Additive was injected at three different rates at each of the four corners of the furnace at the B and C slag blower elevations immediately above the top burners. Boiler loads of 325-330 MW were maintained during the tests, sufficient to promote slagging, and the effectiveness of the additive was judged by the length of time that load could be maintained at this level before operating parameters became critical, forcing a cut-back in load.

Results of the anti-slagging additive trials are summarized in Table 7. Referring to Table 7, it may be seen that tests 200, 201, and 203 (baseline - no additive) achieved 12 hours operation at full load, rated conditions (325-330 MW) before superheat and reheat steam temperatures bordered on uncontrollability. Note test 202 (no additive). However, where the boiler was slagged to the point of being out of control in 4 1/2 hours; a very short period. The reasons for this drastic performance were not readily apparent but may possibly be attributed to the fact that furnace clean-up prior to the test may not have been as effective as before or that a change to a higher slagging coal may have occurred for that day.

In tests 204 and 205 additive was injected continuously at the rate of 15 GPH. Referring to Table 7 it may be observed that full load capability of the boiler could be maintained under these conditions for a period of 15 and 17 hours, respectively, or an additional 3 and 5 hours longer than without additive injection. These results testify to the technical feasibility and effectiveness of the use of additives at low injection rates with pulverized coal firing. Other potential benefits, which were beyond the scope of these investigations, may also acrue from additive usage, such as, easier clean-up of the boiler during nightly reduced load periods. For example, it may not be necessary to reduce load as much and the clean-up period possibly may be shortened to achieve the same degree of cleanliness. Load carrying capabilities, which are of special importance in tight load demand situations, therefore could be improved.

Tests 206 and 207 were run in an attempt to optimize the additive injection rate and to test the effectiveness of other injection methods. Neither results, however, were quite as effective as injecting the additive continuously at the rate of 15 GPH.

It is concluded from these tests that anti-slagging additives may be effective in controlling or ameliorating slagging problems in pulverized coal fired utility boilers especially when "low $NO_x$" combustion modifications may be employed. The degree of slag reduction, the benefits of increased load carrying capability, the optimum rate and the most effective injection method, however, need to be defined in more extensive testing to shed more light on the economics and technical feasibility of additive usage for this purpose.

# SECTION 4

## CRIST NO. 7

## LONG-TERM FURNACE TUBE CORROSION INVESTIGATIONS

Furnace tubes in pulverized coal-fired boilers corrode under oxidizing atmospheres due to the corrosive effect of iron alkali sulfate attack. Under reducing conditions, which may occur as a result of combustion modifications for $NO_x$ emission control, furnace tube corrosion may be accelerated, particularly when high sulfur, high iron content coal is fired, due to intergranular penetration of the tube surfaces by iron sulfide.

Earlier investigations of this potential side effect employed corrosion probes under accelerated conditions to develop corrosion rate data. Average coupon corrosion rates obtained in these programs were approximately 50 mils/year with considerable scatter between high and low values. Subsequent investigations conducted under decelerated conditions approximating the actual tube environment, reduced this average to around 19 mils/year with less scatter in the range of the data. Corrosion rates obtained via probes, however, are still an order of magnitude higher than the 1 to 3 mil/year corrosion normally experienced in boiler furnace tubes.

Since corrosion data developed by probes could not be handily related to actual tube corrosion experience and this question is of major importance to the $NO_x$ emission control program, a special long-term corrosion field study was undertaken. These studies were conducted on Gulf Power Company's, Crist Station, No. 7 boiler with the participation and cooperation of Foster Wheeler Energy Corporation. The major purpose of this long-term study was to obtain quantitative measurements of furnace tube fireside corrosion rates under both baseline and staged combustion operation. Three corrosion measurement techniques were used: (1) corrosion probes, (2) ultrasonic furnace tube wall thickness measurements and (3) replaceable wall tube test sections.

## CORROSION PROBE INVESTIGATIONS

Corrosion probes provide a relatively simple, quick and economical means for determining corrosion rates. Even though corrosion rate data developed in these and previous programs could not readily be related to actual furnace tube experience, this type of measurement was continued in the long-term corrosion investigations with the objective of eventual correlation with rates developed by ultrasonic measurement of actual furnace tubes and from exposure of furnace tube test panels.

Corrosion probe testing on the No. 7 boiler at Gulf Power Company's Crist Station was amplified extensively in order to obtain more data and information on the effect of corrosion with time. Conditions of exposure were maintained the same as in prior testing simulating actual furnace tube environment but exposure, rather than at 300 hours only, was varied to include 30 and up to 1000 hours under both baseline and low $NO_x$ conditions to determine initial, intermediate, and longer term corrosion effects. In addition, special ports were installed in the furnace for the installation of the probes in the most desirable areas. Two of these ports were located in the middle of the sidewalls within the burner zone (elevation 129.8 ft.) in the most corrosion prone area and two others were located at the middle of the sidewalls but in the upper furnace area (elevation 157.8 ft.) outside of the expected corrosion area, in order to provide "control" data.

A comparison of corrosion rate data developed in this program on Gulf Power Company's No. 7 boiler at the Crist Station is best illustrated in Figure 2 showing a plot of corrosion rate vs. exposure time for probes exposed to both baseline and low $NO_x$ firing conditions. Referring to Figure 2 it may be noted that coupon corrosion rates decrease with exposure time asymtotically up to 1000-hour exposure. Initial corrosion rates developed at 24 to 30-hours exposure are high with considerable scatter in the data. At 250 to 300 hours exposure, corrosion rates are much lower and more consistent in range. Above 450 to 500 hours exposure, corrosion rates level out to an average rate of 10 to 12 mils/year with very little scatter in the range of the data. These rates, however, are still much higher than the 1 to 3 mil/year wastage expected in actual furnace wall tubes.

It is concluded from these corrosion probe investigations that:

- There are no major differences in corrosion rates for process exposed to low $NO_x$ vs. baseline firing conditions, especially for exposure exceeding 450 hours.
- Corrosion rates developed via corrosion probes decrease with exposure time through 1000 hours approaching an asymtote above 450 hours exposure.
- Corrosion probes exposed for short terms (up to 30 hours) within the burner areas in the furnace sidewalls experience significantly greater corrosion rates than probes exposed outside the burner levels under low $NO_x$ firing conditions. A similar trend is indicated for baseline operating conditions but more data is needed to reach firm conclusions.
- Probes exposed for periods of 300 to 1000 hours experienced no significant differences in corrosion rates due to furnace location (burner vs. nonburner area) or furnace operating mode (baseline vs. low $NO_x$ firing).
- Effective correlation of actual long-term furnace tube corrosion rates require corrosion probe exposure of a minimum of 450 hour exposure.

## CORROSION TEST PANELS

In planning the long-term corrosion program discussions with the major boiler manufacturers indicated that the most definitive assessment of furnace tube corrosion would be obtained through use of test panels (premeasured and metallurgically characterized) installed as integral sections of the furnace water tube walls. Since boiler walls are very large and vulnerable corrosion areas are difficult to define in advance of exposure, it was decided to concentrate the panels used in the test on the Crist No. 7 boiler mostly on one furnace wall.

Figure 3 presents a schematic side elevation of the Crist No. 7 boiler showing the location of the furnace test panels. Note that panels 1 and 2 were located below the bottom burner centerline (at 93' elevation) while panels 7 and 8 were installed far above the top burners (elevation 157'-8") with panel 8 located in the right hand sidewall only. These locations were felt to be in areas of relatively low corrosion since both temperatures and depth of slag deposit would be lower than in the burner area where panels 3, 4, 5 and 6 were located. It was also felt that panels 2 and 5 could be affected by curtain air at the rear of the furnace and might experience less corrosion than panels 1 and 3 located in areas without curtain air.

The test panels were fabricated five tubes wide and about 5 feet long. Tubes 1, 3 and 5 were made of SA 210 grade T1 ASTM specification steel while tubes 2 and 4 were made from SA-213 grade T-2 ASTM specification steel. Tube wall thickness measurements were made ultrasonically at three inch intervals (hot side) and six inch intervals (cold side) prior to insertion into Crist No. 7 furnace and after removal from the furnace. Two tubes were removed for each test panel during the November, 1977 boiler overhaul period and replaced with premeasured ASTM specification SA 210 grade T1 steel tubes which is the same material specified for the original wall tubes on Crist No. 7. Ultrasonic tube wall thickness measurements were also made in the field during October, 1976 following the baseline operating period. After removal from the furnace, tubes in the test panels were cleaned, ultrasonically measured by Foster Wheeler, sectioned for photomicrographic examination and corrosion determination.

Based on load demand considerations on the boiler, original test plans provided for a 5-month sustained baseline operating test run starting in May, 1976 followed by a 6-month "low $NO_x$" operating period with ultrasonic furnace tube thickness measurements at the beginning and end of the baseline operation and middle and end of the "low $NO_x$" operating period. The prime reasons for including a baseline operating period was the desirability to include "control" measurements and to allow full load operation of the boiler during the summer peak loads. In the period of October, 1976 through January, 1977, a number of operating problems (including pulverizer overhauls furnace tube failures, excessive cold weather, etc.) delayed the start of sustained

"Low $NO_x$" operation until February, 1977. Subsequently, it was mutually agreed to extend the "low-$NO_x$" operation until the normal spring outage in 1978, since the unit came off line in July 1977 due to a generator problem. The final low $NO_x$ operating period turned out to comprise a total of 12 months.

Table 8 summarizes the results of the statistical analysis of the furnace test panel measurements. Columns 1 and 2 present test panel measurement data for exposure during 5 months baseline operation and 12 months "low $NO_x$" operation. Column 3 presents data for the two replacement tubes which were exposed during the last 4 months of the "low $NO_x$" operating period and columns 4 and 5 present the 13 and 17 month mixed operation data. To facilitate comparisons of different length operating periods, the average change in furnace tube wall thickness is shown in mils per year as well as mils.

The results of statistical analysis of Table 8 can be summarized as follows:

(1) The average loss in furnace tube (hot side) wall thickness during the 5 month baseline operation was about 2 mils (or 5 mils per year) except for panel number 5 which experienced about double that loss. Panels in the non-burner area experienced about the same loss as panels located in the burner area (except panel number 5).

(2) The average loss in furnace tube (hot side) wall thickness was about 5 mils (or 5 mils per year) during the 12 month "low $NO_x$" operating period. However, the test panels located in the burner area experienced a significantly higher loss level (10 mils per year) than the panels located within the non-burner area (+0.2 mils per year).

(3) Comparing the corrosion rates (mils per year) for the 5 month baseline and 12 month "low $NO_x$" operating periods revealed:

(a) panels in the non-burner area experienced significantly less corrosion during "low $NO_x$" operation than during baseline operation (+0.2 vs. -5.3 mils per year). No explanation could be found for this result.

(b) the test panels within the burner elevation experienced significantly greater corrosion during the "low $NO_x$" operating period than during the baseline operating period (10.4 vs. 6.2 mils/year).

(4) Measurements on the replacement tubes, exposed for the last four months of "low-$NO_x$" operation, showed no metal loss and the small gain shown must be due to measurement bias or miscalibration.

(5) Columns (4) and (5) of Table 8 containing measurement data representing both baseline and "low-NOx" operation lead to similar conclusions as in (2) above for "low-$NO_x$" operation. Table 9, below, has been constructed to make this comparison more meaningful. The 17 month "mixed" operation data has been used to estimate 12 month "low-$NO_x$" operation measurements by deducting the 5 month baseline operation data measured in the field. The estimated 12 month "low-$NO_x$" operation data is very similar to the actual field measured 12 month "low $NO_x$" operation measurements and statistical analysis using the estimated results lead to the same conclusions as use of the field measurement data.

The data in Table 8 in columns 4 and 5 are also illustrated in Figure 3 in a more readily understood form. Average changes in tube thickness (hot side) are shown for each of the panels for the 13 month and 17 month mixed (baseline and "low $NO_x$") operations. As seen earlier, relatively low corrosion rates were experienced on panels 1, 2, 7 and 8 located at some distance from the burners. Panel 5 experienced considerably less corrosion than panels 3, 4 and 6 located within the burner elevation. The existence of rear curtain air might explain this difference.

In summary, the following conclusions can be stated for the analysis of corrosion data from test panels exposed to furnace conditions as Crist No. 7 Unit.

(1) Corrosion rates of furnace tube panels are generally similar at different sidewall furnace locations (below, within and above the burner elevations) when exposed to baseline operation. The average corrosion rate is about 5 mils per year during the first 5 months of exposure. (95% confidence limits are 3.8 to 6.2 mils/year.)

(2) Corrosion rates of furnace tube panels, within the burner elevations are about 10 mils/year while tubes at least 20 feet above or below the burner show little or no corrosion during "low $NO_x$" operation.

## ULTRASONIC FURNACE TUBE THICKNESS MEASUREMENTS

Another method to obtain corrosion rate data is to measure the tubes ultrasonically before and after the desired exposure period, using the difference in thickness measurements to calculate the corrosion rate. Ultrasonic thickness "mapping" of the furnace tubes was employed in the long-term corrosion investigations on Gulf Power Company's Crist Station, No. 7 boiler. Extensive time and effort were expended in planning the tube mapping program to assure reliable measurements. Major considerations involved in determining how, where and how many measurements should be made included the following:

1. Location of most likely and least likely corrosion areas within each wall.
2. Precision and accuracy of the ultrasonic measuring instruments.
3. Changes in normal corrosion rates due to necessary tube cleaning before measurement (possible bias).
4. Additional measurements for quality control purposes.
5. Costs of cleaning tubes, ultrasonic measurement and necessary supervision.

Operating experience indicated that the middle area of boiler side walls, within and just above the top row of burners, is most likely to experience the highest rate of tube wastage. Consequently, four of the six ultrasonic measurement levels were located at the center of the three burner elevations and about 8 1/2 feet above the centerline of the top burner level. The "control" levels were 13 feet below the centerline of the bottom burners and 28 feet above the top burner level. Measurements were more highly concentrated within the middle of the side wall burner area than near the furnace corners or below and above the burner elevation.

Sandblasting or wire brushing necessary to clean the tubes prior to measurement may remove a protecting coating and result in increased wastage. Elaborate precautions were taken to avoid this possible bias through a program of random cleaning and measurement. Pains were also taken to assure that only sufficient sandblasting was done to clean the tubes without metal removal. In addition, special precautions were taken to ensure that measurements were made at precise elevations on the tubes by welding nuts on the web between tubes in the corners at the given elevations and snapping chalk lines each time prior to measurement.

Statistical Analysis of Ultrasonic Data

To assess the statistical significance of the average tube wall thickness change, the most appropriate "error term" is calculated from the differences between level averages within burner walls. Instrument calibrations were not made more frequently than once per level measured. The levels were far enough apart to expect different corrosion rates and the spots to be measured were determined at each level independently.

This approach does not bias the analysis if calibration errors are insignificant. Comparisons between level means provide a proper error time. The only loss, if calibration variance is negligible, is a slight loss of sensitivity due to a reduced number of degrees of freedom. However, experience has shown that calibration variance appears to be far from negligible.

Table 10 contains a summary of the furnace wall tube (hot side) metal thickness changes (mils/year) for the baseline operation (5 months) and low $NO_x$ operation (12 month duration). The 5 month baseline operation data has been converted to a mils/year basis for ready comparison with the 12 month "low-$NO_x$" operation data. The body of the table presents the average thickness change for each of the six measurement levels of each furnace wall. The averages have been calculated from all of the paired data (before and after measurements) available for each level after screening out obvious outlier data (20 out of 974 differences). The weighted averages ($\bar{X}$), number of differences (n) and pooled standard deviation(s) are shown for half-walls (burner and nonburner areas), walls and the whole furnace for both the baseline and low $NO_x$ operating periods. Individual wall level averages vary from a high loss of -8.26 mils (left wall, middle burner level under low $NO_x$ operation) to a gain of 0.81 mils (right wall, level 1 at 27 feet above top burners under low $NO_x$ operation). These data were also analyzed by Shewhart Control Charts and 95% confidence limits were calculated by classical and successive difference methods.

The furnace average tube wall thickness loss during low $NO_x$ operation was 3.43 mils. However, two of the half-wall averages were outside of the 97.3% probability control limits; left wall, burner area (-6.24 mils) and right wall nonburner area (+0.36 mils). In addition, the right side wall, burner area average of -5.29 mils is outside of the lower limit of -5.10 mils.

Conclusions from these data and the control chart analysis are:

- The variation of measurement level averages within half-walls is uniform within half-walls during both baseline and low $NO_x$ operation and equals about 1.5 mils.
- With the possible exception of the right sidewall nonburner average, all of the half-wall averages during the baseline operation are about equal after allowing for random level to level variation.
- The low $NO_x$ operation produced significantly high metal loss within the left wall burner area and possibly, significantly high metal loss within the right wall burner area. The right nonburner area showed significantly less metal loss than the furnace average.

<u>Comparison of Baseline and Low $NO_x$ Data</u>

Table 11 presents a comparison of five month baseline and 12 month low $NO_x$ furnace tube wall thickness loss data. Column 1 lists the nonburner and burner average loss for each furnace wall (mils, mils per year and mils per $\sqrt{\text{year}}$) for the 12 month low $NO_x$ operating period. For comparison purposes, columns 2, 3 and 4 list the corresponding loss data for the 5 month baseline operating period in mils, mils per year and mils per $\sqrt{\text{year}}$, respectively. Since the right wall, nonburner area results are so much different from the rest of the data (see Table 11, the nonburner grand average has been calculated with and without the right wall results. 95% confidence limits for the low $NO_x$ operation nonburner (less right wall) and burner grand averages are also shown in Table 11.

The baseline and low $NO_x$ loss data for both nonburner and burner furnace area can be compared on three different bases: mils, mils per year and mils per year. Other bases could be used out these three seem adequate considering the state of present knowledge of coal-fired, furnace tube corrosion. Since the comparison using mil loss data is obviously biased in favor of the baseline operation (because of the difference in exposure times), no importance can be attached to its statistically significant difference. Omitting the right wall, nonburner area averages, all 7 of the half wall low $NO_x$ averages produced larger metal losses than the corresponding baseline averages calculated as mils.

However, both the mils per year (equal loss per unit of time) and mils per $\sqrt{\text{year}}$ (decreasing rate of loss with time) can provide valid comparisons. On a mil per year basis, four of the seven half-wall comparisons produced lower baseline loss than low $NO_x$ loss and the overall average difference is not statistically significant. However, it should be noted that noted that the baseline operation average of 4.0 mil/year loss for the overall burner area is outside of the 95% confidence limits for the low $NO_x$ burner area (-6.0 to -4.1 mils/year).

If it is believed that the corrosion rate decreases with time (most boiler corrosion coupon data support this concept) and a mils/$\sqrt{\text{year}}$ model is used, then the low $NO_x$ operating period corrosion loss is statistically significantly higher than the baseline operation loss. Six of the 7 half wall differences produce a higher loss during low $NO_x$ operation than the corresponding loss during baseline operation. However, separating the nonburner area from the burner area, it is found that the average difference (-3.05 less -2.12 = -0.93) for the nonburner area is not statistically significant while for the burner area the average difference (-5.05 less -2.58 = -2.47) is statistically significant at the 5% probability level. Thus, it is concluded that the low $NO_x$ operation produces significantly higher corrosion than baseline operation within the burner area.

Figure 4 presents a visual comparison of 5 month baseline and 12 month low $NO_x$ data for average tube wall thickness loss of nonburner area (omitting right wall) and burner area. The projected baseline data on a mils per year basis are shown as dashed lines on Figure 4. The 12-month projected nonburner area value of-3.30 mil loss is very close to the actual

-3.05 mil loss experienced during the low $NO_x$ operating period. However, the projected baseline operation, burner area corrosion loss of 4.00 mils is less than the actual low $NO_x$ operation loss of 5.05 mils. This latter difference is not statistically significant when allowance is made for the uncertainty of both of these loss averages. Note, however, that the 12 month projected baseline operation loss of 2.58 mils for the mil per year model is statistically significantly less than the 5.05 mils per $\sqrt{\text{year}}$ loss during the low $NO_x$ operation. Thus, the conclusion reached depends upon which model is accepted.

Summary of Corrosion Measurements

Major results developed in the long-term corrosion investigations conducted on Gulf Power Company's, Crist Station, No. 7 pulverized coal-fired boiler using corrosion probes, furnace tube panels, and ultrasonic measurement of both the panels and furnace tubes have been discussed and summarized in the foregoing sections. Table 12, which is self explanatory, provides an encapsulated summary of the overall results of the three methods used in these long-term corrosion tests.

## SECTION 5

## CORROSION TESTING OF UTILITY BOILER COMBUSTION MODIFICATIONS

The influence of $NO_x$ combustion modifications on fireside corrosion, slagging, particulate emissions, boiler performance and other potential side effects has been assessed in prior EPA sponsored studies by Exxon Research and others. As indicated above these adverse side effects, with the possible exception of fireside furnace tube corrosion, have either been proven to be nonexistent or of negligible magnitude at the levels of $NO_x$ control practiced in these investigations. Corrosion assessment studies, however, for the most part, utilized corrosion probes which, in general, provided only a qualitative estimate of furnace tube wastage rates. These studies, normally, were of relatively short duration under "low $NO_x$" operating conditions; typically two weeks.

EPA recognized very quickly the critical importance of this matter to the $NO_x$ program and the necessity to obtain definitive data and a resolution to this question. As a result, Exxon Research under contract to EPA (3)(4) was directed to undertake the first long-term corrosion investigation, discussed above, on the pre-NSPS No. 7 boiler at Gulf Power Company's Crist Station, in Pensacola, Florida. During the course of this investigation it became apparent that more long-term corrosion data would be required to address the same question on boilers of various designs which were being supplied at that time by the boiler manufacturers to comply with the old $NO_x$ standard of 0.7 lbs $NO_x/10^6$ Btu. Subsequently, a new EPA contract (Contract No. 68-02-2696) was awarded to Exxon Research to conduct long-term corrosion tests on four NSPS designed boilers.

The scope of the new contract was described at the "Third Stationary Source Combustion Symposium" in San Francisco in March 1979. Investigation of furnace tube corrosion essentially is the same as employed on the Crist, No. 7 boiler, i.e., a three pronged approach using corrosion probes, furnace tube panels, and ultrasonic thickness measurement of furnace tubes and test panels to develop corrosion rate information as described earlier. However, the scope of the new contract is much more extensive including level 1 pollutant assessment tests involving all pertinent solid, liquid and gas streams entering or leaving the boiler and 30 day continuous monitoring of $NO/NO_2$, CO and $O_2$ levels, according to EPA guidelines, with frequent reference method checks.

## PRESENT STATUS AND PLANS

Original contractual requirements calling for testing of four boilers, one each of the major boiler manufacturers designs, has been changed to more extensive testing of 3 NSPS designed boilers. Two tests have been in progress for the past year and a half in cooperation with the respective utility and boiler manufacturer, as indicated below, and test sites for the third candidate boiler are actively being screened. The investigative program on the third boiler will be combined in a cooperative joint venture with Combustion Engineering in a test of their new "rich fireball" firing concept for the further reduction of $NO_x$ emissions in tangentially fired boilers.

Tests in progress are:

- Columbus and Southern Ohio Electric Company
  Conesville, Unit No. 5 (410 MW)
  Tangential firing with overfire air (5 pulverizers)
  Manufacturer: Combustion Engineering, Inc.
  Start of Testing: December 1978
  Corrosion Panels Installed: Nov./December 1979
  Ultrasonic Thickness Measurements: December 1979
  Corrosion Probes: 30, 300, 1000 hours completed July 1980
- Louisville Gas and Electric Company
  Mill Creek, No. 3 (450 MW)
  Horizontally Opposed Firing-Low $NO_x$ Burners (4 pulverizers)
  Manufacturer: Babcock & Wilcox Company

Start of Testing: March 1979

Corrosion Panels Installed: December 1979

Ultrasonic Thickness Measurements: December 1979

Corrosion Probes

Corrosion probes provide a relatively simple, quick and economical means for determining corrosion rates. Even though corrosion rate data developed in these and previous programs could not readily be related to actual furnace tube experience, this type of measurement is being continued in the long-term corrosion investigations with the objective of eventual correlation with rates developed by ultrasonic measurement of actual furnace tubes and from exposure of furnace tube test panels.

Corrosion probes in the Gulf Power Company, Crist No. 7 tests were exposed for 30, 300 and up to 1000 hours to show the effect of corrosion with time. The type of probe used in this and prior tests conducted by Exxon Research is shown in Figure 5. The orientation of the coupons on this probe at 90° to the furnace wall came under criticism as being unrealistic to furnace tube orientation and results, therefore, were viewed as being unreliable.

To overcome this problem probes designed and built by Combustion Engineering's corrosion research section are being used in the present contract. Design of the new probe is shown in the schematic sketch in Figure 6. Note that the corrosion probe coupons (Figure 6) are installed in a 4"x10" inspection door in the plane of the furnace wall parallel to the furnace tubes, simulating furnace tube exposure. In this position only half of the coupon is exposed to the furnace atmosphere; the same as furnace tubes.

Five of the new probes were used on the Conesville, No. 5 boiler to obtain corrosion data under 30, 300, and 1000 hours exposure. Four of the probes were located in the burner area in panels 2, 4, 5, and 6 (Figure 7) with the fifth probe installed in panel 1, outside of the burner area, to obtain "control" data. Similarly, the location of the four probes which will be used on the Louisville No. 3 boiler is shown in Figure 8. The large rectangles on Figure 7 and 8 are test panels and the corrosion probes are represented by the smaller rectangles (in inspection doors).

## Furnace Tube Test Panels

The schematic sketches depicted in Figures 7 and 8 show the location of the furnace tube corrosion test panels and corrosion probes installed in the Conesville, No. 5 and Louisville, No. 3 boilers, respectively. Because the area of greatest expected corrosion in the Conesville tangentially fired No. 5 boiler is in the vicinity of the front and rear furnace walls adjacent to smallest angle between the flame and the wall (Figure 7), panel locations in these walls were chosen judiciously to provide the greatest amount of information. Note that five panels are located in the front wall and three in the rear wall. Panels 2, 3, 4, 5, 6 and 7 are located in the burner area (greatest expected corrosion) with panels 1 and 8, above and below the burners for "control" purposes. Panels 2, 4 and 6 are in the most vulnerable areas closest to the flame while panels 3 and 6 are somewhat further from the flame but still in corrosion prone areas.

The sketch in Figure 8 shows locations of the furnace panels in the horizontally opposed fired Louisville, No. 3 boiler. Panels 4, 5 and 6 in the left and right walls are in the most vulnerable corrosion areas. Panels 1 and 2 are located in the hopper slopes where corrosion in this type of boiler has also been experienced but to a lesser extent. Panel 3, in the rear wall between the burners, covers the possibility of corrosion in the burner walls and panel 7, far above the burners, will provide "control" information.

As indicated above, installation of the corrosion panels in the Conesville and Louisville boilers was completed in December 1979. One half of each panel in both boilers is scheduled for removal during the annual outage in December 1980. Interim ultrasonic tube thickness measurements are also scheduled to be made on the furnace tubes and the panels at that time.

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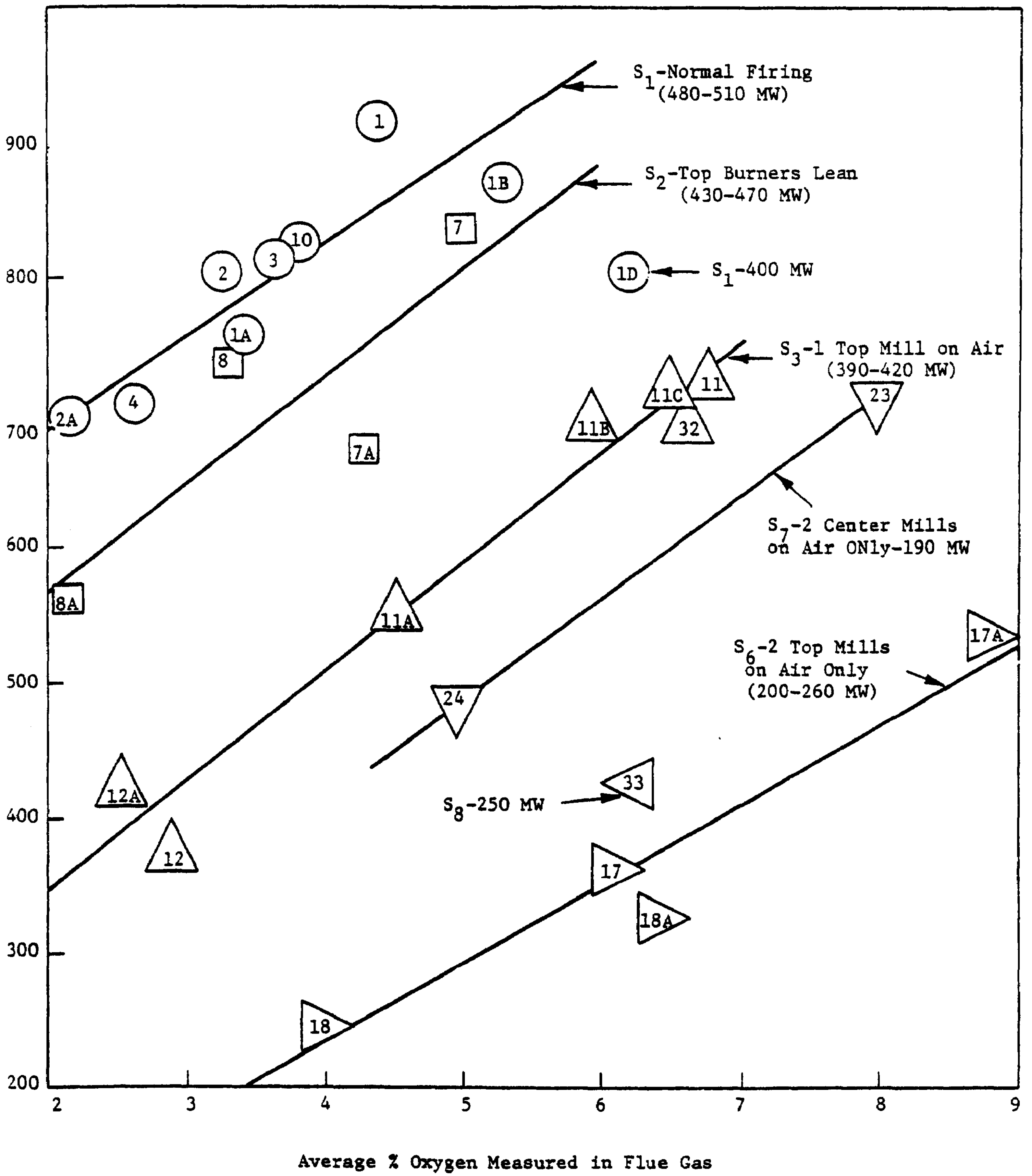


Figure 1. PPM $NO_x$ vs. % Oxygen in Flue Gas
(Crist No. 7 Unit)

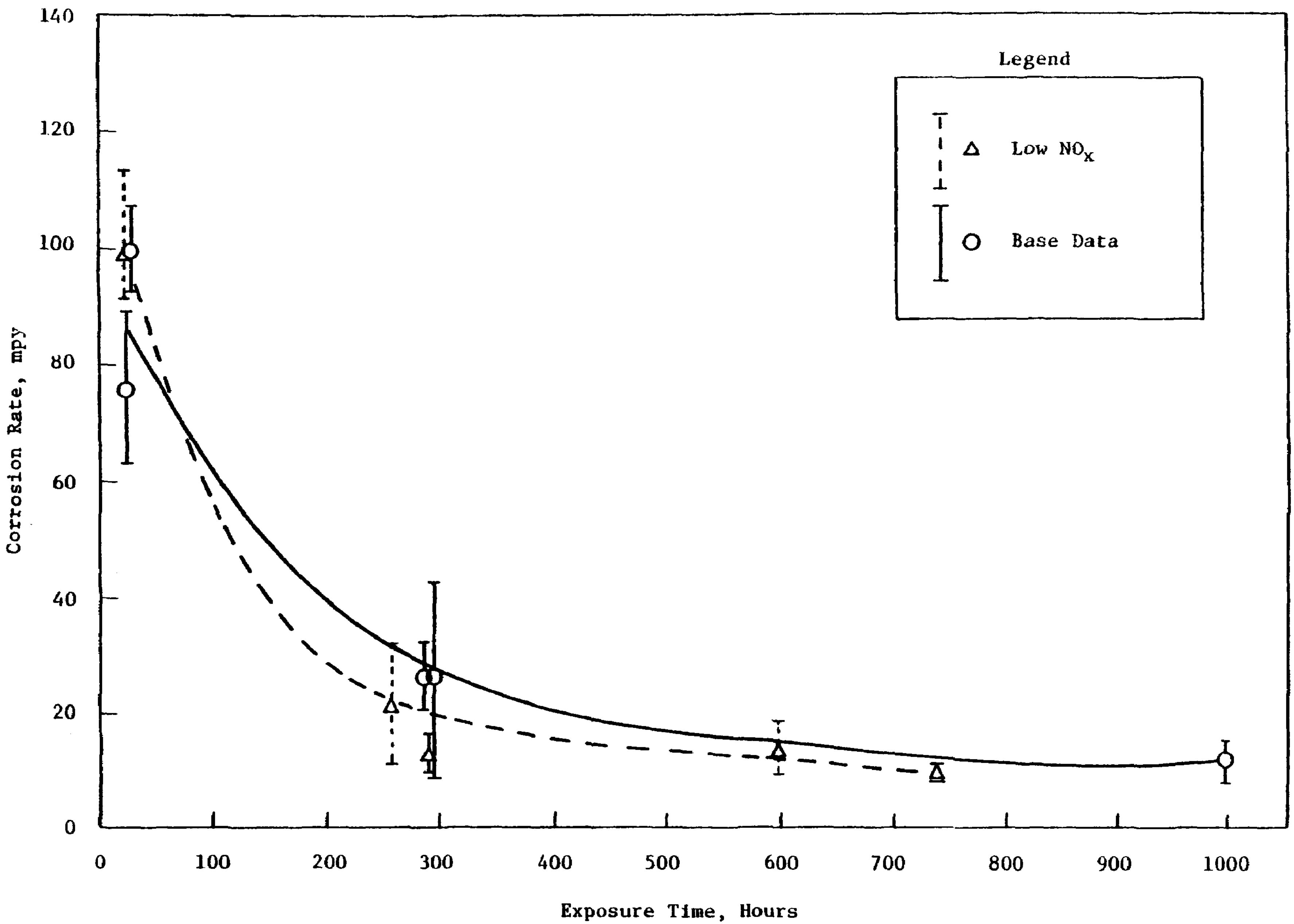


Figure 2. Comparison of Corrosion Rates
Gulf Power Company, Crist Station, Boiler No. 7
*Pulverized Coal Firing.*

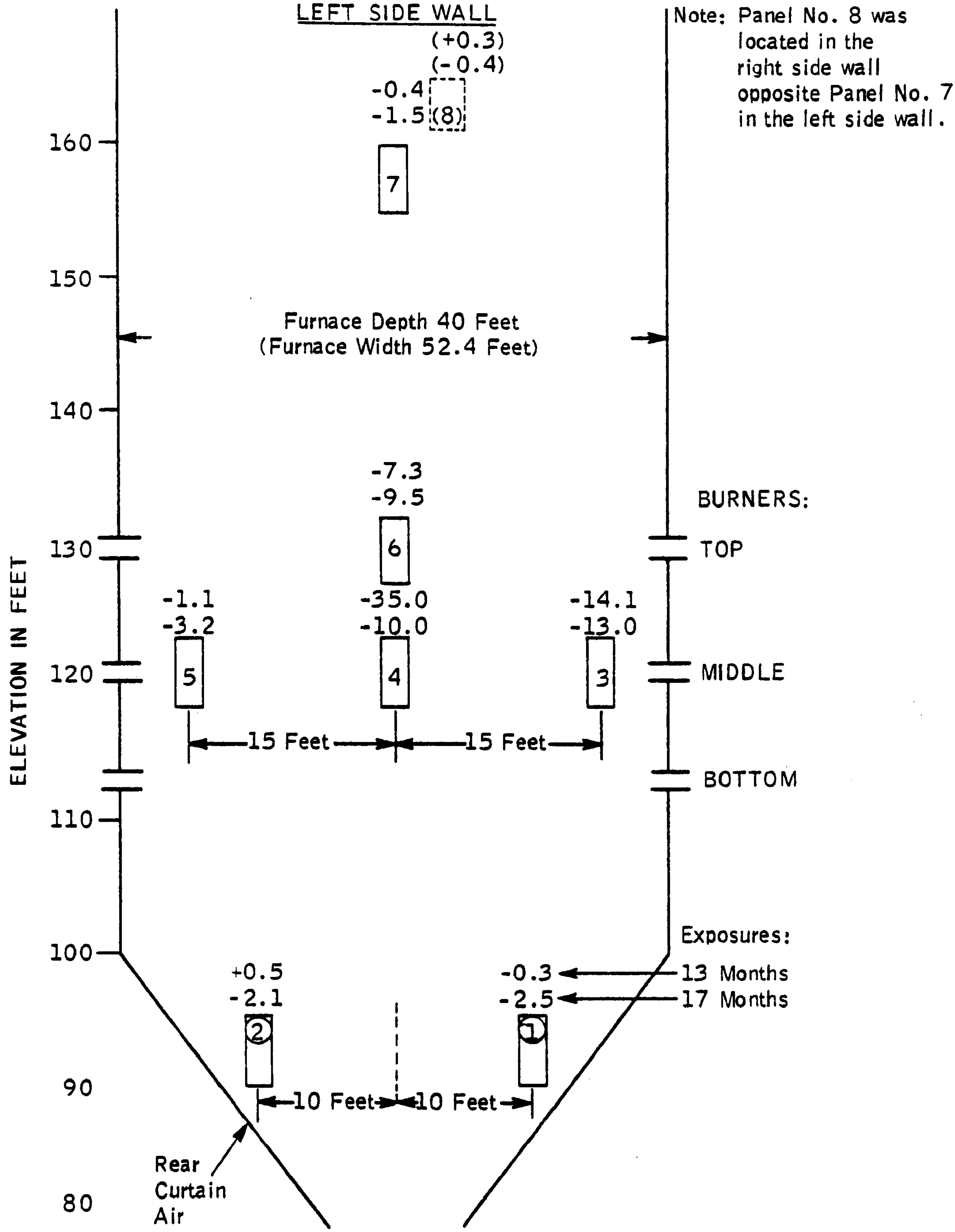


Figure 3. Test panel measurements and locations (average change in tube wall thickness - mils).

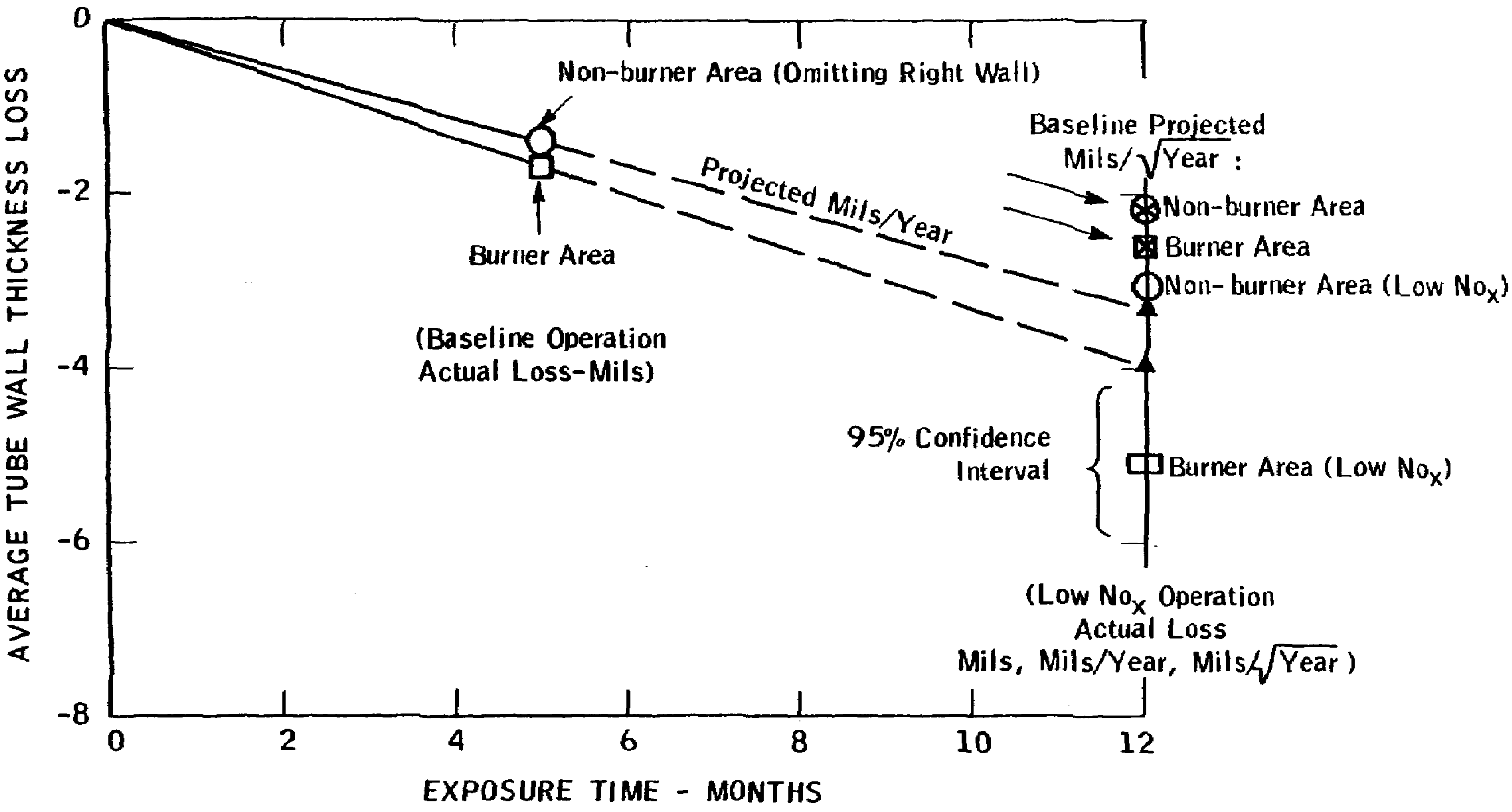


*Figure 4.* ***Comparison of 5 month baseline and 12 month low*** $NO_x$ **corrosion data.**

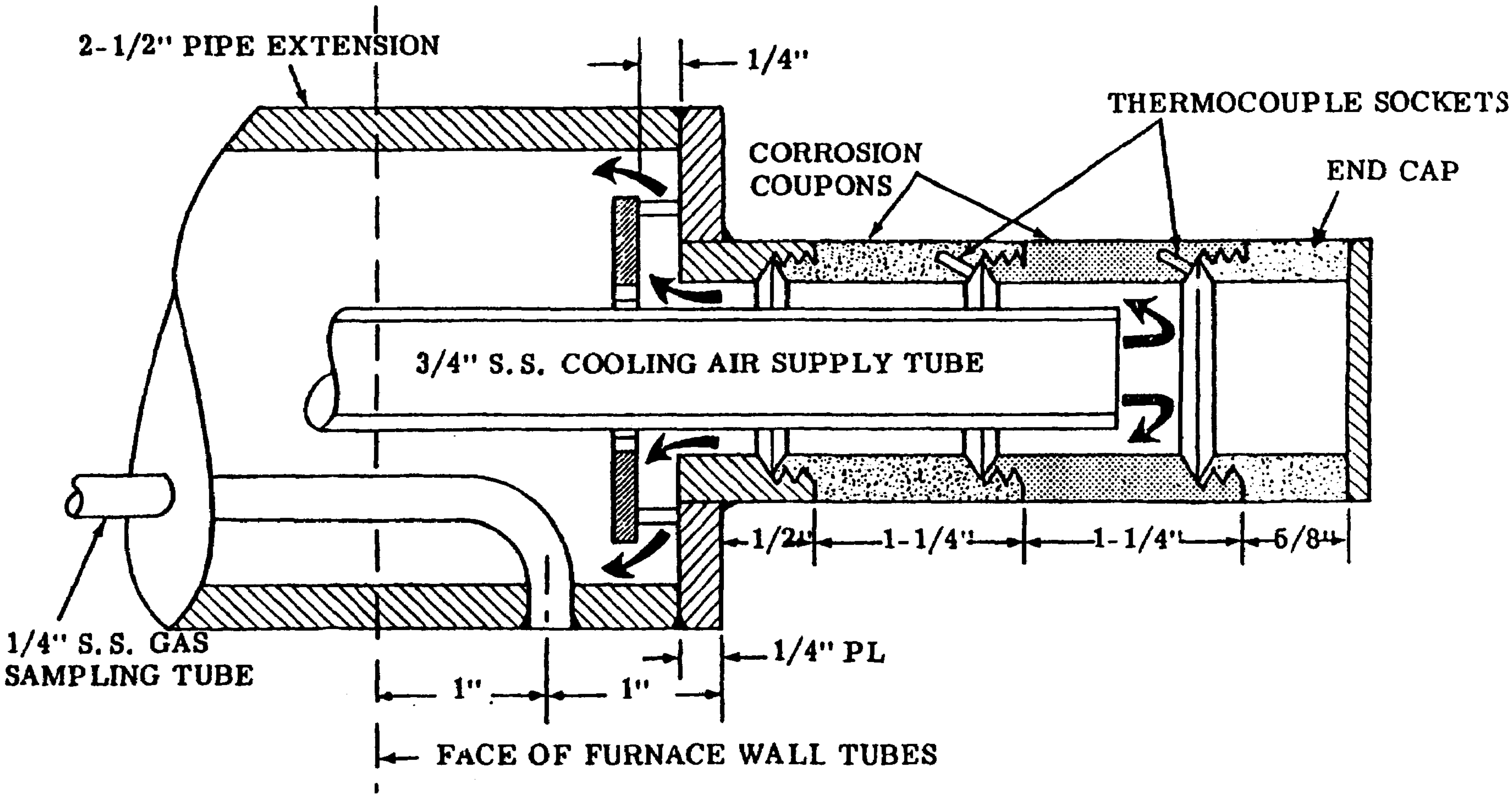


Figure 5. Corrosion probe, detail of corrosion coupon assembly (inside of furnace),

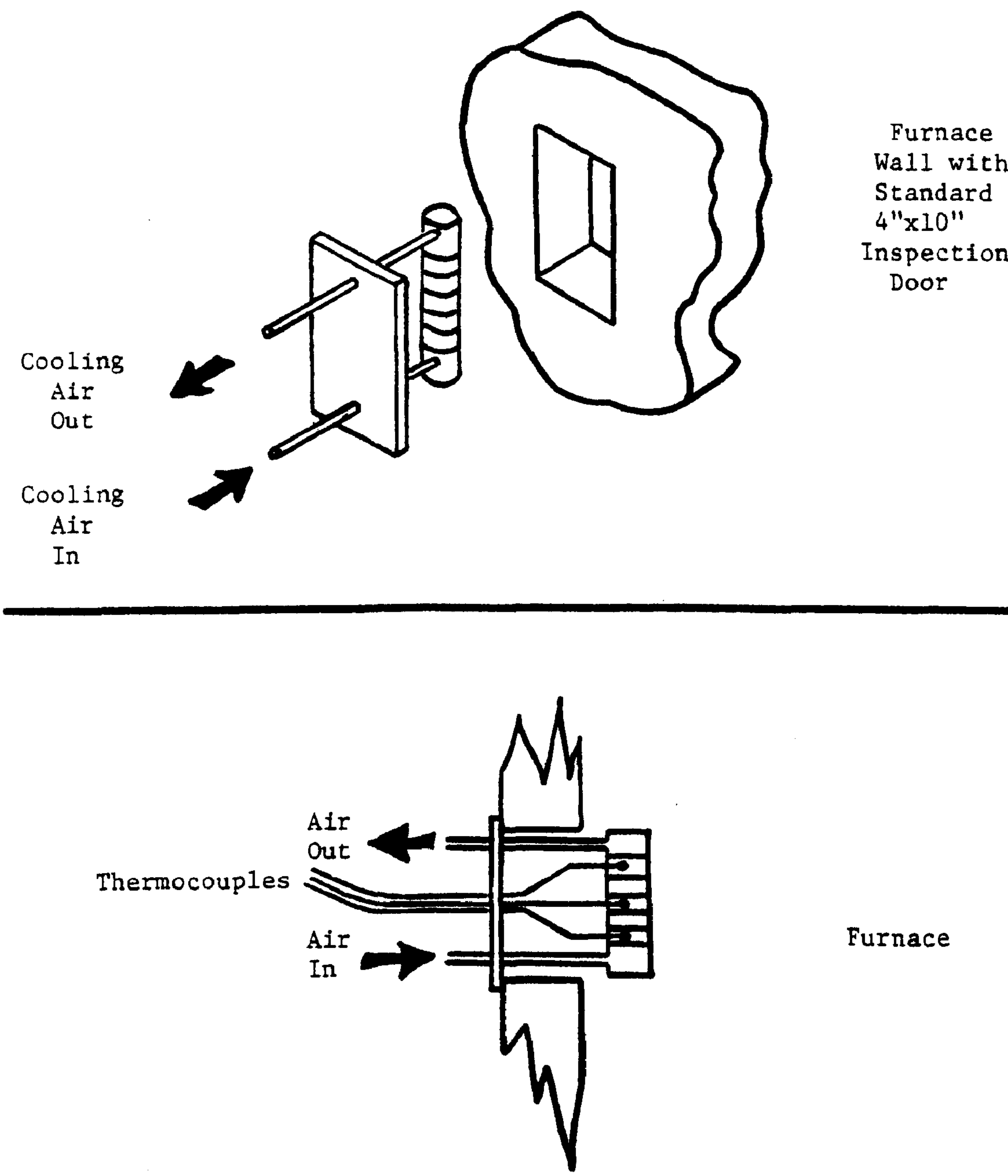


Figure 6. Corrosion probes
(Redrawn from C. E. Design)

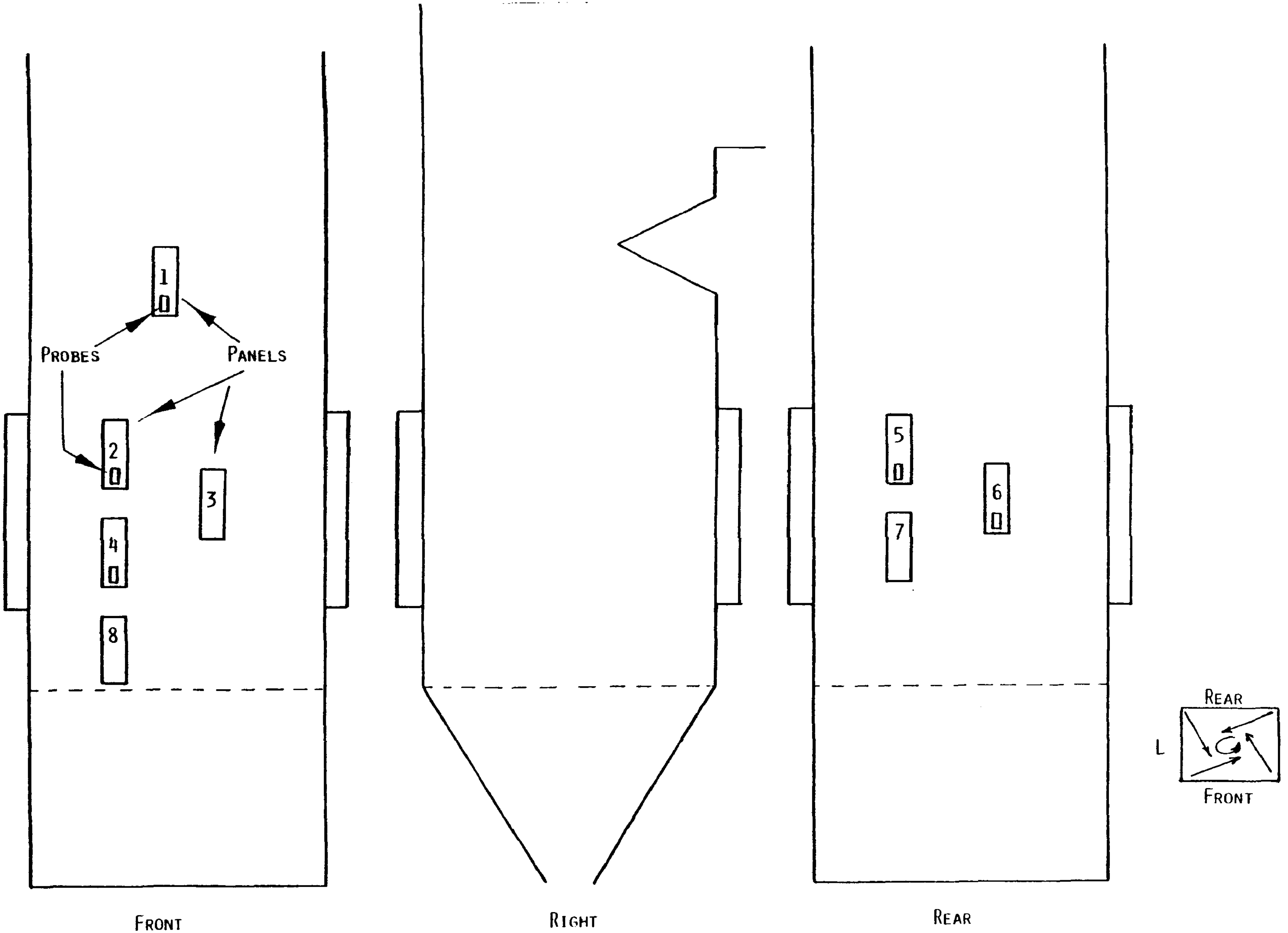


Figure 7. Corrosion probe and test panel locations
CSOE, Conesville, No. 5 boiler.

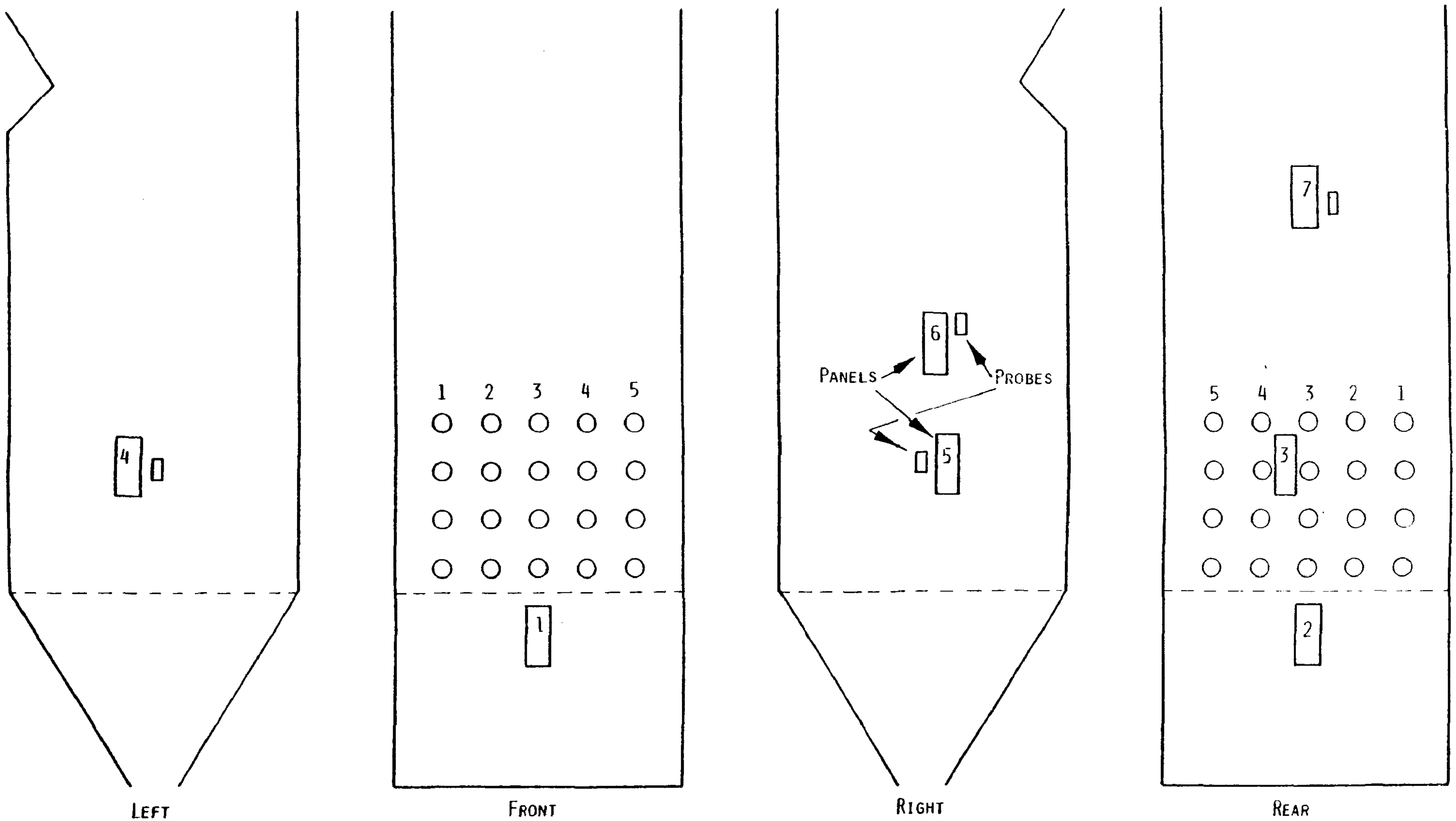


Figure 8. Corrosion probe and test panel locations
LG&E, Mill Creek, No. 3 boiler.

TABLE 1

SUMMARY OF COAL AND MIXED FUEL FIRED BOILERS TESTED DURING PHASE I

| | Boiler Operator | Station and Boiler No. | Boiler Mfr.(a) | Type of Firing(b) | Fuel(c) Burned | MCR (MWe) | No. of Burners | Test Variables | No. of Test Runs | $NO_x$ Emissions Baseline ppm(lb/$10^6$ BTU) | Low $NO_x$ ppm(lb/$10^6$ BTU) | % $NO_x$(h) Reduction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Tennessee Valley Authority | Widows Creek - 5 | B&W | RW | C | 125 | 16 | 4 | 31(d) | 597 (0.81) | 468 (0.64) | 22 |
| 2. | Southern Electric Generating Company | E. C. Gaston - 1 | B&W | HO(e) | C | 270 | 18 | 5 | 37(d) | 389 (0.53) | 278 (0.38) | 29 |
| 3. | Alabama Power Company | Barry - 2 | CE | T(f) | CG | 130 | 16 | 6 | 38 | 341 (0.46) | 189 (0.26) | 45 |
| 4. | Potomac Electric Power Company | Morgantown - 1 | CE | T | CO | 575 | 40 | 5 | 27 | 552 (0.75) | 403 (0.55) | 27 |
| 5. | Salt River Project | Navajo - 2 | CE | T(f) | C | 800 | 56 | 4 | 36(d) | 492 (0.67) | 282 (0.38) | 43 |
| 6. | Public Service Company of Colorado | Comanche - 1 | CE | T(f) | C | 350 | 20 | 4 | 30(d) | 417 (0.57) | 261 (0.35) | 37 |
| 7. | Public Service Electric and Gas Company | Mercer - 1 | FW | FW(g) | C | 270 | 24 | 4 | 33(d) | 1383 (1.88) | 876 (1.19) | 37 |
| | Average of Coal Fired Boilers | | | | | | | | 33 | 656 (0.89) | 433 (0.59) | 36 |

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering, FW - Foster Wheeler

(b) RW - rear wall, HO - horizontally opposed, T - tangential, FW - front wall

(c) C - coal, C-G - coal-gas mixed, C-O - coal-oil mixed

(d) Particulate and corrosion probe tests performed on these boilers

(e) Special low $NO_x$ emission burners

(f) Overfire air ports

(g) Wet bottom furnace

(h) % $NO_x$ reduction at full or near full load

(i) PPM $NO_x$ - 3% $O_2$, dry basis

TABLE 2

SUMMARY OF UTILITY UNITS TESTED DURING PHASE II

| | Boiler Operator | Station and Boiler No. | Boiler Mfr.(a) | Type of Firing(b) | Fuel Burned | MCR (MWe) | No. of Burners | Test Variables | No. of Test Runs | $NO_x$ Emissions Baseline ppm (lb/$10^6$ BTU) | Low $NO_x$ ppm (lb/$10^6$ BTU) | % $NO_x$(g) Reduction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | East Kentucky Power Cooperative, Inc. | Cooper - 2 | B&W | FW | Coal | 220 | 18 | 4 | 101 (c)(d) | (h) 557 (0.76) | (h) 433 (0.59) | 22 |
| 2. | Public Service Company of Colorado | Comanche - 2 | B&W | HO(e) | Coal | 350 | 32 | 3 | 18 (c) | 726 (1.00) | 278 (0.38) | 62 |
| 3. | Public Service Electric and Gas Company | Sewaren - 5 | B&W | HO | Oil | 330 | 24 | 5 | 24 | 311 (0.40) | 211 (0.27) | 32 |
| 4. | Houston Lighting and Power Company | Wharton - 43 (Gas Turbine) | GE | (f) | Gas | 50 | -- | 2 | 16 | 212 (0.29) | 34 (0.044) | 84 |
| 5. | Houston Lighting and Power Company | Wharton - 42 (Gas Turbine) | GE | (f) | Oil | 50 | -- | 2 | 13 | 382 (0.45) | 40 (0.048) | 90 |
| 6. | Louisville Electric and Gas Company | Mill Creek - 1 | GE | T | Coal | 330 | 20 | | (c) | 533 (.71) | - (i) | - |
| 7. | Gulf Power Company | Crist - 7 | FW | HO | Coal | 300 | 24 | 4 | 158 (c)(d) | 827 (1.1) | 570 (.76) | 31 |
| | Average of Coal Fired Boilers | | | | | | | | 92 | 661 (.88) | 427 (.37) | 38 |

(a) B&W - Babcock and Wilcox, GE - General Electric, CE - Combustion Engineering

(b) FW - Front Wall, HO - Horizontally Opposed, T - Tangential

(c) Particulate tests performed on these boilers

(d) Corrosion probe tests performed on this boiler

(e) Overfire air ports

(f) Water injection

(g) % $NO_x$ reduction of full or near full load

(h) PPM $NO_x$ - 3% $O_2$, dry basis

(i) Additive test at baseline conditions only

TABLE 3

PARTICULATE EMISSION TEST RESULTS

| Utility | Date | Test No. | Firing Condition | Load, MW | Emissions mg/m$^3$ | GR/SCF | ng/J | Lb/10$^6$ Btu | Req. Eff. To Meet 0.1 Lb/ 10$^6$ Btu | % Carbon On Particulate | Coal Ash Wt, % | HHV. Wet Cal/g Btu/Lb |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| East Kentucky Power Cooperative, Inc., Cooper Station, Boiler No. 2 | 3/9/77 | 41 | Base* | 178 | 1.06 | 4.65 | 3280 | 7.63 | 98.7 | 1.48 | 12.78 | 11,742 |
| | 3/11/77 | 43 | Base* | 155 | .72 | 3.12 | 2361 | 5.49 | 98.2 | .94 | 12.48 | 12,217 |
| | 3/25/77 | 59 | Low $NO_x$* | 123 | .78 | 3.41 | 2520 | 5.86 | 98.3 | 1.81 | 11.30 | 12,312 |
| | 3/28/77 | 60 | Low $NO_x$* | 123 | .87 | 3.82 | 3130 | 7.28 | 98.7 | 1.87 | 10.47 | 12,291 |
| Public Service Electric & Gas Company Sewaren Station Boiler No. 5 | 9/17/76 | 4D | Base** | 288 | .0059 | .026 | 17.2 | 0.04 | - | - | - | - |
| | 9/17/76 | 6C | Low $NO_x$** | 280 | .0063 | .0274 | 17.2 | 0.04 | - | - | - | - |
| Gulf Power Company, Crist Station, Boiler No. 7 | 6/20/78 | 150 | Base* | 436 | .686 | 3.00 | 2301 | 5.35 | 98.1 | - | - | - |
| | 6/21/78 | 151 | Low $NO_x$* | 432 | .874 | 3.82 | 1926 | 4.48 | 97.8 | 2.98 | 12.45 | 11,263 |
| | 6/22/78 | 152 | Base* | 417 | .864 | 3.78 | 2881 | 6.70 | 98.5 | 0.87 | 16.48 | 10,782 |
| | 6/23/78 | 153 | Low $NO_x$* | 434 | .909 | 3.97 | 2468 | 5.74 | 98.3 | 1.71 | 14.32 | 11,033 |

*Pulverized coal firing.
**Oil firing.

EHM:jbg

TABLE 4

PARTICLE SIZE DISTRIBUTION, WT%

EAST KENTUCKY POWER COOPERATIVE
COOPER STATION - BOILER NO. 2

PULVERIZED COAL FIRING

| | Baseline Firing | | | LOW $NO_x$ Firing | | |
|---|---|---|---|---|---|---|
| Size Range | Test No. 41 | Test No. 43 | Average | Test No. 59 | Test No. 60 | Average |
| >2.5 | 98.86 | 92.68 | 94.8 | 95.65 | 91.75 | 93.7 |
| 2.5 | 2.04 | 3.71 | 2.9 | 3.28 | 5.34 | 4.3 |
| 1.5 | 0.50 | 1.24 | 0.9 | 0.78 | 1.32 | 1.1 |
| 1.0 | 0.41 | 0.95 | 0.7 | 0.61 | 1.07 | 0.8 |
| 0.5 | 0.63 | 1.13 | 0.9 | 1.04 | 1.65 | 1.4 |
| <0.5 | 0.36 | 0.62 | 0.5 | 0.67 | 1.11 | 0.9 |

TABLE 5

PARTICLE SIZE DISTRIBUTION, WT%

GULF POWER COMPANY
CRIST STATION - BOILER NO. 7
PULVERIZED COAL FIRING

| Size Range | Baseline Firing: Test No. 150 | Baseline Firing: test No. 152 | Baseline Firing: Average | LOW $NO_x$ Firing: Test No. 151 | LOW $NO_x$ Firing: Test No. 153 | LOW $NO_x$ Firing: Average |
|---|---|---|---|---|---|---|
| >2.5 | 93.10 | 94.00 | 93.6 | 92.50 | 89.80 | 91.2 |
| 2.5 | 2.15 | 3.48 | 2.8 | 3.15 | 3.68 | 3.4 |
| 1.5 | 0.90 | 0.72 | 0.8 | 1.12 | 1.94 | 1.5 |
| 1.0 | 0.83 | 0.84 | 0.7 | 0.83 | 1.43 | 2.3 |
| 0.5 | 1.24 | 01.20 | 1.2 | 1.16 | 1.84 | 1.5 |
| <0.5 | 1.80 | 0.72 | 1.3 | 1.24 | 1.33 | 01.3 |

## TABLE 6

## SUMMARY OF BOILER PERFORMANCE CALCULATIONS

| | Boiler No. | Firing Mode | Test No. | Load, MW | % $O_2$ | $NO_x$ Emissions, (3% $O_2$) PPM | $NO_x$ Emissions, (3% $O_2$) Lb/$10^6$ Btu | $NO_x$ Emissions, (3% $O_2$) ng/J | Coal Ash, % (Wet Basis) | % Carbon on Particulate | Boiler Efficiency, |
|---|---|---|---|---|---|---|---|---|---|---|---|
| East Kentucky Power Cooperative Inc, Cooper Station | 2 | Baseline | 41 | 178 | 4.2 | 612 | 0.82 | 351 | 12.37 | 1.48 | 89.82 |
| | 2 | Baseline | 43 | 155 | 5.4 | 574 | 0.77 | 329 | 12.76 | 0.94 | 90.12 |
| | 2 | Low $NO_x$ | 59 | 123 | 5.0 | 381 | 0.51 | 218 | 11.30 | 1.81 | 90.44 |
| | 2 | Low $NO_x$ | 60 | 123 | 6.6 | 490 | 0.65 | 281 | 10.41 | 1.87 | 90.36 |
| Gulf Power Company, Crist Station | 7 | Low $NO_x$ | 151 | 432 | 3.1 | 508 | 0.68 | 291 | 12.45 | 2.98 | 88.92 |
| | 7 | Baseline | 152 | 417 | 5.5 | 848 | 1.13 | 486 | 16.48 | 0.87 | 88.86 |
| | 7 | Low $NO_x$ | 153 | 430 | 1.9 | 456 | 0.61 | 261 | 14.32 | 1.71 | 89.27 |

TABLE 7

SUMMARY OF ANTI-SLAGGING ADDITIVE TEST RESULTS

| Test No. | Date | Time | | Hours @ Full Load (325-330 MW) | $O_2$, % | $NO_x$ PPM (3% $O_2$) | Test Condition |
|---|---|---|---|---|---|---|---|
| 200 | 6/11/79 | 07:27 | Start | 12 | | | Baseline (No Additive) |
| | | 13:53 | | | 5.0 | 584 | |
| | | 16:16 | | | 5.3 | 599 | |
| | | 19:27 | End | | | | |
| 201 | 6/13/79 | 10:00 | Start | 12 | | | Baseline (No Additive) |
| | | 11:06 | | | 4.7 | 512 | |
| | | 15:36 | | | 5.2 | 566 | |
| | | 22:00 | End | | | | |
| 202 | 6/14/79 | 10:00 | Start | 4.5 | | | |
| | | 13:18 | | | 5.0 | 557 | Baseline (No Additive) |
| | | *14:30 | End | | | | |
| | | 16:15 | Load Cut Back | | | | |
| 203 | 6/18/79 | 07:00 | Start | 12 | | | Baseline (No Additive) |
| | | 08:16 | | | 4.8 | 448 | |
| | | 13:45 | | | 4.8 | 479 | |
| | | 15:58 | | | 4.9 | 517 | |
| | | 19:00 | End | | | | |
| 204 | 6/20/79 | 07:10 | Start | 15 | | | Additive (15 GPH) |
| | | 09:26 | | | 4.5 | 447 | |
| | | 13:35 | | | 4.6 | 473 | |
| | | 16:00 | | | 4.6 | 572 | |
| | | 22:20 | End | | | | |
| 205 | 6/21/79 | 08:15 | Start | 17 | | | Additive (15 GPH) |
| | | 09:38 | | | 5.3 | 514 | |
| | | 13:00 | | | 5.3 | 534 | |
| | | 15:35 | | | 5.7 | 581 | |
| | | 01:15 | End | | | | |
| 206 | 6/25/79 | 09:00 | Start | 12 | - | - | Additive (7.5 GPH) |
| | | 21:00 | End | | | | |
| 207 | | 09:30 | Start | 14 | - | - | Additive (15 GPH Slugs) |
| | | 23:10 | End | | | | |

*SH/RH sprays max. @ 14:30.

TABLE 8

TEST PANEL MEASUREMENTS
(Average Change in Tube Hot Side Wall Thickness)

| Test Panel Number and Location | *Baseline*(1) Operation-5 Mo. (5/76 to 10/76) | | | *Low $NO_x$*(2) Operation-12 Mo. (11/76 to 4/78) | | *"Low $NO_x$"*(3) Operation-4 Mo. (12/77 to 4/78) | | "Mixed"(4) Operation-13 Mo. (5/76 to 11/77) | | | "Mixed"(5) Operation-17 Mo. (5/76 to 4/78) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mils | (n) | Mils/Yr. | Mils | (n) | Mils | (n) | Mils | (n) | Mils/Yr. | Mils | (n) | Mils/Yr. |
| **Non-Burner Area** (20 Feet Below Burners) | | | | | | | | | | | | | |
| 1. Left Wall-Front | -1.9 | (6) | -4.6 | -1.2 | (4) | +1.3 | (20) | -0.2 | (34) | -0.2 | -2.5 | (51) | -1.8 |
| 2. Left Wall-Rear | -2.4 | (8) | -6.0 | +0.4 | (5) | +1.4 | (20) | +0.5 | (34) | +0.5 | -2.1 | (51) | -1.5 |
| (28 feet above burners) | | | | | | | | | | | | | |
| 7. Left Wall-Center | -2.3 | (6) | -5.4 | +1.3 | (5) | +1.1 | (18) | -0.4 | (30) | -0.4 | -1.5 | (42) | -1.1 |
| 8. Right Wall-Center | - | | - | - | | +1.9 | (20) | +0.3 | (34) | +0.3 | -0.4 | (51) | -0.3 |
| Average | -2.20 | (20) | -5.33 | +0.17 | (14) | +1.42 | (78) | +0.05 | (132) | +0.05 | -1.62 | (195) | -1.18 |
| **Burner Area** (Middle Burner Level) | | | | | | | | | | | | | |
| 3. Left Wall-Front | -1.7 | (7) | -4.2 | - 8.7 | (4) | +1.6 | (18) | -14.1 | (30) | -12.9 | -13.0 | (42) | -9.2 |
| 4. Left Wall-Center | -1.5 | (7) | -3.5 | -12.8 | (3) | +1.4 | (18) | -35.0 | (30) | -32.3 | -10.0 | (40) | -7.1 |
| 5. Left Wall-Rear | -4.4 | (5) | -10.6 | - | | +1.4 | (18) | - 1.1 | (30) | - 1.0 | - 3.2 | (42) | -2.3 |
| (Top Burner Level) | | | | | | | | | | | | | |
| 6. Left Wall-Center | -2.6 | (8) | -6.4 | - 9.7 | (4) | +2.4 | (18) | - 7.3 | (30) | - 6.7 | - 9.5 | (45) | -6.7 |
| Burner Area Average | -2.55 | (27) | -6.2 | -10.40 | (11) | +1.70 | (72) | -14.4 | (120) | -13.3 | - 8.92 | (169) | -6.30 |
| Grand Average | -2.40 | (47) | -5.72 | - 5.12 | (25) | +1.56 | (150) | -7.16 | (252) | -6.61 | - 5.28 | (364) | -3.73 |

(n) Number of paired measurements used in calculation average tube wall thickness changes.

(1) 5 tubes per panel. Initial measurements in laboratory; final measurement in the field.
(2) 3 tubes per panel. Initial measurements in the field; final measurements in the laboratory.
(3) *2 replacement tubes per panel. Initial measurement in the field; final measurement in the laboratory.*
(4) 2 tubes per panel. Initial and final measurements made in the laboratory.
(5) 3 tubes per panel. Initial and final measurements made in the laboratory.

TABLE 9

COMPARISON OF FIELD AND LABORATORY MEASUREMENTS

| Panel No.: | Field Measurements: 5 Month Baseline Operation | Field Measurements: 12 Month "Low $NO_x$" Operation | Lab Measurements: 17 Month "Mixed" Operation | Lab Measurements: Estimated 12 Month "Low $NO_x$" Operation* |
|---|---|---|---|---|
| Outside Burners | | | | |
| 1 | -1.9 | -1.2 | -2.5 | -0.6 |
| 2 | -2.4 | +0.4 | -2.1 | +0.3 |
| 7 | -2.3 | +1.3 | -1.5 | +0.8 |
| Average | -2.20 | +0.17 | -2.03 | +0.17 |
| Inside Burners | | | | |
| 3 | -1.7 | -8.7 | -13.0 | -11.3 |
| 4 | -1.5 | -12.8 | -10.0 | -8.5 |
| 5 | (-4.4) | - | (- 3.2) | - |
| 6 | -2.6 | -9.7 | -9.5 | -6.9 |
| Average | -1.93 | -10.40 | -10.83 | -8.90 |

*17 month "mixed" operation minus 5 month baseline operation = estimated 12 month "low $NO_x$" operation measurements.

TABLE 10

## WALL TUBE HOT SIDE METAL THICKNESS CHANGE RATE-MILS/YEAR
(Paired Data)

| LEVEL MEASURED RELATIVE TO BURNERS | BASELINE OPERATION - 5 MONTHS | | | | | "LOW NOx" OPERATION - 12 MONTHS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | FURNACE WALL | | | | FURNACE AVERAGE | FURNACE WALL | | | | FURNACE AVERAGE |
| | LEFT | RIGHT | FRONT | REAR | | LEFT | RIGHT | FRONT | REAR | |
| NON BURNER AREA | | | | | | | | | | |
| 1 | -3.62 | -12.96 | +1.10 | - | -7.49 | -3.89 | +0.81 | -2.92 | -1.50 | -1.94 |
| 2 | -3.24 | -10.66 | -5.74 | -0.31 | -5.66 | -4.45 | +0.07 | -4.04 | -4.10 | -2.96 |
| 6 | -0.30 | - 5.30 | - | -9.05 | -5.74 | -2.48 | +0.04 | - | +0.21 | -0.51 |
| $\bar{x}$ | -3.17 | -10.56 | -3.24 | -3.62 | -6.24 | -3.94 | +0.36 | -3.37 | 1.84 | -2.11 |
| n | 73 | 85 | 22 | 29 | 209 | 102 | 94 | 55 | 89 | 340 |
| sp | 5.57 | 6.47 | 4.59 | 4.86 | 5.78 | 4.71 | 3.40 | 3.47 | 5.43 | 4.42 |
| BURNER AREA | | | | | | | | | | |
| 3 | +1.75 | - 9.41 | -4.27 | -1.49 | -3.24 | -4.99 | -7.14 | -4.31 | -3.46 | -5.48 |
| 4 | +0.10 | - 2.11 | -4.30 | -3.74 | -2.06 | -8.26 | -3.49 | -2.68 | -5.11 | -4.86 |
| 5 | -5.57 | -10.18 | -7.30 | +0.41 | -6.74 | -7.17 | -2.47 | -3.51 | -4.13 | -4.41 |
| $\bar{x}$ | -1.51 | - 6.94 | -5.21 | -1.73 | -3.98 | -6.24 | -5.29 | -3.50 | -4.17 | -5.05 |
| n | 54 | 56 | 29 | 29 | 168 | 83 | 91 | 48 | 54 | 276 |
| sp | 4.49 | 5.59 | 4.80 | 4.13 | 4.88 | 6.77 | 4.78 | 3.71 | 6.00 | 5.55 |
| $\bar{\bar{x}}$ | -2.46 | - 9.12 | -4.36 | -2.68 | -5.23 | -4.97 | -2.42 | -3.431 | -2.72 | -3.43 |
| n | 127 | 141 | 51 | 58 | 377 | 185 | 185 | 103 | 143 | 616 |

## TABLE 11

## COMPARISON OF 5-MONTH BASELINE AND 12-MONTH LOW $NO_x$ AVERAGE TUBE WALL THICKNESS LOSS DATA

| Area | Low $NO_x$ 12 Months Mils, Mils/Year, Mils/$\sqrt{\text{Year}}$ | Baseline 5 Months Mils | Baseline 5 Months Mils/Year | Baseline 5 Months Mil/$\sqrt{\text{Year}}$ |
|---|---|---|---|---|
| **Nonburner:** | | | | |
| Left Wall | -3.94 | -1.32 | -3.17 | -2.04 |
| Right Wall | +0.36 | -4.40 | -10.56 | -6.82 |
| Front Wall | -3.37 | -1.35 | -3.24 | -2.09 |
| Rear Wall | -1.84 | -1.51 | -3.62 | -2.34 |
| Total | -2.11 | -2.60 | -6.25 | -4.03 |
| Less Right Wall | -3.05 | -1.37 | -3.30 | -2.12 |

-4.6 to -1.5   95% simultaneous confidence limits

| Area | Low $NO_x$ 12 Months Mils, Mils/Year, Mils/$\sqrt{\text{Year}}$ | Baseline 5 Months Mils | Baseline 5 Months Mils/Year | Baseline 5 Months Mil/$\sqrt{\text{Year}}$ |
|---|---|---|---|---|
| **Burner:** | | | | |
| Left Wall | -6.24 | -0.063 | -1.51 | -0.98 |
| Right Wall | -5.29 | -2.89 | -6.94 | -4.48 |
| Front Wall | -3.50 | -2.17 | -5.21 | -3.36 |
| Rear Wall | -4.17 | -0.72 | -1.73 | -1.12 |
| Total | -5.05 | -1.66 | -4.00 | -2.58 |

-6.0 to -4.1   95% simultaneous confidence limits

TABLE 12

QUALITATIVE SUMMARY OF CORROSION MEASUREMENTS

| Method Used to Obtain Corrosion Measurements | | Baseline Operation | Low $NO_x$ Operation | Low $NO_x$ vs. Baseline Operation |
|---|---|---|---|---|
| 1. Furnace Wall Tubes (Ultrasonic) | | Burner area equal to nonburner area | Burner area loss greater than non-burner area loss | Low $NO_x$ loss $>$ base-line within burner area |
| 2. Test Panel Tubes (Ultrasonic) | | No significant differences (except panel No. 5) | Burner area loss greater than non-burner area loss | Low $NO_x$ loss $>$ base-line within burner area. Low $NO_x$ loss $<$ baseline outside burner area |
| 3. Probe Coupons (Weight) | One Day Exposure | Burner area loss greater than non-burner area | Burner area loss greater than $NO_x$ burner area loss | No significant difference |
| | 10-42 Days Exposure | No significant difference | No significant difference | No significant difference |

# COMBINED-CYCLE POWERPLANT EMISSIONS

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ABSTRACT

The retrofit of existing utility steam boilers with a combustion gas turbine to supply hot vitiated combustion air to the windbox of a fired boiler, in place of the normal forced-draft fans and air preheaters (i.e., repowering), can lead to increased power output at improved heat rates. A major consideration in converting to combined-cycle operation is the impact on the nitrogen oxides ($NO_x$) emissions from the system.

A field test program was conducted to determine the $NO_x$ characteristics of a 220-MW supplementary-fired unit. A primary objective was to determine the fraction of the gas-turbine-generated $NO_x$ that can potentially be reduced upon passage through the combustion zone of the boiler. As part of this test program, the boiler was operated in a low-$NO_x$, staged-combustion configuration by removing selected burners from service.

Baseline $NO_x$ emissions from the combined-cycle system were found to be substantially lower than $NO_x$ emissions from the boiler alone when operated with ambient air supplied by forced-draft fans: 1.4 lb $NO_2$/MW-hr compared to 2.3 lb $NO_2$/MW-hr at boiler loads of 190 MW and 200 MW, respectively. In a staged-combustion configuration with four of twenty burners removed from service, the combined-cycle $NO_x$ emissions were reduced to 0.9 lb $NO_2$/MW-hr.

The fraction of gas-turbine-generated $NO_x$ reduced upon passage through the combustion zone of the boiler was determined by doping the gas turbine fuel with nitrogen (ammonia) to artificially vary the boiler inlet $NO_x$ levels during combined-cycle operation. The results showed that during normal operation of the combined-cycle system with all burners in service, 10 to 28 percent of the $NO_x$ produced by the gas turbine was reduced (destroyed) in the supplementary fired boiler. During operation of the boiler in a combustion configuration staged by removing four burners from service, a greater portion of the gas-turbine-generated $NO_x$ was reduced in the boiler.

## ACKNOWLEDGMENT

This project was sponsored by the Electric Power Reserach Institute (project RD 782) and conducted by KVB, Inc., the Babcock and Wilcox Company, and General Electric Company. KVB, Inc. appreciates the cooperation and efforts extended on the project by the B&W staff (D. Anaki, G. Brechun and E. Campobenedetto), and General Electric.

Also we are very appreciative of the cooperation and technical support of the Oklahoma Gas and Electric Company which provided a combined-cycle unit for testing during this program: Horseshoe Lake Station Unit 7. The station engineering and operating staff at Horseshoe Lake was very helpful in equipment installation, instrumentation, establishment of numerous modified operating modes, net heat rate determinations, control system analysis, and engineering support.

## SECTION 1

## INTRODUCTION

The retrofit of existing utility steam boilers with a combustion gas turbine to supply hot vitiated combustion air to the windbox of a supplementary-fired boiler in place of the normal forced-draft fans and air preheaters (i.e., repowering), can lead to increased power output at improved heat rates. One of the main considerations in converting to combined-cycle operation is the impact of this modification on the $NO_x$ emissions from the system. The purpose of the study reported in this paper was to assess the $NO_x$ characteristics of a supplementary-fired combined-cycle system and the effectiveness of combustion modifications to the boiler in reducing $NO_x$ emissions.

Prior EPRI-sponsored research projects have indicated that there can be emission as well as efficiency benefits in certain combined-cycle operating modes. Specifically, a combined-cycle system has the potential of operating with substantially lower emissions of $NO_x$, CO, hydrocarbons, and smoke compared to a gas turbine and a boiler operating separately (1-2) or even compared to a boiler operating with some degree of combustion modifications for $NO_x$ control. In the case of $NO_x$, the gas turbine exhaust products with reduced oxygen content (approximately 17 percent $O_2$), supplied to the windbox of the associated boiler, provide some of the benefits that normally would be obtained with flue gas recirculation into the combustion air of a conventionally-fired boiler. This effect would generally outweigh the $NO_x$ disadvantage of higher windbox temperatures encountered in the combined-cycle boiler as compared to a conventional boiler (typically 1000°F compared to 650°F). Thus, the $NO_x$ produced in the boiler of a combined-cycle system will be less than that produced utilizing a conventional preheated combustion air system. Furthermore, laboratory-scale tests have indicated that the application of two-staged combustion to the boiler could lead to additional $NO_x$ reductions of up to 55 percent from a supplementary-fired combined-cycle system (2). This reduction would be accomplished by operating the burner flame zone of the associated boiler in a low-$NO_x$ staged-combustion mode where local regions in the boiler are operated fuel-rich. The staged combustion mode not only reduces $NO_x$ formed in the boiler but also leads to partial destruction of gas-turbine-generated $NO_x$ as it passes through the fuel-rich region.

Although the repowering concept is very attractive from both a heat rate and emissions standpoint, there has been a lack of full-scale operational data from existing combined-cycle installations to confirm the laboratory-scale results for $NO_x$ control. The application of two-stage combustion is the key element in emissions reduction. Therefore, the principal objective of this test program was to obtain full-scale data to confirm the feasibility of reducing gas-turbine-generated $NO_x$ in the fuel-rich flame of the associated boiler.

Oklahoma Gas & Electric's Horseshoe Lake Plant was selected since the combined-cycle unit at this station has one of the largest supplementary-fired boilers permitting flexibility in establishing low-$NO_x$ operating modes.

During this study, both the gas turbine and boiler were fired with natural gas, due to the unavailability of fuel oil at the time. Although this might be viewed as a shortcoming of this work in light of current utility fuel trends, it is believed that the results may be semi-quantitative for liquid fuels as well.

## PROGRAM APPROACH

To accomplish the major program objectives, it was desirable to establish not only the total combined-cycle $NO_x$ emissions with modified combustion modes applied to the boiler, but also to determine the specific reductions in turbine-generated $NO_x$ in the fuel-rich boiler flame zone and the reduction in boiler-generated $NO_x$. A characterization of the amount of turbine-generated

$NO_x$ reduced in the boiler under varied boiler operating modes and principal test parameters (load, burner air/fuel ratios, etc.) could then be used to predict emissions reductions at other existing or proposed combined-cycle units. It should be noted that these results are for a natural-gas-fired system. Oil fuel $NO_x$ emissions reductions with modified combustion modes more frequently depend on boiler firing configuration than those with natural gas fuel.

An important aspect of the field testing at Horseshoe Lake was to isolate the contributions to the total combined-cycle stack emissions by the boiler and gas turbine. Since gas turbine emissions can be conveniently measured at the boiler windbox inlet, and combined-cycle emissions are readily measured at the stack, a determination of the boiler's contribution to $NO_x$ emissions appears to be the only obstacle to determining the final contribution of the gas turbine to the stack emissions. That is (combined-cycle stack $NO_x$) - (boiler NO contribution) = (net or final turbine $NO_x$).

The Horseshoe Lake unit was equipped with back-up forced-draft fans capable of providing full-load boiler combustion air requirements, so it might intially appear that the boiler contribution to total $NO_x$ emissions could conveniently be determined by operating the boiler alone with the FD fans. However, this is not the case for two important reasons: (1) the combustion air temperature would be ambient with only the forced-draft fans instead of 900°F when operating with the gas turbine (boiler air preheaters were not provided); and (2) the unpreheated combustion air would contain 21 percent oxygen instead of the approximately 17 percent oxygen present in the gas turbine exhaust. Both air preheat temperature and combustion air oxygen content (or equivalent gas recirculation rate) are known to have an important influence on NO formation, particularly on gas fuel. Accurate means do not exist to predict the effect of these two variables; hence, calculating the boiler-produced $NO_x$ with combined-cycle operation using the data obtained with forced-draft fan operation was not feasible.

The only practical approach was to preserve the desired boiler inlet preheat and combustion air oxygen content while varying the inlet gas turbine NO, thus generating a plot of stack total NO emissions as a function of gas turbine inlet NO to the boiler. In this fashion, the boiler contribution to the total combined cycle (stack) $NO_x$ was obtained by extrapolating to a hypothetical condition of zero gas turbine $NO_x$. This is illustrated in Figure 1.

Because the normal range of turbine operating parameters did not give the desired range of inlet $NO_x$ levels to the boiler, doping the gas turbine fuel with ammonia ($NH_3$) was selected as a practical way to artificially increase $NO_x$ for purposes of this test. $NH_3$ reacts with oxygen in the gas turbine combustor, producing $N_2$, $NO_x$, and $H_2O$ as the reaction products; in effect, it acts as a fuel nitrogen compound.

The principal boiler operating mode test parameters were load, excess air level, burner air/fuel ratio, and burner firing pattern. The test program was designed to provide answers to the following questions:

- To what degree can combined-cycle $NO_x$ emissions be reduced by implementation of two-stage combustion in the boiler?
- What portion of the $NO_x$ reduction is attributable to reduced $NO_x$ formation in the boiler and what portion is due to destruction of turbine-generated $NO_x$?
- How dependent is the $NO_x$ reduction on boiler burner firing pattern, excess air level, load, etc., and to what degree are these parameters coupled?
- What potential operational problems, impacts on efficiency, etc., may exist with the implementation of this approach?

A number of limitations in the operating configuration of the boiler were dictated by the gas turbine, which is essentially a constant-volume-flow device with virtually no turndown capability. Because of this the excess-oxygen-versus-load dependence of the boiler is essentially fixed, by the size of the turbine, to provide all the boiler combustion air at full boiler load. At reduced boiler loads, some of the excess combustion air must be directed into the boiler hopper or dumped to the atmosphere.

Although this study is particularly relevant to the repowering of existing gas- and oil-fired plants, there is a wide range of concepts or interpretations of the term "repowering." As we have said, the elementary approach is substitution of a gas turbine for the forced-draft fans so that the turbine exhaust satisfies the boiler's combustion air requirements are full load. Other considerations, in addition to emissions, are (1) modifications to the windbox to accommodate 900°F+ preheat, (2) additional boiler pressure drop and added heat load in the convective section, (3) physical space for the added gas turbine, and (4) added combustion controls to integrate turbine and boiler firing with accommodations for continued boiler operation with gas turbine loss (3).

A complex approach to repowering is to add gas turbine capacity in excess of that required for the burners in the supplementary-fired boiler, using the boiler convective sections to absorb the extra heat load. This can be accomplished by bypassing the burner regions with a portion of the gas turbine flow and discharging it into the boiler through tempering ports at the top of the radiant or furnace section (3). Other considerations include the ability of the boiler steam circuits to absorb the additional heat load, possible substitution of convective sections, and steam turbine load capacity.

In the more extreme cases of repowering, the boiler may have reached the limits of its serviceable life or it is an inefficient low-pressure, low-reheat design and it is therefore practical to totally replace it with a new waste heat boiler. The existing steam turbine is usually left intact. For these applications, other options must be evaluated: whether the boiler should be supplementary-fired and what power split is most efficient between the gas turbine and the steam turbine output. These are the considerations involved in new combined-cycle unit design; frequently it is more effective not to fire the new boiler. The reader is referred to EPRI Report FP-862 (3) for a more detailed discussion of these considerations from the efficiency and emissions standpoints. Other considerations are existing steam turbine capacity, unit maintenance and life cycle costs, and lost generation during repowering construction.

This paper deals with the current combined-cycle system at Oklahoma Gas and Electric, Horseshoe Lake Station, which was designed so that the turbine exhaust provides all the boiler combustion air. Therefore, these results are directly applicable to the elementary repowering approach of direct substitution for the forced-draft fans. With some caution in interpretation, these results could also be applied to the case of additional gas turbine bypass into the upper furnace region as long as this flow does not influence boiler combustion conditions or emissions.

The final configuration already discussed requires repowering with a new <u>unfired</u> waste heat boiler and thus does not directly relate to the combined-cycle configuration tested during this program. Emissions are directly dependent on the most recent advances in gas turbine combustor design. Nor will these results be directly applicable to repowering situations where duct burners are used to heat the gas turbine exhaust only 100 to 300°F. In this latter case, the duct burner fuel combustion consumes only a minimal amount of the oxygen in the gas turbine exhaust, with the majority of the gas turbine flow effectively bypassing the burners.

## SECTION 2

## COMBINED-CYCLE SYSTEM DESCRIPTION

Oklahoma Gas & Electric's Unit No. 7, placed in service in 1963, is a 220-MW combined-cycle system incorporating a General Electric frame 8 gas turbine and a front-wall-fired Babcock & Wilcox boiler with the following general characteristics:

| | |
|---|---|
| Gas turbine: | Maximum output 25 MW |
| Boiler: | Maximum continuous steam flow 1,286,000 lb/hr<br>Maximum continuous output 205 MW gross |
| Combined cycle: | Heat rate 9629 Btu/kW-hr<br>(at 219.3 MW net station output, natural gas fired) |

The gas turbine exhaust normally provides all the oxidizer to the boiler. Two forced-draft fans furnish combustion air to the boiler when the gas turbine is not operating. Under normal operation, these fans also supplement the turbine exhaust from the most economical load of approximately 1,145,000 lb steam/hr to the top load of 1,339,000 lb steam/hr. No air preheating, other than turbine exhaust, is provided for the boiler; ambient-temperature air is used for combustion when the gas turbine is out of service.

A large economizer instead of an air preheater lowers the stack temperature to nominally 321°F. With the gas turbine operating, all of its exhaust must either pass through the burner region or the furnace hopper bottom. (Gas tempering ports to bypass turbine exhaust to the boiler convective section were not in service, and a turbine startup bypass duct to the atmosphere was not sufficient to handle the full turbine exhaust flow.)

## GAS TURBINE SYSTEM

The gas turbine generator is a General Electric Company frame 8 two-shaft turbine rated at 25,000 kW with an 80°F compressor inlet temperature and 14.17 psia at the compressor inlet and turbine exhaust flange. At rated conditions, the high-pressure turbine (which drives the compressor) turns at approximately 3285 rpm. Gas temperature at the inlet to the first-stage nozzles is 1500°F; the exhaust temperature is 870°F. This gas turbine unit has no provisions for $NO_x$ control.

Control of the gas turbine fuel flow is dictated by control of the exhaust gas temperature within specified limits. The control system is such that, if ambient conditions change, the electrical load from the gas turbine generator will change since the gas turbine compressor, running at constant speed, will pump a constant volume, but not constant weight or air.

No other means is employed to vary the steam generator excess air. The gas turbine output depends on ambient temperature only. Air tempering dampers installed with the unit to permit turbine exhaust bypass to the boiler convective section are not in use, and a bypass duct which diverts the turbine exhaust to a separate stack is used only for startup.

## BOILER SYSTEM

The steam generator is a front-wall-fired Babcock & Wilcox radiant-type boiler with a nominal rated steam flow of 1,286,000 lb/hr (205 MW). The physical configuration of the combined cycle unit is shown in Figure 2. The pressurized furnace is normally fired with natural gas fuel, with oil on standby. The 20 center-fire Laredo-type burners are arranged in a four-wide by five-high pattern as shown in Figure 3. Steam temperature control is by means of spray attemperation and flue gas recirculation into the hopper bottom of the furnace. Outlet superheat and reheat steam temperatures are 1005°F and 1005°F, respectively.

Over most of the combined-cycle load range, the gas turbine supplies all the combustion air for the steam generator. However, combustion air is supplemented by forced-draft fans at boiler loads about 180 MW, depending on the ambient temperature. At steam turbine gross loads below about 150 MW, the excess air level at the burners becomes excessively high. When this occurs, dampers are opened to divert some of the gas turbine exhaust into the bottom hopper of the boiler, reducing the $O_2$/fuel ratio through the burners.

## AMMONIA INJECTION SYSTEM

A system was devised for injecting ammonia ($NH_3$) into the fuel (not the exhaust) system of the gas turbine so that the turbine exhaust $NO_x$ level could be varied from approximately 50 to 100 ppm (dry at 15 percent $O_2$). The $NH_3$ reacted in the gas turbine flame to form $NO_x$, $N_2$, and $H_2O$, greatly increasing the total $NO_x$ output when injected in small concentrations. The limit of 100 ppm was chosen since in a prior laboratory study (2) it had been shown that the gas turbine reduction factor was independent of the initial $NO_x$ level up to 100 ppm, and data were not available to confirm the independent relationship at levels much greater than 100 ppm. The ammonia was sprayed as a liquid upstream against the direction of the natural gas flow at a point just after the gas line control valve and just prior to a "T" in the line which carried the gas to either side of the circular gas header to the combustor cans. Subsequent evaporation of the maximum $NH_3$ flow in the fuel supply line would cool the natural gas by 5°F at most.

## GASEOUS EMISSIONS SAMPLING SYSTEM

Boiler flue gas was sampled at the stack with six three-point probes. Multi-point water-filled gas bubblers were used to obtain a composite flue gas sample. The flue gas was drawn into the bubbler with an air aspirator. The gas was analyzed with a Dynascience $NO_x$ analyzer, Beckman $O_2$ and CO analyzers, and an Orsat analyzer.

The gas turbine exhaust was sampled at the turbine outlet just before it divides to supply the north and south sides of the boiler. Nine probes were installed in the turbine exhaust duct. NO/$NO_x$ measurements at the turbine exhaust were made with a Thermo-Electron chemiluminescent analyzer. Other gaseous measurements were made with the following analyzers: Teledyne

Model 326A, $O_2$; Horiba Model A1A-21 NDIR, $CO_2$; and Beckman Model 315A NDIR, CO.

## SYSTEM TEST CONFIGURATIONS

The test program comprised a series of tests over a wide range of system configurations. This included both combined-cycle and single cycle operation (forced-draft fans only, no preheat). Staged combustion was also investigated on both basic configurations. Table I outlines the system configurations and range of variables investigated.

A more extensive test program was initially planned than is outlined in Table I to investigate boiler performance and emissions over a wider range of load and firing configurations. Unfortunately, the difficulties encountered in gas turbine firing rate control with $NH_3$ injected into the fuel could not be resolved, and the extent of the resulting test data, although sufficient to accomplish major project objectives, is considerably less than what was initially desired for a thorough study of the topic.

## DATA REDUCTION

Before discussing data reduction methods it is appropriate to briefly reiterate the basis for which emissions reductions for combined-cycle systems are being calculated. We are concerned with $NO_x$ emissions control or $NO_x$ reduction potential, so it is important to establish the conventional baseline operating configurations to which the reduced emissions operating mode is being compared.

There are two basic measure of interest in combined-cycle emissions in the current study:

1. Reduction in total stack emissions by implementing staged combustion in the boiler using as-found combined-cycle emissions as a baseline.

2. Reduction in gas turbine emissions by the more fuel-rich boiler flame zone; judged by comparison to the initial gas turbine exhaust $NO_x$ level.

The latter gas turbine $NO_x$ reduction potential can be expressed as:

$$r = 1 - \left[ \frac{\dot{M}_{NO_{x\,stack}} - \dot{M}_{NO_{x\,boiler}}}{\dot{M}_{NO_{x\,gas\ turbine}}} \right]$$

where:

$r$ = fraction of oxides of nitrogen produced in the gas turbine which is destroyed in passing thorough the boiler

$\dot{M}_{NO_{x\,stack}}$ = mass emission rate of oxides of nitrogen in the combined cycle exhaust products (lb/hr)

$\dot{M}_{NO_{x\,boiler}}$ = mass emission rate of oxides of nitrogen produced by the boiler while fired with gas turbine exhaust with no inlet nitric oxide (lb/hr)

$\dot{M}_{NO_{x\,turbine}}$ = mass emission rate of oxides of nitrogen from the gas turbine (lb/hr).

The interrelationship of these terms is shown in Figure 4.

A clear distinction should be made of the basis upon which the combined-cycle system emissions are compared. This requires that boiler operating conditions be clearly stated:

(a) The emissions from a boiler operating normally without flue gas recirculation but with preheated combustion air (21 percent $O_2$, approximately 600°F).

(b) The emissions from a boiler operating without flue gas recirculation but with combustion air at ambient temperature (21 percent $O_2$, approximately 70°F).

(c) The hypothetical emissions from a boiler operating on gas turbine exhaust that has all the normal characteristics except zero $NO_x$ content (approximately 17 percent $O_2$ and 900°F).

Case (a) above would be of interest as representative of the current emissions of a boiler being considered as a candidate for "repowering."

Case (b) is unlikely to be encountered in normal utility practice but is of interest in terms of plant emissions when the gas turbine is out of service. It also was investigated during the current program as an operating configuration that would provide more insight into the emissions reduction potential of low $NO_x$ firing modes in the boiler.

Case (c) is the hypothetical condition necessary to calculate the gas turbine $NO_x$ reduction factor as indicated in the previous equation. It is desirable to isolate the effect of the boiler flame zone conditions on the destruction of the turbine exhaust $NO_x$ from the overall unit NO emissions so that the results of this study can be generalized to other combinations of turbine and boiler $NO_x$. Otherwise, the study conclusions would be applicable only to repowering cases having similar boiler and candidate gas turbine emissions.

This raises the subject, touched on previously, of the possible dependence of the $NO_x$ reduction factor on the gas turbine exit or boiler inlet $NO_x$ level. The subscale laboratory study (1-2) showed that the $NO_x$ reduction factor (r) was not a function of the $NO_x$ levels in the gas turbine exhaust, at least up to concentrations of 100 ppm (at 15 percent $O_2$). Data were not available to assess whether or not the reduction factor was independent of the boiler inlet $NO_x$ levels above 100 ppm. Based on the assumption that the reduction factor is independent of inlet $NO_x$ level, the resulting nitric oxide emissions from the combined cycle would plot linearly versus gas turbine NO and could be linearly extrapolated to a condition of zero $NO_x$ in the gas turbine exhaust, thus determining boiler-produced $NO_x$. This approach was followed in the reduction of Horseshoe Lake field test data and indeed did confirm the assumption that the reduction factor is independent of gas turbine $NO_x$ concentration.

The primary step in the data reduction procedure was the calculation of the gas turbine $NO_x$ reduction factor. To do this it was necessary to express all oxides of nitrogen emissions on a mass flow (lb/hr) basis. Other quantities which were calculated from the measured parameters include the gas turbine and boiler air/fuel ratios (or stoichiometric ratios), and the approximate stoichiometric ratios at the burners while operating in a staged combustion configuration. The resulting data of stack $NO_x$ versus gas turbine $NO_x$ was plotted and the data extrapolated to zero gas turbine $NO_x$.

This plot of stack $NO_x$ versus gas turbine $NO_x$ for a typical test condition is shown in Figure 5. For this particular case the tests show that the boiler would have produced 115 lb/hr of oxides of nitrogen if it had been fired with gas turbine exhaust with no $NO_x$ present (intercept). Also, the test results indicate that for this configuration, 49 percent of the oxides of nitrogen produced in the gas turbine were destroyed upon passing through the supplementary-fired boiler (i.e., r = 49 percent).

## SECTION 3

## TEST RESULTS AND INTERPRETATION

### BOILER-ONLY TESTS

The boiler-only tests provide an understanding of the responsiveness of the unit to load variations, changes in excess oxygen, and burner-out-of-service patterns for low $NO_x$ emissions. Performing these tests with the forced-draft fans prevents problems in data interpretation introduced by the gas turbine and allows an assessment of the boiler's behavior. These tests were also conducted to select an effective pattern of burners out of service to be used during the combined-cycle tests. Finally, the data obtained when the boiler was operated with only the forced-draft fans provided a common basis of comparison with the combined-cycle emissions. As previously mentioned, this does not allow a totally valid comparison with normal utility boiler operation as the combustion air is not preheated in this unit when operating with the forced-draft fans. Since $NO_x$ formation, particularly for natural gas firing, is a direct function of the combustion temperatures and air preheat, the $NO_x$ emissions for the boiler-only tests with no air preheat are expected to be lower than would be emitted from a unit with combustion air preheated (nominally 600°F).

The sensitivity of the $NO_x$ emissions to excess oxygen levels and load for single-stage (ABIS: all burners in service) and staged combustion (BOOS: burners out of service) is shown in Figure 6. At a load of 169 MW, increasing the stack $O_2$ level from 2 to 4 percent resulted in an 8 percent increase in NO levels. At the lower load of 130 MW, the unit exhibited little sensitivity to excess oxygen changes with only a 4 ppm increase in $NO_x$ as the $O_2$ level in the stack was increased from 3.9 to 5.0 percent. If the unit had been operated with the combustion air preheated to 600°F, it is estimated that boiler emissions could be two to three times higher than measured during this program with ambient temperature combustion air.

Staged combustion was implemented by removing burners from service. This entailed terminating the fuel flow to selected burners while maintaining load, resulting in an increase in fuel flow to the remaining in-service burners. The nominal air flow was maintained through the out-of-service burners (registers open). Staged combustion tests were conducted with forced-draft fan operation to determine the overall sensitivity of the unit to staging and identify the burner patterns to be used during the combined-cycle tests. Again, during these tests, the boiler overall excess air level was maintained at the same level as in the normal all-burners-in-service operating mode, and the minimum excess air limit was not determined for each burner pattern tested. During combined-cycle operation, the stack $O_2$ level was determined by the power split between the gas turbine and supplementary-fired boiler and was not at the discretion of the operator. These test results are summarized in Table II.

In performing these tests, burner air registers were open to their normal open position (60 to 70 percent) whenever burners were taken out of service. The burner pattern testing focused on removing burners from the top two rows, either the entire row--13, 14, 15, 16; 17, 18, 19, and 20--or the two middle burners of each row--14, 15 or 18, 19. (See Figure 3 for the burner numbering system.) Previous studies (4) have shown that removing burners from the upper rows is more effective in reducing $NO_x$ than removing bottom rows of burners, but it was beyond the scope of the present program to explore all possible burner patterns for this unit. This is consistent with the objectives of the program in investigating the combined-cycle $NO_x$ emission reduction potential (in particular the reduction of the gas-turbine-generated $NO_x$ through staged combustion in the boiler). Since time was insufficient to explore the $NO_x$ reduction potential of all burner patterns, a burner pattern was sought that resulted in $NO_x$ reductions that were typical (not necessarily optimum) of previous experience with gas-fired utility boilers. Further, it is not currently known whether a burner pattern which produces minimum $NO_x$ with forced-draft fan operation necessarily results in the largest reduction in gas-turbine-generated $NO_x$. Previously reported laboratory studies (1-2) indicate that the gas turbine $NO_x$ reduction increases as the stoichiometric ratio of the in-service burners decreases.

Removing the middle burners of a row from service (14, 15) resulted in a $NO_x$ reduction of 25 percent at a load of 169 MW (Test 15). When the middle burners of the top row (18, 19) were removed from service, the $NO_x$ reduction was only 2 percent (Test 3); these tests were conducted at a higher overall boiler excess air level. Based on the $NO_x$-versus-$O_2$ characteristic shown in Figure 6, the differences in the excess $O_2$ level may have accounted for 25 ppm or 14 percent of the reduction.

When four burners were removed from service, the $NO_x$ reductions obtained were not highly dependent on whether the top row or second row was removed. At a load of 169 MW and nominal stack $O_2$ level of 4 percent, a 22 percent reduction in $NO_x$ was measured with the top row out of service and 24 percent reduction in $NO_x$ with the second row from the top removed from service. When reducing the stack $O_2$ level to 2.25 percent at 168 MW (Test 14) the $NO_x$ reductions increased to 43 percent with the second row from the top out of service (13, 14, 15, 16).

Because removing from service either two burners or four burners of the second row from the top resulted in $NO_x$ reductions typical of those achieved in other gas-fired utility boilers, this pattern was selected for use during the combined-cycle tests.

## COMBINED-CYCLE TEST RESULTS

The primary objectives of the combined-cycle tests were to evaluate the potential for destroying a portion of the $NO_x$ generated in the gas turbine and to determine the relationship between this destruction process and the boiler operating configuration. The boiler configurations evaluated included:

- Baseline operation (all burners in service).
- Staged operation (burners 13, 14, 15, and 16 out of service).
- Low load, with turbine exhaust bypass through the ash hopper.

The results of these tests are summarized in Table III. Each test series represents a fixed turbine operating condition and set boiler configuration (i.e., excess $O_2$, load, burner pattern). For each test series a number of tests were conducted. The different test numbers in a series vary only the gas turbine exhaust $NO_x$ level by varying the $NH_3$ injected into the gas turbine fuel. In the table the gas turbine emissions and combined-cycle stack emissions are reported for conditions with no ammonia doping of the gas turbine fuel.

Although a number of different boiler operating configurations were tested to characterize the $NO_x$ destruction in the boiler flame, the gas turbine was operated at relatively constant conditions throughout the test series.

In analyzing combined-cycle test results, the following aspects need to be assessed:

- Stack $NO_x$ emissions rate and the effect of operating conditions.
- Boiler contribution to the stack $NO_x$ emission rates.
- Gas turbine reduction factor.

First, consider the stack $NO_x$ emissions from the combined cycle. For normal combined-cycle operations, the stack $NO_x$ emission rates were substantially lower than those when the boiler was operated with only the forced-draft fans. For example, comparing Tests 17 and 47 indicates that at a boiler load of about 200 MW the combined cycle emits 305 lb/hr of $NO_x$ (as $NO_2$) whereas single-cycle operation with the forced-draft fans yielded stack $NO_x$ emissions of 467 lb/hr. Combined-cycle emissions are 35 percent lower, even when compared to operation with cold boiler air.

$NO_x$ emissions from the combined cycle are substantially lower if they are normalized on a unit load basis as shown in Table IV and Figure 7a. In Table IV and Figure 7a, the emissions are normalized by the load of the specific device. Thus, for single-cycle operation, the boiler emissions are normalized by the boiler load, the gas turbine by the gas turbine load and, for combined-cycle operation, the emissions are normalized by the combined-cycle load (boiler plus gas turbine).

$NO_x$ emissions are plotted on a mass-emission-rate basis in Figure 7b, illustrating an interesting comparison to the $NO_x$ emissions normalized on an output-load basis. First, it can be seen that for single-cycle operation, the mass emission rate from the gas turbine was substantially less than the $NO_x$ emission rate from the boiler. Second, the emissions reduction with combined-cycle operation compared to single-cycle operation was primarily due to a reduction in the emissions from the boiler. Finally, with staged-combustion operation of the combined cycle (4 BOOS), the $NO_x$ emissions were reduced by 36 percent compared to combined-cycle operation with all burners in service. This 36 percent $NO_x$ reduction was a result of a 40 percent reduction in the boiler emissions and a 27 percent reduction in the $NO_x$ contribution from the gas turbine. Thus, even though a substantial fraction of the gas-turbine-generated $NO_x$ was destroyed in the boiler, the overall $NO_x$ reduction from combined cycle operation with the implementation of staged combustion was primarily due to reductions in the $NO_x$ contribution from the boiler.

It should be noted that the single-cycle emissions in Table II were obtained at an excess oxygen level approximately 1 percent higher than the combined cycle operating mode. Even if the results were normalized to a common $O_2$ level, this would reduce the single-cycle emissions by about 10 percent, indicating that the combined-cycle emissions are still substantially lower.

For normal operation of a typical natural-gas-fired utility boiler, the $NO_x$ emissions were estimated to be up to two to three times higher than the 2.3 lb $NO_2$/MW-hr tabulated in Table IV due to the use of combustion air preheat, which was not used in this case.

Similar comparisons can be made at other loads from Tables II and III, with similar conclusions. Two factors affected the $NO_x$ emissions from the combined-cycle configurations, in addition to the fact that the oxidizer stream (gas turbine exhaust) contained $NO_x$. The primary factor was the presence of combustion products in the oxidizer stream ($CO_2$ and $H_2O$) which acted as inerts and reduced the oxygen concentration in the boiler oxidizer flow to 16.6 percent $O_2$ compared to 21 percent. This was equivalent to approximately 26 percent flue gas recirculation. The diluent effect resulted in reduced flame temperatures and lower $NO_x$ formation in the boiler, similar to flue gas recirculation. Second, counteracting this effect was a gas turbine exhaust temperature of 800°F, whereas with the forced-draft fans the air was at ambient temperature. However, the results suggest that the effect of preheat temperature was less compared to the reduced oxygen content. This may not be the case for an oil-fired unit with high fuel nitrogen content as it is generally known that flue gas recirculation with high nitrogen fuels (e.g., residual oil) is less effective than with natural gas fuel.

Next consider the effect of a staged boiler operating configuration on stack $NO_x$ emissions from the combined-cycle operation. At the high boiler load condition (190 to 198 MW), removing four burners from service resulted in a 36 percent reduction in $NO_x$ emissions. It should also be noted that the boiler $O_2$ dropped to 1.9 percent during the tests with four burners out of service at a load of 198 MW compared to the baseline $O_2$, which was in the range of about 2.7 percent at 190 MW. This should result in a further $NO_x$ reduction beyond just removing the four burners from service at the same $O_2$ level, as indicated in the general behavior of the unit with excess air (forced-draft fan operation) as depicted in Figure 6. Thus the 36 percent $NO_x$ reduction was due to both removing four burners from service and reducing the $O_2$ level from 2.7 to 1.9 percent. It was not possible to independently control the overall boiler $O_2$ and the load during the combined-cycle operation and thus establish the relationship between boiler excess $O_2$ and combined-cycle $NO_x$ emissions at a fixed load. This limitation exists because the gas turbine is essentially operated at a fixed condition with all of the combustion products fed to the boiler. The boiler load, or fuel flow, determined the flue gas oxygen concentration.

At the lower boiler load (150 MW) the stack NO emissions were not altered by removing four burners from service (compare Tests 27-29 and 33-34). A major contributing factor appears to be the unexpected increase in boiler-produced NO accompanying staged combustion. Although no clearcut explanation can be offered for this, as it is contrary to the behavior with the forced-draft fan operation, the excess oxygen level was high (6.2 percent) during these combined-cycle tests. So, even with four burners out of service, the in-service burners were still operating with excess oxygen.

During Tests 30-32, an attempt was made during combined-cycle operation to lower the air/fuel ratio at the burners by diverting a portion of the gas turbine exhaust away from the burners and adding it through the bottom hopper as the only available means to simulate low-excess-air operation at the burners. As seen in Table III, this resulted in a 28 percent increase in $NO_x$ emissions. In actuality, this configuration did not simulate low-excess-air operation as visual observation showed that the bypass flow through the hopper flowed up the furnace walls into the burner region. This appears to have resulted in enhanced mixing with the burner flow, producing more intense flames. This in turn resulted in higher $NO_x$ formation in the boiler; none of the gas-turbine-produced $NO_x$ was destroyed with this configuration.

Next consider the reduction of the gas-turbine-generated $NO_x$ which occurred in the boiler. The test results for normal and low $NO_x$ combined-cycle operating modes showed that from 10 to 49 percent of the $NO_x$ generated in the gas turbine was destroyed upon passage through the boiler. The specific reduction factors are tabulated as (r) in Table III. At a boiler load of 150 MW, the reduction factor increased from 10 to 27 percent when four burners were removed from service. However, it can be noted in Table III that while the reduction factor increased, the boiler-produced $NO_x$ apparently increased, resulting in no change in the stack $NO_x$ emission rate. No definitive explanation of this result is presently available. As discussed above, with bypass through the ash hopper to simulate low-excess-air operation at the burners, none of the gas turbine $NO_x$ was destroyed in the boiler.

The reduction factors measured at the higher load conditions (188 to 198 MW, baseline) exhibited a similar trend. During Tests 27 and 28 with all burners in service, the test results indicated that 28 percent of the turbine $NO_x$ was destroyed. With four burners out of service, the reduction factor was determined to be 49 percent. This, coupled with a 40 percent reduction in the boiler-generated $NO_x$ as a result of the staged combustion mode, produced the overall 36 percent reduction in stack $NO_x$ emissions. It should be noted that between Tests 37-38 and 23-26 there was a decrease in excess $O_2$, tending to lower the $NO_x$ emissions, and a slight increase in load, tending to offset the reduction.

The previous laboratory studies (1-2) showed that the gas turbine $NO_x$ reduction factor, r, was a function of the equivalence ratio (i.e., the reciprocal of the stoichiometric ratio, $\Phi_b = 1/SR_b$) of the in-service burners. Thus as the in-service burners were made to operate more fuel-rich (higher $\Phi_b$), (r) increased. For the test series tabulated in Table III, the approximate in-service burner equivalence ratio $\Phi_b$ was calculated. The resulting relationship between the $NO_x$ reduction factor and the in-service burner equivalence ratio is shown in Figure 8.

The data plotted in Figure 8 include both high and low load as well as as all-burners-out-of-service test configurations. The relationship appears to be linear with a correlation coefficient of 0.99 for a least squares linear fit. However, the number of data points is limited, and further data are needed to substantiate the relationship.

## GENERALIZATION OF TEST RESULTS

The test results have generally shown that (1) combined-cycle $NO_x$ emissions are less than single-cycle emissions and (2) a substantial portion of turbine-generated $NO_x$ can be destroyed in the boiler. The extent to which these results can be treated as "general" warrants discussion.

The extent to which the combined-cycle emissions are lower than normal will be dependent on the function of the power split of the combined-cycle system. For these tests approximately 27 percent of the fuel is burned in the gas turbine. As lower-heat-rate turbines come into use, less fuel will be burned in the boiler; this will affect both the $NO_x$ formed in the boiler and the reduction of turbine-generated $NO_x$. In fact, the most thermally efficient combined-cycle system is comprised of a gas turbine and unfired waste heat boiler. The emission characteristics of this system will be greatly different from the unit tested during this program.

Bypassing a portion of the gas turbine exhaust to the ash hopper produced interesting and unexpected results. Operational situations can exist at low load where bypassing a portion of the gas turbine exhaust from the burners is desirable. One might be inclined to conclude that the $NO_x$ emissions should fall. Instead, these tests results indicated that bypassing the gas turbine exhaust to the ash hopper yielded more intensely mixed flames, producing higher $NO_x$. A more successful approach might be to divert the flow and inject it in a region above the burners, avoiding mixing of the bypass with the burner flow.

Also worthy of discussion is the method of implementing staged combustion for low $NO_x$ operation. In this study burners were removed from service and the fuel diverted to in-service burners to create fuel-rich regions. With this configuration, the portion of the gas turbine exhaust which passes through the out-of-service burners does not directly pass through a fuel-rich flame. One might anticipate that this portion of the gas-turbine-generated $NO_x$ cannot be reduced, limiting the reduction factor. This turns out not to be the case. In reported small-scale tests (2), it was shown that not only was the $NO_x$ reduced in the portion of the gas turbine stream fed directly to a fuel-rich burner, but also a portion of the $NO_x$ in the staged oxidizer flow that bypassed the burner was also reduced. It was not possible to quantify the relative portion representing the fraction of the $NO_x$ destroyed passing through the fuel-rich region and the fraction reduced as the staged air is mixed with the fuel-rich stream. Reduction factor (r) reported in (2) represents the total reduction of the gas turbine $NO_x$ and is thus directly comparable to the reduction factor calculated in this study (i.e., the reduction factor is not apportioned to the fuel through the burner and that which is bypassed as staged air).

A similar situation will probably exist with low $NO_x$ burners that may be available in future new installations. These low $NO_x$ burners will more than likely achieve reduced $NO_x$ by aerodynamically staging the flame at the burner rather than staging the entire furnace, as occurs with burners-out-of-service operation. Since the low $NO_x$ burners use a form of staging with probably comparable boiler $NO_x$ levels, it is reasonable to anticipate a reduction in gas-turbine-generated $NO_x$ using low $NO_x$ burners in combined-cycle systems. However, data are not available to quantify these anticipated reductions relative to the results with burners out of service tested during this study.

A final note of caution is appropriate in the use of gas turbine and boiler emissions data obtained during this program. As with all combustion equipment $NO_x$ emissions, they are design type, fuel type, operating mode, and site specific. Therefore, one should use considerable care in applying the data obtained during this test series to predict emissions from future potential repowering candidates. This is particularly true because the General Electric frame 8 two-shaft gas turbine is not a recent design and is not completely representative of recent gas turbine emission factors for $NO_x$. Although the data here can be effectively used in a proportional $NO_x$ reduction manner for comparative purposes in evaluating operating modes, its use in an absolute sense for emissions forecasting is ill advised.

Additionally it must be noted that this study was conducted with a natural-gas-fired system (both turbine and boiler). Current interest focuses on oil-fired systems. A note of caution is thus offered in extrapolating these natural-gas-fired results to oil firing.

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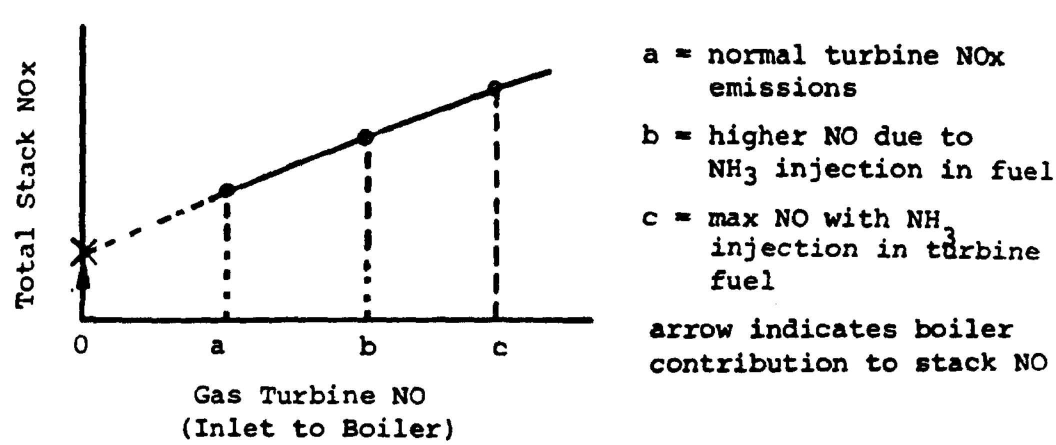



Figure 1. Sketch of stack NOx levels versus gas turbine NO levels

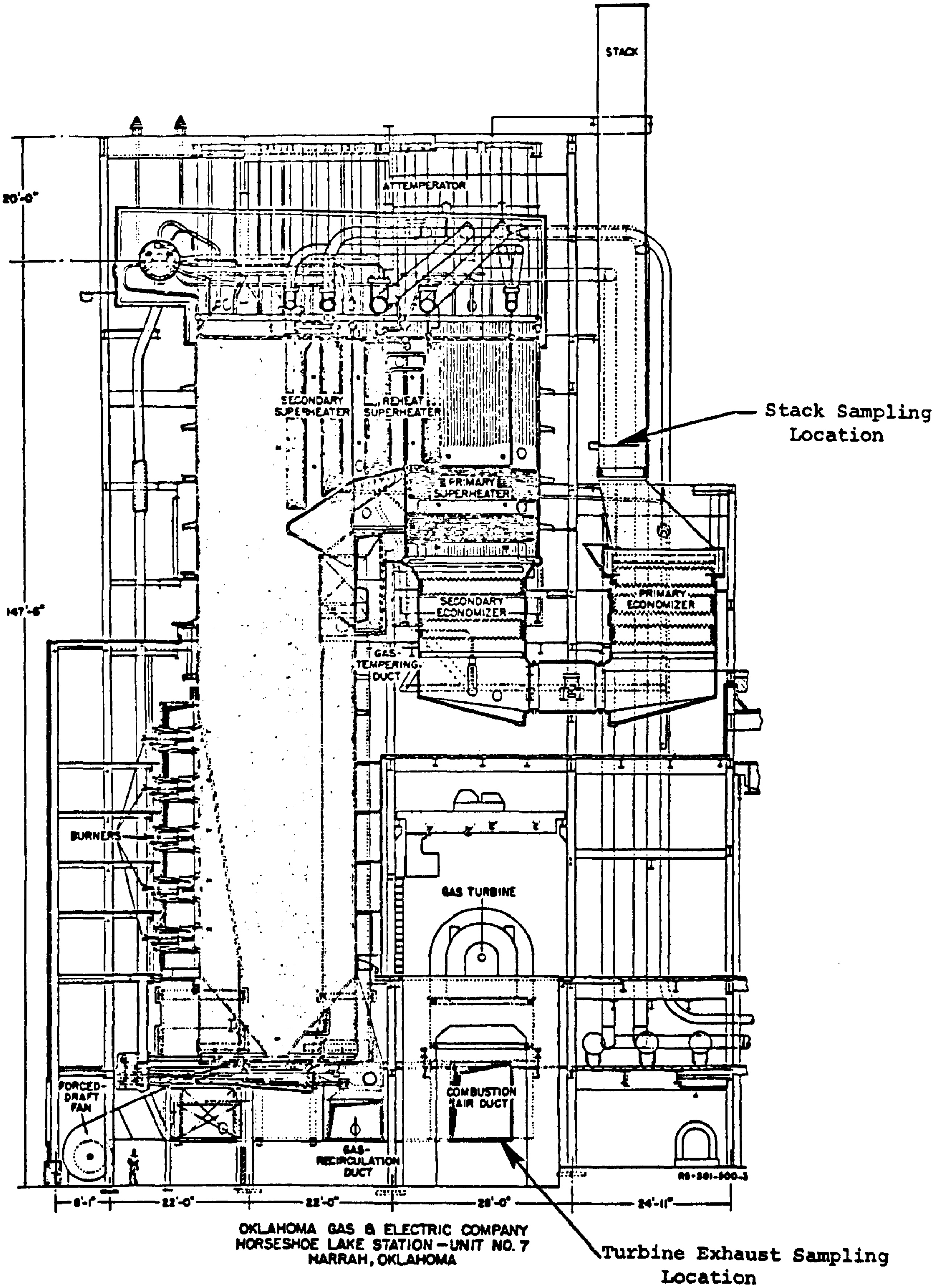



Figure 2. Physical configuration of OG&E Unit No. 7

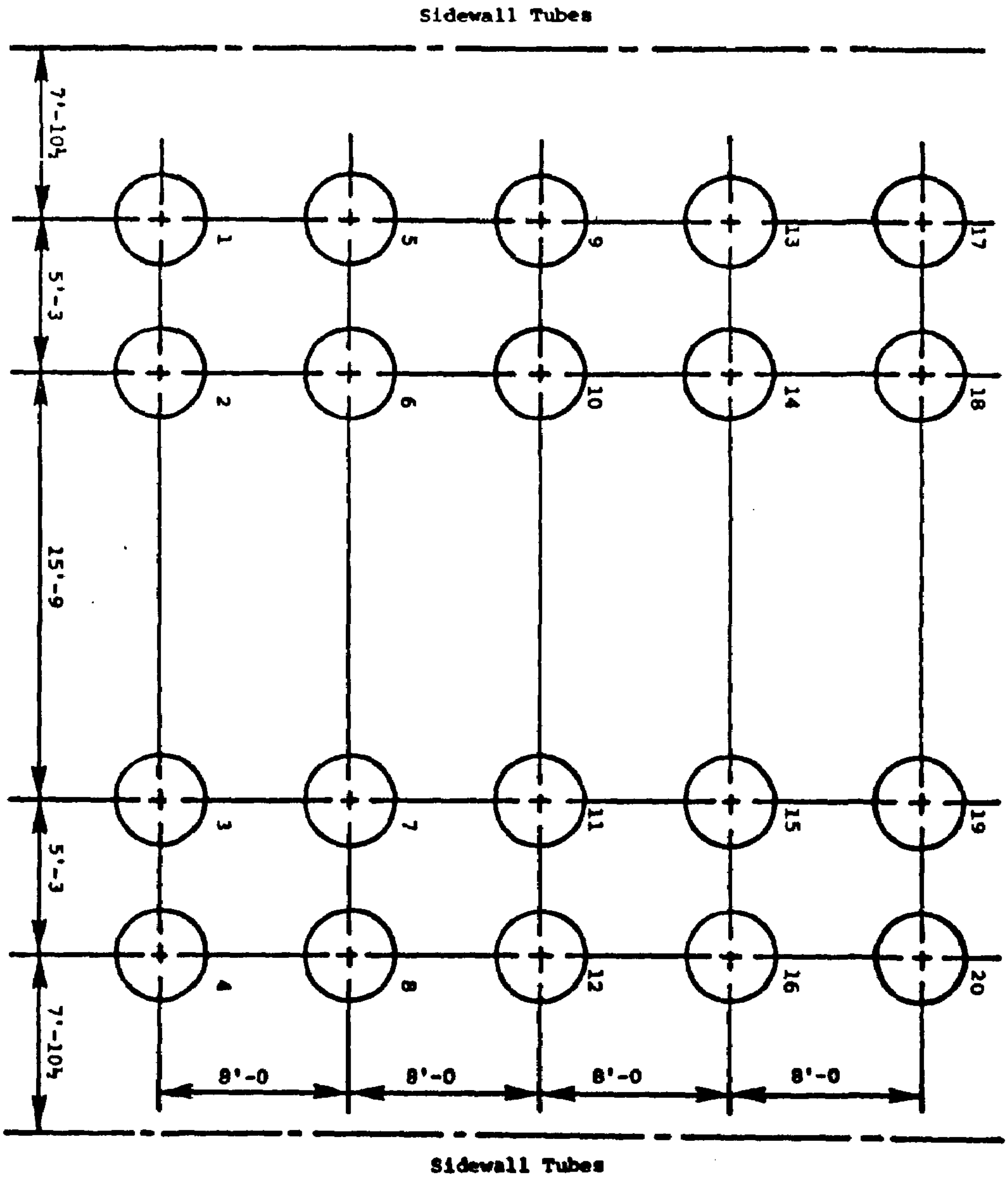



Figure 3. Arrangement of burners in the steam generator

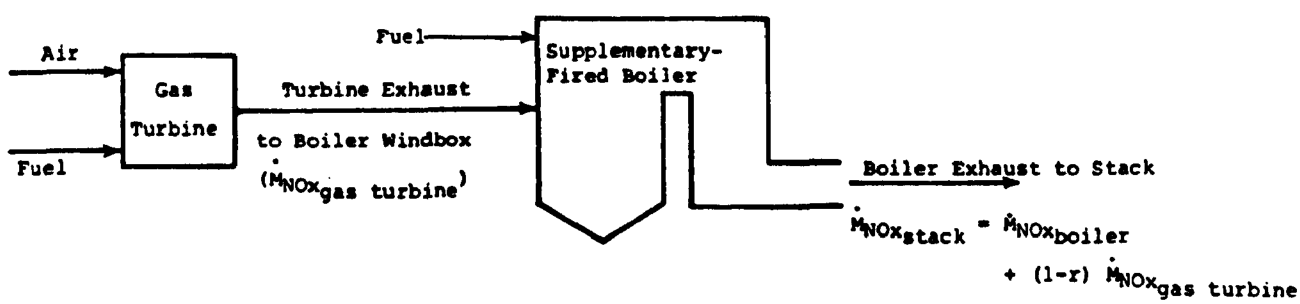



Figure 4. Sketch of the NOx contributions for the combined-cycle system

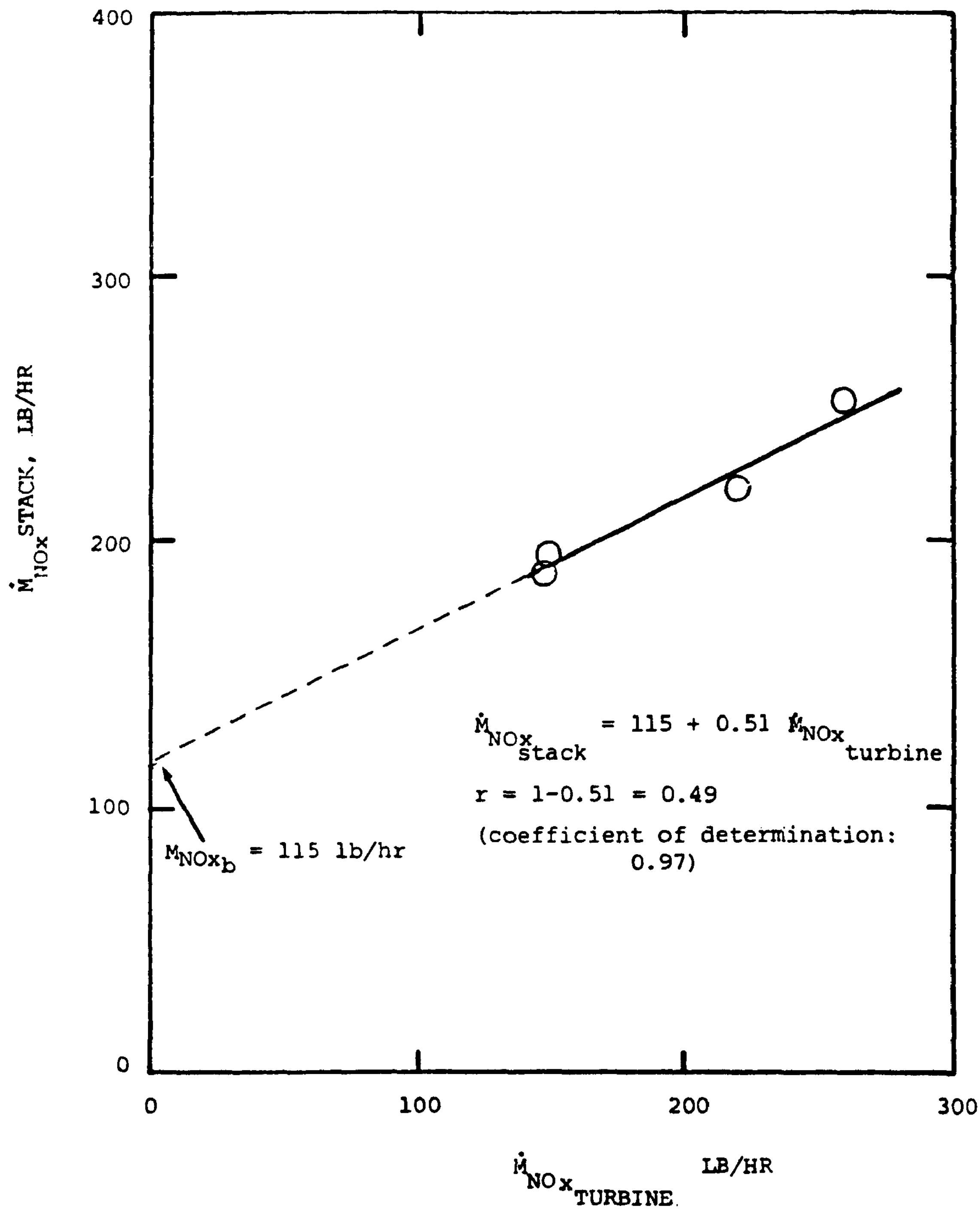



Figure 5. Typical combined-cycle stack NOx versus gas turbine NOx

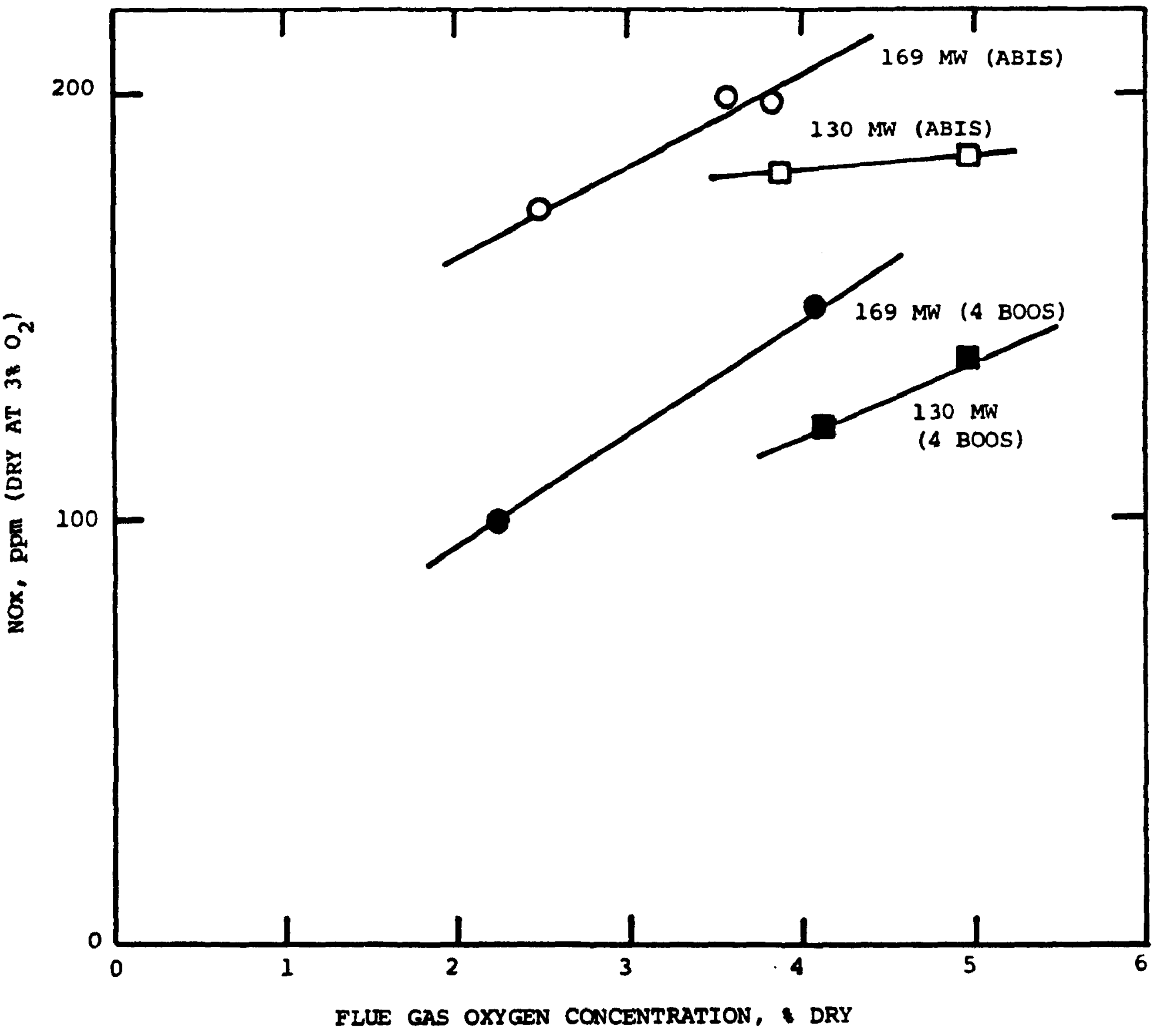
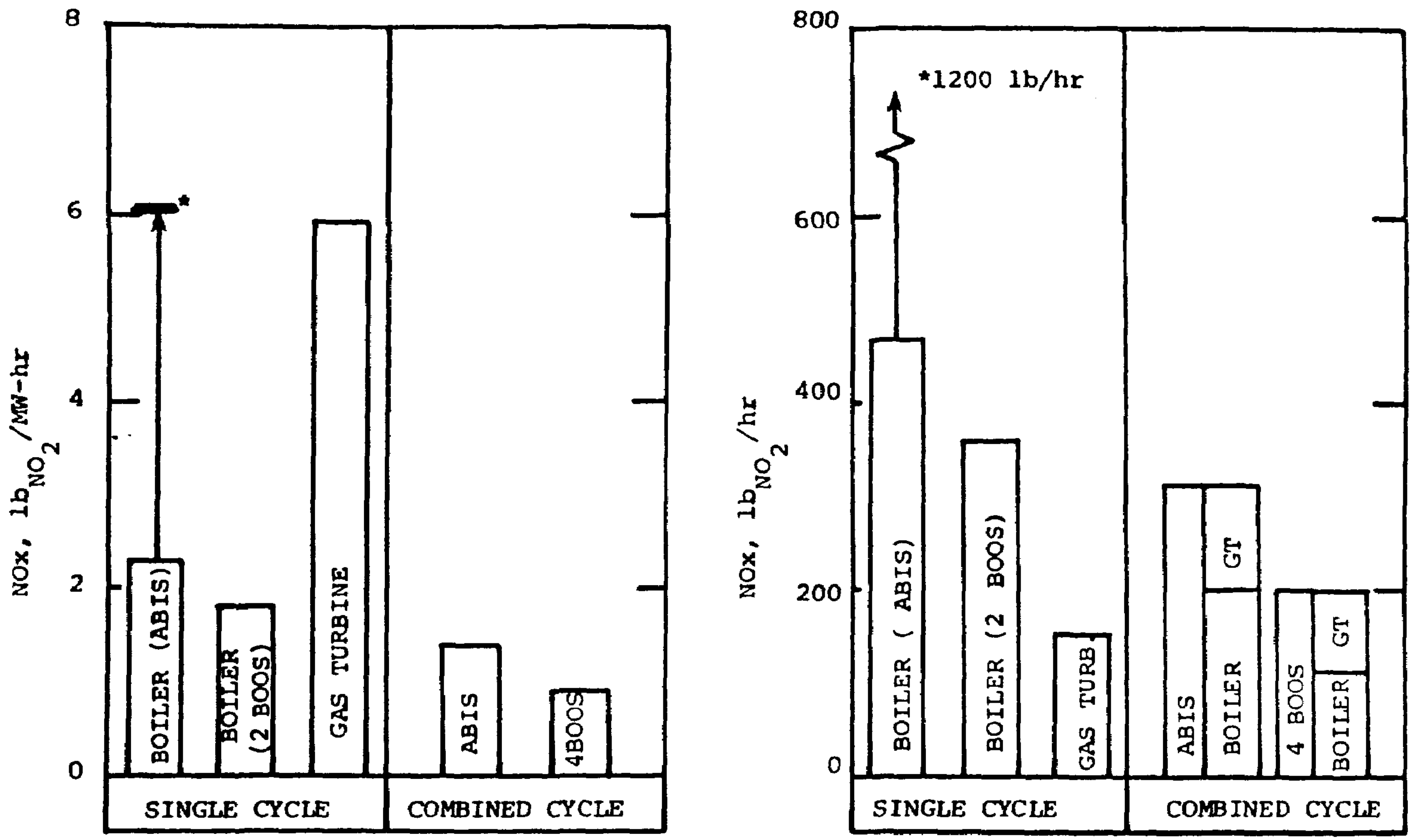



Figure 6. Effect of excess oxygen levels on NOx emissions, boiler-only operation




(a)
Normalized by unit load

(b)
Mass emission rates

ABIS = All Burners In Service
BOOS = Burners-Out-Of-Service

Figure 7. Comparison of single-cycle and combined-cycle emissions. (OG&E Unit No. 7 boiler load approximately 200 MW, gas turbine load 25 MW.)

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*Arrows indicate estimated increase in boiler NOx emissions if operated with normal 600°F combustion air preheat instead of ambient air.

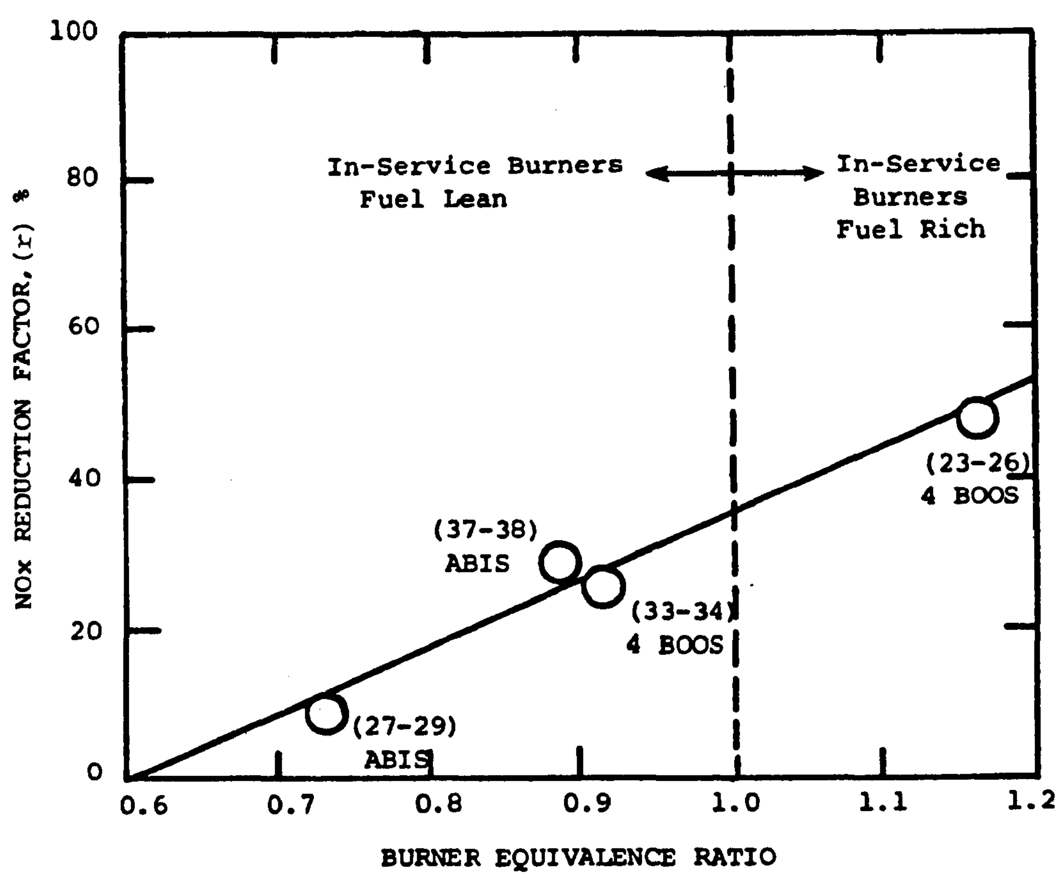


Figure 8. Correlation of NOx reduction factor (r) with the in-service burner equivalence ratio

TABLE I. BASIC TEST PLAN

Single-Cycle Operation

| Variable | Range Tested | Number of Variations |
|---|---|---|
| Load | 130 - 200 MW | 3 |
| Boiler $O_2$ concentration | 2.25 - 5.0% | 3 |
| Burner configuration | All burners in service | 1 |
| | 2 burners out of service | 2 |
| | 4 burners out of service | 2 |

Combined-Cycle Operation

| Variable | Range Tested | Number of Variations |
|---|---|---|
| Gas turbine load | 25 MW | 1* |
| Gas turbine NO level ($NH_3$ injection into turbine fuel) | 50 - 105 ppm | 3 |
| Boiler load | 150 - 190 MW | 2 |
| Boiler $O_2$ concentration | 1.9 - 6.2% | 3 |
| | All burners in service | 1 |
| | 4 burners out of service | 1 |
| | Partial turbine exhaust bypassed to bottom hopper† | 1 |

*Gas turbine load was essentially constant throughout the test program.
†To simulate low excess air at the burner.

TABLE II. BOILER-ONLY TEST RESULTS

| Test No. | Burners Out of Service | Load MW | Flue Gas Flow lb/hr | $O_2$ % dry | CO ppm | NO ppm @ 3% $O_2$ | lb/hr as $NO_2$ | % NO Reduction |
|---|---|---|---|---|---|---|---|---|
| 1 | 0 | 138 | $1.10x10^6$ | 4.75 | 0 | 152 | 212 | -- |
| 2 | 0 | 169 | $1.39x10^6$ | 3.85 | 0 | 199 | 367 | Baseline |
| 3 | 2 (#18,19) | 167 | $1.38x10^6$ | 3.80 | 0 | 196 | 360 | 2% |
| 4 | 4 (#17,18,19,20) | 165 | $1.39x10^6$ | 4.05 | 0 | 155 | 283 | 22% |
| 5 | 4 (#13,14,15,16) | 167 | $1.40x10^6$ | 4.10 | 0 | 151 | 276 | 24% |
| 6 | 0 | 130 | $1.16x10^6$ | 5.00 | 0 | 186 | 268 | Baseline |
| 7 | 2 (#14,15) | 130 | $1.15x10^6$ | 4.90 | 0 | 166 | 240 | 11% |
| 8 | 4 (#13,14,15,16) | 130 | $1.16x10^6$ | 4.95 | 0 | 138 | 200 | 26% |
| 9 | 4 (#13,14,15,16) | 129 | $1.09x10^6$ | 4.15 | 0 | 122 | 174 | 33% |
| 10 | 0 | 130 | $1.08x10^6$ | 3.90 | 0 | 182 | 260 | Baseline |
| 11 | 0 | 130 | | 5.00 | 0 | 186 | 263 | -- |
| 13 | 0 | 169 | $1.37x10^6$ | 3.60 | 0 | 200 | 367 | -- |
| 14 | 4 (#13,14,15,16) | 168 | $1.26x10^6$ | 2.25 | 105 | 99 | 179 | 43% |
| 15 | 2 (#14,15) | 167 | $1.27x10^6$ | 2.58 | 235 | 130 | 234 | 25% |
| 16 | 0 | 165 | $1.27x10^6$ | 2.50 | 0 | 173 | 311 | Baseline |
| 17 | 0 | 200 | $1.68x10^6$ | 3.75 | 0 | 209 | 467 | Baseline |
| 18 | 2 (#14,15) | 199 | $1.68x10^6$ | 3.75 | 0 | 160 | 357 | 23% |

TABLE III. SUMMARY OF COMBINED-CYCLE TEST RESULTS

| Test Series | Test Description | Turb. Load MW | Boiler Load MW | Boiler $O_2$ % Dry | Stack CO ppm | Turbine NOx lb/hr* | Boiler NOx# lb/hr* | Stack NOx lb/hr* | r (%) | $SR_b$ † | $\phi_b$ § |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 27,28,29 | ABIS | 26 | 150 | 6.2 | 0 | 146 | 96 | 229 | 10 | 1.37 | 0.73 |
| 37,38 | ABIS | 24 | 190 | 2.7 | 0 | 156 | 193 | 305 | 28 | 1.12 | 0.89 |
| 30,31,32 | ABIS, hop-per bypass) | 25 | 150 | 5.8 | 0 | 147 | 145 | 293 | 0 | -- | -- |
| 23,24,25 26 | 4 BOOS (#13, 14,15,16) | 25 | 198 | 1.9 | 80-125 | 148 | 115 | 195 | 49 | 0.86 | 1.16 |
| 33,34 | 4 BOOS (#13, 14,15,16) | 23 | 150 | 6.2 | 0 | 137 | 129 | 229 | 27 | 1.10 | 0.91 |

* As $NO_2$

† $SR_b$ = stoichiometric ratio of the in-service burners, based on the boiler $O_2$ measurement (O/F)stoichiometric

$SR_b > 1 \longrightarrow$ oxygen lean

$SR_b < 1 \longrightarrow$ fuel rich

§ $\phi_b = 1/SR_b$

\# Determined by a least squares fit; thus may not exactly satisfy the equation $\dot{m}_{NO_s} = \dot{m}_{NO_b} + (1-r)\,\dot{m}_{NO_{gt}}$, using the values in the table.

TABLE IV. COMPARISON OF COMBINED- AND SINGLE-CYCLE EMISSIONS

Single Cycle Operation

Boiler (cold air operation, ABIS): (467 lb/hr)/(200 MW) = 2.3 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

(cold air operation, 2 BOOS): (357 lb/hr)/(199 MW) = 1.8 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

Gas turbine: (148 lb/hr)/(25 MW) = 5.9 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

Combined Cycle Operation

Combined cycle (ABIS) : (305 lb/hr)/(24 MW+190 MW) = 1.4 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

Boiler NOx (ABIS): (193 lb/hr)/(190 MW) = 1.0 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

Combined cycle (4 BOOS): (195 lb/hr)/(198 MW+25 MW) = 0.9 $\frac{\text{lb NO}_2}{\text{MW-hr}}$

# PILOT SCALE EVALUATION OF A LOW $NO_x$ TANGENTIAL FIRING METHOD

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## ABSTRACT

The Environmental Protection Agency (EPA)/Acurex 293 kWt pilot-scale facility was used to develop a low-$NO_x$ pulverized coal-fired tangential system. Low $NO_x$ is achieved by directing the fuel and less than 20 percent of the secondary combustion air into the center of the furnace with the remaining secondary combustion air directed parallel to the furnace walls. The separation of secondary combustion air in this manner creates a fuel-rich zone in the center of the furnace where $NO_x$ production is minimized. This combustion modification technique has lowered $NO_x$ 65 percent relative to conventional tangential firing. In addition, CO, UHC, and unburned carbon emissions are substantially unaffected by the modification. Also, the modification places a blanket of air on the furnace walls which is beneficial from a wall corrosion and slagging point of view. Finally, the modification shows a decrease in $NO_x$ emissions as firebox gas temperature is increased. This characteristic might be beneficially applied in a large-scale system to reduce furnace volume, and thereby capital cost, for a given combustion heat release.

Tests are now underway to further optimize and characterize this low-$NO_x$ combustion modification technique.

## ACKNOWLEDGEMENTS

This work is supported by the EPA under Contract 68-02-1885. David G. Lachapelle is the EPA Project Officer. The assistance of Acurex staff, P. M. Goldberg and E. B. Merrick, in this study is gratefully acknowledged.

# INTRODUCTION

Maintenance of ambient air quality in the United States requires the restriction of $NO_x$ emissions from stationary combustion sources. Tangentially coal-fired utility boilers account for about half of the steam-electric capacity generated in the U.S. by coal-fired utility boilers and produce about 40 percent of the $NO_x$ emissions attributed to coal-fired boilers (Reference 1). These significant $NO_x$ emissions and the projected increase in the number of these boilers make them candidates for emission control development both in terms of retrofit and new boiler designs.

During the combustion of pulverized coal, $NO_x$ is generated from the nitrogen chemically bound in the fuel as well as from the oxidation of atmospheric nitrogen. For typical bituminous coals, $NO_x$ emissions from the fuel-bound nitrogen can be a significant fraction of the total (Reference 2). $NO_x$ emissions have been shown to respond to combustion modification techniques that alter oxygen concentration, residence time, and temperature during combustion (Reference 3). Lowering the oxygen concentration surrounding the fuel, either locally by fuel/air stratification or globally by limiting the air flow in the combustion volume, shifts the fuel and atmospheric nitrogen emission reactions from predominantly $NO_x$ formation to a balance between $NO_x$ and molecular nitrogen formation (Reference 3). In addition, given sufficient residence time at oxygen deficient conditions, previously formed $NO_x$ can be reduced to molecular nitrogen by homogeneous (Reference 4) and heterogeneous (Reference 5) catalyzed and noncatalyzed reactions.

Lowering peak temperature under excess air conditions decreases atmospheric nitrogen $NO_x$ formation (Reference 6). However, under very fuel-rich staged combustion conditions, lowering first stage temperature can increase $NO_x$ (Reference 6). This is due to less fuel nitrogen being volatilized in the first stage and carrying over and being converted into $NO_x$ in the oxygen-rich second stage.

Even though imperfectly understood, these basic relationships between system parameters and $NO_x$ emissions have been employed to moderately reduce $NO_x$ emissions from tangential as well as other types of utility boilers (Reference 7). Some combustion modification techniques, such as staged combustion, can lead to significant $NO_x$ reduction. However, a major portion of the firebox is operated under reducing conditions, which is undesirable from a wall corrosion and slagging point of view. Significant further reductions in $NO_x$ from tangentially-fired boilers under acceptable combustion conditions requires a better understanding of the combustion processes that control $NO_x$ formation/reduction. Therefore, this study is separated into two phases. The objective of the first phase is to develop an understanding of the processes controlling $NO_x$ formation/reduction in pulverized coal-fired tangential boilers. Using the results of the first phase, the objective of the second phase is to develop and demonstrate, in pilot-scale, low-$NO_x$ combustion modification techniques that can be retrofitted to existing, or incorporated into new, tangential boiler designs.

## DEFINITION OF COAL-FIRED TANGENTIAL SYSTEMS

Figure 1 illustrates the main features and flow patterns of a tangentially-fired boiler. Fuel and air are introduced into the furnace through rectangular registers located in the four corners. The bulk of the combustion air enters above and below the fuel jet as shown. The jets are nonswirling and fuel/air mixing is slow relative to burners used in wall-fired boilers.

The tangential alignment of the centerlines of the corner jets to the circumference of a circle in the center of the furnace promotes the formation of a large-scale vortex within the furnace. Ignition of the fuel is provided by impingement of hot burnt gases from laterally adjacent burners and large-scale internal recirculation of combusted gases. Because ignition occurs primarily on the vortex core side of the fuel jet, combustion is asymmetric in the horizontal plane.

In addition to providing ignition, jet impingement and vortex interaction help mix fuel and air to complete combustion. Partially burnt gases from lower burner levels sweep past and interact and mix with higher burner level fuel and air jets, helping to mix the fuel and air.

### Pilot-Scale Combustion Facility

Figure 2 shows the EPA/Acurex pilot-scale facility used for the baseline and combustion modification testing during this study. This facility has been used to study various firing modes (tangential, front-wall-fired) and fuels (coal, oil, gas, coal-oil mixture, refuse-derived fuel) (References 6 and 8). The maximum firing rate is approximately 600 kWt. The firebox is a 99-cm refractory-lined cube attached to a 61-cm refractory-lined tower in which convective heat exchangers are placed. Volumetric heat release, overall residence time, and furnace exit gas temperature are matched between pilot- and full-scale facilities. Also, burners and their placement in the firebox are patterned after full-scale tangential systems. During tests, NO, $O_2$, $CO_2$, CO, and UHC emissions are continuously monitored with particulate samples taken intermittently. Table 1 lists the continuous measurement instrumentation. A complete description of the facility is given in Reference 6.

The simulation of full-scale firebox flow patterns and mixing by the pilot-scale facility was evaluated by comparing water model flow and pilot-scale flow and flame patterns to corresponding full-scale results. In the comparison, similarities were found for (1) ignition standoff and character, (2) flame spreading angle from burners, (3) apparent jet centerline angle from corners, and (4) vortex size.

## Baseline Test Results

Figure 3 compares the NO emission levels achieved by the pilot-scale facility at various excess air levels on several coal types to full-scale utility boiler levels. The pilot-scale results correspond well with the full-scale results. Matching of the NO trend with excess air is encouraging in that this, as well as the abovementioned comparison of flame patterns, may be an indication of the matching of mixing processes between the full- and pilot-scale systems.

During baseline testing the CO, UHC, and carbon loss emissions were small and comparable to full-scale system levels indicating that complete combustion is occurring in the pilot-scale facility.

## JET AND VORTEX CHARACTERIZATION TEST RESULTS

To assist in the definition of NO emission control strategies, conventional tangential-fired tests were carried out to characterize the important processes to NO formation/reduction in this system and establish the effect of design variables on these processes. During the characterization tests, the facility was operated at baseline conditions. The fuel chosen for all combustion system definition and modification testing was Utah bituminous coal. The fuel properties are given in Table 2.

### In-Flame Sampling Test Results

In-flame gas and solid samples were taken by a water-quenched probe at a variety of firebox locations to determine the relative importance of near-burner, jet interaction, and vortex zones (see Figure 1 for zone definitions) on NO processes. The probe quenches particle and gas reactions by injecting water directly into the sample stream at the probe entrance. A limited number of sampling locations 7.6 cm below, 26.7 cm above, and at the burner centerline were chosen to characterize near-burner, jet interaction, and vortex zones.

Figure 4 presents the as-measured NO, $O_2$, and $CO_2$ concentrations, respectively, at the fuel tube elevation superimposed on a plan view of the firebox. These results show that, near the burner face, minimum NO occurs in the center of the fuel jet, where the fuel is relatively unburnt, and peaks on the vortex core side of the jet. The peak NO levels occur in hot ignition zones observed during testing. These zones, defined as jet interaction zones in Figure 1, are created by the interaction and mixing of the fuel jet with hot combustion gases from the adjacent upstream corner burner. Since the fuel is only 60 percent burnt and has been in this zone less than 100 ms, most of the combustion and NO production in this zone can be associated with the volatile components of the fuel. The bulk of the total net NO production occurs in this near-burner region.

Downstream of the burner face and just prior to the next burner interaction, $O_2$ and $CO_2$ concentrations are more uniform and the NO peak is not as pronounced. Oxygen concentrations are low and NO concentrations are high in this zone, and the net NO production is small. This zone is downstream of where the vortex was observed to significantly impact with and cause rapid mixing of the fuel and air jets. Burning in this zone and downstream is mostly char combustion.

Probing results 26.7 cm above the burner level show $CO_2$, $O_2$, and NO levels are relatively flat and consistent with furnace exit conditions. Very little net NO production occurs in this zone and solid samples show that only 10 percent of the fuel is unburnt at this level.

Staged combustion probing tests were run at a firebox stoichiometric ratio (SR) of 0.85 with an overall stack excess air level of 15 percent. As expected (Reference 6), staged combustion significantly lowered stack NO through reduction of prior-formed NO and lower conversion efficiency of fuel N to NO. Of greatest interest were the probing results presented in Figure 5, which showed that, near the burner face, the vortex core side NO formation peak was eliminated by operating the firebox fuel rich. Operating the active zone on the vortex side of the fuel jet under $O_2$-deficient conditions appeared to eliminate the peak NO formation leading to a low firebox burner elevation NO level which is even further reduced by decay processes occurring above the furnace burner elevation.

## NO Dopant Test Results

Information on the NO reduction capability of various zones in the firebox was obtained by injecting NO dopant into the firebox. A ceramic injector tube 1.9 cm in diameter was used to distribute NO over roughly a horizontal line source 15 cm long. The NO flow in the injector was set at a level required to give 375 ppm in the stack for an inert injectant. Injection locations were chosen above, at, and below the burner centerline to assess the NO reduction potential of the near-burner and vortex zones probed earlier. NO dopant was also injected into the primary air/coal supply line to assess the effect of the very-near-burner zone on NO reduction. Figure 6 presents, on a plan view of the furnace, the percent of NO dopant remaining in the stack for the indicated injectant locations. The percent remaining is found by subtracting the exit NO concentration without dopant from the measured doped level and dividing by the theoretical inert injectant concentration of 375 ppm. Conventional as well as staged combustion conditions at a first-stage SR of 0.85 were tested.

For conventional combustion conditions, injecting NO on the fuel jet centerline near the burner gives NO reduction efficiencies of 70 to 80 percent. Away from the burner and in the vortex, reducton efficiency is about 50 percent. In the active zone on the vortex core side of the fuel jet, explored in the probing tests, reduction is 94 percent. Below the burner level, NO reductions of 80 percent were measured whereas above the burner level reductions were small, being less than 13 percent.

Under staged combustion conditions, at a first-stage SR of 0.85, reductions at the burner elevation were better by a factor of two from the unstaged results, except at a single point for which no explanation can be given. Below the burner level, reductions observed were about the same as conventional unstaged reductions. Above the burners, the reductions were significantly better for the staged conditions.

These results show that NO is most effectively reduced if the NO is injected into the active combustion and peak NO production zone formed by the interaction of hot burnt gases and the fuel jet. In this zone, reaction is probably fast and addition of NO can drive the reactions from $NO_x$ production toward a balancing of $NO_x$ production and reduction. Another effective reduction zone is near the burner face at the burner elevation. In this zone, oxygen is not abundant and NO is reduced. Below the burner level, NO reduction is effective for both staged and unstaged conditions. Since reduction is not observed above the burner level for lean conditions, this indicates that NO injected below the burner centerline must get entrained and reduced in burner elevation flame zones.

## TANGENTIAL BURNER CHARACTERIZATION TEST RESULTS

Different burner designs were tested to assess their impact on NO and to determine the relationship between burner design parameters and NO. Burner designs tested were limited to nonswirling slow mix designs such as those presently used in tangential systems. Compact intense flames produced by swirl burners are not compatible with tangential firing due to potential corner slagging and deposition problems.

Based on the probing test results and the known importance of $O_2$ availability in the fuel jet to NO (Reference 6), burner designs were tested where the exposure of the fuel jet to combustion air and the hot combustion gases that provide ignition was varied. Also, in some of these tests the relative position between the fuel and air was varied to operate the vortex side of the flame more fuel-rich. For the burner design tests, three conventional baseline burners firing on gas and one experimental burner firing on coal were used to generate a conventional tangential system vortex.

Figure 7 presents the NO results and the burner fuel and air port configurations tested. In the burner configurations given in Figure 7, the open circles correspond to the end view of the burner combustion air supply tubes and the filled circles represent the fuel supply tubes. The NO results are given as a function of temperature since baseline testing showed that NO increases with temperature. Also shown is the NO level when all four corner burners are operated on gas. The results are uncorrected for the dilution effect of the lower NO gas combustion products. Actual differences in NO due to coal burner alterations are greater than, by up to a factor of four, the differences appearing in Figure 7. Going from configuration 1 to 5, exposure of the fuel jet to hot combustion gases decreases. Configuration 1 is the fuel jet alone with all of the secondary combustion air distributed to the other three corner burners firing on gas.

The NO results in Figure 7 show that configurations 2 and 5 have, for a given temperature, the lowest and highest NO levels of all the burners tested. In configuration 5, the fuel jet is surrounded by combustion air and entrainment of hot combustion gases into the fuel jet is limited. Configuration 2 has the fuel jet located on the vortex core side of the furnace with the secondary air jets aligned in a vertical row behind the fuel jet. It was observed that configuration 2 had rapid ignition and burning compared to configuration 5.

Configuration 1, the fuel jet by itself, had the greatest exposure to hot combustion gases of all the configurations tested, and had NO results similar to conventional tangential burner type arrangements such as configurations 3 and 4. It was observed that the fuel jet by itself was heavily impacted by the vortex flow, and fuel jet spreading and mixing was extreme compared to other configurations.

## FIREBOX MIXING TESTS

Burner configurations 2, 3, and 4 were tested for the effect of firebox mixing intensity and jet breakup on NO by varying the three gas burner firing rates while maintaining the coal burner at a constant 73 kW. Varying the gas firing rate changes the vortex strength and the turbulence intensity in the firebox, which alters the coal burner mixing.

Figure 8 shows the NO results for configurations 2, 3, and 4 for gas firing rates from 0 to 293 kW. At 0 kW gas firing, the vortex is absent and the burner flames are long and narrow. As the gas firing rate is increased, the firebox vortex develops and the coal flame begins to broaden somewhat near the burner face and bend slightly while ignition and burning increase on the vortex side of the fuel jet. An even more significant change in flame character with increasing gas firing rate is the strong impact and dispersion of the fuel jet about one-half the firebox length from the burner face. At this location, vortex interaction with the jet is significant enough to destroy the original collimated character of the coal jet and disperse the fuel in the firebox. This fuel dispersion in an overall oxygen-rich environment is detrimental to NO emissions. Figure 8 shows that the as-measured NO results do not change significantly for gas firing rates from 0 to 293 kW. However, these results are uncorrected for dilution by the considerably lower NO content gas burner combustion products. A simple correction for dilution would show a consistent and large (an estimated 900 ppm at maximum gas firing rate) increase of NO for the coal burner as the gas firing rate is increased. This demonstrates the importance of firebox mixing on NO.

The results in Figure 8 also showed the importance of the vortex to maintaining ignition and preventing lifted flames which have high NO. At 50 kW gas firing rate, or higher, ignition of the coal flame by the vortex is very positive and the difference in NO between configurations is small. At 0 kW gas firing rate, where the vortex is absent and ignition is somewhat tenuous, configuration 4 experienced positive ignition at the burner face whereas configuration 3 did not and the flame became detached. This resulted in an increase in NO from the 200 to the 430 ppm NO level. This abrupt increase in NO has been observed elsewhere (Reference 11) for detached flames.

## DISCUSSION OF TANGENTIAL SYSTEM CHARACTERIZATION RESULTS

Probing tests showed that, near the burner face, where the bulk of total NO is formed, combustion is asymmetric with ignition, intense burning and peak NO production occurring on the vortex core side of the fuel jet in the jet interaction zone. At this location approximately 60 percent of the fuel has been burned and this fraction can be associated primarily with the fuel volatiles. Fuel/ai· mixing in this zone is enhanced by the crossflow of hot combustion gases over the fuel and air jets. Since the initial fuel nitrogen volatiles see an abundance of oxygen in this zone, NO formation is very high (Reference 6). Lifted flame and dispersed fuel jet burner test results were extreme examples of how high $O_2$ concentrations at the fuel ignition point can lead to high NO. In addition, this zone has a high gas temperature, due to reduced wall heat transfer and high entrained combustion gas temperature. High temperature under $O_2$-rich conditions generates significant atmospheric nitrogen NO (Reference 6). NO dopant tests also showed that NO can be significantly reduced in the near burner zone, with the reduction most effective under fuel-rich combustion conditions. Adding NO in concentrated form to this very chemically active zone reduces some of the NO to $N_2$ even under overall lean conditions.

As shown by the staged probing and burner configuration tests, the high NO production rate of the jet interaction zone can be reduced by operating this zone fuel-rich through limits on fuel/air mixing. Under these conditions the volatilized fuel nitrogen will be in a more oxygen-deficient environment and the fuel nitrogen NO formation reaction will shift to a balance between NO and molecular nitrogen formation (Reference 3). Also, atmospheric nitrogen NO formation will be reduced under $O_2$ deficient conditions (Reference 3).

Downstream of the near burner zone, beyond roughly half the firebox length, the vortex interacts with the burner jets and causes the fuel and air to mix rapidly. Combustion and NO production in this zone and beyond are dominated by char burning and the net NO production is small relative to the near burner region. In this zone, the fuel nitrogen in the char matrix reacts in an environment that has a much lower $O_2$ concentration than the near burner region where the volatiles react. Also, previously formed NO concentrations in this zone are high. In this environment, NO reduction of the fuel nitrogen to molecular nitrogen can occur (Reference 3). In addition, previously formed NO can be reduced by homogeneous reactions with fuel components (Reference 4) or by catalytic and noncatalytic reactions on fuel particle surfaces (Reference 5). These processes together account for the small net NO production observed for this zone. Similar comments also apply to the above burner elevation zone.

Staged probing tests showed that operating the downstream burner zone fuel-rich causes decay of previously formed NO (References 4 and 5). In this environment the homogeneous and heterogeneous NO decay reactions discussed above overwhelm any NO production yielding low stack NO levels. The effectiveness of rich zones in decaying previously formed NO is also clearly demonstrated by the NO dopant tests. Reductions of up to 94 percent of the original dopant were observed when the combustor was operated fuel-rich at an SR of 0.85.

Based on burner flame observation and probing tests, the lower NO found for reduced firebox mixing is primarily due to the maintenance of locally rich zones downstream of the burner face where NO production from the char is minimized and previously formed NO decay is maximized. The same NO reduction processes that occur under globally rich conditions for staged combustion are active in the locally fuel-rich zones created by burner fuel/air stratification. Burner tests also showed that too low a mixing level can result in loss of ignition and lifted flames. These flames have high $O_2$ availability at the fuel ignition and volatile reaction point and thereby high NO.

## LOW-$NO_x$ SYSTEM

Based on the observations detailed in the last section, the requirements for a low-$NO_x$ tangential system were identified. These are: (1) initiate burning sooner to minimize $O_2$ availability at the ignition point, (2) operate the jet interaction zone fuel-rich, (3) protect fuel jet from dispersion by vortex flow, (4) lower firebox mixing with the constraint of positive ignition, and (5) operate a portion of the char burnout zone oxygen-deficient to get NO decay. In addition to these low-$NO_x$ requirements, constraints must be applied on the system relative to boiler size and efficiency, wall corrosion and slagging, and heat transfer. These constraints dictate that, to minimize corrosion and slagging problems, oxygen-deficient combustion gases should not contact the walls. Also, sufficient time and oxygen must be available to fully burn out the fuel and minimize carbon loss, CO, and UHC emissions. Finally, furnace volume and exit gas temperatures must be constrained to those typical of presently operating units.

Figure 9 presents a top and side view schematic of the low-$NO_x$ system with rich and lean zones identified. The major system features are: (1) fuel directed at conventional tangential $6^o$ yaw angle into the center of the furance, (2) some secondary air, either displaced toward the wall side of the firebox or surrounding the fuel jet, directed parallel to the fuel jet, (3) the bulk of the secondary air directed along the wall at and above the fuel jet elevation.

These major system features create oxygen-deficient conditions in the active near burner and the char burnout zone and fuel-lean conditions on the furnace walls at and above the fuel jet elevation. These system characteristics address both the low NO requirements and operational constraints noted above.

The initial low-$NO_x$ system tests used a configuration that had variable wall air injection angles with respect to both the furnace wall and the horizontal plane. This configuration, denoted System 1, is shown schematically in Figure 10. The later testing used a configuration where all of the wall air jets were confined to the burner blocks set in the corners of the firebox. This configuration, denoted System 2, is also shown schematically in Figure 10. Though less flexible than the initial configuration, this later configuration is a closer representation of how the system might be retrofitted into a full-scale boiler. The primary emphasis of System 2 testing is to define the benefits of distributing the secondary combustion air over a wider elevation in the firebox than the initial testing. It should be noted that the true optimal low-$NO_x$ configuration might occur when secondary combustion air is more uniformly distributed over the furnace wall than by the few discrete jets tested. However, the primary emphasis of this program is on retrofittable concepts that can achieve significant $NO_x$ reductions without requiring major changes to tangentially-fired boiler hardware. This constrains the wall air introduction jets to the corners of the firebox.

## System 1 Test Results

For System 1 testing, the corner burners in the pilot-scale facility were modified as shown in Figure 10 to simulate the low-$NO_x$ system illustrated in Figure 9. Tests were then initiated to optimize the primary fuel, secondary and wall jet configuration, placement, direction and velocity. As shown in Figure 11, tests where the primary fuel and secondary jet configurations were varied showed that directing approximately 20 percent of the secondary combustion air into the center of the furnace and 80 percent along the walls at the fuel jet elevation gave the lowest NO for most of the System 1 primary configurations tested. For the fixed air jet area cases tested, increasing the percent air on the wall increases the velocity of the wall jet as well as distributes more of the air on the wall. The minimum NO levels may represent a balance between the benefits of the outward displacement of the combustion air, causing a wider separation of fuel and air, and the negative effects of increased fuel/air mixing caused by the higher velocity wall jets. Higher percentages of wall air than the optimal will give high wall air velocity and excessive mixing, and lower percentages of air flow will place too much air in the center of the furnace, yielding nonoptimal results.

At 80 percent air on the wall, probing results showed that the center of the furnace is oxygen-deficient with this zone typically occupying 40 percent of the firebox at 20 cm above the burner level for most configurations tested. As the wall air mixes into this oxygen deficient zone it typically shrinks to 20 percent at 46 cm above the burner centerline. At this location, NO formation/reduction processes are essentially complete and NO levels are comparable to stack values.

Vicinity of wall oxygen concentrations are 10 percent at 20 cm above the burner elevation for the low-$NO_x$ system versus 4 percent typical of conventional tangential firing in the pilot-scale facility.

Figure 3 shows the effect of excess air at the optimal 80 percent air on the wall for several primary configurations. As shown in Figure 3, the best configuration was a coannular primary/secondary air configuration. In this configuration the circular primary is surrounded by an annular passage that contains 20 percent of the secondary combustion air. Flame observation showed that this configuration had the smallest amount of fuel dispersion prior to entering the fuel-rich core zone. Various length slot primaries, though initially burning much sooner than the other configurations, had fuel dispersion problems. The dispersed fuel would burn in fuel-lean zones and yield high NO. Circular primaries having swirling or diverging flow also yielded higher NO at 15 percent excess air.

Figure 12 shows the effect of varying the wall air jet inclination angle on NO. The primary and secondary air jets for this case were similar to the configuration 2 jet locations shown schematically in Figure 7. At $0^o$, the wall air jet is behind the fuel jet and is shielded from the direct impact of the vortex flow. As the wall jet inclination angle is varied from the horizontal, the wall jet is directed out from behind the fuel jet which, due to the lack of fuel jet shielding, might be more easily entrained and mixed into the fuel-rich core. The decrease in fuel/air separation caused by this mixing might be the reason for the observed NO increase.

Besides yielding minimum NO, directing the wall air jet horizontally is desirable for multiburner level firing. For a system with several burner levels, directing the wall air upwards or downwards with respect to the fuel jet might result in undesirable burner to burner air jet interactions.

In addition to varying the inclination angle of the wall jets, one test considered the effect of directing the wall air at $10^{o}$ away from the furnace wall. As shown in Figure 11, directing the wall air $10^{o}$ off of the wall (configuration O) increased the minimum NO approximately 25 ppm over the $0^{o}$ (configuration N) wall jet angle results. In addition, firebox probing tests showed that $O_2$ concentrations near the wall 20 cm and 46 cm above the fuel tube elevation were decreased for the $10^{o}$ wall angle case. The higher wall $O_2$ concentrations and the lower minimum NO levels for the case where the air is directed along the wall makes this jet orientation the optimum.

Comparison of the best low-$NO_x$ concepts results to conventional pilot- and full-scale tangential firing results in Figure 3 shows that the System 1 concept reduces NO emissions by roughly 60 percent and lowers the sensitivity of NO to excess air. This reduced sensitivity may be a result of the more diffusive burning nature of the fuel-rich core.

Combustion characteristics for the low-$NO_x$ System 1 are not markedly different from conventional pilot scale tangential firing. Carbon monoxide, UHC, and percent carbon in flyash levels for this sytem are <36 ppm, <9 ppm, and <3 percent, respectively, versus conventional tangential firing results of <22 ppm, <1 ppm, and <7 percent. These NO reductions and good combustion efficiency are achieved while increasing vicinity of wall oxygen concentrations to 10 percent near the burner elevation. This oxygen blanketing of the wall is beneficial from a wall corrosion and slagging point of view.

An additional feature of the low-$NO_x$ System 1 configuration is the improvement in NO emissions as temperature rises. Figure 13 shows that as gas temperature is increased for two different air-on-wall system configurations, NO decreases. As discussed earlier, under the fuel-rich conditions existing in the center of the furnace, increases in temperature will lead to more volatilization of the fuel nitrogen in the rich zone and more conversion of this nitrogen to molecular nitrogen rather than to NO. This attractive emission behavior with temperature might be beneficially used to reduce boiler size and capital cost for a given heat release.

Also shown in Figure 13 is the NO reduction caused by decreasing load at a fixed gas temperature. As discussed previously, reducing load decreases firebox mixing thereby maintaining rich zones in which NO is minimized.

System 2 Test Results

The burner configuration used in System 2 testing is shown schematically in Figure 10. This system differs from the initial configuration in that four wall jets, instead of two, are used and these jets are confined to the corner burner blocks. This configuration more closely simulates the retrofitting of the low-$NO_x$ concept into a full-scale tangential boiler. In addition, operating the four levels of wall air in this configuration defines the emissions and efficiency benefits of vertically distributing the combustion air.

Figure 14 presents the variation of NO levels with percent of secondary combustion air on the wall for the System 2 configuration. Each curve represents a different vertical distribution of air flow between wall air ports 1a, 1b, 2, and 3 as defined in Figure 10. The SR's achieved at each wall air level as a result of the vertical distribution of air is given in Figure 14. Configurations 1b and 1ab denote tests where air was flowing only in port 1b or air flow was equally split between ports 1a and 1b, respectively. Also included in Figure 14 are the optimal results from System 1 testing.

The cases where $SR_1$, $SR_2$, and $SR_3$ are 1.15 do not have wall air flowing in ports 2 and 3. Therefore, these cases are comparable to System 1 configurations where wall air ports 2 and 3 are absent. As shown in Figure 14, System 1 gives the lowest NO results and System 2, with only the 1B jet operational, gives the highest levels. The percent air on the wall at minimum NO falls between 80 and 85 percent for these cases.

Differences in wall jet configuration and location between these cases probably account for the differences in NO. As shown in Figure 10, the wall jet for System 1 exits downstream of the corner, nearly half way down the furnace wall, whereas the wall jet exit for System 2 is in the corner. In addition, the wall jets in System 1 protrude into the firebox whereas the System 2 jets are confined to the corner burner blocks. These configurational factors can impact aerodynamics and mixing between the wall and fuel jets leading to the observed differences in NO. For example, the protruding wall jets may create separated flow zones in the firebox corners which help set up pressure fields to deflect the wall air away from the root of the fuel jets. This may reduce fuel/air mixing and benefit NO emissions. In addition, when only wall jet 1b is operating, the wall jet flow area is one-half that when 1a and 1b are working or when System 1 is tested. Therefore, the 1b test conditions represent very high wall air velocities as compared to the other cases. As discussed previously, higher velocities can lead to enhanced fuel/air mixing and thereby higher NO.

Even though System 2 NO results are marginally higher under these conditions, this configuration is preferred, since a retrofittable full-scale system simulation is more accurate with the System 2 configuration.

For both configurations 1a and 1ab the Figure 14 results show that, when wall air is distributed vertically to ports 2 and 3, NO levels decrease with the minimum NO point shifting to higher levels of percent air on the wall. In these cases, the vertical separation of the fuel and air is creating a larger and more fuel-rich zone at the fuel entry elevation where NO production is minimized.

Figure 15 shows the variation of configurations 1a and 1ab NO for a fixed percent air on the wall for a wide range of vertical distributions of wall air. These conditions were taken at a different temperature than the results in Figure 14. As can be seen in Figure 15, NO decreases for $SR_1$ less than 0.88, reaches a local minimum and then increases before finally achieving a second low level for the case where all of the wall air is evenly distributed between ports 2 and 3. As wall ports 1a, 1b, 2, and 3 air flow is varied, both the distribution and velocity of wall air is changing. For the 1ab case at the two extreme conditions, with no flow in wall air ports 2 and 3 and all of the air flow in ports 2 and 3, all of the jet velocities are equal and the observed NO reduction is due entirely to the vertical displacement of wall air. Therefore, the results presented in Figure 15 under these extreme conditions show a distinct advantage in vertically separating the fuel and wall air. At intermediate air splits, the jet velocities are lower, which might be part of the reason for the local NO minimum. This point will be explored in further testing.

For application to real systems, conditions at $SR_1$=0.8 are more attractive than at $SR_1$=0.2. This is because at $SR_1$=0.8 significant amounts of wall air are present along the walls at and above the fuel tube elevation. Probing tests at the wall showed 15, 12, and 12 percent oxygen at, 20 cm, and 46 cm above the fuel tube elevation, respectively . Lower levels at the fuel tube elevation are expected for the $SR_1$=0.2 conditions. As indicated previously, maintaining a high oxygen concentration on the wall is beneficial from a wall corrosion and slagging point of view.

The minimum NO achieved with System 2 is lower than System 1 levels and represents a 65 percent reduction from baseline tangential system levels. Combustion efficiency during these tests was excellent with CO, UHC, and percent carbon in flyash emissions being less than 40 ppm, 3 ppm, and 2.4 percent, respectively. These levels are comparable to System 1 and conventional tangential system results.

# CONCLUSIONS

Based on coal-fired and pilot-scale tangential system burner and vortex characterization tests, a low-$NO_x$ system was defined. The major system feature is the dividing of the secondary combustion air between injection into the center of the furnace and injection along the furnace walls. The delayed mixing of the wall air into the vortex causes a rich combustion zone to develop in the furnace, minimizing fuel and atmospheric $NO_x$ formation. Primary, secondary, and wall jet configurations and flowrates strongly influence the effectiveness of the system to lower $NO_x$ emissions. Testing showed that the best results are achieved with (1) wall air directed horizontally and along the wall (2) wall air flow equal to or greater than 80 percent of secondary combustion air (3) primary/secondary air coannular configuration (4) wall air vertically distributed at and above fuel entry location. At optimal parameter settings, reductions of 65 percent in NO from conventional tangential system levels can be achieved at comparable combustion efficiency. In addition, wall oxygen concentration at the burner level is significantly increased over conventional tangential firing. This increase is beneficial from wall corrosion and slagging points of view. Also, the system shows a decrease in $NO_x$ emissions as temperature is increased. This characteristic could be beneficially applied to reduce furnace volume for a given heat release.

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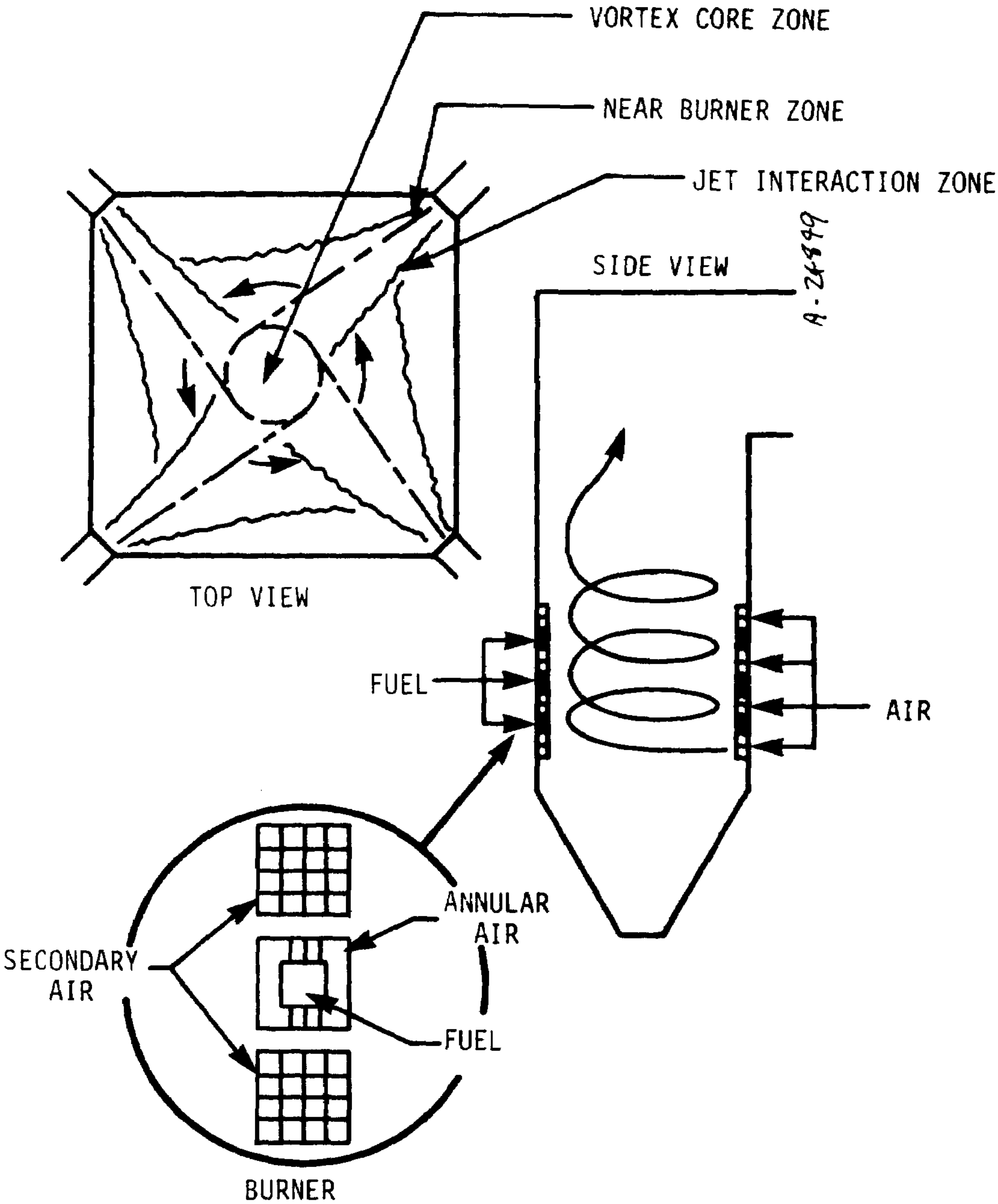


Figure 1. Tangential boiler schematic.

1. Combustion chamber
2. Ignition and flame safeguard
3. Observation ports
4. Ashpit
5. 440 kW swirl burner for front wall firing
6. Corner burners for tangential firing
7. 2033K refractory
8. Tower sections
9. Heat exchanger assemblies
10. Staged air injection ports

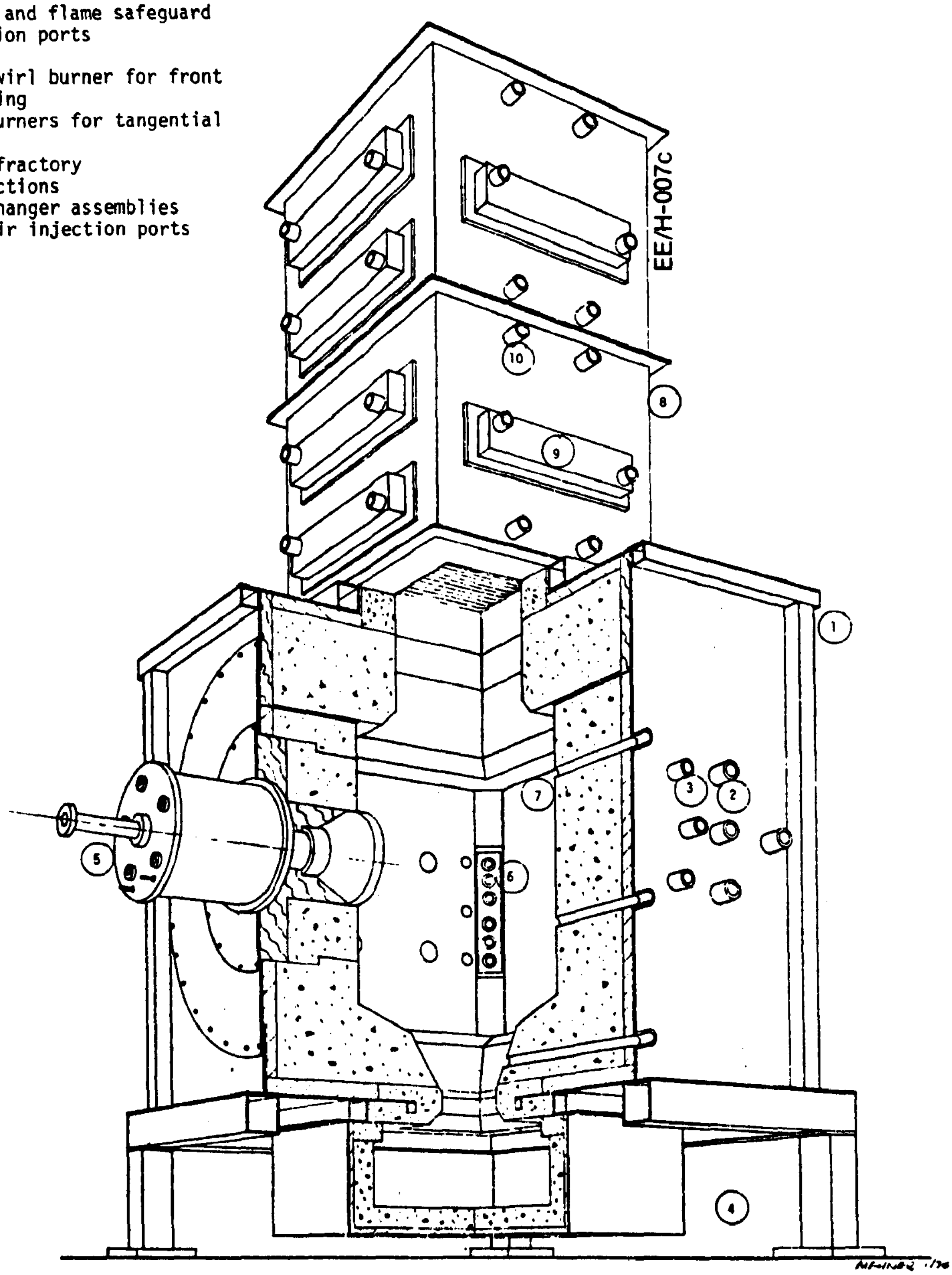


Figure 2. Pilot-scale test facility.

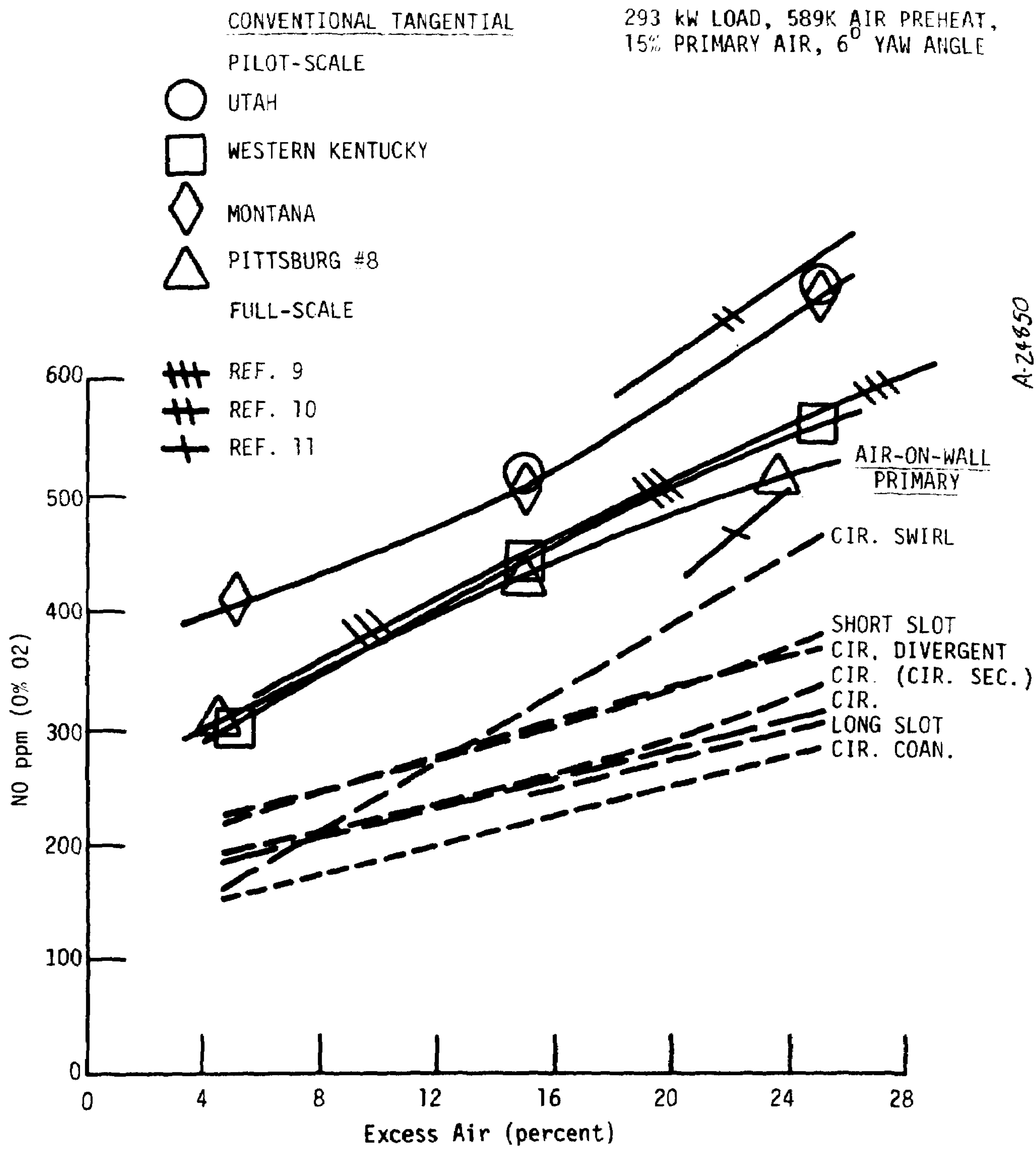


Figure 3. Effect of excess air on pilot-, full-scale and air-on-wall system NO emissions.

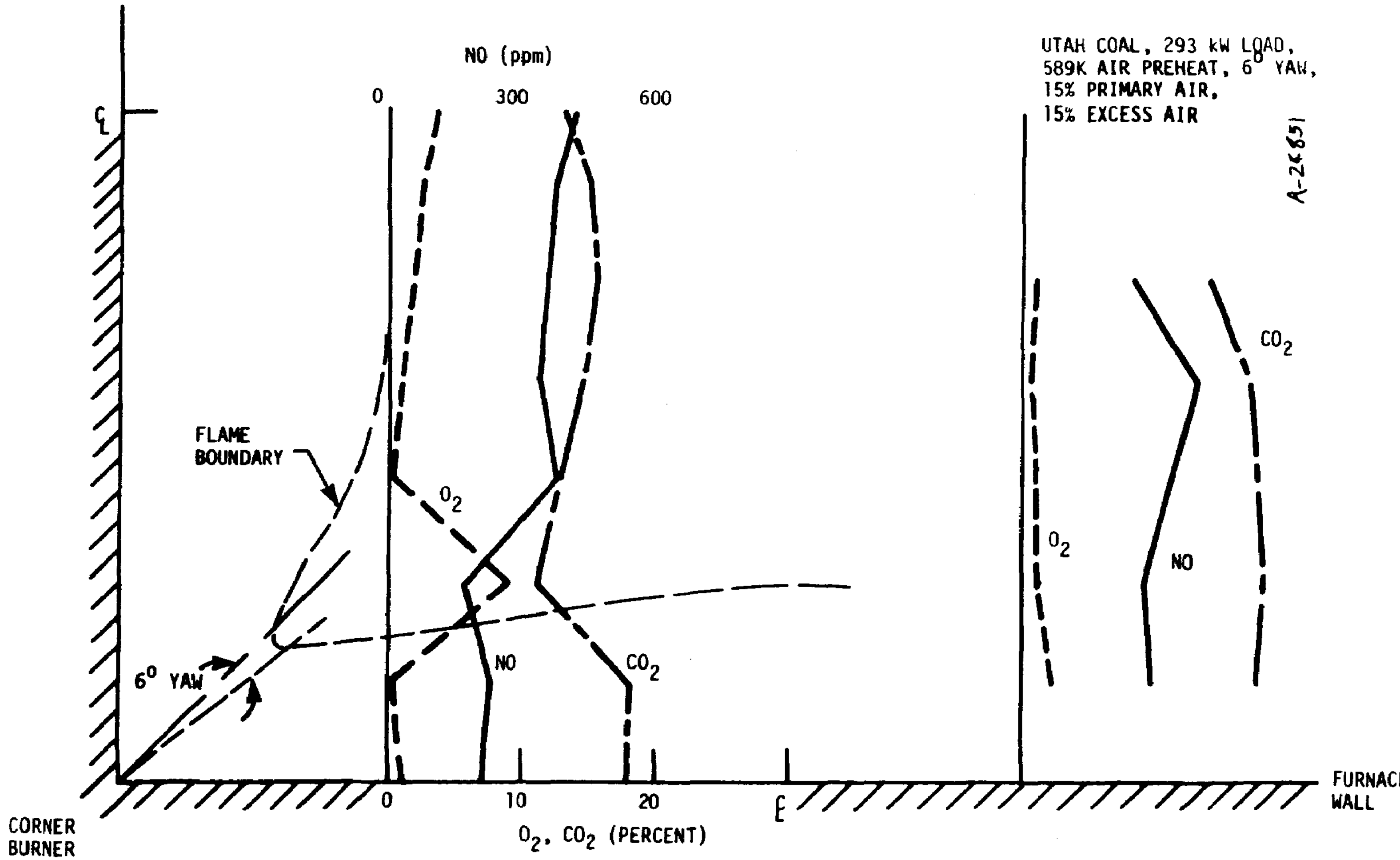


Figure 4. Concentration distributions at the fuel tube elevation superimposed on a plan view of the firebox.

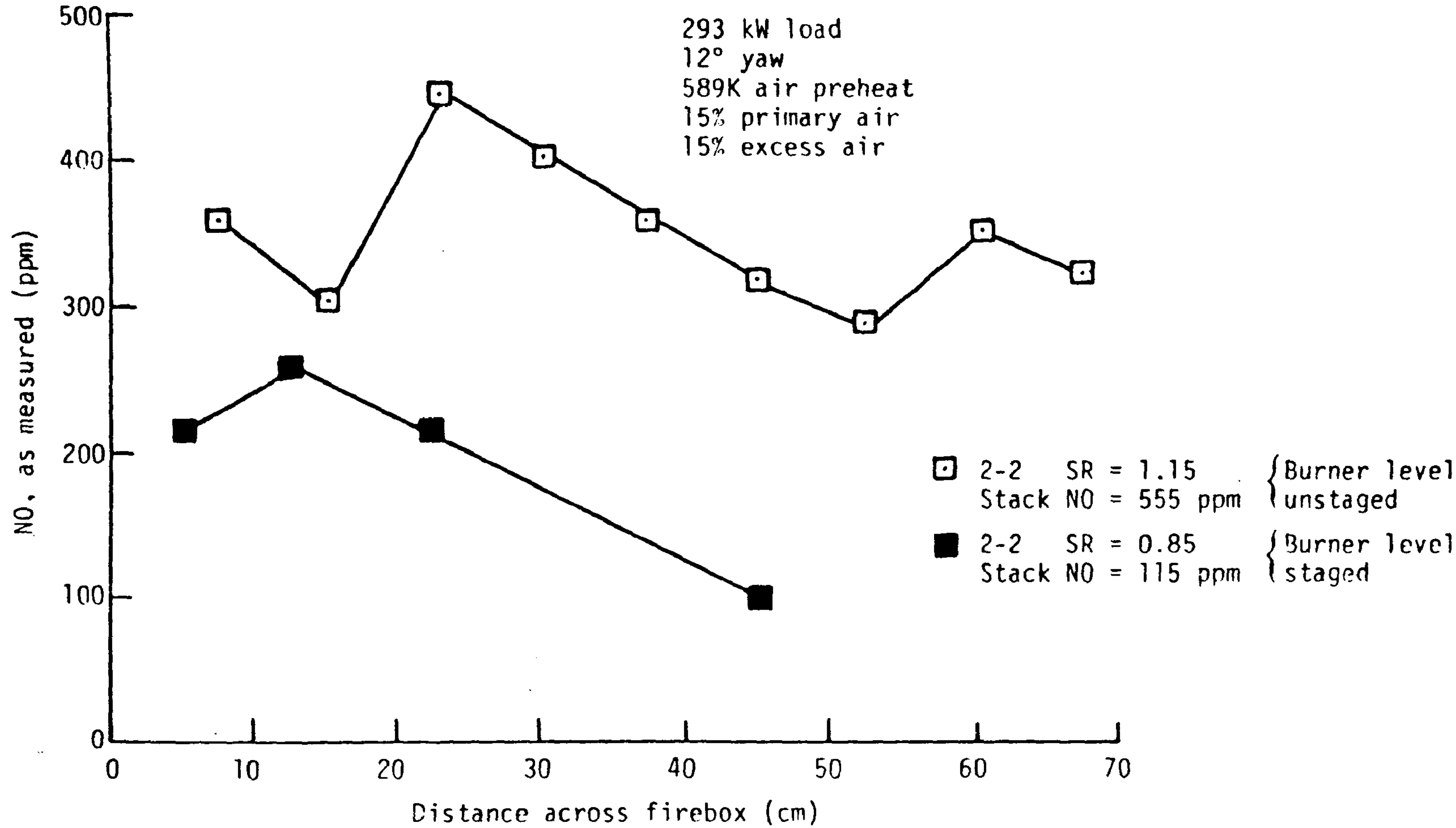


Figure 5. Comparison of unstaged and staged firebox NO probing results.

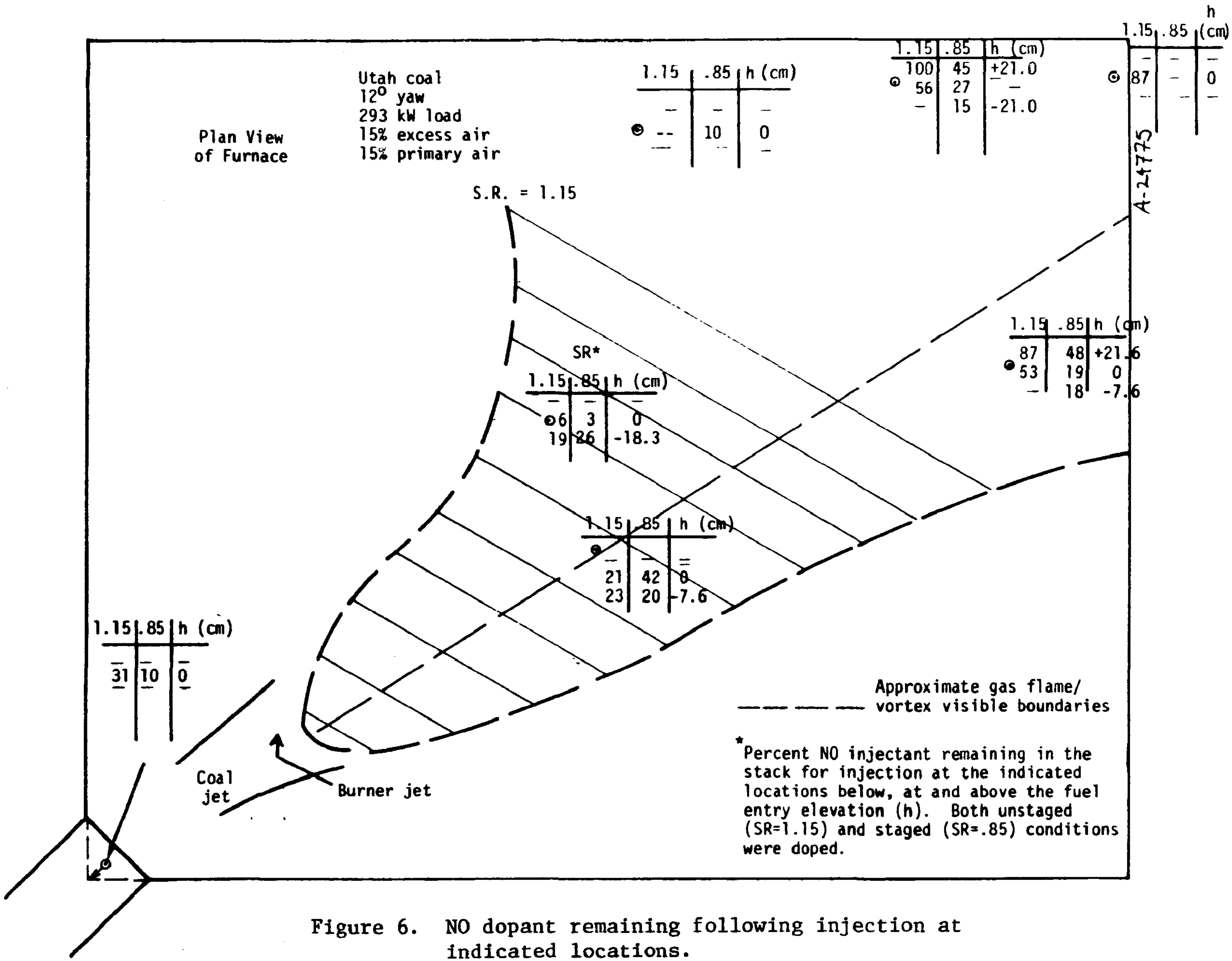


Figure 6. NO dopant remaining following injection at indicated locations.

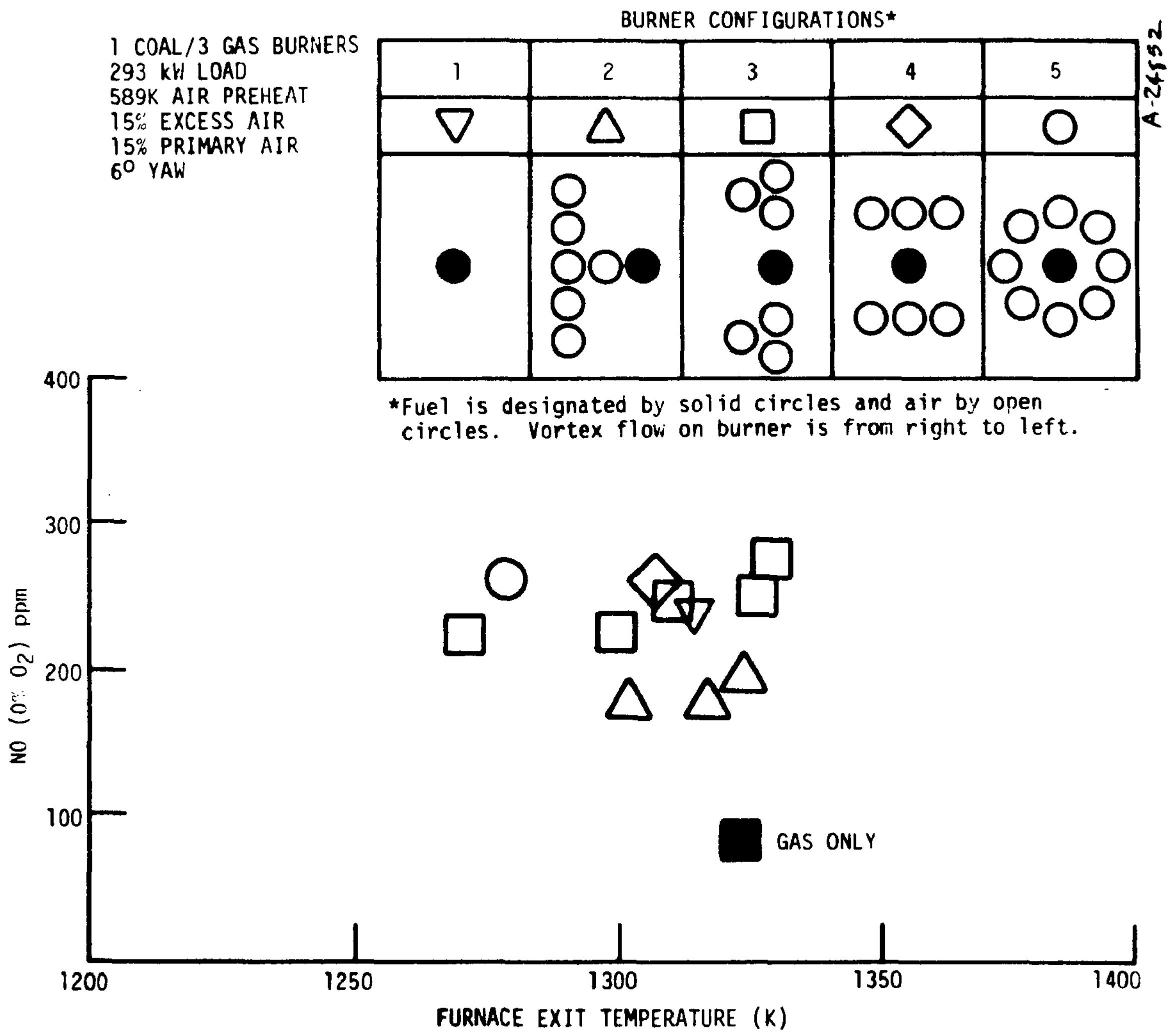


**Figure 7. Burner configuration NO levels.**

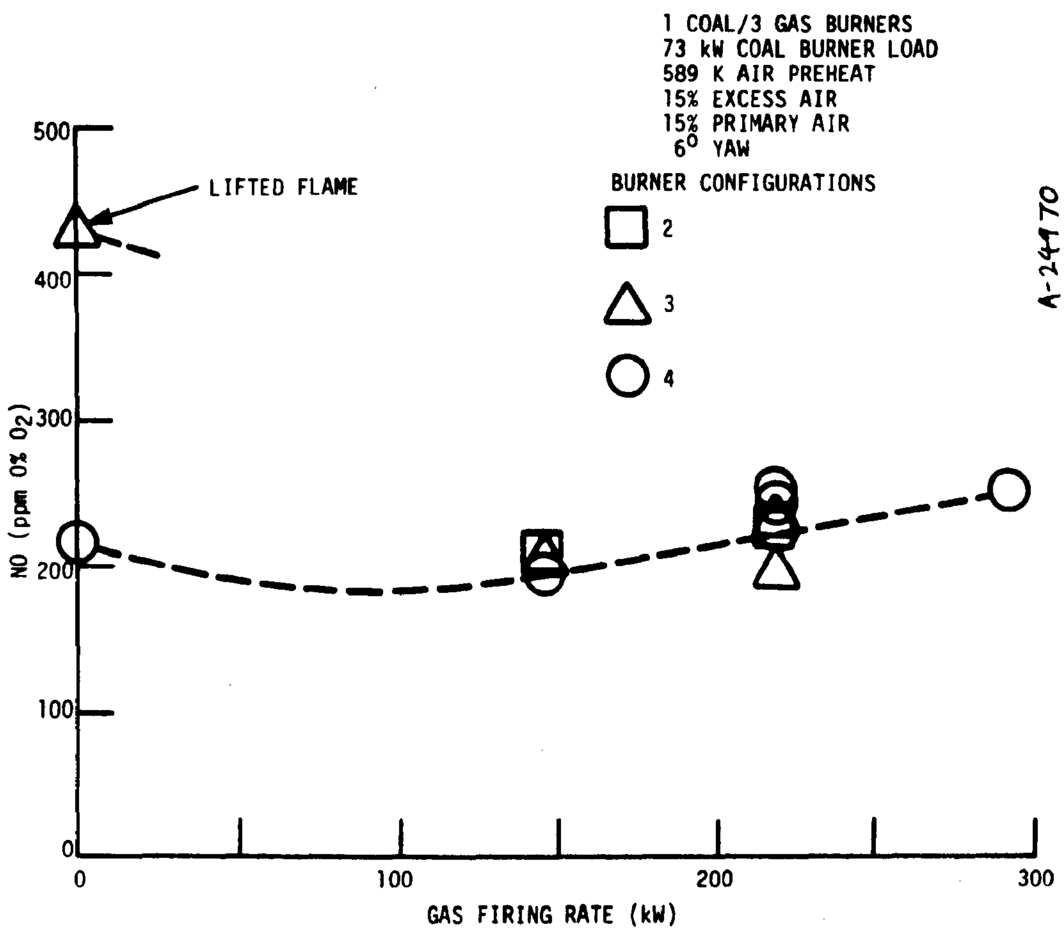


**Figure 8. Burner configuration NO level variations with firing rate.**

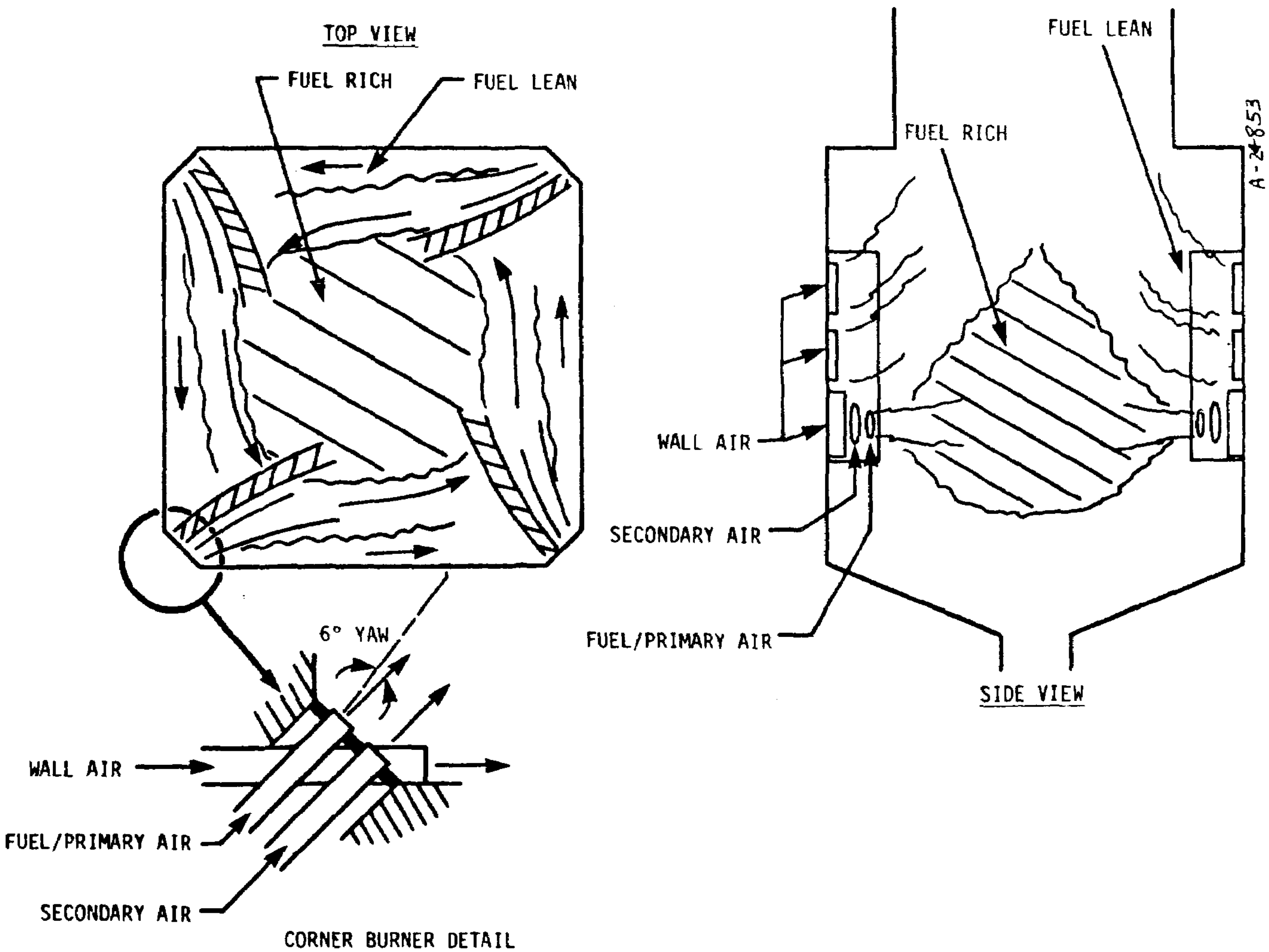


Figure 9. Low-$NO_x$ air-on-wall system schematic.

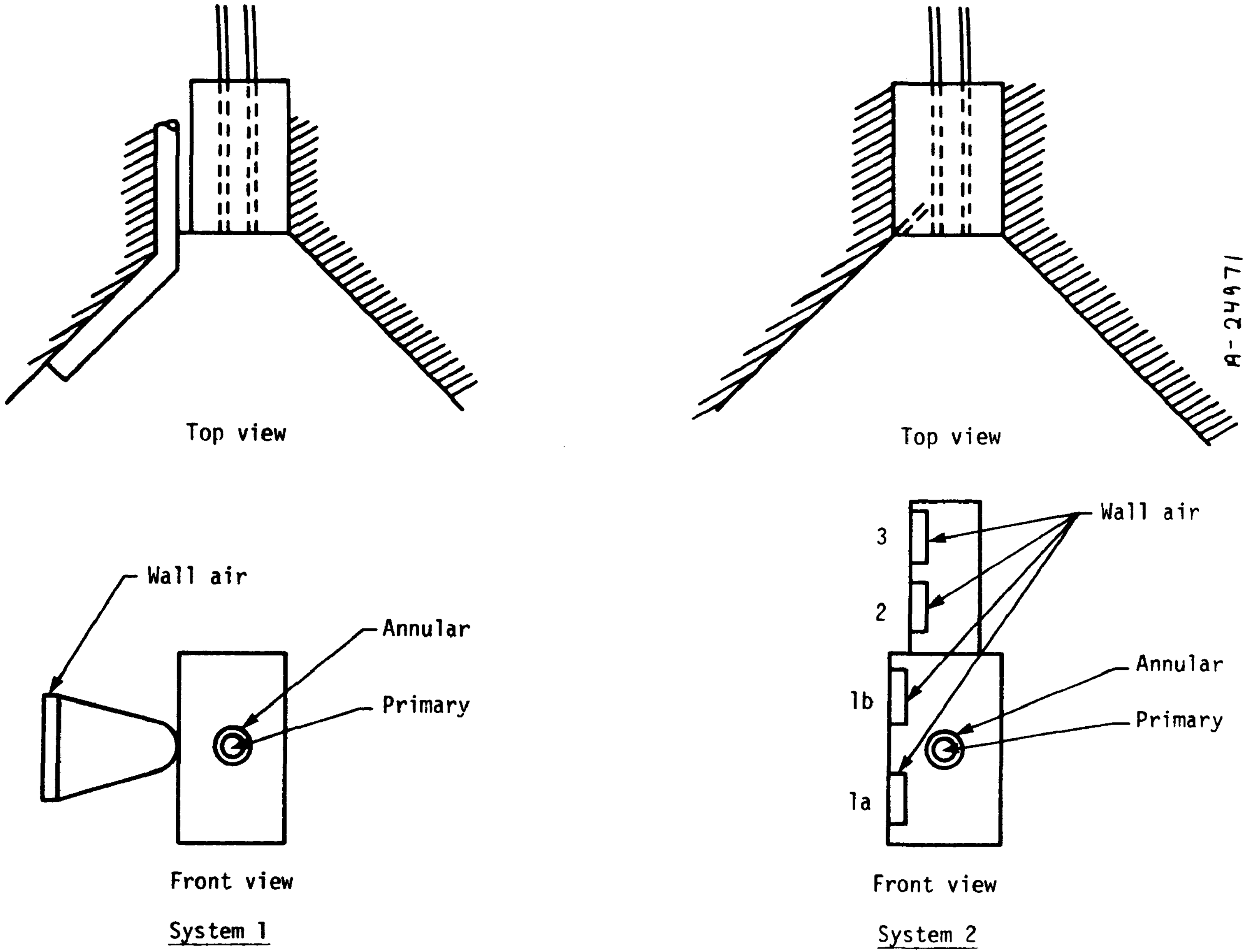


**Figure 10. Low-$NO_x$ system burner types.**

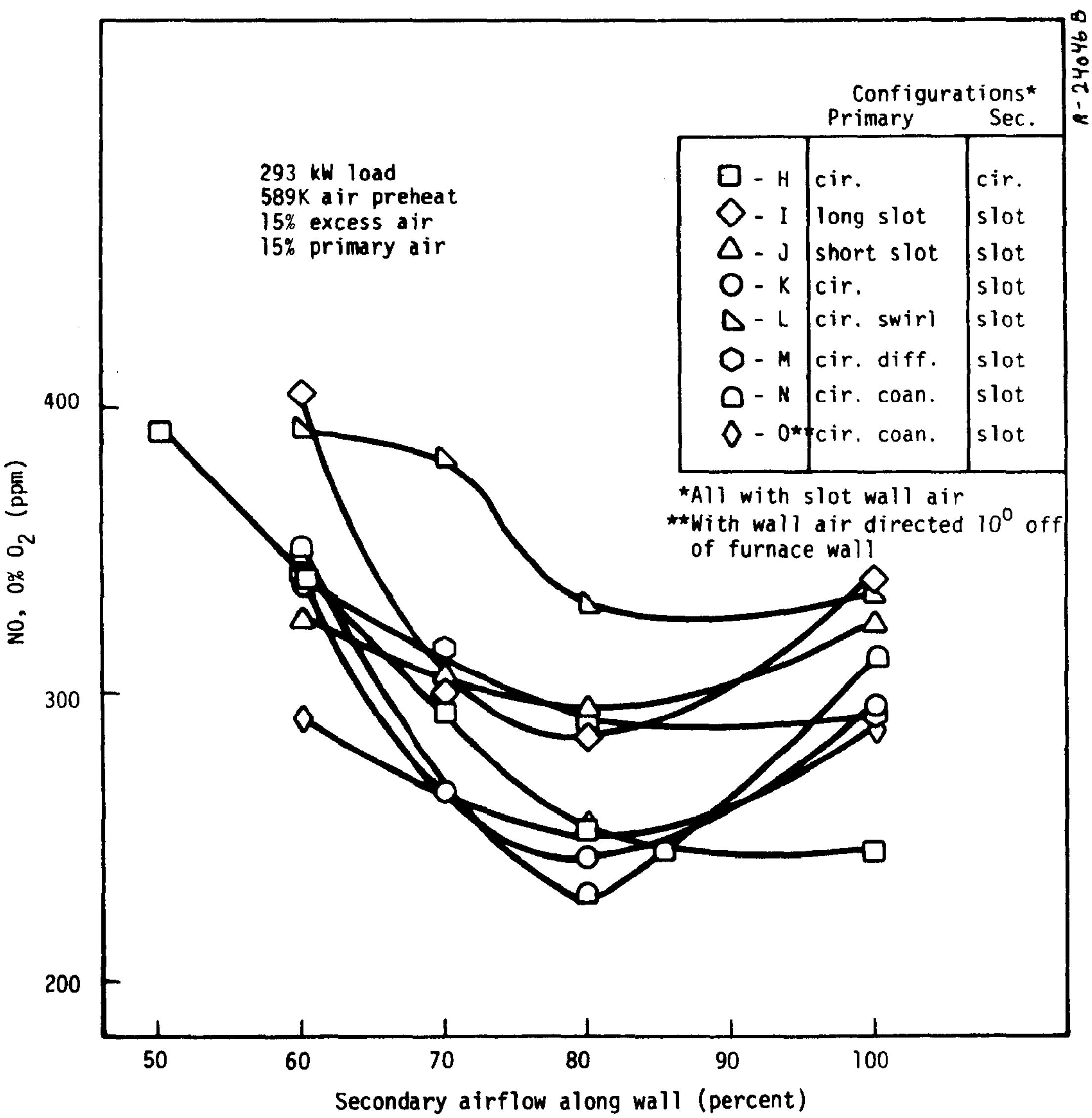


Figure 11. Comparison of NO for a variety of primary configurations with percent secondary air-on-wall.

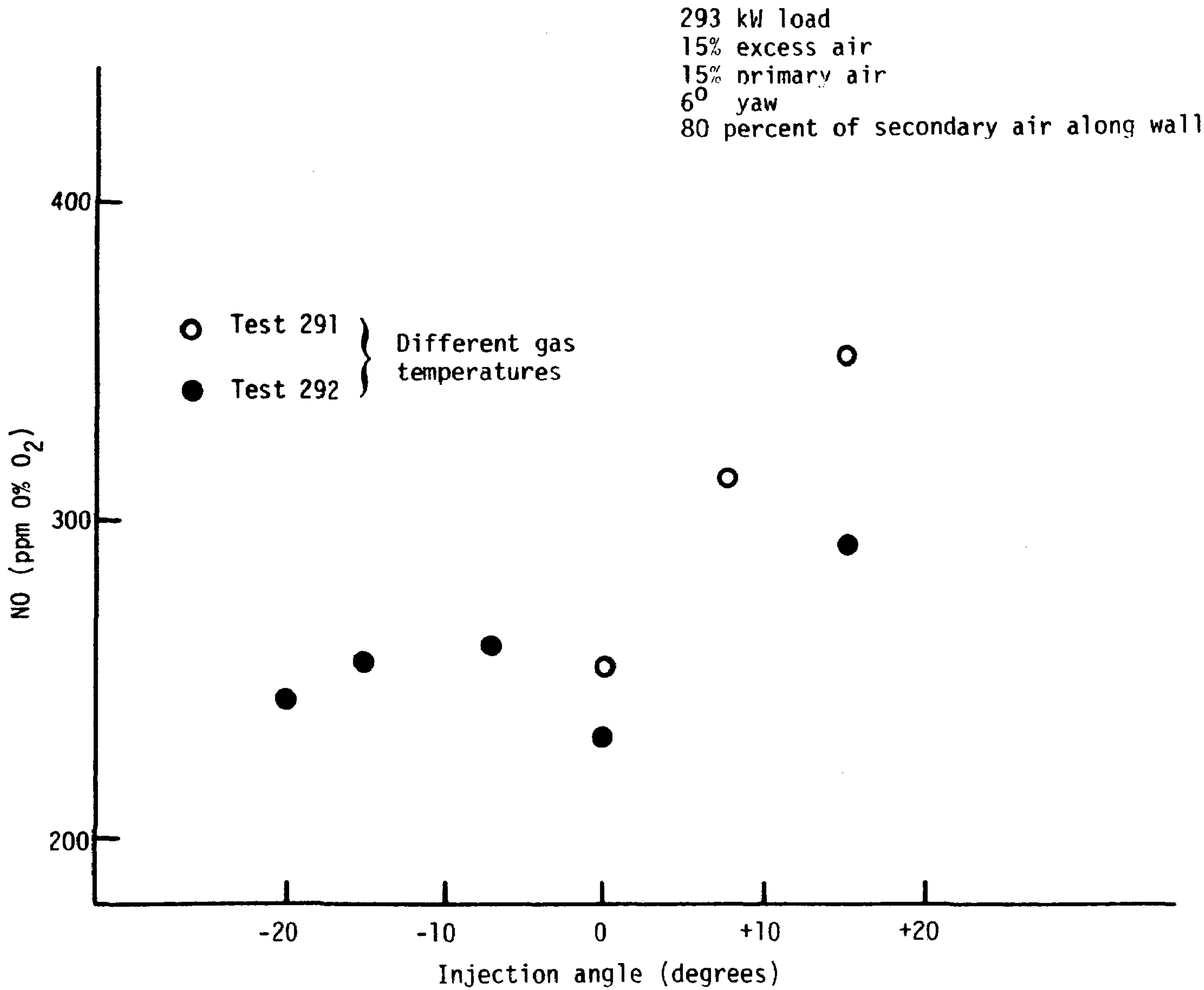


**Figure 12. Effect of wall jet inclination angle.**

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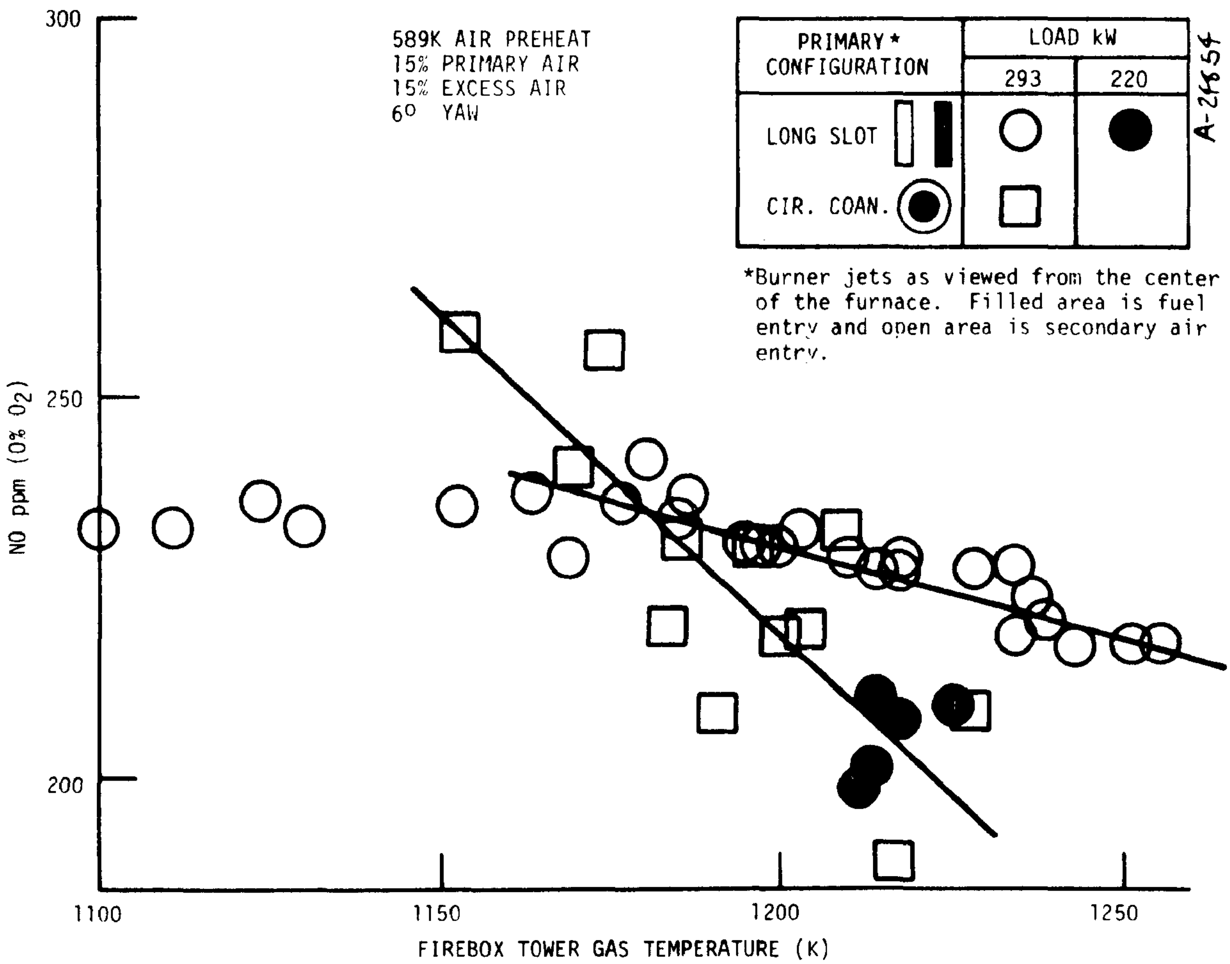


Figure 13. NO versus gas stream temperature for air-on-wall low $NO_x$ system.

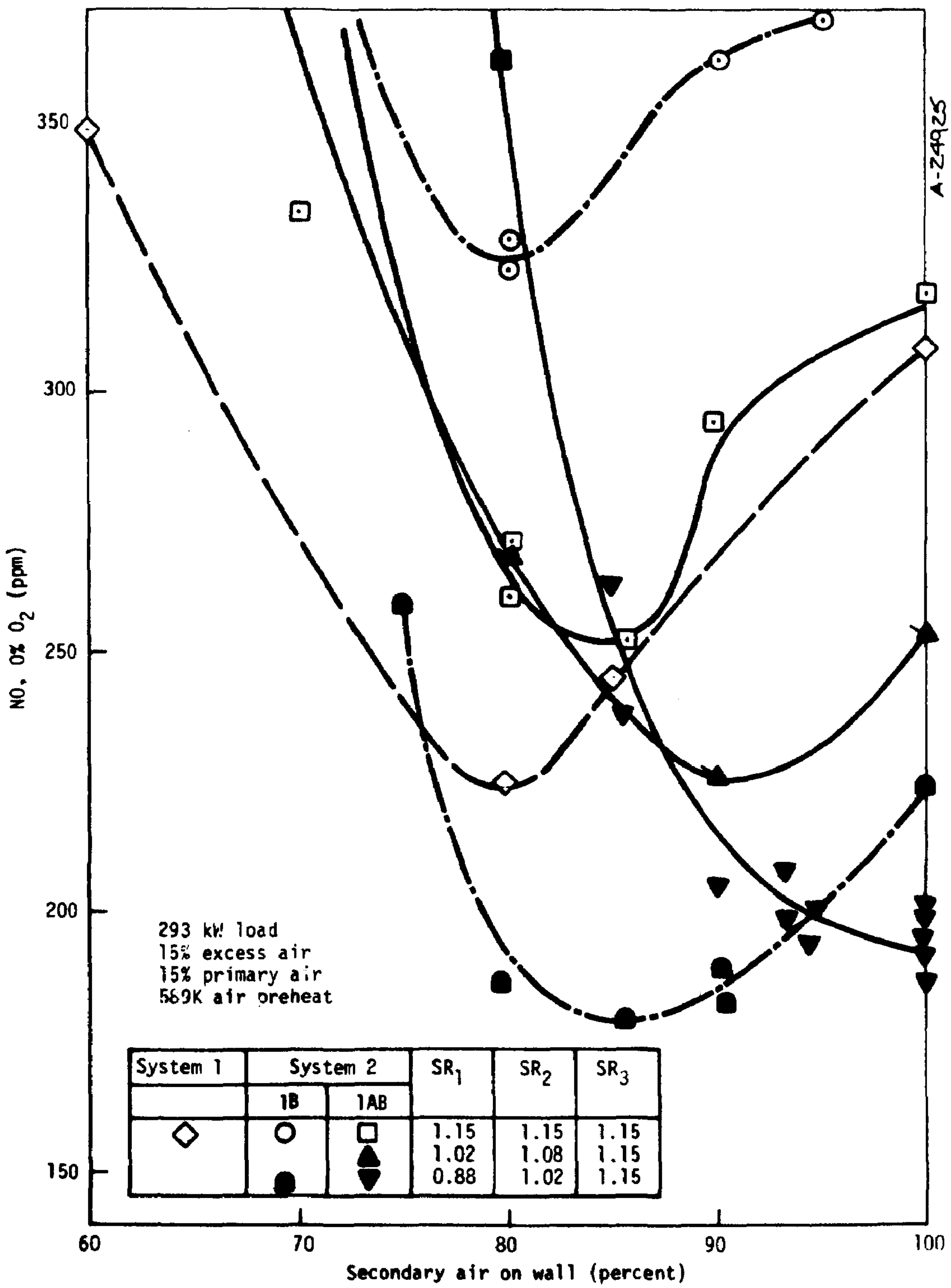


Figure 14. NO variation with percent air-on-wall for vertical wall air configurations.

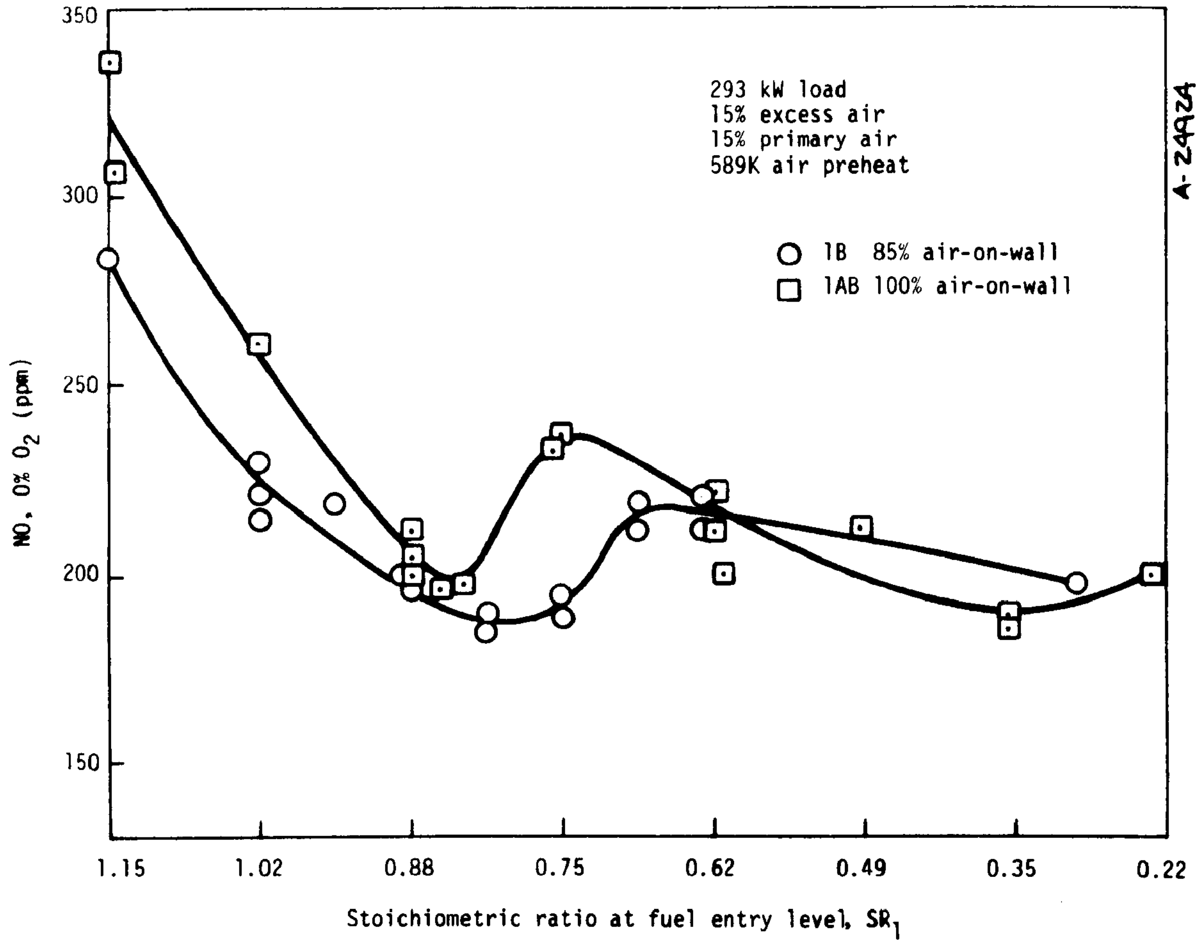


Figure 15. NO variation with wall air flow above fuel entry elevation.

TABLE I. ANALYTICAL POLLUTANT MEASUREMENT EQUIPMENT

| | |
|---|---|
| $NO/NO_x$ | Air Modeling Model 32C chemiluminescent analyzer |
| $O_2$ | Intertech Model Magnos 5T paramagnetic $O_2$ analyzer |
| CO | Anarad Model AR500R NDIR analyzer |
| $CO_2/CO$ | Anarad Model AR600R NDIR analyzer |
| UHC | Intertech Model FID0008 FID H/C analyzer |
| $SO_2$ | TECO Series 40 Pulsed Fluorescent analyzer |

TABLE II. UTAH COAL ANALYSIS

| Ultimate Analysis | Dry basis (% wt) |
|---|---|
| Carbon | 69.91 |
| Hydrogen | 5.15 |
| Nitrogen | 1.5 |
| Sulfur | 0.98 |
| Oxygen (diff) | 12.46 |
| Ash | 10.0 |
| **Proximate Analysis** | **As received (% wt)** |
| Moisture | 5.6 |
| Ash | 9.4 |
| Volatile | 40.6 |
| Fixed carbon | 44.4 |
| Heating value (cal/gm) (dry basis) | 6,966 |
| Sieve analysis | 77.3% wt percent through 200 mesh |

# THE DEVELOPMENT OF A LOW $NO_x$ DISTRIBUTED MIXING BURNER FOR PULVERIZED COAL BOILERS

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ABSTRACT

This paper describes the development of a low $NO_x$ pulverized coal burner for demonstration in two small pulverized coal-fired boilers by 1982. The "Distributed Mixing Burner" concept provides for controlled mixing of the coal with the combustion air to minimize $NO_x$ emissions while maintaining an overall oxidizing environment in the furnace to minimize slagging and corrosion. The design of a prototype field operable burner is discussed, and test data in a research facility suggesting that $NO_x$ emissions less than 84 ng/J (0.2 lb/$10^6$ Btu) might be attainable in the field are presented.

## ACKNOWLEDGMENTS

This paper is based upon work conducted under Contract Nos. 68-02-1488, 68-02-2667 and 68-02-3127 with the U. S. Environmental Protection Agency. The authors wish to express their appreciation to Mr. G. B. Martin of the U. S. Environmental Protection Agency for his considerable help and advice.

## SECTION 1

## INTRODUCTION

The projected increase in pulverized coal use for industrial and utility steam generation will result in significant increases in pollutant emissions. One recent report predicts that $NO_x$ emissions will increase 80 percent by the year 2000, even if current control technology is fully employed (1). Maintaining or improving the current air quality will clearly require the development and application of advanced $NO_x$ control techniques. Combustion modification through the installation of low $NO_x$ burners is one of the most promising techniques for reducing emissions without greatly increasing overall costs or reducing efficiency.

For the last several years Energy and Environmental Research Corporation has been working with the EPA to develop a low $NO_x$ pulverized coal burner. This "Distributed Mixing Burner", DMB, provides for controlled mixing of the coal with combustion air to minimize $NO_x$ emissions while maintaining an overall oxidizing environment in the furnace so as to minimize the detrimental effects of furnace corrosion. DMBs have been tested at firing rates up to 29 thermal MW (100 x $10^6$ Btu/hr) in single and four-burner arrays in two research furnaces. The tests covered wide ranges of burner adjustments and operating conditions. Under optimum experimental conditions, $NO_x$ levels less than 65 ng/J (0.15 lb/$10^6$ Btu) were obtained (2). The minimum $NO_x$ levels obtainable in field operating boilers will, of course, vary with boiler design and operating conditions and may be higher than these experimental results.

Application of the DMB concept to new pulverized coal-fired boilers requires an evaluation of long-term performance in field boilers. This evaluation is being conducted on small pulverized coal-fired boilers (less than 455 x $10^3$ kg: 1.0 X $10^6$ lb of steam per hour) under EPA Contract 68-02-3127 and on larger utility boilers under EPA Contract 68-02-3130 (3). The small boiler demonstration, which is the subject of this paper, has been scheduled first so that the larger utility boiler demonstration can benefit from the test results. However, the actual burner components being utilized in each program are representative of those which are used commercially by the respective boiler manufacturers. Consequently, the utility program (68-02-3130) will benefit from the small boiler program (68-02-3127) only in that the concept will be first demonstrated in the field in the small boiler program. The burner components provided to the small boiler program will not be utilized in the utility program.

The small boiler demonstration involves two Foster Wheeler front wall-fired units which are representative of industrial size boilers. The first unit has a capacity of 98 x $10^3$ kg/hr (215 x $10^3$ lb/hr) and has four burners in a 2 x 2 array. The second unit being considered has a capacity of 175 x $10^3$ kg/hr (385 x $10^3$ lb/hr) and has six burners in a two-high by three-wide array. The DMBs to be installed in these units will be designed by incorporating DMB flow parameters into a commercial burner design and adding the requisite number of tertiary air ports. Prototype burners will be fabricated by Foster Wheeler using commercial burner components and construction methods. The design parameters will then be optimized by testing in the research furnace. The final configurations will be installed in the field boilers and tested for 18 months duration. During this long-term evaluation all aspects of the burner/boiler performance will be assessed, including: $NO_x$ emissions, other environmental impact, burner and boiler efficiency, durability, operability, safety, boiler performance and integrity and heat transfer surface duties.

This paper discusses the status of the DMB under development for the initial demonstration. The prototype burner has been designed and fabricated. The test data leading to the DMB design criteria and the prototype burner design are discussed in the following section. The prototype burner and a burner similar to the burners currently installed in the initial demonstration boiler have been tested in the research furnace. The results of these tests and an estimate of potential DMB performance in the initial demonstration boiler are discussed in Section 3.

## SECTION 2

## PROTOTYPE DMB DESIGN

The prototype DMB for the initial field demonstration has been designed to meet the following requirements:

- DMB design criteria
- Compatibility with host burner/boiler specifications
- Commercial burner construction methods and operational characteristics

### DMB DESIGN CRITERIA

The DMB concept involves staging the combustion process to minimize $NO_x$ emissions while maintaining an overall oxidizing atmosphere in the furnace so as to have minimal impact on furnace slagging and corrosion. $NO_x$ production from fuel nitrogen compounds is minimized by driving a majority of the compounds into the gas phase under fuel-rich conditions and providing a stoichiometry/temperature history which maximizes the decay of the evolved nitrogen compounds to $N_2$. Thermal $NO_x$ production is also minimized by enthalpy loss from the fuel-rich zone which reduces peak temperatures.

A schematic representation illustrating how the DMB design sequentially stages the fuel/air mixing is shown in Figure 1. The combustion process occurs in three zones. In the first zone pulverized coal transported by the primary air combines with the inner secondary air to form a very fuel-rich (30 to 50 percent theoretical air) recirculation zone which provides flame stability. The coal devolatilizes and fuel nitrogen compounds are released to the gas phase. Outer secondary air is added in the second "burner zone" where the stoichiometry increases up to about 70 percent theoretical air.

This is the optimum range for reduction of bound nitrogen compounds to $N_2$ (2). Air to complete the combustion process is supplied through tertiary ports located outside the burner throat. This allows substantial residence time in the burner zone for decay of bound nitrogen compounds to $N_2$ and radiative heat transfer to reduce peak temperatures. The tertiary ports surrounding the burner throat provide an overall oxidizing atmosphere in the burner zone.

Figure 2 shows the DMB as it would be installed in the small wall-fired boiler. This DMB design uses components illustrated below:

- Four independently controlled airstream systems divide the total combustion air into:
  1. An annular coal nozzle;
  2. A central passageway containing an ignitor for start-up;
  3. Two concentric secondary airstreams to provide inner and outer secondary airflow; and
  4. Four outboard tertiary air ports.
- The annular fuel nozzle and tangential coal inlet produce a uniform annular coal distribution.
- Two adjustable air registers connected to the secondary air passages to control both the airflow rates and degree of swirl.
- Ignition and main flame scanner systems for safety.

Six DMB configurations using other components have been evaluated in two research furnaces to determine the effects of design parameters on flame shape and stability, as well as efficiency (as indicated by CO emissions) and $NO_x$ emissions. These burners ranged in capacity from 3.6 thermal MW ($12.5 \times 10^6$ Btu/hr) to 29 thermal MW ($100 \times 10^6$ Btu/hr), and were tested as single burners. In addition a 2X2 array of 3.6 thermal MW ($12.5 \times 10^6$ Btu/hr) burners was also tested. Each configuration was evaluated over a range of operating conditions and the ersults will be discussed in terms of the following burner systems:

- Fuel System
- Secondary Air System
- Tertiary Air System

Fuel System

The DMB fuel system includes the following geometric variables and fuel/air characteristics through the fuel nozzle:

- Primary stoichiometry
- Nozzle size and axial position
- Exit velocity
- Swirl

The effects of each of these variables (except nozzle size) on burner performance have been evaluated. Although nozzle size has not been specifically evaluated, it is considered to have only secondary effects on burner performance over the practical range.

The DMBs tested in the research furnaces utilized a circular coal nozzle located on the burner axis. In two of the burners there was no provision for primary swirl, and as a result, the rate of mixing between the primary and secondary streams was low. This produced a longer diffusion-type flame and low $NO_x$ emissions. Long flames can be utilized in furnaces with sufficient depth and when low burner liberations are used. However, the goal of this program is to develop a burner which has a short flame, requires no reduction in burner capacity, and is more compatible with a wide range of furnace configurations including short furnace depths of 6 m (20 ft) or less. The other DMB configurations tested in the research furnaces included impellers in the nozzle to impart swirl and increase the rate of mixing between the primary and secondary airstreams. The resulting flames were considerably shorter, but had slightly higher $NO_x$ emissions. The following discussion will include the test results from the short flame burners. Test results from the long flame burners are discussed in References 2, 3 and 4.

Figure 3 shows some typical results obtained with a 14.6 thermal MW ($50 \times 10^6$ Btu/hr) single secondary DMB firing at full load and 125 percent theoretical air. Minimum $NO_x$ levels are in the range of 100 ppm* which

*All NO and CO concentrations in this paper are corrected to 0 percent $O_2$, dry conditions.

corresponds to 46 ng/J (0.11 lb/$10^6$ Btu). CO emissions are in the range of 250-500 ppm which is considerably higher than typical burner performance in field boilers (~50 ppm). This difference is believed to be a consequence of the research furnace design, and will be discussed in a subsequent section. With the swirl vanes removed (axial flow) it was not possible to obtain acceptable flame stability. At 30° swirl angle an acceptable flame was achieved with minimum emissions, and no measurable increase in $NO_x$ was observed when the swirl angle was increased to 45°. Further increasing the swirl angle to 60° resulted in a large increase in $NO_x$. Due to the limited range and scatter in the CO data, the effect of swirl angle on CO is unclear. The indicated lines represent a best judgment as to interpretation of the results. This interpretation would indicate that both the fuel/air mixing characteristics and ignition flame characteristics are changing significantly. Therefore, there should be a design trade-off between NO and CO with primary swirl, with lower swirl angles providing lower $NO_x$ levels. However, if in the final configuration the CO levels are extremely sensitive to burner parameters, then this will limit its $NO_x$ capabilities. Ignition stability represents the lower limit of operation, although it would not be prudent to design at that low a level. Since ignition stability plays a key role in the ability to minimize both NO and CO, the specific design parameters will depend on the site-dependent conditions. It is not yet known if the burners' $NO_x$ capabilities will vary with these site-dependent conditions.

Secondary Air System

The DMB secondary air system includes all components which provide air through the burner throat except for the coal nozzle. Specific variables include:

- Air distribution between secondaries
- Velocity
- Swirl
- Burner zone stoichiometry

The DMBs tested in the research furnaces included designs with single, as well as dual secondary air passages. The dual secondary design is preferred because of the additional control over fuel/air mixing rates which can be achieved by varying the flow rates and swirl in the two secondary passages. However, for simplicity, most of the DMBs were designed with a single secondary air passage.

Figure 4 shows the effects of secondary air system variables on the performance of the single secondary 14.6 thermal MW (50 x $10^6$ Btu/hr) burner. The operating conditions were the same as for the data presented in Figure 3, and the primary swirl was $45^o$. Variations in burner zone stoichiometry are produced by varying the amount of air through the outboard tertiary air passages. For burner zone stoichiometries equal to the overall stoichiometry (125 percent theoretical air) all of the air passes through the burner throat (unstaged condition). Figure 4 shows that for unstaged conditions the DMB produces NO and CO levels of 400 and 300 ppm, respectively. As the burner zone stoichiometry is decreased (air diverted through the tertiary ports) keeping the overall stoichiometry constant at 125 percent theoretical air, NO decreases. At a burner zone stoichiometry of 60 percent theoretical air the range of $NO_x$ is 90-180 ppm. CO remains essentially constant down to about 70 percent theoretical air where the airflow through the secondary air passages has decreased to the point where the flame stability decreases and CO emissions rise. While the flame is still stable initially, continued reduction in burner zone stoichiometry eventually leads to instability and flameout. Due to the onset of instability, operation near the knee of the CO curve is unacceptable. Consequently, actual NO levels in the field may be higher than those shown in Figure 4. For this burner, operation at 70 percent throat stoichiometry appears to be acceptable. Under this minimum condition $NO_x$ is about 0.2 lb/$10^6$ Btu.

In comparing the CO and NO characteristics, note that the impact of burner zone stoichiometry on NO remained unchanged even as the CO markedly increased. This suggests that the NO formation is being controlled principally by the burner zone stoichiometry and not by the primary/secondary mixing rates. The conditions producing the increase in CO shown in Figure 4 were found to be strongly dependent on the burner settings, as well as design velocity. In fact, at full load it was possible to obtain minimum CO and NO over a wide range in excess air levels by simply varying both burner zone stoichiometry and swirl conditions. (This is not meant to imply that it is the intent of this program to vary the burner setting in the field during the load or excess air changes). Although not shown in Figure 4, at zero swirl the flame could not be operated stably, even at high burner zone stoichiometry, and resulted in flameout. As secondary swirl was increased to 30° it was possible to achieve a stable flame over a burner zone stoichiometry range from about 70 percent theoretical air to essentially unstaged conditions (120 percent of theoretical air). Lower burner zone stoichiometries were possible as the secondary swirl angle was increased. Note that the NO characteristics were essentially unchanged with secondary swirl angle, while the burner performance (CO) was improved by increasing secondary swirl. Thus, there is a trade-off in NO and CO emissions as burner zone stoichiometry and swirl are varied. Optimum values with this burner for invarient operating conditions are: (1) secondary swirl angles of 30° to 45°, and (2) a burner zone stoichiometry of about 60 percent theoretical air.

Tertiary Air System

The DMB tertiary air system includes all components which provide air through the tertiary air passages. Specific variables include:

- Velocity
- Number of ports
- Location of ports

Variations in tertiary velocity have been found to have little effect on NO and CO emissions for tertiary port configurations of practical significance. However, the number and location of the tertiary ports have been found to affect CO but not NO emissions. Figure 5 shows some results from tests of a four-burner array of 3.6 thermal MW (12.5 x $10^6$ Btu/hr) DMBs. The tertiary ports for adjacent burners were combined as shown to minimize the total number of tertiary ports. The tests were conducted by maintaining the secondary air flow rate (burner zone stoichiometry) constant and varying the tertiary air flow rate (overall stoichiometry) and the number of ports in service. The decrease in NO as the overall stoichiometry is reduced is typical of performance for most burners. CO emissions for all ports in service are constant, independent of overall stoichiometry, over the range tested. Although not shown in Figure 5, lower values of overall stoichiometry (less than 110 percent theoretical air) caused a sharp increase in

CO and smoke emissions. This is also typical performance for most burners.

Tests were conducted with various rows and/or columns out-of-service to define the sensitivity of NO and CO to the number and location of the tertiary ports. The results presented in Figure 5 show that within experimental accuracy the NO characteristics were completely unaffected by the variations in tertiary air velocity or tertiary port location. The general conclusion from this is that for these short flames the burner zone is essentially premixed and burns at the burner zone stoichiometry and, therefore, NO is formed in the burner flame zone before substantial interaction with the tertiary air. While NO was not affected by tertiary port location in the multiburner configuration, the variations in CO were dramatic. Note that unsymmetric changes in tertiary ports out of service were accompanied by an increase in CO. This result reveals that the tertiary port location relative to the burners has a strong impact on the overall mixing in the lower furnace, and that improper port location will result in incomplete CO burnout in the high temperature region of the furnace.

Based upon the test results presented above and other data involving variations in exit geometry, operating conditions and coal composition, nominal prototype burner design criteria have been identified and are listed in Table I. These criteria are nominal in that they are the starting point for prototype burner testing and final optimization.

HOST BURNER/BOILER SPECIFICATIONS

The boiler selected for the initial demonstration is Pearl Station which is owned and operated by Western Illinois Power Cooperative (WIPCO). Table II lists the characteristics of this unit which impact prototype burner design. The coal currently supplied to this unit is an Indiana bituminous coal with the characteristics listed in Table III.

The Pearl Station characteristics are compatible with the DMB design criteria listed in Table I with the following exceptions:

- Windbox Depth and Burner Exit Length. The windbox depth is designed for the currently installed pre-NSPS Intervane burners which have a single register and a short exit. However, it is too short to accommodate the dual registers and exit length specified in the DMB design criteria. The maximum exit length which can be used corresponds to about 40 percent of the prototype DMB throat diameter, whereas the design criteria specify 100 percent. Burner exit geometry affects flame stability and the effects of this short exit length were evaluated in the prototype tests (Section 3).

- Burner Spacing and Tertiary Port Locations. The burner spacing is too close for the tertiary ports to be located as specified in the design criteria. In addition, windbox and furnace structural considerations limit the potential tertiary port locations. Figure 6 shows the tertiary port locations selected for the WIPCO unit. Although this configuration deviates from the design criteria, the tertiary air is well-distributed around and between the burners and the velocity matches the design criteria.

  It should be noted that installation of the tertiary air ports results in removal of a buckstay and elimination of most of the firing wall support tubes. Consequently, an under hopper support must be installed. This technique is questionable for larger utility boilers and an alternate approach would have to be developed for this equipment.

PROTOTYPE BURNER DESIGN

The prototype DMB for the initial industrial boiler demonstration has been designed by integrating the DMB design criteria and the host firing system/boiler characteristics into a design using commercial burner components. The prototype DMB has been designed to allow variation of several burner parameters during testing. The optimum configuration will then be used as the basis for field operable burners.

Figure 7 is a cross-sectional view of the prototype burner showing its design details. The following Foster Wheeler commercial burner components have been incorporated into the design:

- Annular Coal Nozzle
- Telescoping Coal Nozzle for Primary Velocity Control
- Registers for Swirl Control and Flow Shutoff

- Air Hoods for Secondary Flow Rate Control and Measurement
- Commercial Flame Scanning and Ignition System

The coal and primary air enter the annular coal nozzle through a tangential inlet to provide swirl. The coal nozzle is a tapered annulus. The exit end of the coal nozzle is formed from two concentric cones. The inner cone can be moved axially to vary the exit area, and hence, the primary velocity. The outer portion of the coal nozzle is constructed of removable sections so that the overall length of the coal nozzle may be changed to vary the nozzle setback within the burner throat. There are two concentric secondary air passages supplied from a common windbox. Each is equipped with an adjustable register for swirl control, an axially movable sleeve for flow control and perforated plate (air hood) for flow rate measurement. Pressure taps on both sides of each perforated plate allow the pressure drop to be measured and correlated with sleeve position and flow rate.

The portion of the burner inside the coal nozzle is termed the core, and is supplied with a small amount of cooling air from the windbox. A retractable ignition system, including spark ignition, a 2.9 thermal MW ($10 \times 10^6$ Btu/hr) oil gun and an ignition flame scanner is located in the core on the burner centerline. The main flame scanner views the flame through the inner secondary air passage.

Tertiary (staging) air is supplied from the windbox through outboard tertiary air ports. During testing in the research facility the airflow rate through each port will be controlled and measured by the assembly shown in Figure 8. The hemispherical poppet pivots to vary the open area, and thus, control the flow rate. The pressure drop across the perforated plate air hood provides an indication of flow rate. Alternate tertiary air port control system designs will also be evaluated during the prototype burner tests.

In summary, the prototype burner has been designed with "flexible" parameters to permit the flow rates, velocities and swirl in the burner passages to be varied to optimize burner performance. The dimensions and ranges of adjustment are listed in Table IV. All of the dimensions listed match the prototype design point except the exit length and tertiary port locations as previously discussed. The effects of these deviations from the design criteria will be evaluated during prototype tests.

## SECTION 3

## COMMERCIAL BURNER AND PROTOTYPE DMB TEST RESULTS

The prototype DMB design which will be recommended for installation and demonstration in a field-operating steam generator must be capable of (1) stable characteristics while (2) providing low $NO_x$ levels. Since the DMB prototype burner design was based on the results of tests in the research furnace, some assurance is required that these test results can be used to predict burner performance in the field boilers. Though indirect, the approach taken was to evaluate the operating characteristics of a commercial burner in the research furnace and compare the results with field experience. Similarity of the research furnace and field results were then taken as an indication that the operating characteristics of the DMB in the research furnace and in field operating boilers would also be similar. In addition, burner manufacturers have found that when two burners are tested in a research facility that the ratio of $NO_x$ emissions measured in the test facility will be comparable to the ratio of $NO_x$ emissions when the identical burners are operated in field boilers. Thus, the ratio of $NO_x$ emissions for a commercial burner and the prototype burner tested in the research furnace should be approximately the same as the ratio of $NO_x$ emissions from the same burners operated in the host boilers.

### COMMERCIAL BURNER TESTS IN THE RESEARCH FURNACE

A Foster Wheeler Intervane burner similar to those in service at the initial demonstration site has been tested in the research combustor. In general, the burner performance was similar to that observed in field boilers. The flame was short, bright, intense and stable, but somewhat narrower and longer than those observed with multiburner arrays in the field. This suggests that the DMB flame shape and stability characteristics observed in the research furnace will be similar in the field.

The CO and NO characteristics for the Intervane burner tested in the research furnace are shown in Figure 9. The CO characteristics are more sensitive to excess air variations than observed in the field. For example, in field units it is expected that the sharp rise in CO would occur at a lower value of excess air ( 110 percent T.A.) than that shown in Figure 9. In addition, the asymptotic value of CO measured in the research furnace was about 185 ppm (corrected to 0 percent $O_2$) which is greater by a factor of four than that observed in multiburner field units, less than 50 ppm. This suggests that the high CO levels measured in the research furnace may be a result of the furnace design and sampling point location (at the furnace exit). The LWS is currently being modified to correct the suspected causes of high residual CO emissions. The Intervane burner will be retested to determine if the resulting CO emissions match those obtainable in the field.

The variations of NO with load and overall stoichiometry are within the normally observed field ranges. However, the NO levels are 50 to 100 ppm lower than expected in a multiburner field operating boiler. Figure 9 also shows typical NO levels from four-burner bituminous coal-fired boilers similar to the initial demonstration site. Extrapolation of the research furnace results to full load (16.4 thermal MW (90 x $10^6$ Btu/hr)) gives an NO level of 500 ppm while 600 ppm are typically measured at full load in field units. The NO emissions from the initial demonstration boiler are expected to be in this range. This will be verified during baseline tests of the unit.

PROTOTYPE DMB TESTS IN THE RESEARCH FURNACE

The prototype DMB has been tested in the research furnace. This initial test series was brief and primarily evaluated performance without tertiary ports (unstaged). The flame was bright and somewhat longer and wider than the Intervane burner flame. There was no indication of flame impingement on the target wall which was 4.88 m (16.0 ft) from the firing face. The DMB should, therefore, be compatible with the initial demonstration boiler where the furnace depth is 6.28 m (20.6 ft).

The NO and CO characteristics for the prototype DMB operating unstaged and the Invervane burner are shown in Figure 10. The NO emissions for the prototype DMB are comparable to those measured when previous DMB designs were tested unstaged. However, they are 50 to 100 ppm lower and more sensitive to overall stoichiometry than the Intervane burner. The lower NO level is expected because the prototype DMB has dual registers and lower throat velocity than the Intervane burner, and thus, lower fuel/air mixing rates. CO emissions at a typical operating condition of 125 percent theoretical air are also somewhat lower for the prototype DMB. However, this is probably not significant as discussed above.

It should, however, be noted that this prototype DMB's geometrical configuration has not been optimized. Since this design is based on Foster Wheeler's commercial hardware, which has been adapted to meet DMB velocity and flow criteria, further geometrical changes may be necessary to obtain optimum NO and CO performance with acceptable stability. Among the differences between this prototype and EER's previous experimental DMBs are:

| Prototype DMB | Experimental DMBs |
|---|---|
| Registers for swirl control | Block-type swirl generators |
| Annular coal nozzle with tangential inlet | Cylindrical pipe nozzle with articulated inlet |
| Open coal nozzle outlet with adjustable velocity feature | Impeller/swirler at outlet fixed velocity |
| Medium quarl depth | Long quarl depth |

It is reasonable and prudent to assume that these differences can result in NO and CO performance which are also different. The prototype results were obtained with an initial geometry which is likely to be nonoptimum. Consequently, as part of the test program, the prototype's geometrical and flow parameters will be varied to determine the configuration which provides optimum NO, CO and stability performance.

A limited test series was conducted with the prototype DMB operating staged to obtain an approximate indication of its potential for low NO emissions. These tests were preliminary; no attempt was made to optimize burner adjustments and the burner was not operated at the design point. The results in Figure 11 show the same decrease in NO as burner zone stoichiometry decreases as that observed in tests of other DMB designs. Extrapolation to the DMB design point (overall stoichiometry 118 percent theoretical air and burner zone stoichiometry 70 percent theoretical air) results in approximately 100 ppm NO. CO emissions increased to unacceptable levels as burner zone stoichiometry decreased. This is probably due to nonoptimum burner configuration and adjustment. Optimization of burner adjustments and of burner geometry should result in the characteristic knee as in Figure 4.

ESTIMATE OF NO EMISSIONS FROM THE FIELD DEMONSTRATION

A rough estimate of the potential NO emissions from the DMB operating in a small pulverized coal-fired boiler can be made from these data. The prototype DMB and Intervane burners have been tested in the research furnace at 23.4 thermal MW (80 x $10^6$ Btu/hr) firing rate and 125 percent theoretical air. Field data are also available for Intervane burners operating in small pulverized coal-fired boilers. The table below summarizes these results and presents an estimate of the NO emissions from the DMB operating in a small pulverized coal-fired boiler based on the ratio technique described above.

| | Research Furnace | | Field Burner | |
|---|---|---|---|---|
| | NO (ppm) | Basis | NO (ppm) | Basis |
| Intervane | 450 | Measured | 600 | Typical Field |
| Prototype DMB | 100 | Extrapolation of Test Results to Design Point | 120–150 | Rough Estimate |

The 120 to 150 ppm NO range corresponds to approximately 59 to 76 ng/J (0.14 to 0.18 lb/$10^6$ Btu) which is less than the program objective of 82 ng/J (0.2 lb/$10^6$ Btu). This estimate is, of course, very rough and is based on preliminary test results. An improved estimate will be made as soon as additional prototype burner tests are conducted in the research furnace, and the performance of the host boiler (with Intervane burners) is measured.

As discussed earlier, the prototype DMB tests involve no optimization of either burner geometry or adjustments and resulted in unacceptably high CO levels at the design operating point. Therefore, the "rough estimate" prediction given above is achievable only if modification and optimization of the burner can reduce CO levels in the field boiler typical to those attainable with the steam generater's original equipment Intervane burners (typically less than 50 ppm).

## SECTION 4

## SUMMARY

Preparations are underway for the demonstration of the low $NO_x$ DMB concept on two small pulverized coal-fired boilers. Several DMB designs have been tested in research furnaces over a wide range of conditions and nominal design and operating parameters have been identified. These nominal design criteria and the characteristics of the first demonstration boiler have been integrated into a prototype burner design which incorporates commercial burner components. The prototype burner has been briefly tested in the research furnace and additional tests will be conducted to fully evaluate and optimize performance prior to installation in the initial demonstration boiler.

Analysis of test data from the prototype DMB and a commercial burner tested in the research furnace indicates that in the field the DMB flame characteristics will be acceptable. Field $NO_x$ emissions are estimated to be in the range of 59 to 76 ng/J (0.14 to 0.18 lb/$10^6$ Btu).

Further developmental tests are planned to optimize burner geometry and to ensure that satisfactory stability and combustion efficiency exist over an acceptable range of burner adjustments and normal load and excess air variation. Prior to field installation satisfactory operation, as well as compatibility with commercial ignition and flame scanning equipment, will be demonstrated in the test furnace.

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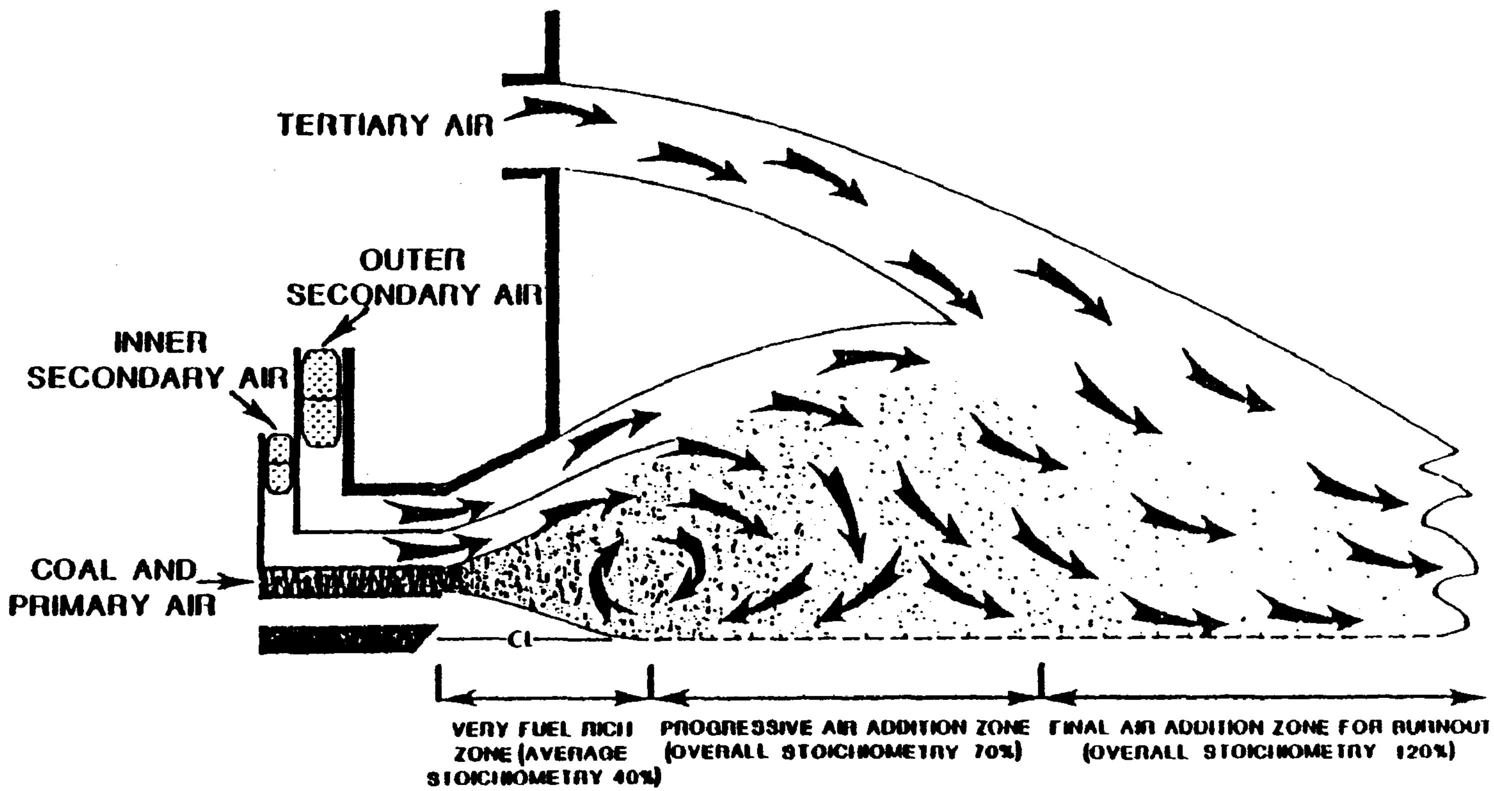


Figure 1. DMB Concept.

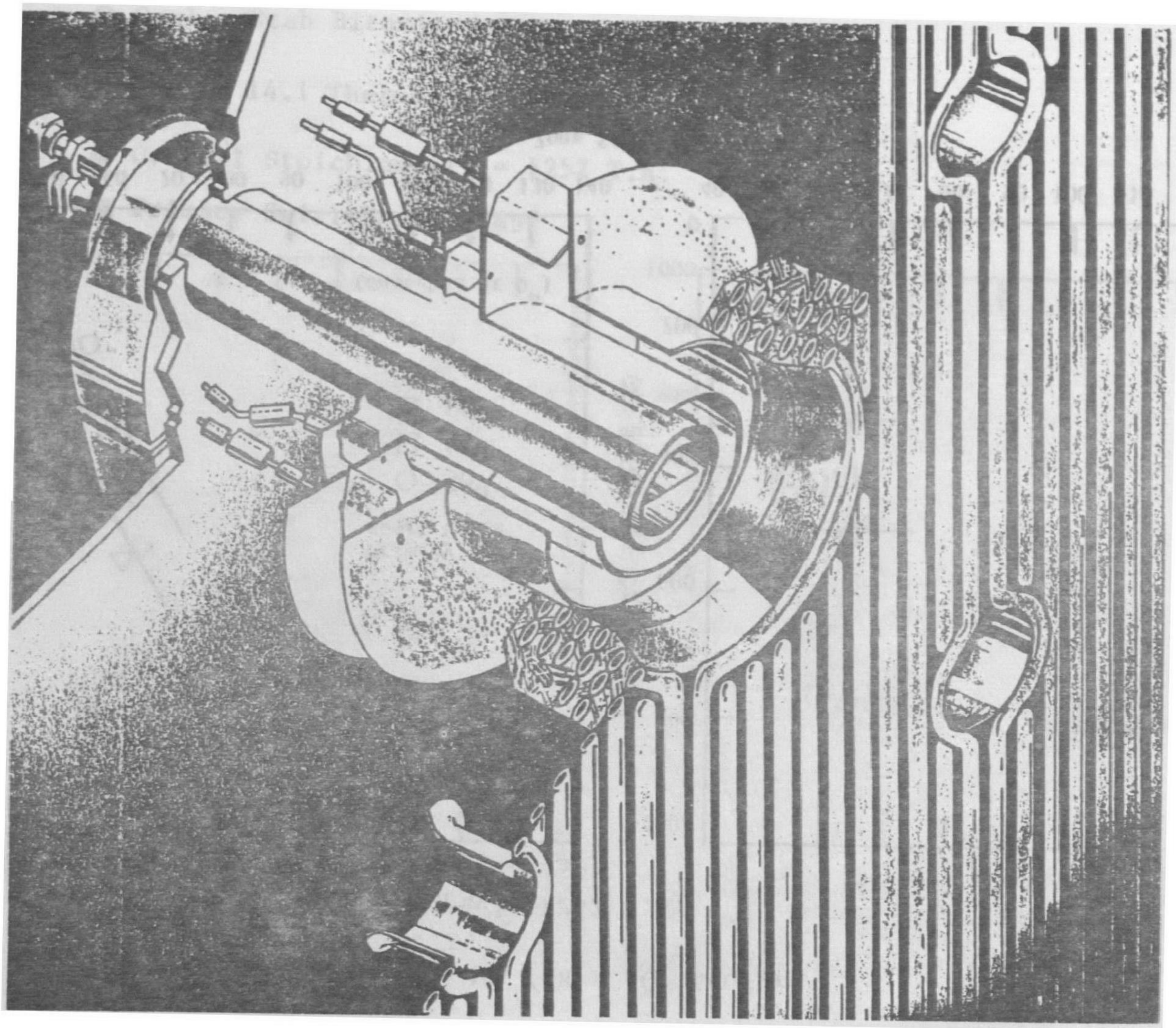

Figure 2. Distributed Mixing Burner.

- 14.6 Thermal MW ($50 \times 10^6$ Btu/Hr) Single Secondary DMB
- Coal = Utah Bituminous
- Load = 14.1 Thermal MW ($48 \times 10^6$ Btu/Hr)
- Overall Stoichiometry = 125% T.A.
- Secondary Swirl Vanes = 45°

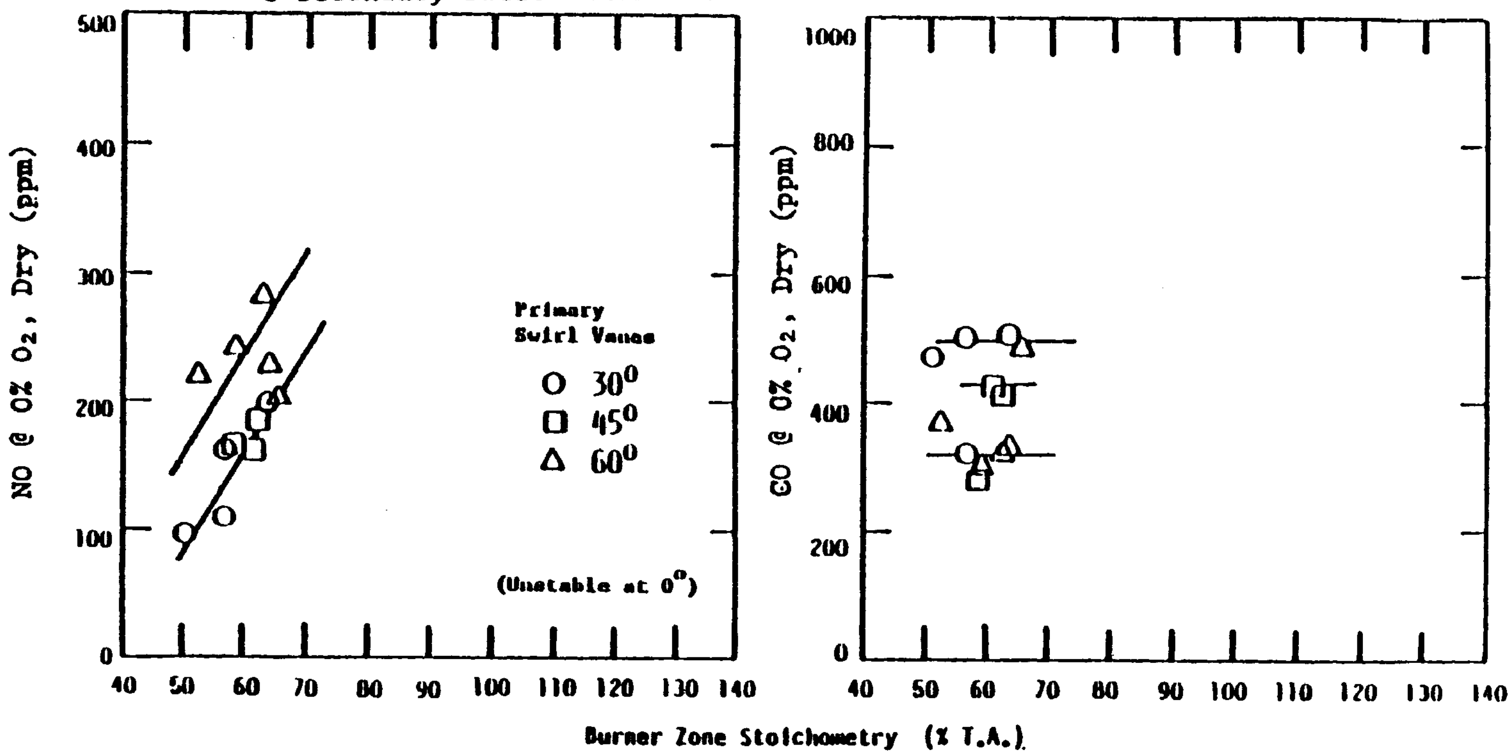


Figure 3. Effects of Fuel System Variables on DMB Performance.

- 14.6 Thermal MW (50 x $10^6$ Btu/Hr) Single Secondary DMB
- Coal = Utah Bituminous
- Load = 14.1 Thermal MW (48 x $10^6$ Btu/Hr)
- Overall Stoichiometry = 125% T.A.
- Primary Swirl Vanes = 45°

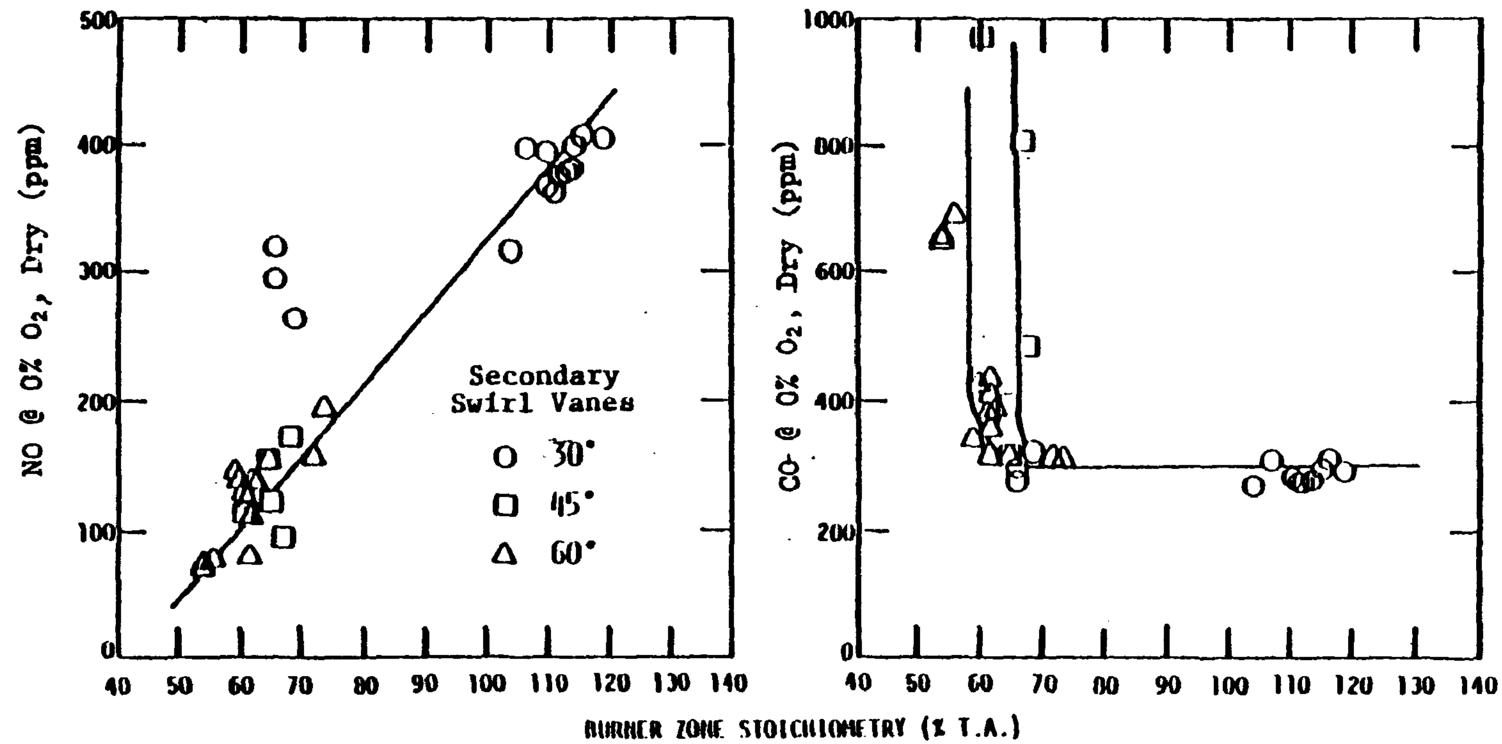


Figure 4. Effects of Secondary Air System Variables on DMB Performance.

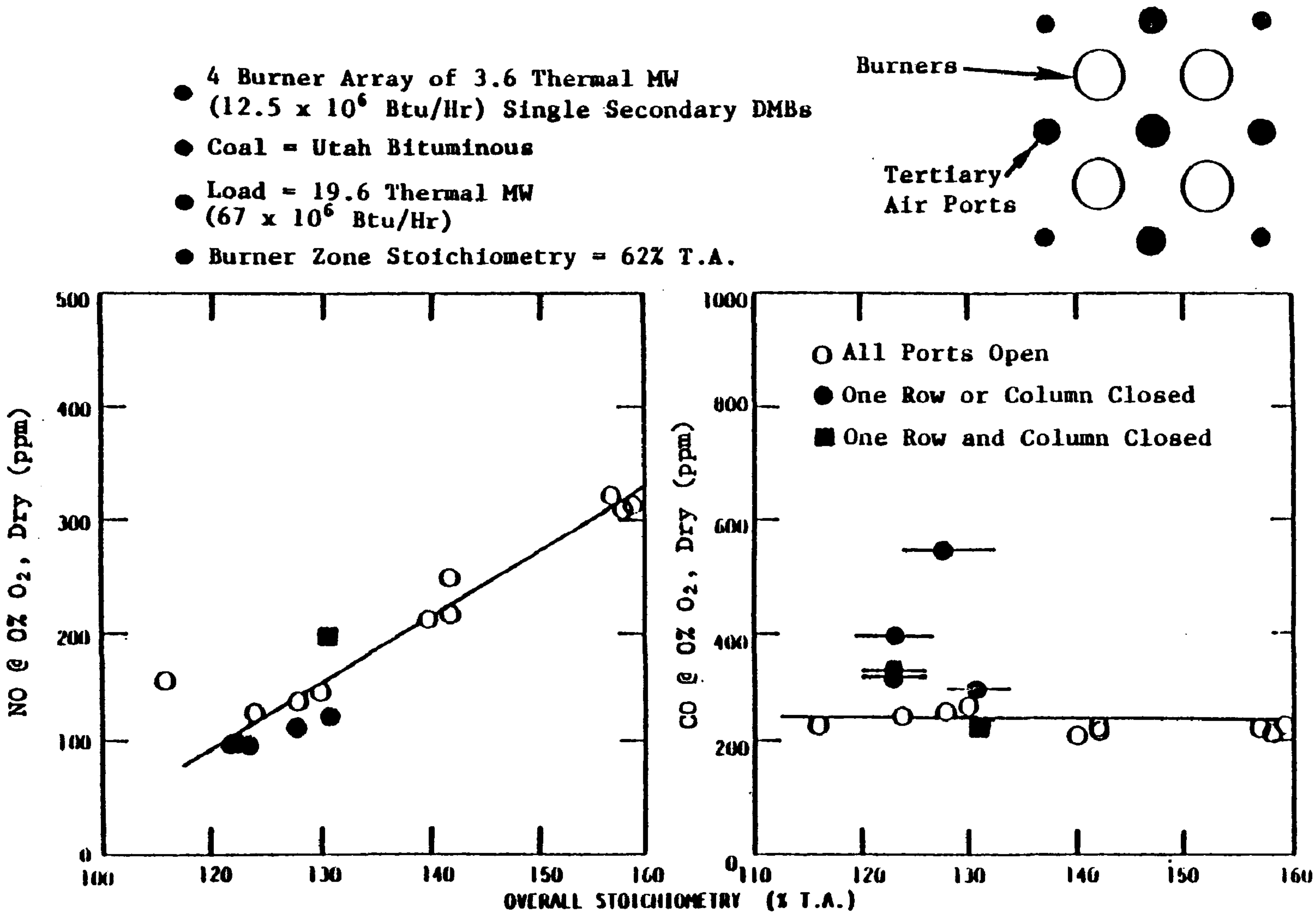


Figure 5. Effects of Tertiary Air System Variables on DMB Performance.

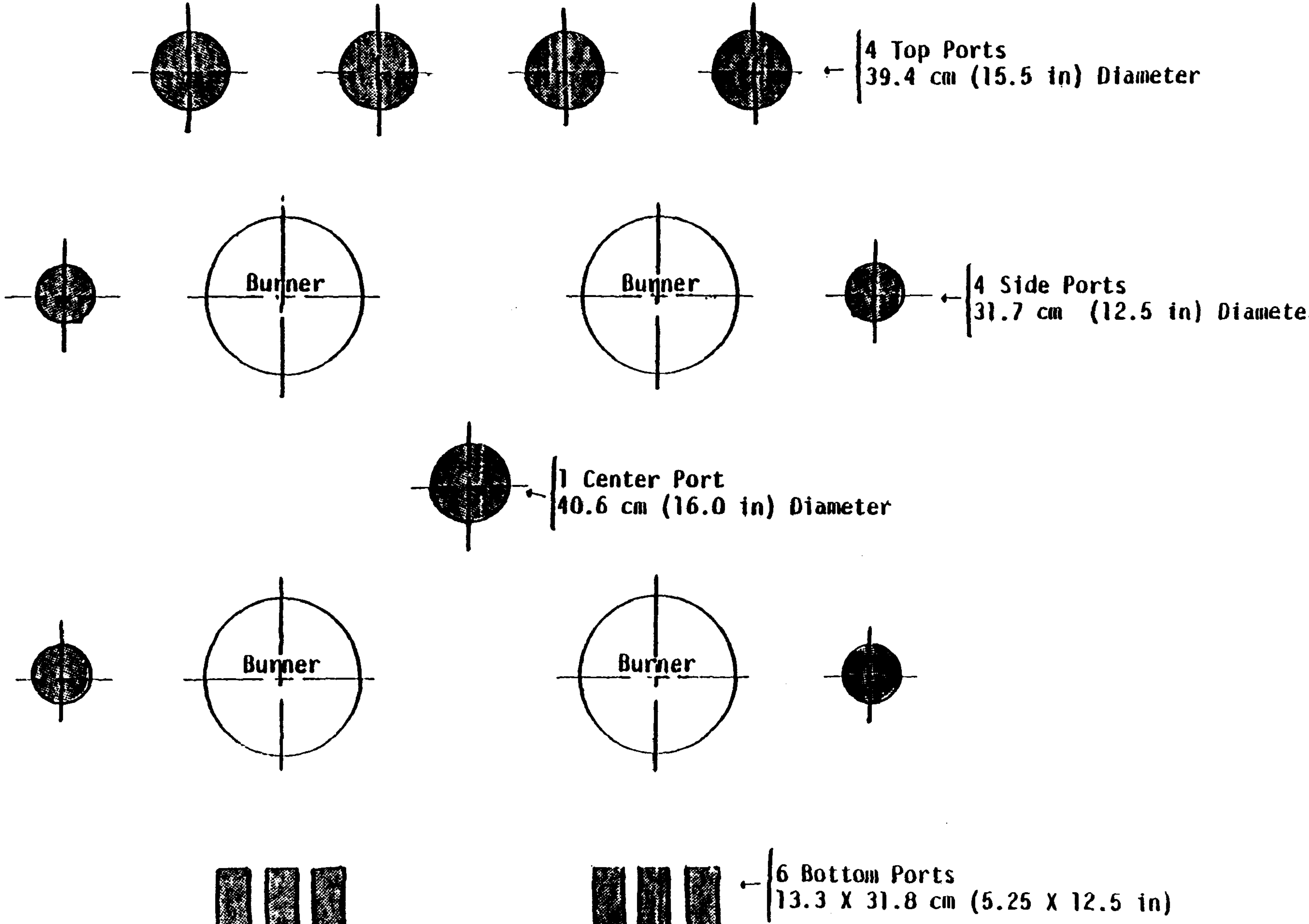


Figure 6. Tertiary Port Configuration for Initial Demonstration Boiler.

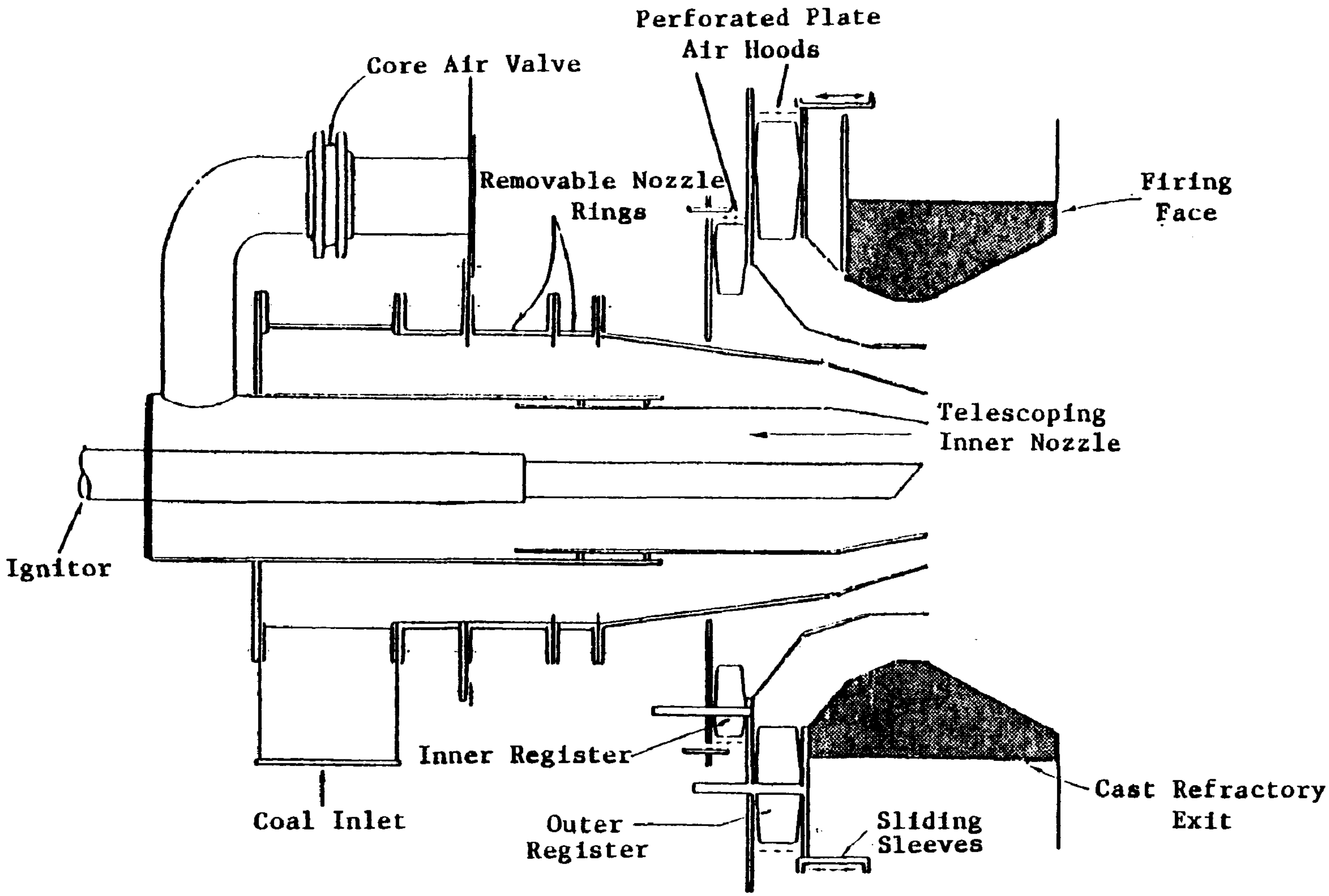


Figure 7. Prototype DMB (Tertiary Ports not Shown).

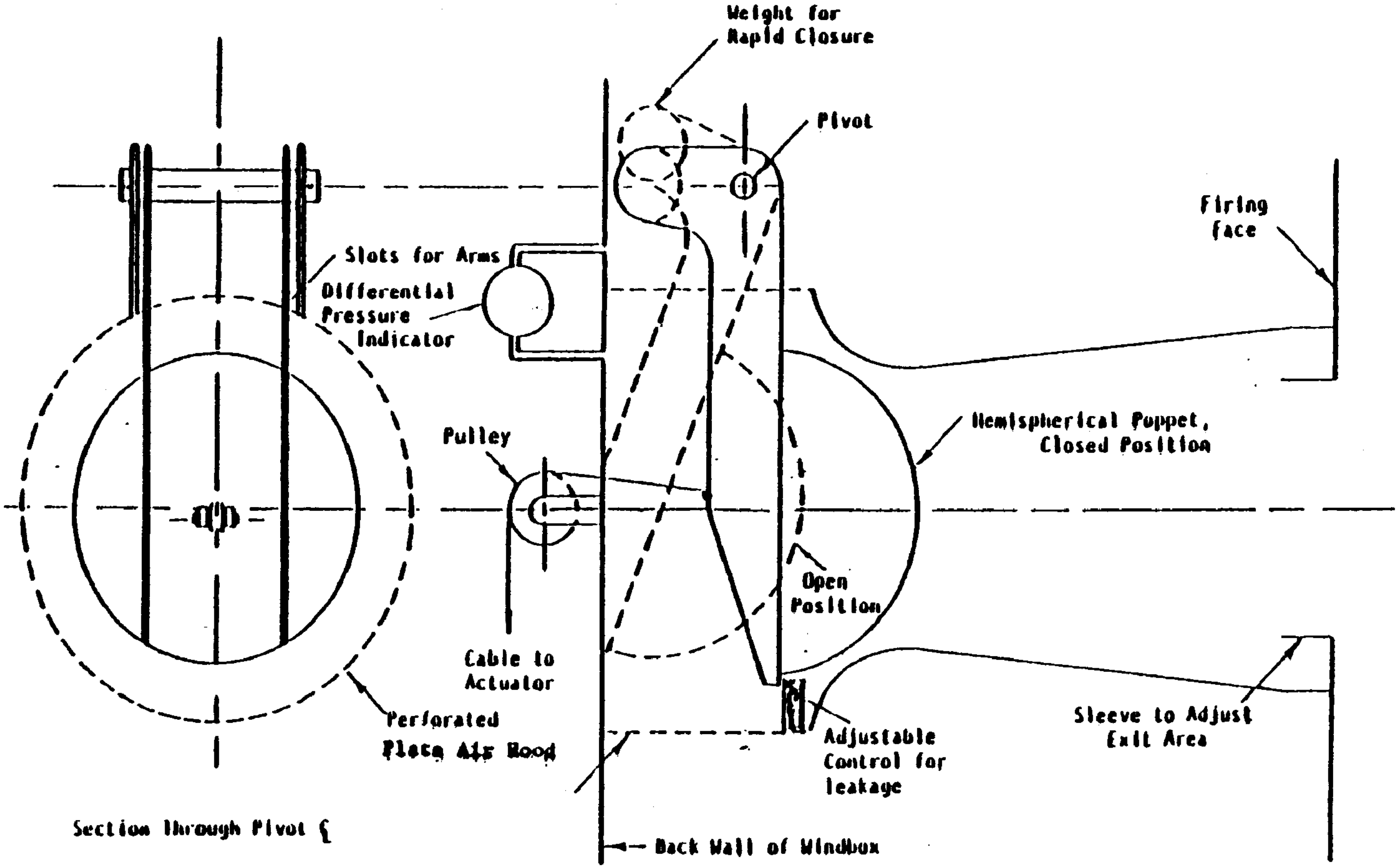


Figure 8. Tertiary Port Control Valve.

Coal = Utah Bituminous

Full Load = 26.4 Thermal MW ($90 \times 10^6$ Btu/Hr)

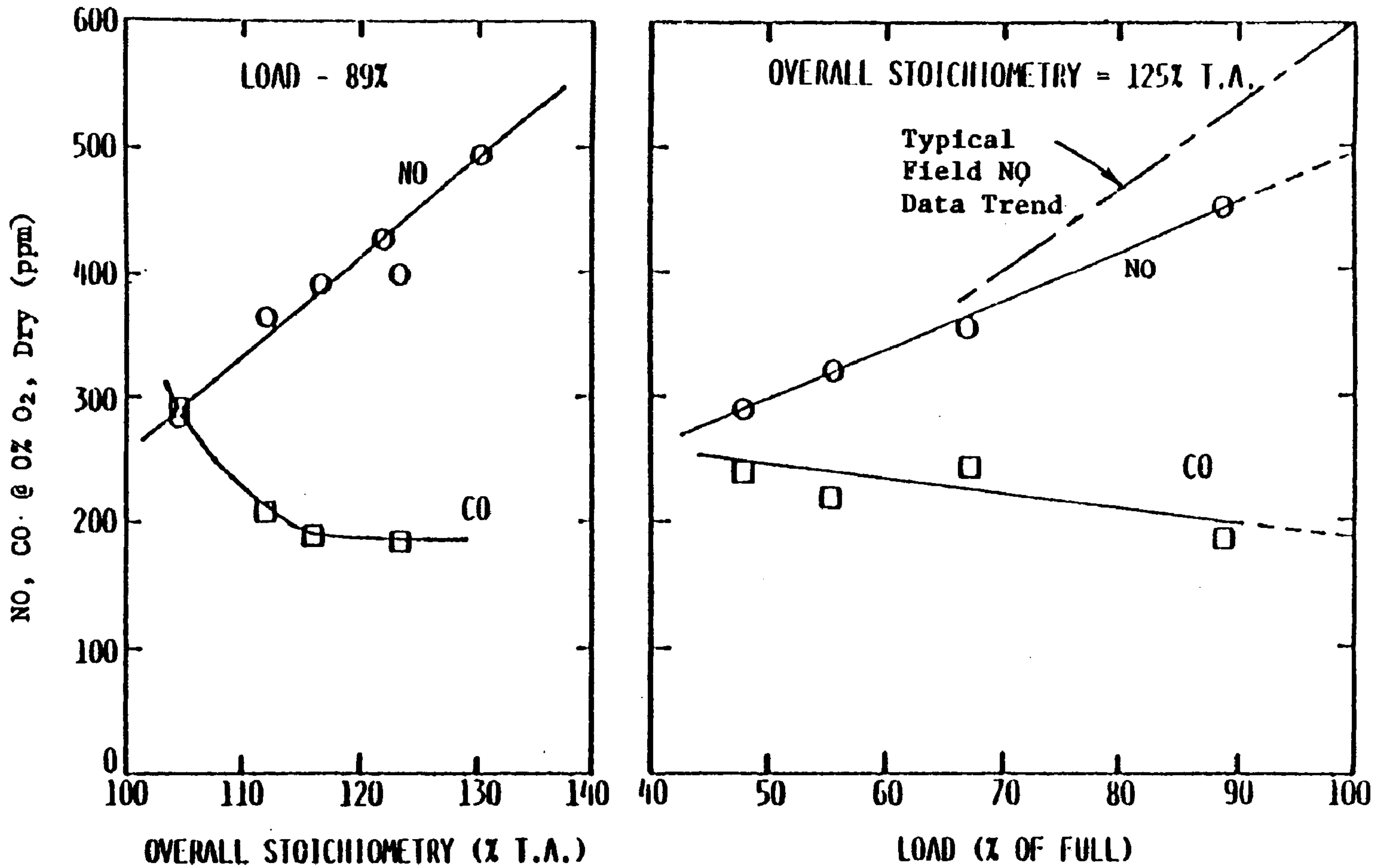


Figure 9. Intervane Burner Performance in Research Furnace.

Coal = Utah Bituminous

Load = 23.4 Thermal MW (80 x $10^6$ Btu/Hr)

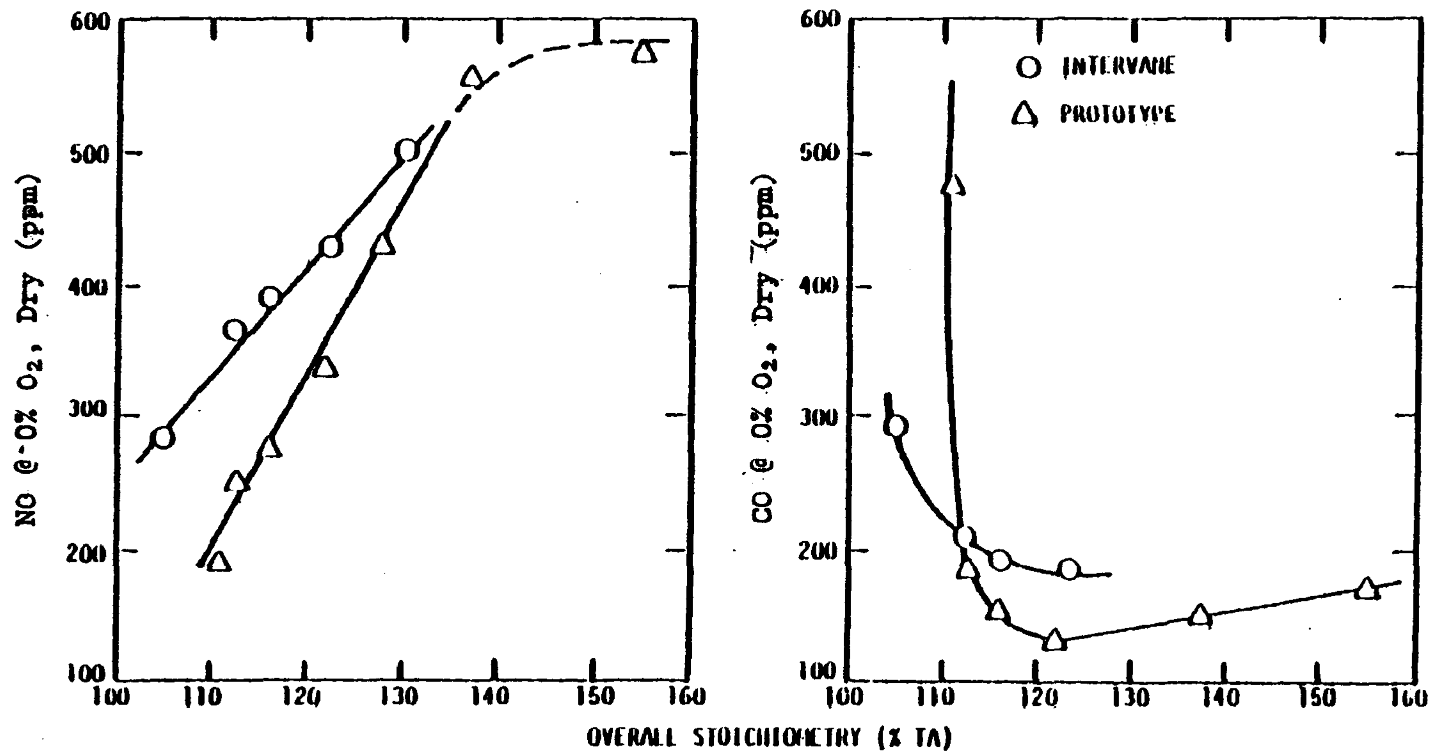


Figure 10. Unstaged Prototype DMB and Intervane Burner Performance in the Research Furnace.

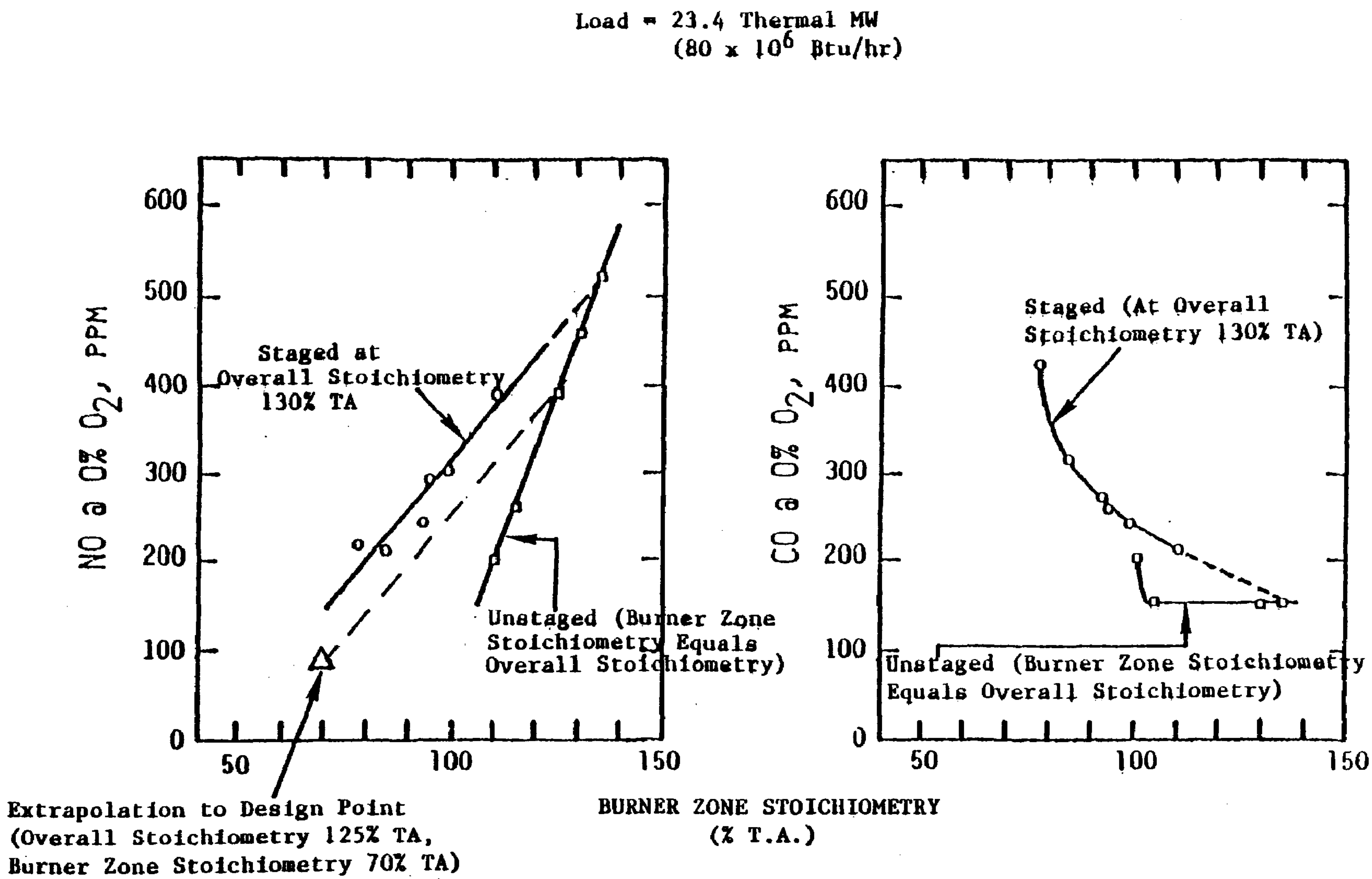


Figure 11. Prototype Burner Performance in Research Furnace.

TABLE I. DMB NOMINAL DESIGN CRITERIA

| Burner System | Parameter | Nominal Design Point |
|---|---|---|
| Fuel | Swirl | $45^{\circ}$ Vanes |
| | Axial Velocity | 22.9 m/sec (75 ft/sec) |
| Secondary Air | Stoichiometry | 50-70% T.A. |
| | Swirl | Variable |
| | Axial Velocity | 18.3 m/sec (60 ft/sec) |
| Tertiary Air | Number/Shape | 4/Round |
| | Radius/Throat Diameter | 2.2 |
| | Velocity | 15.2 m/sec (50 ft/sec) |
| Exit | Half Angle | $25^{\circ}$ |
| | Length/Diameter | 1.0 |
| | Setback | 0 |

TABLE II. INITIAL DEMONSTRATION SITE CHARACTERISTICS

| Parameter | | Value |
|---|---|---|
| Boiler | | |
| Configuration | | Single Wall-Fired |
| Capacity | MCR | $98 \times 10^3$ Kg/hr ($215 \times 10^3$ lb/hr) |
| | Peak | $111 \times 10^3$ Kg/hr ($245 \times 10^3$ lb/hr) |
| Burners | | |
| Type | | Foster Wheeler Intervane |
| Array | | 2 x 2 |
| Capacity | MCR | 20 Thermal MW ($69 \times 10^6$ Btu/hr) |
| Throat Diameter | | 61 cm (24 in.) |
| Spacing | Horizontal | 182 cm (71.5 in.) |
| | Vertical | 198 cm (78.0 in.) |
| Furnace | | |
| Construction | | Membrane Wall |
| Depth | | 6.28 m (20.6 ft) |
| Width | | 5.01 m (16.4 ft) |
| BZLR | | 492 Thermal kW/m$^2$ ($156 \times 10^3$ Btu/hr-ft$^2$) |
| Fuel | | |
| Coal Type | | Indiana Bituminous |
| Pulverizers | Type | Foster Wheeler MB |
| | Number | 2 |
| Air Supply | | |
| Air Heater Type | | Regenerative |
| Secondary Air Temperature | | 265°C (510°F) |
| Draft | | Pressurized |
| Windbox Depth | | 132 cm (52 in.) |
| Burner Pressure Drop (Nominal) | | 8.9 cm $H_2O$ (3.5 in. $H_2O$) |

TABLE III. INITIAL INDUSTRIAL BOILER DEMONSTRATION SITE COAL CHARACTERISTICS

| | As Received | Dry Basis |
|---|---|---|
| Proximate Analysis | | |
| % Moisture | 13.03 | |
| % Ash | 10.14 | 11.66 |
| % Volatile | 36.08 | 41.49 |
| % Fixed Carbon | 40.75 | 46.85 |
| | 100.00 | 100.00 |
| Ultimate Analysis | | |
| Moisture | 13.03 | |
| Carbon | 61.30 | 70.48 |
| Hydrogen | 4.36 | 5.01 |
| Nitrogen | 1.30 | 1.49 |
| Chlorine | 0.03 | 0.04 |
| Sulfur | 2.87 | 3.30 |
| Ash | 10.14 | 11.66 |
| Oxygen (diff) | 6.97 | 8.02 |
| | 100.00 | 100.00 |

TABLE IV. INDUSTRIAL PROTOTYPE BURNER DIMENSIONS AND ADJUSTMENTS

| Design Variable | Nominal* Value | Adjustment Range | Adjustment Method |
|---|---|---|---|
| **Fuel Injector** | | | |
| Core Diameter (in.) | 9.75 | | |
| Core Area (in.$^2$) | 74.7 | | |
| Nozzle Diameter (in.) | 14.5 | | |
| Annulus Thickness (in.) | 2.375 | 1.7-3.3 | Telescoping Nozzle |
| Primary Area (in.$^2$) | 90.5 | 68-136 | Telescoping Nozzle |
| Setback (in.) | 0 | -2-+12 | Remove/Replace Nozzle Rings |
| **Inner Secondary Channel** | | | |
| Outer Diameter (in.) | 20.75 | Variable | Replace Secondary Divider |
| Annulus Thickness (in.) | 3.125 | Variable | Replace Secondary Divider |
| Area (in.$^2$) | 173.0 | Variable | Replace Secondary Divider |
| Setback (in.) | 0 | Variable | Replace Secondary Divider |
| **Outer Secondary Channel** | | | |
| Outer Diameter (in.) | 30.25 | Variable | Recast Exit |
| Annulus Thickness (in.) | 4.75 | Variable | Recast Exit |
| Area (in.) | 380.5 | Variable | Recast Exit |
| Setback (in.) | 0 | Variable | Recast Exit |
| **Tertiary Ducts** | | | |
| Distance from Burner ℄ (in.) | 53 | Variable | Modify Windbox |
| Spacing Around Burner (deg) | 90 | Variable | Modify Windbox |
| Number of Ports | 4 | | |
| Injection Angle (deg) | 0 | | |
| Axial Position (in.) | 0 | | |
| Diameter (in.) | 13.25 | Variable | Sleeve |
| Total (in.$^2$) | 553 | Variable | Sleeve |
| **Throat and Exit** | | | |
| Throat Diameter (in.) | 30.25 | Variable | Recast Exit |
| Throat Area (in.) | 718.7 | Variable | Recast Exit |
| Half Angle of Exit (deg) | 25 | Variable | Recast Exit |
| Length of Exit (in.) | 12.0 | Variable | Recast Exit |
| Length/Diameter | 0.40 | Variable | Recast Exit |

*Conversion Factors:

1.0 in. = 2.54 cm
1.0 in.$^2$ = 6.45 cm$^2$

FIELD EVALUATION OF LOW EMISSION COAL BURNER TECHNOLOGY ON A UTILITY BOILER

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## ABSTRACT

A program is currently in progress to demonstrate the $NO_x$ reduction potential of the EPA distributed mixing burner applied to a utility boiler. The demonstration program will be designed to evaluate both emissions attributed to this burner as well as the effects of the burner retrofit on overall boiler performance and efficiency.

The boiler selection process is near completion with a single wall-fired unit being reviewed by the EPA prior to final negotiations. Several opposed-fired units are still under consideration, pending final decisions by the utilities as to their interest in participating in the retrofit demonstration program.

## ACKNOWLEDGEMENT

The work presented in this paper was performed as part of the Utility Boiler Field Evaluation of Low Emission Coal Burner Technology Program funded under EPA contract 68-02-3130. The contract is sponsored by the Industrial Environmental Research Laboratory, Combustion Research Branch. The author acknowledges the assistance of the EPA Project Officer, G.B. Martin and the Energy and Environmental Research Corp. in the planning stages of this program.

## INTRODUCTION

The Environmental Protection Agency has regulated the emissions of nitrogen oxides ($NO_x$) from utility boilers sold and erected since 1971 through enactment of the New Source Performance Standards. The Clean Air Act Amendments of 1977 required the EPA to review and revise the NSPS at four year intervals. The 1978 revisions lowered the NSPS for $NO_x$ emissions from utility boilers and it is anticipated that further reductions in the maximum allowable emission level of $NO_x$ will occur. In addition, utilities in $NO_x$ non-attainment areas could be required to retrofit $NO_x$ control equipment to existing units as part of the state implementation plans.

The EPA has developed a low emissions burner to provide for optimum reductions in $NO_x$ levels produced during the combustion of pulverized coal. The development of this low emission coal burner technology began in 1970 under a contract with the International Flame Research Foundation in an attempt to characterize the effects of burner design parameters on $NO_x$ emissions from pulverized coal combustion[1]. The results of this and further studies indicated that the levels of $NO_x$ could be controlled to low levels through combustion modifications.

A nine task contract was awarded to the Babcock and Wilcox Co. in 1978 to demonstrate the use of this technology on a multiple burner utility boiler. The purpose of this paper is to highlight the program and to describe the progress to date in the areas of the boiler selection and the burner design.

## TEST PLAN STRUCTURE

The objective of the program is to evaluate the EPA low emission coal burner on a multiple burner utility boiler. The evaluation will attempt to determine the lowest practical $NO_x$ limit under normal operating conditions without a sacrifice in boiler availability, performance, or efficiency. The program consists of nine tasks as detailed below:

| TASK | DESCRIPTION |
| --- | --- |
| 1.0 | Program Definition |
| 2.0 | Prototype Fabrication & Testing |
| 3.0 | Host Boiler Baseline Evaluation |
| 4.0 | Burner Fabrication & Installation |
| 5.0 | Unit Performance Evaluation |
| 6.0 | Industry Coordination Panel |
| 7.0 | Unit Restoration |
| 8.0 | Data Analysis |
| 9.0 | Guideline Preparation & Reports |

A brief description of each task is provided below:

## 1.0 PROGRAM DEFINITION

This task provides for the initial planning and management plan for the overall program effort. The task is divided into four subtasks to provide planning in each of the major areas of the initial program plan. The subtasks are: 1.1 Boiler Selection, 1.2 Burner Engineering Design, 1.3 Analytical Measurements Plan, and 1.4 Overall Program Plan.

### 1.1 Boiler Selection

The prime purpose of this subtask is to identify and select an existing unit to retrofit and evaluate the distributed mixing burner. The unit selection is based on willingness of the utility to participate as well as the state-of-the-art for pulverized coal firing as applied to utility boilers both in the existing population and the current new boiler market. Based on the above, a detailed selection criteria was established to evaluate potential candidate boilers. The utilities were then contacted to determine interest in the program. A detailed summary of the site selection process will be presented later in the paper.

### 1.2 Burner Engineering Design

The experimental data on the low emissions burner was reviewed to establish the optimum design criteria for the prototype burner and subsequent retrofit burner. This information will be incorporated with the site specific requirements of the unit selected to finalize the prototype burner design. Also included in the resultant design package will be the specifications for the auxiliary equipment required for the retrofit and any constraints placed on the burner design due to the limitations of the existing boiler.

## 1.3 Analytical Measurements Plan

In this subtask, the overall approach for evaluation of the emissions resulting from this burner will be defined. In addition, the entire boiler performance evaluation program will be established in the performance of this subtask. It is essential that both boiler performance and emissions data be collected simultaneously to determine the overall performance of the distributed mixing burner system vs. the existing burner system which will be characterized during the boiler baseline evaluation.

Energy and Environmental Research Corporation, EER, as a subcontractor to B&W has the lead responsibility in the development of the Analytical Measurements Plan for monitoring pollutant emissions. This structure will provide for consistency between the Industrial and Utility emissions monitoring programs. Also, EER will establish the overall procedures necessary to satisfy the requirements established by the EPA's Office of Air Quality

Planning and Standards. Further discussions of the Analytical Measurements Plan will be presented by EER.

### 1.4 Overall Program Plan

The results of the above subtasks will be incorporated into a final program plan detailing the performance of the remainder of the burner evaluation program. The plan will be based on the selection of a boiler and the resultant outage schedule, burner design, and measurements plan established for the specific unit. This plan will be reviewed and revised periodically, as required, to insure successful completion of the demonstration program.

## 2.0 PROTOTYPE FABRICATION AND TESTING

A prototype burner will be fabricated based on the results of Subtask 1.2 detailed above. The prototype burner will be a full size burner of the design to be installed in the host boiler. This burner will be installed in the EPA's large watertube simulator (LWS) to verify the performance of the burner prior to finalization of the design and fabrication of the multiple burners required for the field demonstration. Tests will be performed to evaluate the burner performance over a range of operating conditions and with several coal types (including the coal to be burned during the utility demonstration) to compare the results with those obtained during the experimental burner test programs. A burner of the design currently utilized on the selected utility unit will also be fabricated and tested on the

LWS for comparison of emissions and burner performance.

## 3.0 HOST BOILER BASELINE EVALUATION

The baseline evaluation will consist of 4-6 weeks of boiler testing prior to any modifications. These tests will provide a data base for direct comparison of the distributed mixing burner. The data to be collected will be used to evaluate overall system performance, unit efficiency, and pollutant emissions. A continuous monitoring system will be utilized to collect the gaseous emissions data. The data will be collected over the normal operating range of the boiler to characterize the combustion system currently installed. Parameters to be varied and reviewed will be boiler load, burner configuration, excess air levels, and burner zone liberation rate.

## 4.0 BURNER FABRICATION AND INSTALLATION

The prototype testing will culminate in a final design package for the burner system to be applied in the field. When the final design package has been approved by the EPA and the utility, the required number of burners will be fabricated and shipped to the site. All required auxiliary equipment will also be fabricated or purchased during this period. The above equipment will be installed in the unit during an outage scheduled by the utility.

At the completion of the outage, the boiler system will proceed through a normal start-up sequence. All burner settings will be determined and preliminary tests will be performed to insure that overall operation of the unit over its normal load range has not been adversely affected by the retrofit.

## 5.0 UNIT PERFORMANCE EVALUATION

At the completion of the burner system start-up, the performance evaluation program will commence. The first step in the program will be burner system optimization tests. Burner settings will be varied to determine the optimum settings for burner stability, carbon utilization, and minimization of gaseous pollutant emissions. The final burner settings to be utilized during the long term evaluation program will be established during this period.

The eighteen (18) month unit performance evaluation will begin after the optimization tests are complete. Emissions data will be collected on a continuous basis throughout the demonstration. In addition, detailed measurements of boiler performance and emissions will be conducted during the initial 30 day period of operation and during the eighteenth months of operation. These detailed measurements will be repeated periodically throughout the program to evaluate the long term operation of the burner system.

## 6.0 INDUSTRY COORDINATION PANEL

The purpose of this task is to secure the advice of manufacturers and users of pulverized coal burners on the practical aspects of the technology and to assure the timely dissemination of the developing technology to the potential users. The technical advisory panel established includes potential users, boiler and burner manufacturers, representatives of research and academic organizations involved in coal combustion studies, and members of the EPA's Combustion Research Branch. The members of this panel review all aspects of the experimental programs as well as the industrial and utility programs to facilitate the technology transfer through the various stages of development for the distributed mixing burner.

## 7.0 UNIT RESTORATION

At the completion of the testing period, the boiler will be restored to its original configuration during an outage scheduled by the host utility. At the completion of the site restoration, the system will then proceed through a normal start-up to insure that the unit is operating in a mode acceptable to the utility.

## 8.0 DATA ANALYSIS

The boiler and emissions data collected throughout the test program (prototype, baseline, and retrofit) will be analyzed and tabulated continuously throughout the program to provide the input to direct the ongoing program. The data will be analyzed to evaluate overall system performance, emissions, and the effects of low emissions operation on boiler performance. The specific analyses include:

1) Comparison of the experimental and prototype burner data to identify the optimum design for the retrofit burner.

2) Comparison of the prototype and existing host boiler equipment in the LWS to provide an estimate of the performance of the distributed mixing burner in the host boiler.

3) Evaluation of the baseline data to determine the existing performance and emissions from the unit. This will provide a reference point to evaluate the benefits of the distributed mixing burner.

4) Evaluation of the burner settings during the optimization stage to determine the flexiblity of the burner performance in meeting low $NO_x$ over the normal load range of the utility boiler while maintaining acceptable system performance as evaluated against the baseline tests.

5) Continuous review of the long term burner performance to document any changes in emissions or unit efficiency due to fuel changes or burner system deterioration. This analysis program will provide input to the ongoing design review to identify potential design modifications required to apply this technology to the wide range of wall fired boilers both as a retrofit and as an application to new units. The data will be evaluated utilizing the baseline data as well as the burner evaluation techniques

developed by B&W for evaluating $NO_x$ emissions and boiler performance to generalize the technology for future applications.

## 9.0 GUIDELINE PREPARATION AND REPORTS

A guideline manual will be compiled at the completion of the test program to summarize the results of the design study, field tests, and the overall data evaluation. The manual will provide a forum to present the program results and problems and solutions to the manufacturers and utilities and will be used to assess the potential applicability of this low $NO_x$ system on a commercial basis.

The manual will include:

1) Final design information for the prototype and field burners.

2) Design problems that must be addressed for various fuels.

3) Data summaries for each phase of the burner development program (experimental, prototype, baseline, and retrofit).

4) Prediction curves developed for application of this technology to utility boilers.

5) Functional and mechanical operation of the burner, including problems that developed and the solutions employed to rectify

the problems.

6) Effect of the low $NO_x$ operating conditions on boiler performance and other pollutants monitored throughout the program.

7) Parameters to optimize to obtain system performance equivalent to the baseline performance.

8) Benefits and detriments of this method of low $NO_x$ operation compared to other proven $NO_x$ control methods.

## PROGRAM STATUS

The major effort for this program has been in the development of the overall plan leading to a prototype test and subsequent field demonstration. The two major items leading to conclusion of the planning stage were selection of a suitable host site and development of the preliminary distributed mixing burner design package for the host site selected.

The following section summarizes the work leading to the boiler selection and preliminary burner design:

### Boiler Selection

The two major factors in establishing the host site selection criteria were: 1) The unit selected was representative of a large segment of the existing population of units or of current designs being sold and, 2) The economics of a retrofit of this magnitude must be evaluated to establish a maximum boiler size. Based on the above, the initial criteria was established to evaluate opposed fired units less than 300 MWe capacity. The final selection criteria and prioritization schedule were established after a review of the trends in fossil-fired utility boilers.

A) History

Over the past ten years, the trend in the electric utility fossil-fired population has been to coal fired units. This shift to coal has been caused by the economics of coal vs. oil as well as the uncertainty of oil supply from the Middle-East. Figures 1 and 2 provide a summary of the fossil-fired plant orders for the electric utilities. Since 1975, virtually all units sold have been designed for pulverized coal. The percentages shown in Figure 1 are somewhat low because the "coal only" megawatts do not include the units designed for fuel combinations (coal/oil/ gas) as shown in Figure 2. In addition, the Fuel Use Act of 1978 prohibits the use of natural gas or petroleum products as a primary fuel for a utility boiler.

The average size of an electric utility boiler has also increased significantly over the past twenty years. Figure 3 indicates the trend in boiler size. In 1960, the average size unit place in service was 133 MW with the largest unit being 500 MW. This average stayed fairly constant through the mid-1960's. From 1965 on, the average size of the steam generating units placed in service by the electric utility industry increased steadily. Today, the average size unit is about 500 MW. The largest units in service are rated at 1300 MW.

Figure 4 provides an indication of the distribution pattern by size of operating boilers as of 1979. As indicated, the majority of the units (65%) are less than 250 MW. In addition, most of these units are one wall fired due to their size. However, with the trend toward larger units, the majority of the units sold today are opposed-fired units. A review of firing pattern and unit size of operating B&W utility boilers is provided in Figure 5. As previously stated the majority of the units are one wall-fired units (ranging in size to about 250 MW maximum). The opposed fired units in the size range initially established (300 MW maximum) represent a very small segment (7.98%) of the existing population. Although the one wall-fired units represent almost half of the total operating units, the one wall and small opposed-fired units represent a very small portion of the total steaming capacity of the electric utility boiler population (14.1%).

In addition to the overall boiler population, a review of the B&W furnace design criteria relating to $NO_x$ was also performed. The two factors evaluated were the burner zone heat release rate ($HA/SC_1$) and the burner input. Figure 6 provides a summary of the changes in $HA/SC_1$ as $NO_x$ emission limits became a factor in boiler design. Prior to promulgation of the New Source Performance Standards (NSPS) of 1971, the burner zone heat release rate for the larger units averaged between 700-800 KBtu/ HR-FT$^2$. Field tests of these units indicated a direct correlation between this parameter and $NO_x$ emissions for a given burner system. The $HA/SC_1$ was reduced to the range of 400-500 KBtu/HR-FT$^2$ in 1971 to meet the NOx emission levels established by the 1971 NSPS. Currently, the average boiler is designed with a

$HA/SC_1$ of 350-450 $KBtu/HR-FT^2$ to meet the 1978 NSPS $NO_x$ emission levels.

The burner heat input has remained constant although the pulverized burner design has changed significantly for $NO_x$ considerations. The burner input has remained in the range of 100-135 x $10^6$ Btu/HR as shown in Figure 7. The standard burner designed by B&W has a nominal input of 125 x $10^6$ Btu/HR and varies in the above range based on matching of the number of pulverizers and burners required. For the smaller units, the burner input can be as low as 75 x $10^6$ Btu/HR again dependent on the matching of the required number of pulverizers and burners.

B) Selection Criteria

The preliminary selection criteria which was established based on the above review was as follows:

- Unit Size - 350 MW Maximum
- Burner Zone Heat Release Rate - 500 $KBtu/HR-FT^2$ Maximum
- Firing Mode - Opposed Wall
- Burner Type - B&W Circular or Dual Register
- Fuel - Pulverized Coal

The initial list of potential units which fit the above criteria was assembled and is shown in Figure 8. These units were considered as the prime potential candidates for the burner retrofit program. As the initial contacts were made, however, the responses received from the utilities detailed above indicated minimum interest in a program of this magnitude. In general, the responses from the utilities were as follows:

- The unit under consideration by B&W was a base loaded unit and the utility could not risk an experimental program on a unit which was the heart of their system.

- With the generating capacity constraints what they are today, the utility could not afford an extended outage to retrofit the combustion equipment to their boiler.

- The utility could not risk deterioration of unit performance or a loss of availability or reliability for the unit as is possible with an experimental program.

- Utilities were very reluctant to cooperate with the EPA on a program which could adversely impact future boiler designs with additional constraints on pollutant emissions. This concern not only included $NO_x$ but carbon monoxide, hydrocarbons, fine particulate, and trace elements which will be determined throughout the program.

- Inadequate space was available in the burner zone to fit the burner/tertiary air port configuration required. Burner-to-burner side and vertical spacings were not adequate for the installation of the required DMB hardware.

As a result of this response, the initial candidate list was expanded and a selection prioritization schedule was developed. This unit prioritization is detailed in Figure 9. The initial seven (7) units under review represented categories 1 and 2. Several larger units, up to 750 MW were reviewed as potential candidates with the same results as described above. A comparison of the design parameters of several of these units are detailed in Figures 10 and 11. All units to this point were opposed fired units.

The next series of units for review were the single wall-fired units. Based on a review of several units, discussions were held with several utilities that were interested in the program. These discussions led to three units which the utilities were willing to commit to this program. The design parameters for these three units are shown in Figure 12. Based on this review, unit 3 was eliminated because it was too small (75 MW). In the design review of units 1 and 2, it was determined that unit 2 would be more difficult to retrofit because of obstructions in the windbox which could cause improper airflow distribution to the tertiary air ports. Therefore, it was determined that unit 1, a 175 MW unit operated by Northern States Power (NSP) would be the prime candidate for the EPA low $NO_x$ burner retrofit.

This unit, located at NSP's Highbridge Station, has a maximum capacity of 1,200 MLB/HR main steam flow and is currently equipped with 16 circular burners arranged in a 4 x 4 matrix on the front wall. The burner zone is 48 feet wide by 21 feet deep. The unit was originally designed for an Illinois high sulfur coal, but currently burns a blend of Illinois and Montana coals for $SO_2$ emission considerations. A sketch of this unit is shown in Figure 13.

NSP has consented to participate and negotiations are continuing pending approval of this unit by the EPA Project Officer.

In addition, discussions are still continuing with utilities which are operating the larger, opposed-fired units to determine if an opposed fired unit can be made available for this demonstration.

Burner Design

A preliminary burner design was developed during the early stages of the contract. This was established based on a nominal 125 x $10^6$ Btu/HR burner input. A general set of criteria was established to identify the practical requirements for the low $NO_x$ burner retrofit. These criteria are identified in Figure 14. These criteria are based on the practical limitations of pulverized coal combustion and will be used to evaluate the success of this burner retrofit along with the $NO_x$ reduction potential of the burner.

The final design specifications for the prototype and field retrofit burners will be established based on the requirements of the host boiler selected. A preliminary design, based on the experimental results obtained by EER, the current B&W design limits, and a nominal 125 x $10^6$ Btu/HR burner are detailed in Figure 15. Figure 16 is the preliminary sketch of the prototype burner design based on the design specifications detailed above.

One problem that has narrowed the field of potential host boilers has been the burner spacing on several units under preliminary review. To fit the tertiary ports around the burners, there must be adequate clearances to install the ports and the required airflow control systems while maintaining an adequate number of straight tubes in the furnace walls for support. Several units under review had inadequate burner to burner spacings to even consider the retrofit program.

Another problem that has developed is the problem of retrofitting this burner design to an operating unit. Besides the burner design, it appears that major revisions to the structural supports in the windbox will be required to install this burner. Also a stress review of any unit under consideration must also be made to evaluate the structural integrity of the furnace wall after bending all the additional furnace wall tubes required to form the tertiary air ports. At present, these studies have not been pursued in detail pending final approval of the host boiler by EPA.

After approval has been received, a complete evaluation of the unit will be performed to determine the modifications to the boiler and supports required to retrofit this low $NO_x$ burner.

## CONCLUSIONS

- A tentative host boiler has been selected at Northern States Power's Highbridge Station.
- The utility burner retrofit program is behind schedule due to delays in obtaining a host site.
- The current schedule, pending EPA approval, is to start the demonstration program late in 1981.
- The retrofit will be more difficult than originally anticipated due to the structural modifications required to install the burner and tertiary air ports.
- Efforts are still proceeding to locate a utility operating a small opposed-fired B&W boiler for possible participation in this program.

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PLANT ORDERS (MWE) IN THE U.S.
BY ELECTRIC UTILITIES[2]

BOILERS

| YEAR | COAL ONLY | TOTAL FOSSIL** | COAL AS % OF TOTAL FOSSIL |
|---|---|---|---|
| 1963 | 5,103 | 13,767 | 37.1 |
| 1964 | 4,684 | 15,535 | 30.2 |
| 1965 | 13,435 | 21,613 | 62.2 |
| 1966 | 13,242 | 20,797 | 63.7 |
| 1967 | 14,006 | 24,975 | 56.1 |
| 1968 | 13,383 | 22,810 | 58.7 |
| 1969 | 18,720 | 27,012 | 69.3 |
| 1970 | 12,234 | 29.635 | 41.3 |
| 1971 | 6,784 | 15,817 | 42.9 |
| 1972 | 9,424 | 16,956 | 55.6 |
| 1973 | 21,434 | 26,605 | 80.6 |
| 1974 | 29,438 | 32,522 | 90.5 |
| 1975 | 7,281 | 7,690 | 94.7 |
| 1976 | 5,318 | 6,018 | 88.4 |
| 1977 | 12,373 | 12,431 | 99.5 |
| 1978 | 13,457 | 14,424 | 93.3 |
| 1979 | 5,467 | 5,467 | 100.0 |

**GAS, OIL, OR COAL (OR SOME COMBINATION THEREOF).

FIGURE 1

NUMBER OF FOSSIL BOILER ORDERS BY ELECTRIC UTILITIES[2]

| YEAR | GAS | OIL | GAS/OIL | OIL/COAL | COAL, OIL & GAS | COAL |
|---|---|---|---|---|---|---|
| 1969 | 3 | 6 | 9 | - | 6 | 29 |
| 1970 | 2 | 16 | 11 | - | 8 | 24 |
| 1971 | 1 | 11 | 3 | - | 4 | 15 |
| 1972 | - | 10 | 4 | 2 | 7 | 20 |
| 1973 | - | 4 | 3 | - | 5 | 38 |
| 1974 | - | - | 4 | - | 7 | 60 |
| 1975 | - | - | 1 | - | 1 | 14 |
| 1976 | - | - | - | - | 1 | 12 |
| 1977 | - | 1 | - | - | - | 24 |
| 1978 | - | - | - | - | 3 | 27 |
| 1979 | - | - | - | - | - | 14 |

NOTE: THIS TABLE INDICATES THAT MOST OF THE FUTURE ORDERS OF FOSSIL BOILERS FOR THE ELCTRIC UTILITY INDUSTRY WILL BE FUELED BY COAL.

FIGURE 2

STEAM-ELECTRIC GENERATING UNITS
PLACED IN SERVICE
BY THE ELECTRIC UTILITY INDUSTRY [3]



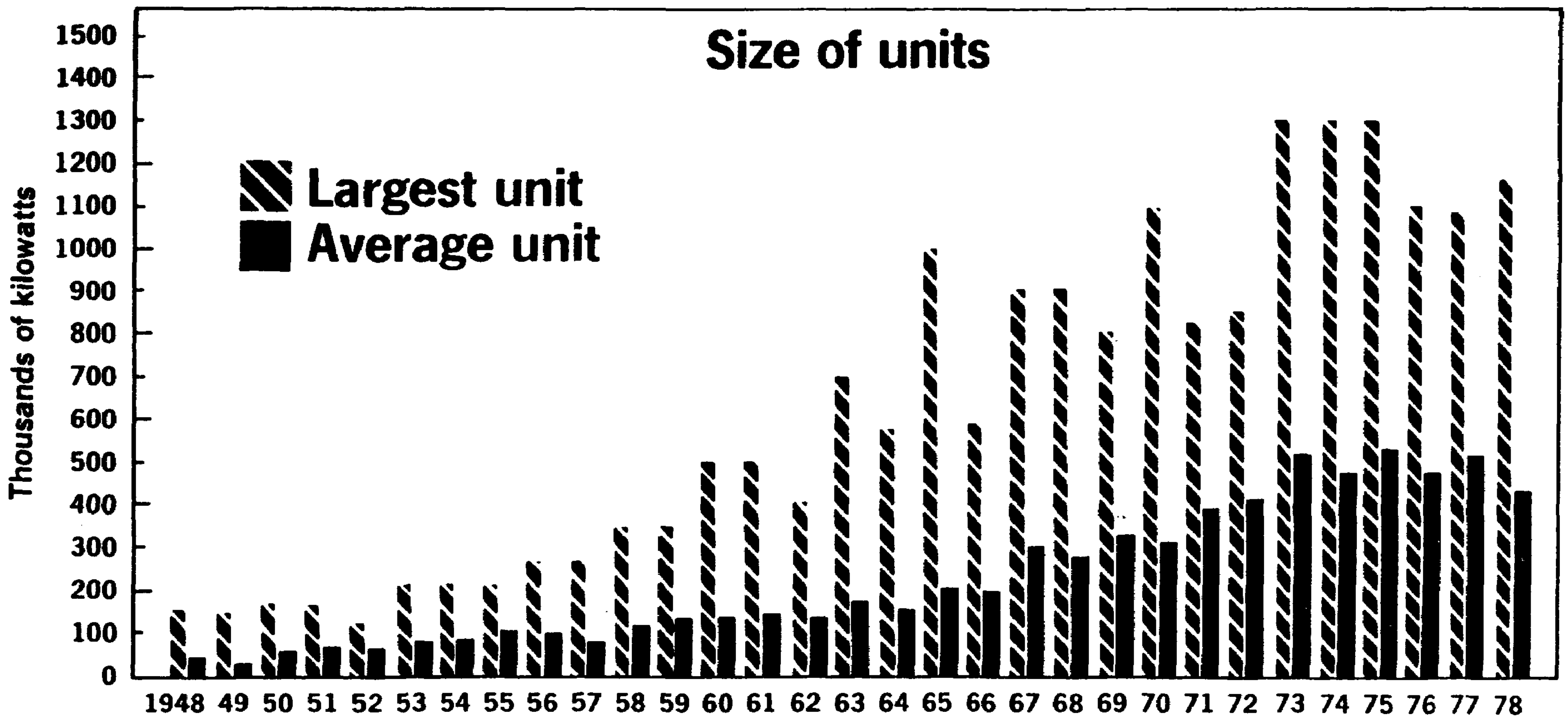


FIGURE 3

DISTRIBUTION PATTERN OF COAL FIRED UNITS
IN SERVICE IN THE U.S. IN EARLY 1979 [2]

| | NUMBER OF UNITS |
|---|---|
| RANGE (MW) | COAL |
| 50-250 | 481 |
| 250-450 | 130 |
| 450-650 | 76 |
| 650-850 | 45 |
| 850-1050 | 2 |
| 1050-1250 | 3 |
| 1250-1450 | 5 |

FIGURE 4

## FIRING PATTERN & UNIT SIZE DISTRIBUTION

| | % BY UNITS | % STEAM FLOW |
|---|---|---|
| ONE WALL FIRED UNITS | 42.9 | 8.8 |
| OPPOSED-LESS THAN 300 MW | 8.0 | 5.3 |
| OPPOSED-300 TO 600 MW | 22.3 | 27.7 |
| OPPOSED-GREATER THAN 600 MW | 26.8 | 58.2 |

FIGURE 5

PULVERIZED COAL FIRED BOILER EXPERIENCE [4]

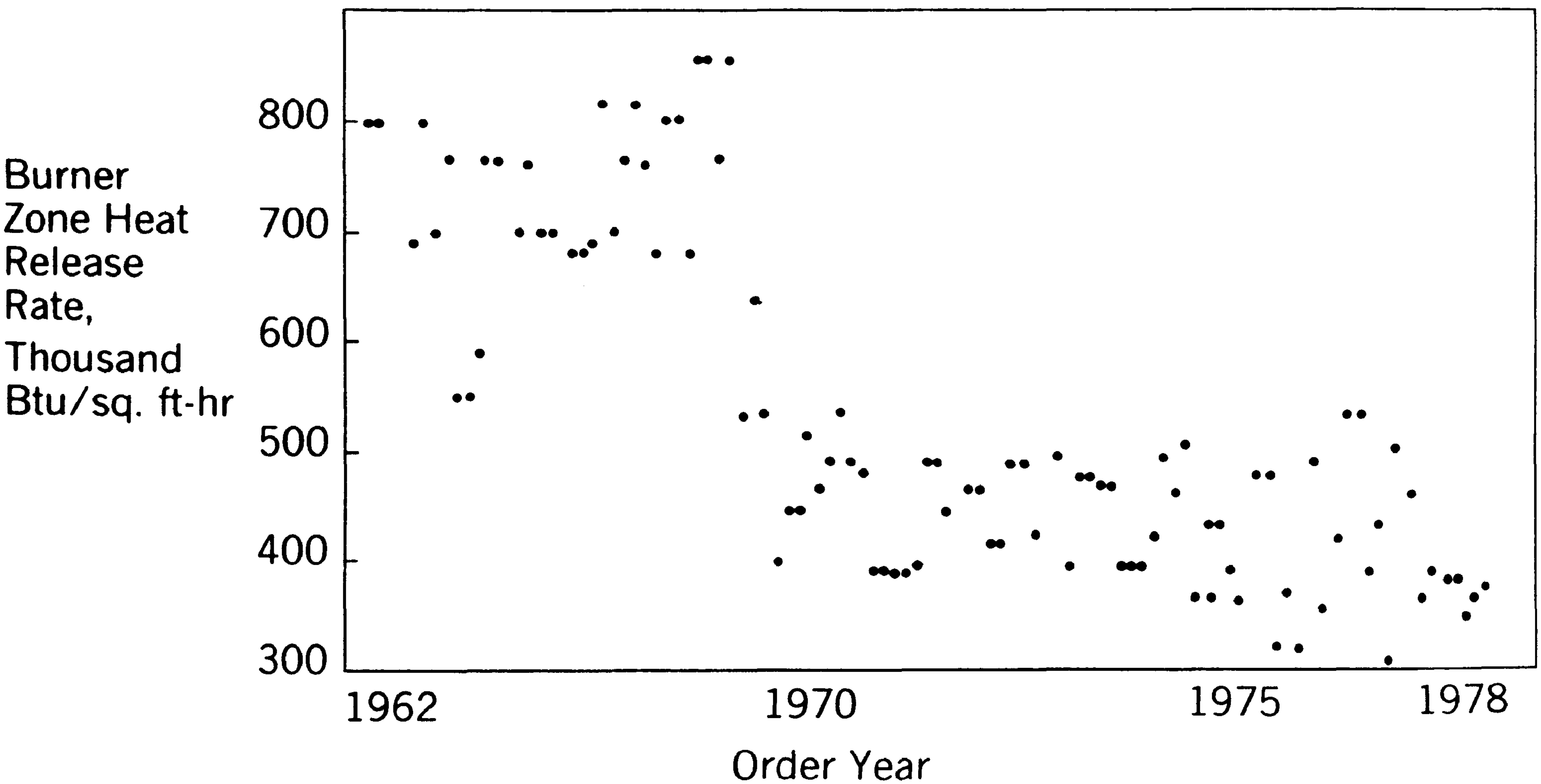


FIGURE 6

PULVERIZED COAL FIRED BOILER EXPERIENCE[4]

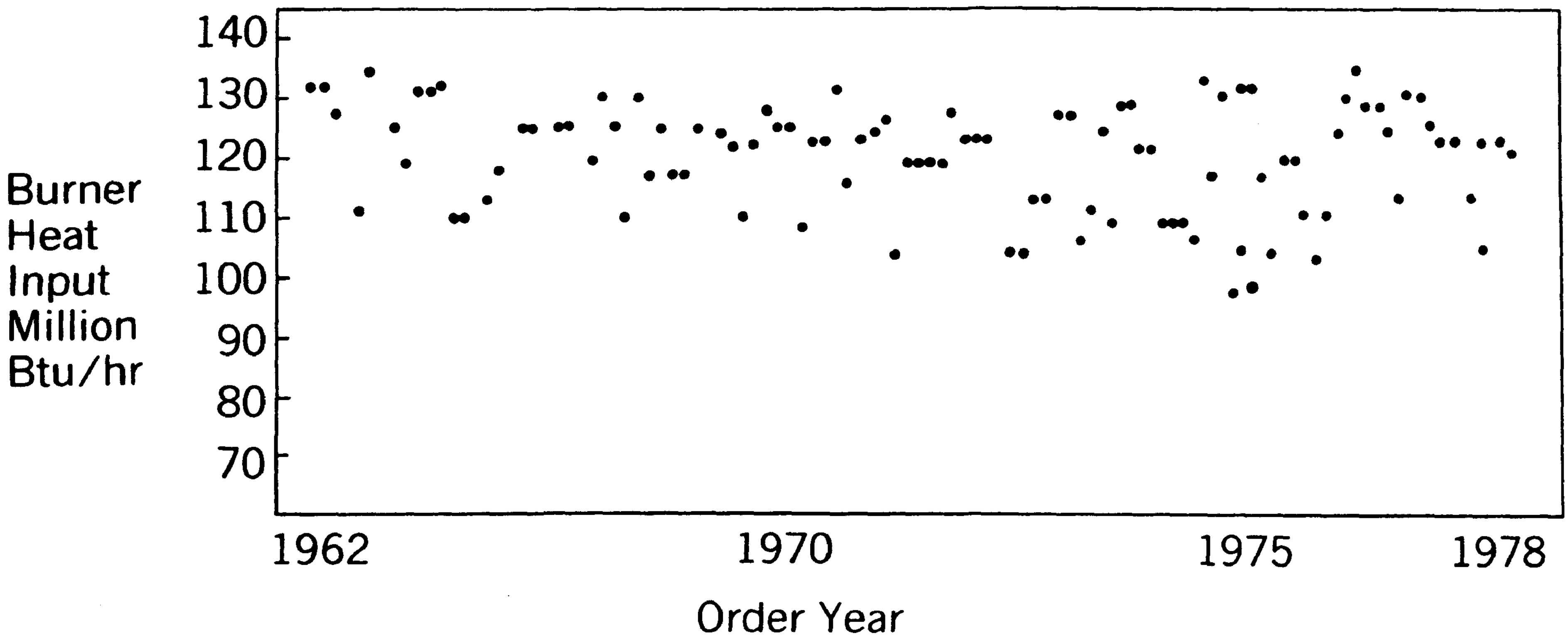


FIGURE 7

POTENTIAL HOST SITE CANDIDATES

| UTILITY | SIZE MW | HEAT RELEASE RATE | BURNER PATTERN | BURNER TYPE | NUMBER OF BURNERS | COAL TYPE | NOx PORTS |
|---|---|---|---|---|---|---|---|
| A | 350 | 384 | OPPOSED | CIRCULAR | 32 | SUBBIT. | YES |
| B | 333 | 508 | " | DUAL REG. | 24 | BIT. | NO |
| C | 265 | 502 | " | CIRCULAR | 18 | BIT. | NO |
| D | 250 | 325 | " | CIRCULAR<br>DUAL REG. | 18 | BIT. | NO |
| E | 250 | 299 | " | CIRCULAR | 24 | BIT. | NO |
| F | 350 | 390 | " | DUAL REG. | 30 | SUBBIT. | NO |
| G | 216 | 342 | " | CIRCULAR | 20 | LIGNITE | NO |

FIGURE 8

## SELECTION PRIORITIZATION

- NEW UNITS - REPRESENTATIVE OF CURRENT DESIGNS
- OLDER UNITS - 300 MW RANGE AND REPRESENTATIVE FURNACE DESIGN.
- LARGER OPPOSED UNITS
- ONE WALL FIRED UNITS
- UNITS WHERE NO BASELINE IS POSSIBLE.

FIGURE 9

# DESIGN PARAMETER COMPARISON
## PRIMARY UNITS

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| STEAM FLOW (MLB/HR) | 2300 | 2534 | 1450 |
| S.H. TEMP ($^oF$) | 1005 | 1005 | 1005 |
| S.H. PRESS. | 2610 | 2500 | 1990 |
| FEEDWATER TEMP. | 485 | 486 | 460 |
| SEC. AIR ($^oF$) | 541 | 600 | 647 |
| TEMP. GAS LVG. BOILER ($^oF$) | 655 | 690 | 750 |
| TEMP. GAS LVG. AH ($^oF$) | 291 | 266 | 270 |
| UNIT EFF. (%) | 88.88 | 84.57 | 85.23 |
| FUEL, BTU/LB | 11,500 | 8250 | 8624 |
| ASH | 16.0 | 5.2 | 4.87 |
| $H_2O$ | 5.0 | 29.0 | 28.11 |
| $N_2$ | 1.3 | 0.9 | 0.67 |
| DRUM PRESS.(PSIG) | 2770 | 2660 | 2115 |
| HA/SC (KBTU/HRFT$^2$) | 508.4 | 383.5 | 314.5 |

FIGURE 10

# DESIGN PARAMETER COMPARISON

## SECONDARY UNITS

| | UNIT 5 | UNIT 6 | UNIT 7 |
|---|---|---|---|
| STEAM FLOW (MLB/HR) | 2,404 | 2,355 | 4,050 |
| S.H. TEMP ($^{O}F$) | 1,000 | 1,005 | 1,005 |
| S.H. PRESS. (PSIG) | 3,575 | 2,625 | 3,805 |
| FEEDWATER TEMP. ($^{O}F$) | 500 | 542 | 550 |
| SEC. AIR ($^{O}F$) | 603 | 565 | 589 |
| TEMP. GAS LVG. BOILER ($^{O}F$) | 646 | 635 | 628 |
| TEMP GAS LVG. AH ($^{O}F$) | 244 | 267 | 240 |
| UNIT EFF. (%) | 91.20 | 89.13 | 89.90 |
| FUEL, BTU/LB | 13,550 | 12,180 | 11,000 |
| ASH % | 8.5 | 11.6 | 12.48 |
| $H_2O$ % | 4.0 | 5.2 | 5.2 |
| $N_2$ | 1.3 | 1.2 | 1.0 |
| DRUM PRESS. (PSIG) | NA | NA | NA |
| HA/SC (KBTU/HR $FT^2$) | 600 | 460 | 690 |

FIGURE 11

# DESIGN PARAMETER COMPARISON
ONE WALL-FIRED UNITS

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| STEAM FLOW (MLB/HR) | 1,200 | 1,000 | 600 |
| S.H. TEMP. ($^0F$) | 1,005 | 1,003 | 1,005 |
| S.H. PRESS. (PSIG) | 1,875 | 1,825 | 1,990 |
| FEEDWATER TEMP. ($^0F$) | 470 | 485 | 463 |
| SEC. AIR ($^0F$) | 593 | 608 | 590 |
| TEMP. GAS LVG. BOILER ($^0F$) | 705 | 719 | 695 |
| TEMP. GAS LVG. AH ($^0F$) | 287 | 292 | 283 |
| UNIT EFF. (%) | 87.31 | 88.33 | 87.58 |
| FUEL, BTU/LB | 10,400 | 11,530 | 11,683 |
| ASH % | 12.2 | 13.0 | 9.31 |
| $H_20$ % | 13.0 | 8.5 | 6.90 |
| $N_2$ % | 0.97 | 1.4 | 1.21 |
| DRUM PRESS. (PSIG) | 2150 | 2,050 | 2,225 |
| HA/SC (KBTU/HR $FT^2$) | 254 | 235 | 290 |

FIGURE 12

NORTHERN STATES POWER
HIGHBRIDGE #12

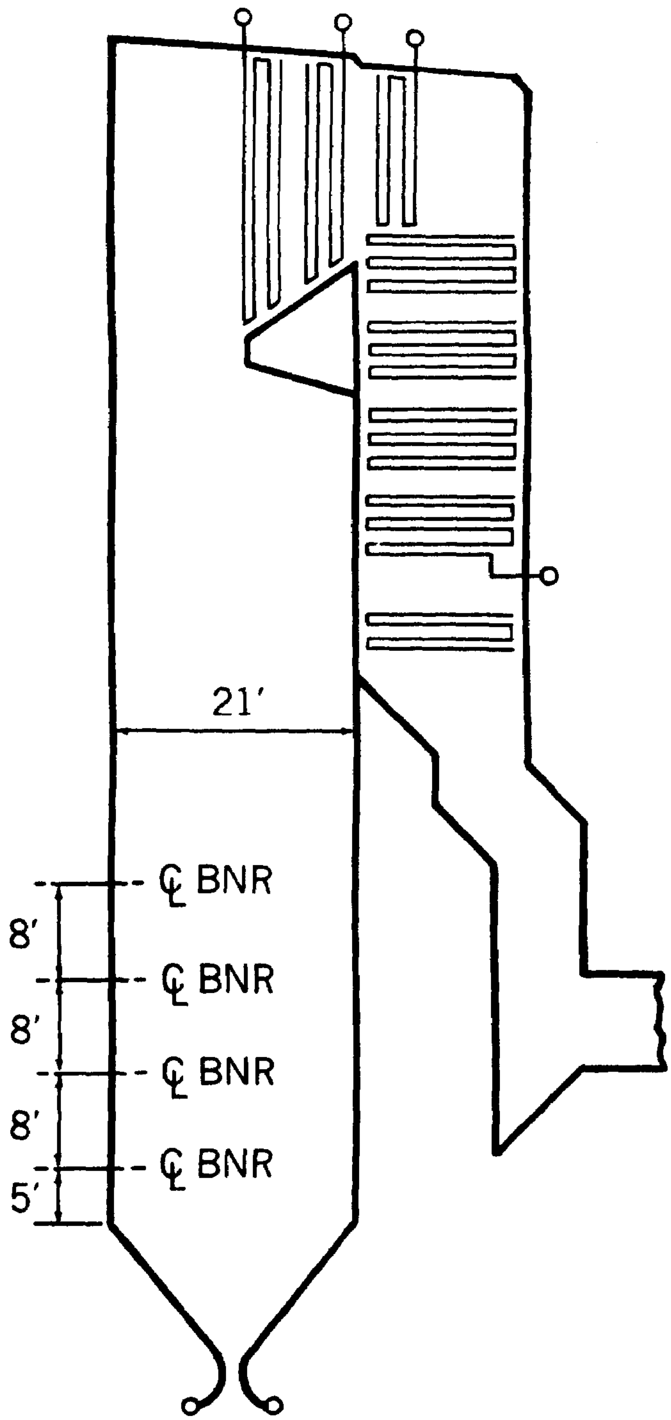


FIGURE 13

# PRACTICAL REQUIREMENTS OF LOW NOx BURNERS

- SUITABLE FOR EXISTING ENVELOPE
- MINOR MODIFICATION TO HEAT FLUX PROFILE
- NO EFFECT ON THERMAL EFFICIENCY
- NO EFFECT ON UNIT PERFORMANCE
- NO INCREASE IN RELATED POLLUTANTS
- NO INCREASE IN LOWER FURNACE CORROSION POTENTIAL

FIGURE 14

# LOW EMISSIONS BURNER DESIGN

## A. ASSUMPTIONS

1. BURNER SIZE - NOMINAL 125 MKB/HR.
2. AREA INNER ANNULUS = AREA OUTER ANNULUS
3. THEORETICAL AIR = 7.57 LB/10 KB (AS FIRED)
4. SECONDARY AND TERTIARY AIR TEMPERATURE = 550°F
5. PRIMARY AIR TEMPERATURE = 150°F @ BURNER
6. WINDBOX PRESSURE = 4 INCHES W.C.
7. PRIMARY AIR PRESSURE = 5 INCHES W.C. @ BURNER
8. BAROMETRIC PRESSURE = 29.92 INCHES HG

## B. DESIGN CRITERIA

1. DUAL AIR ZONE BURNER
2. TOTAL EXCESS AIR = 15%
3. STOICHIOMETRY
   - PRIMARY AIR - 0.2-0.25
   - BURNER - 0.7 TOTAL (INCLUDING PRIMARY AIR)
   - TERTIARY PORTS - 0.45
4. VELOCITIES
   - THROAT - 3600 FPM
   - PORTS - 3000 FPM (4 PORTS)
   - NOZZLE - 4500 FPM (3000 FPM MINIMUM)
5. THROAT (QUARL) HALF ANGLE - 25°

FIGURE 15

DISTRIBUTED MIXING BURNER
PRELIMINARY DESIGN

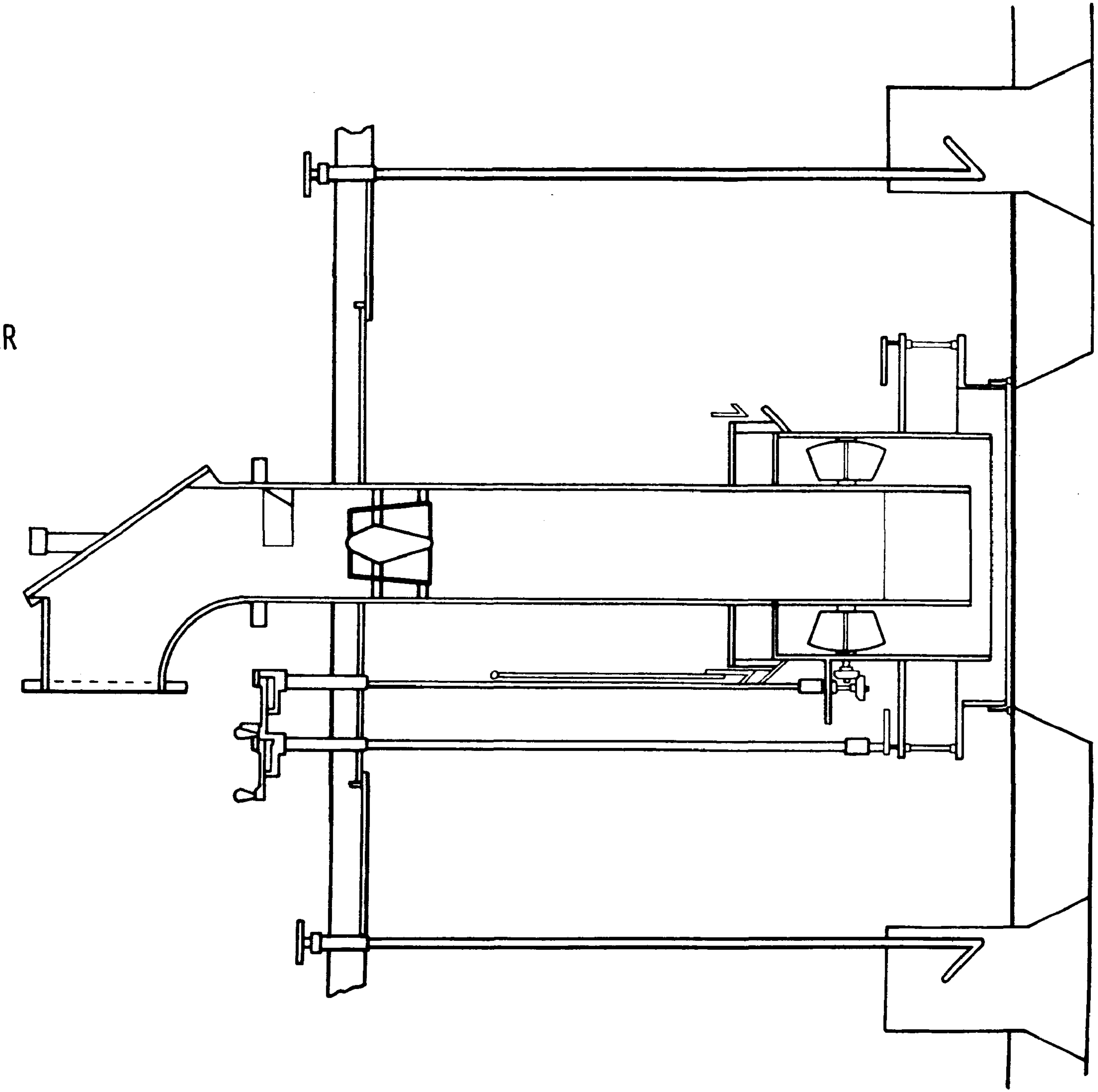

FIGURE 16

# OPERATING EXPERIENCE AND FIELD DATA OF A 700 MW COAL-FIRED UTILITY BOILER WITH RETROFIT LOW $NO_x$ STAGED MIXING BURNERS

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ABSTRACT

Forthcoming new federal regulations on emission control for stationary combustion systems will clearly define tolerable $NO_x$-emission levels in Germany and thus replace the present "best technical means" approach.

This fact gave reason to the initiation of a R&D program for the development of cost effective low $NO_x$-combustion equipment for use in pulverized coal fired boilers.

The program which was financially assisted by the Federal Ministry for Research and Development (Bundesministerium für Forschung und Technologie, BMFT) was subdivided into two parts:

As a first step a distributed mixing burner design concept adopted for an envisaged 50 % $NO_x$-reduction was tested and optimised in a pilot plant test program with a 2.5 MW burner. The burner design concept was based on a conventional circular burner with additional tertiary air nozzles distributed concentrically about the burner mouth. Within this program a 65 % $NO_x$ reduction was achieved with an optimised configuration of the distributed mixing - respectively staged mixing burner (SM-burner) without disadvantageous changes in combustion and emission characteristics.

Following the successful pilot plant tests the combustion equipment of a 700 MW coal fired power station was changed to SM-burners. Both, to ease the retrofit and to safely allow the execution of a measuring program as retrofit burner a modified version of the optimized pilot burner design was used for the boiler. The modification resulted in a limitation of the safely operable tertiary air mass flows and thus to a certain extent reduced the staging capability of the large burner.

In spite of the narrower operational limits the envisaged goal of a 50 % $NO_x$ reduction was met in the boiler demonstration tests. Furthermore a burner load dependent automatic secondary/tertiary air flow control system developed to guarantee a safe burner operation at low $NO_x$ levels over a wide turn down ratio, was operated successfully.

Parametric studies, in flame and flue gas measurements were carried out to identify effects on $NO_x$-formation and potential problem areas at low $NO_x$-operation. Similarly to the pilot plant tests the staged mixing - dividing the flame into a fuel rich primary and a secondary burnout zone - proved to be the most effective single parameter on $NO_x$ reduction. In the past 24 months of operation neither short term nor long term performance problems due to low $NO_x$ operation could be detected.

## SECTION 1

## INTRODUCTION

Both federal government and local regulations on $NO_x$-emission from power station boilers in Germany force utilities and power station manufacturers to develop techniques which allow the operation of power station boilers in compliance with present and future regulations.

Unlike to flue gas desulphurization it has been shown by various international R&D programs that the most cost effective method to meet present and medium future $NO_x$ legislation lies in the reduction of $NO_x$-formation by optimizing the combustion process, respectively the combustion equipment.

Numerous researches have clearly indicated that it has to be differentiated between basically two $NO_x$-formation mechanisms,

- the 'thermal $NO_x$' route, comprising all reactions which in their final result lead to the oxidation of originally molecular nitrogen, and
- the 'fuel $NO_x$' route, describing the oxidation of fuel bound nitrogen.

It is now well established that the thermal $NO_x$-formation predominantly depends upon the reaction temperature and the prevailing residence time at high temperatures, whereas the fuel $NO_x$-formation is more dependent on the oxygen concentration in the pyrolysis zone of the flame.

The relative importance of these individual reaction routes on the overall $NO_x$ formation varies with the nitrogen content of the fuel. With natural gas firing due to the absence of fuel bound nitrogen only thermal $NO_x$ can be formed, and thus the emission be minimized by controlling the time temperature history of the combustion products.

At residual fuel oil and pulverized coal firing the fuel $NO_x$ formation mechanism often plays the dominant role. Experiments by Pershing et al (1) have shown that upto 80 % of the overall $NO_x$ emission at coal firing was contributed by the fuel $NO_x$-formation mechanism.

As coal is or soon will be the only important fossil fuel for power generation in Germany it is evident that controlling $NO_x$ emission from power stations will only be possible when the fuel $NO_x$ formation mechanism can be controlled.

As stated above, this calls for an oxygen concentration control in the pyrolysis zone of the flame, which at the simultaneous requirement of short intense flames can be achieved by a staged respectively distributed mixing burner concept.

Using the Steinmüller circular burner configuration as basis, a novel distributing respectively staged mixing prototype burner (SM-burner) was designed which was subsequently further optimized and demonstrated in a two-phase program upon which is reported in this paper. A pilot test and optimization program with a 2.5 MW test burner was followed up by a largescale demonstration at a 700 MW power station which is equipped with 24 retrofit SM-burners.

Both program phases were carried out in cooperation with and financial assistance of the German Federal Ministry of Research and Development (Bundesministerium für Forschung und Technologie, BMFT).

## SECTION 2

## THE SM-BURNER CONCEPT

As Fig. 1 shows the SM-burner is derived from the reliable circular swirl burner. The pulverised coal is fed to the burner throat by an annular fuel gun and injected concentrically to the burner axis.

The former secondary air is now split up into two streams, a reduced secondary air flow which is passed as usual through the annular air duct surrounding the fuel gun, and a tertiary air flow to four tertiary air nozzles which are placed concentrically about the burner quarl exit.

At 100 % coal firing the core air butterfly valve is almost closed. It is adjusted in such a way that just sufficient core air is passed through the central duct to avoid recirculation flows induced by the swirling secondary air into the core air duct.

A variable swirl device allows a control of the secondary air swirl intensity.

The tertiary air quantity, respectively the tertiary/secondary air ratio , can be controlled by the butterfly valve in the tertiary air duct.

To control the overall burner stoichiometry, the total air flow to each burner is measured individually by a venturi type flow meter.

Fig. 2 shows a schematic of the anticipated flow and mixing regime of the SM-burner. As a result of the air supply chosen, the flame, which is stabilized within the burner mouth due to the prevailing aerodynamic conditions, is characterized by two distinct zones of different stoichiometry, a fuel-rich primary zone close to the burner exit, followed by an overstoichiometric secondary or burnout zone. The design concept thus enables to fulfil the low fuel $NO_x$-formation requirement of low oxygen concentration in the fuel pyrolysis zone of the flame and additionally, but to a lesser degree, reduces the thermal $NO_x$-formation as a consequence of lowering the maximum flame temperatures due to interstage cooling and increase of recirculation matter entrainment.

One of the main problems to be solved was to optimize the burner design and control in such a way to achieve optimum, low $NO_x$' conditions without substantial loss of combustion intensity, turndown potential and burnout performance.

The realization of simultaneous optimum, low $NO_x$-conditions, high combustion intensity and good burnout performance was achieved by an experimental optimization of

- shape, number and outlet area of staging air nozzles
- cross-sectional area of secondary air duct
- swirl intensity of secondary air flow
- fuel injection angle and velocity, and
- length of burner quarl.

As described in more detail in (2) a burner configuration could be derived from the pilot plant results for the 2.5 MW prototype burner which yielded the anticipated flow pattern (Fig. 3, type II flame) for a wide range of input conditions. At an overall burner stoichiometry of $n_t$ = 1.25 a stable type II flame flow pattern was achieved at full load down to a 'staging ratio' of $n_p$ = 0.55, 'staging ratio' $n_p$ being defined as the stoichiometry of the primary zone (Fig. 2).

A further decrease of $n_p$ caused a dramatic increase in flame length due to a change in flow pattern (Fig. 3, type I flame).

As long as the type II flow pattern is preserved ($n_p > 0.55$) staged mixing operation results in only moderate changes of flame length and combustion intensity. This fact is manifested by the axial decay of CO concentration on Fig. 4. Also plotted on Fig. 4 is the axial concentration of free oxygen with the staging ratio as parameter. The oxygen pattern proves the presence of a fuel-rich primary respectively pyrolysis zone close to the burner at $n_p<1$.

The necessity to keep the fuel transport air quantity virtually constant independent of burner load in order to maintain the transportation characteristics does at decreased burner loads result in a reduction of the secondary air to primary air momentum ratio as long as the staging ratio $n_p$ is kept constant. This momentum ratio, however, controls the flow pattern. At load reduction this causes the danger of a flame pattern change from type II to type I (Fig. 3).

To overcome this problem, an automatic load-dependent secondary/tertiary air distribution control procedure has been developed for the SM-burner, which was first tested during the demonstration of the 24 retrofit SM-burners at the 700 MW power station.

The load-dependent air flow control procedure is graphically illustrated on Fig. 5. Whereas the total air ($n = 1.25$) is reduced linearly with load, the secondary air flow follows the total air reduction only up to a certain load limit. At a further load decrease the secondary air flow is only degressively reduced which, of course, can be verified only at the expense of the tertiary air flow. As a consequence thereof the staging ratio is increased at reduced load in order to safely maintain the desired combustion characteristics at low load and yet to enable a maximal obtainable $NO_x$ reduction at full load where the prevailing conditions allow safe operation at lower staging ratios.

## SECTION 3

## DEVELOPMENT DATA AND RETROFIT EXPERIENCE

The single burner pilot plant tests (2) had clearly indicated that at the conditions investigated the by far strongest individual effect on $NO_x$ emission was caused by the staging ratio $n_p$. Fig. 6 exhibits the $NO_x$ emission as a function of the staging ratio with the burner load as parameter. From this information it is also obvious that with respect to $NO_x$ control the low load burner air flow control illustrated on Fig. 5 is tolerable, as load reductions result in considerably lower $NO_x$ emissions anyhow.

The retrofit action was carried out at a 700 MW opposite wall fired single pass power station boiler with 24 burners. The boiler radiant section was subdivided by an evaporator-integrated division wall to minimize the slagging potential.

To reduce the retrofit costs and to minimize the operational risks it was decided to make use of the existing burners, thus adding only the tertiary air ports, the necessary ducting, flow control devices and instrumentation. Whereas this decision ensured that by only closing the valves of the tertiary air duct the original burner conditions could be restored at any time it limited the full exploitation of the SM-burner design for maximum $NO_x$ reduction, as the optimum secondary air duct design could not be incorporated in the retrofit burner.

Results obtained from the power station after retrofitting the SM-burners are presented in two subsections. The data discussed and presented below refer always to flue gas measurements and simultaneous operation of 24 burners under same conditions, unless otherwise specified.

The demonstration tests as well as the pilot investigations were carried out with German SAAR coal of the following average composition:

| | | |
|---|---|---|
| Total water: | 10 | % by weight |
| Inherent moisture: | 1.9 | % by weight |
| Ash: | 8.24 | % by weight daf |
| Volatiles: | 32.2 | % by weight daf |
| Sulphur: | 0.89 | % by weight daf |
| Nitrogen: | 1.1 | % by weight daf |
| Net calorific value: | 26.42 | MJ/kg |

Analyses taken over a longer period and illustrated on Fig. 7 show a considerable variation of the nitrogen content with time, which can of course affect $NO_x$ emissions. The data for each individual parameter study have, however, been taken over a comparatively short time (several hours) so that a constant N-content can be assumed during the investigation of individual parameters.

PARAMETRIC EFFECTS ON $NO_x$ EMISSIONS (700 MW BOILER)

Although the staging ratio in the retrofit burners was limited due to the above-mentioned design compromise, it proved to be again the most effective individual parameter. Fig. 8 shows a strong dependency of flue gas emission levels on the staging ratio. The overall excess air level, characterized by the various symbols on Fig. 8, has only a negligible influence.

Furnace respectively burner loading has also a substantial effect on $NO_x$ emission, as is illustrated on Fig. 9. This fact is important as it more than equalizes the effect of the limited staging ratio at low load burner operation due to the automatic air flow control (Fig. 5).

Whereas some authors have reported an effect of combustion air swirl intensity on $NO_x$ formation, this investigation revealed, neither at unstaged nor at staged operation, an influence of secondary air swirl intensity on $NO_x$ emission (Fig. 10, $n_p = 0.9$).

Heap and Pershing (3) measured a pronounced increase in $NO_x$ formation with decreasing particle size distribution in a one-dimensional flow reactor at unstaged condition. A change of the coal fineness during this demonstration test from nominal 35 % > 90 % µm to 29 % > 90 µm indicated an opposite trend (Fig. 11). The likely reason for this discrepancy lies in the different flow and mixing regimes. An increase of fineness in the one-dimensional flow reactor results at unstaged conditions in the first place in a better mixing between fuel and oxidant and thus also increases the probability that nitrogen species are oxidized immediately after devolatilization. Under staged conditions with the SM-burner a decrease in particle size distribution also leads to a better mixing resulting in a faster reaction, however with the important difference that at the overall fuel rich equivalence ratio in the primary zone this rather leads to an increase in oxygen deficiency than to an increase in nitrogen species oxidation.

## IN-FLAME MEASUREMENTS AND OPERATIONAL EXPERIENCE (700 MW BOILER)

### Flame Measurements

Measurements within the radiant chamber of the boiler have been carried out to identify any significant changes due to the staged mixing operation. Visual observations did not show any important changes.

Temperature measurements carried out with a radiation pyrometer (Pyropto) illustrate the relativechanges in ignition zone (primary zone) temperature and the overall axial temperature distribution (Fig. 12). It can be seen that the primary zone temperature, respectively radiation intensity, drops when the burner is operated in the distributed mixing mode, whereas the axial temperature pattern exhibits a slight increase. Inspite of these changes the heat absorption characteristics of both radiant section and superheater remained, however, unchanged. A further reduction of the slagging tendency at the burner level cross-sections of the boiler, observed when the burners were operated in the distributed mixing mode, may be attributed to the temperature reduction in the primary zone.

Another important question which could be clarified partially by measurements within the furnace atmosphere is if corrosion processes at the outer tube surfaces would be stimulated or accelerated due to the distributed mixing burner operation. As potential danger an increased CO-content, with its detrimental effect on CO-corrosion mechanisms, was identified. To investigate these potential problems, two measurements have been performed:

. CO-concentration measurements in the furnace chamber

. tube wall thickness measurements before the retrofit action and again after 24 months of boiler operation with staged mixing burners.

The 2nd series of tube wall thickness measurements have not yet been carried out, but results should be available at the time this paper is being presented.

Gas concentration measurements in the external recirculation matter, which are illustrated on Fig. 13 however, do not indicate any increase in CO-corrosion danger. Inspite of the inspected CO concentration increase towards the burner axis, staged mixing operation does not lead to an increase of CO at the furnace wall areas.

Long-Term Flue Gas Data

At no time any change in flue gas CO emissions was observed, the retrofit of SM-burners thus had no detrimental effect on the CO emission characteristics.

Long-term measurements of uncombusted carbonaceous matter in the fly ash did exhibit a moderate but distinct increase (Fig. 14). Before the retrofit of the SM-burners, ash analyses revealed a 2-3 % content of combustible matter in the fly ash. After the retrofit of SM-burners, the carbonaceous matter in the fly ash increased to a maximum of 4-6 %. This tendency seemed to present basic problems in as much as it results in an efficiency loss and, furthermore, leads to potential problems in the use and sale of fly ash to cement works who limit the content of carbonaceous matter in fly ash for their use generally to 5 %.

A crosscheck with fly ash obtained from an unstaged operation, which was possible due to the retrofit burner compromise (reuse of old burner with controllable tertiary air streams), gave however no change in fly ash composition. This indicated that the fly ash problem had to be attributed mainly to another cause which was found in the mill system. The mills had run more than 15 000 hours without any change of wear parts, resulting in an increase in particle size distribution up to 42 % > 90 µm.

After an appropriate adjustment of the classifiers the unburnt matter in fly ash could again be reduced to an average of 3.5 %, as shown for the 2nd half of 1979 in Fig. 14.

Additionally to the problem of unburnt matter in fly ash, it was of interest if and to what extent the collection efficiency (respectively the fly ash properties) of the electrostatic precipitator would be effected by the distributed mixing mode operation of the SM-burners. Neither precipitator efficiency and total solids emission measurements nor electron microscopic evaluations of ash samples revealed any influence of staged mixing. The latter results are to some extent contradictory to preliminary results from Martin (4) who reported that retrofitting low $NO_x$ coal burners to a boiler in the U.S. had resulted in a distinct increase of fine particulate formation.

Finally, long-term $NO_x$ emission data are plotted on Fig. 15, which are representative for today's continuous boiler operation with the adopted automatic combustion air control illustrated on Fig. 5. Whereas the triangles on Fig. 15 are points from a measuring series which has been taken to assess the dependency of $NO_x$ emission on burner load for the adopted air flow control, the circular points represent data which have been collected over a 10-week period in March/April 1979 and two weeks in February 1980. In spite of the considerable scatter of $\pm$ 40 ppm, which may be attributable to irregularities in the coal composition, all values were below the 1979 EPA NSPS.

## SECTION 4

## SUMMARY - CONCLUSIONS

The paper reports on a development and design optimization programme for a distributed mixing burner and on retrofit experience from a 700 MW opposed wall single pass boiler. Notable results can be summarized as follows:

1) The staged mixing, respectively distributed mixing principle, was proven to be an effective tool for the reduction of $NO_x$ emission from coal-fired power station boilers. The achieved reduction of more than 50 % is predominantly attributable to the suppression of fuel $NO_x$ formation.

2) The SM-burner concept realizes the $NO_x$ reduction without significant changes in combustion intensity and flame shape nor loss in turndown capacity.

3) It can be expected from the pilot experiments that a full size SM-burner design based upon the optimized pilot burner configuration - without compromise as accepted for the retrofit burner - will result in a further increase in $NO_x$ reduction efficiency to approximately 70 %.

4) The slagging tendency in the radiant section reduced when the SM-burner was operated in the distributed mixing mode. No disadvantageous effects on operational safety and CO corrosion potential were detectable up to now. Tube wall thickness measurements which will be carried out shortly after a 24-month operation cycle shall allow final conclusions on this point.

5) Neither a change in fly ash properties and particle size distribution nor an increase in CO emission have been found at distributed mixing operation.

6) A slight increase in uncombusted carbonaceous matter in the fly ash has been detected. The absolute values of approximately 3.5 %, however, lie within the tolerable limits. This increase in carbonaceous matter in the fly ash is noted here as a potential disadvantage although a crosscheck with non-staged mixing operation indicated that it has to be rather attributed to a change in coal quality than to the distributed mixing concept.

7) Until now the operational experience is limited to one coal and one boiler only. Before a final generalization of the reported results and experience is possible more information is required. The effect of coal type will be investigated by further tests in the 2nd half of 1980 as part of a joint program between EPA, BMFT and Steinmüller.

   These tests will be carried out atEnergy & Environmental Research Corporation, Santa Anna in California. Further experience will be gained from two new 600 MW boilers presently under construction in Germany.

8) Once the information to be generated from the additional tests and the new boilers is available it can be hoped that with the SM-burner concept a cost effective low $NO_x$ technology is available for both new and via retrofit also existing installations.

## SECTION 5

## REFERENCES


(1) Pershing, D.W., Brown, J.W., Martin, G.B. and Berkau, E.E.: Influence of design variables on the production of thermal and fuel NO from residual oil and coal combustion. Presented at 66th Annual AIChE Meeting, Philadelphia, Nov. 1973.

(2) Michelfelder, S., Leikert, K. Development program and operating experience with pulverised coal staged combustion burners for steam boilers. American Flame Research Committee, Oct., 22-23, 1979, Houston, Texas

(3) Heap, M.P., Pershing, D., EER- SANTA ANNA Private communication on experimental data obtained in bench scale tests Sept. 1978

(4) Martin, B., EPA - RTP Private Communication

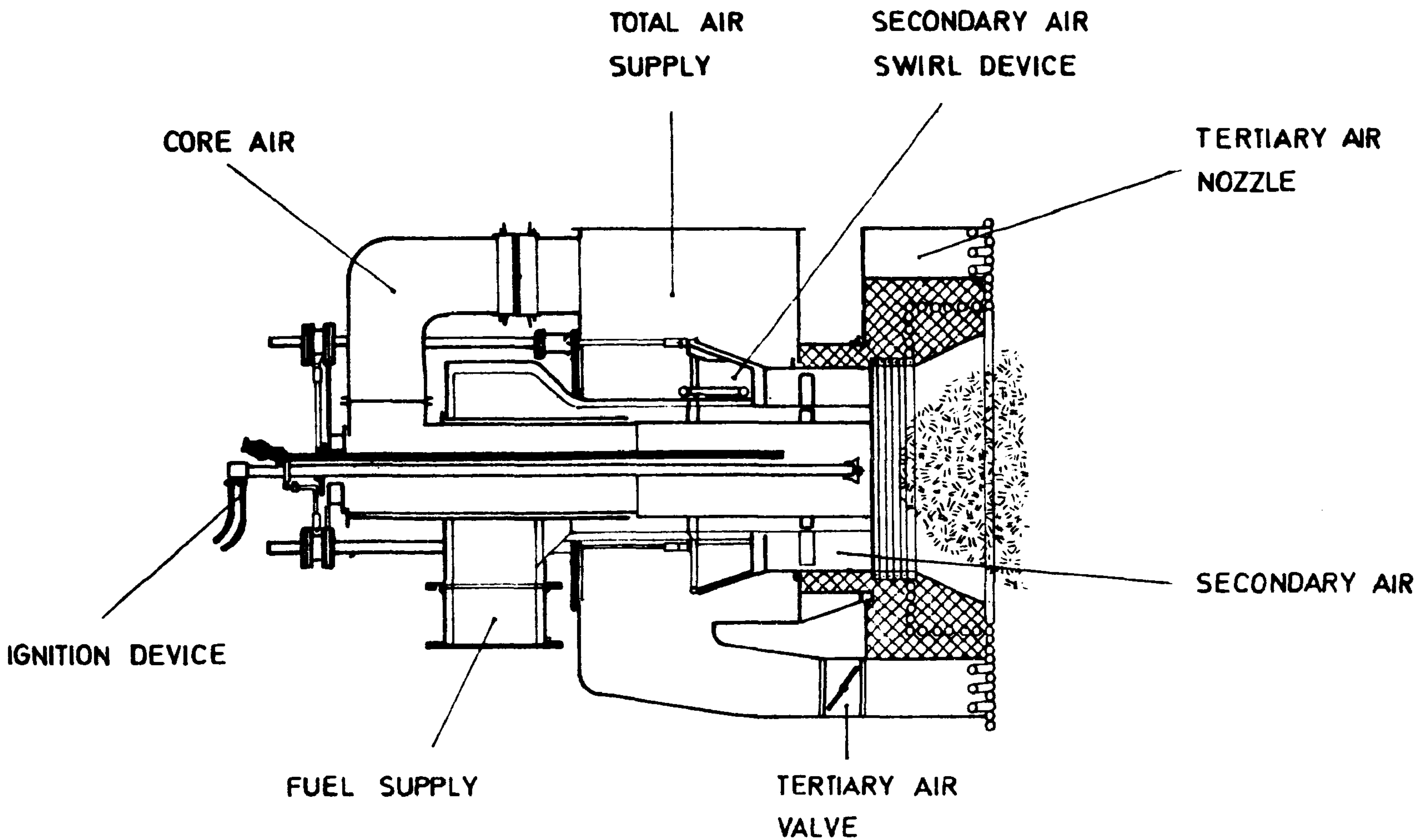



Figure 1. Staged Mixing Burner (SM-Burner).

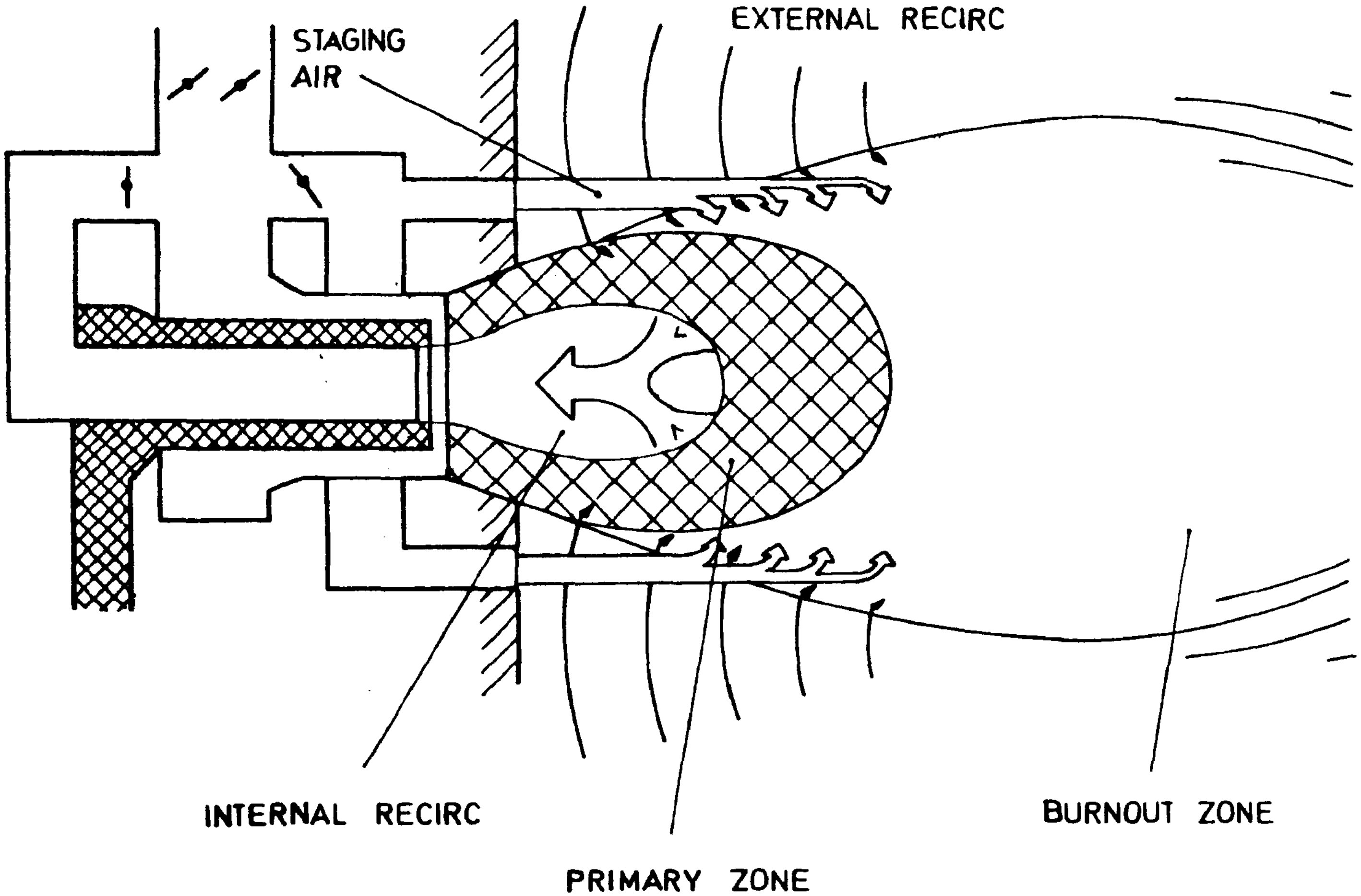



**Figure 2. SM-Burner, Schematic of Flow and Mixing Regime.**

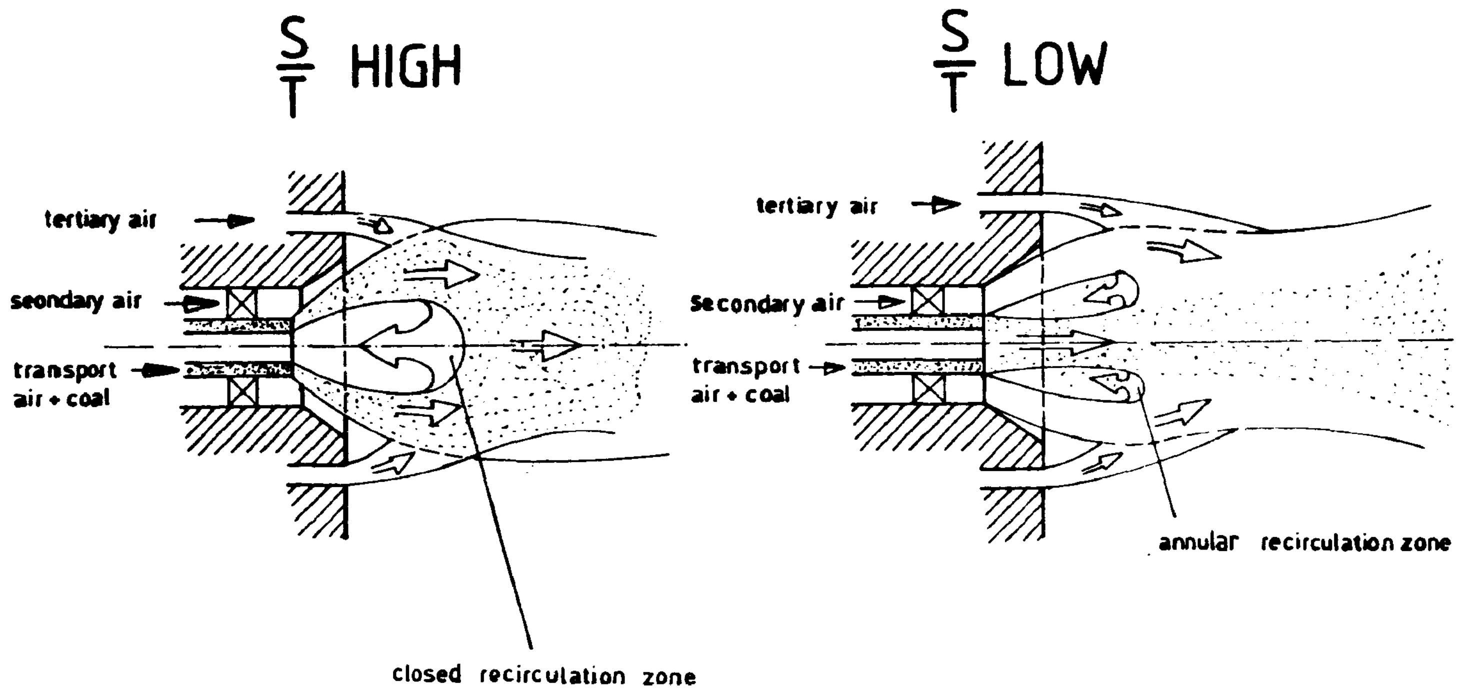



Figure 3. SM-Burner, Flowpattern Depending on Secondary Air/Transport Air (S/T) Ratio.

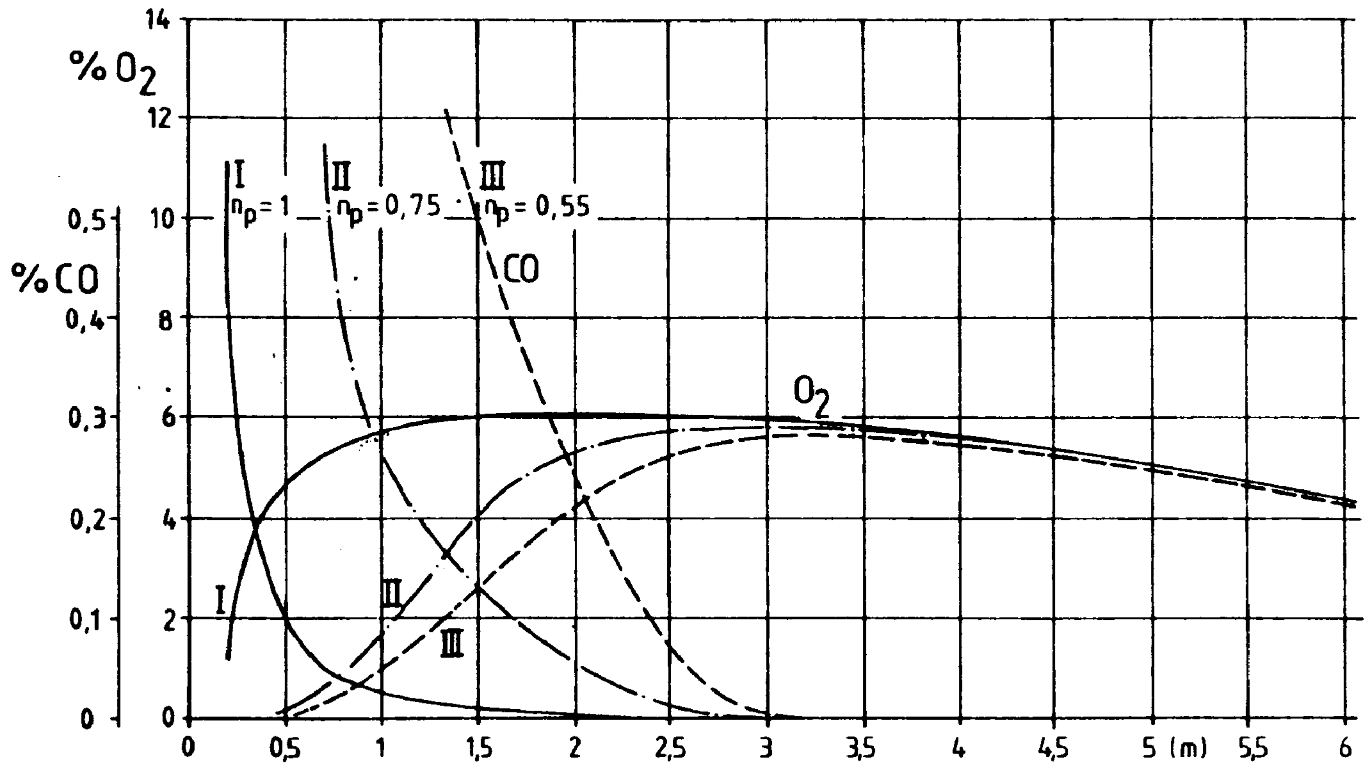



**Figure 4. Axial CO and $O_2$ Concentration Profiles as Function of Primary Zone Stoichiometry (np).**

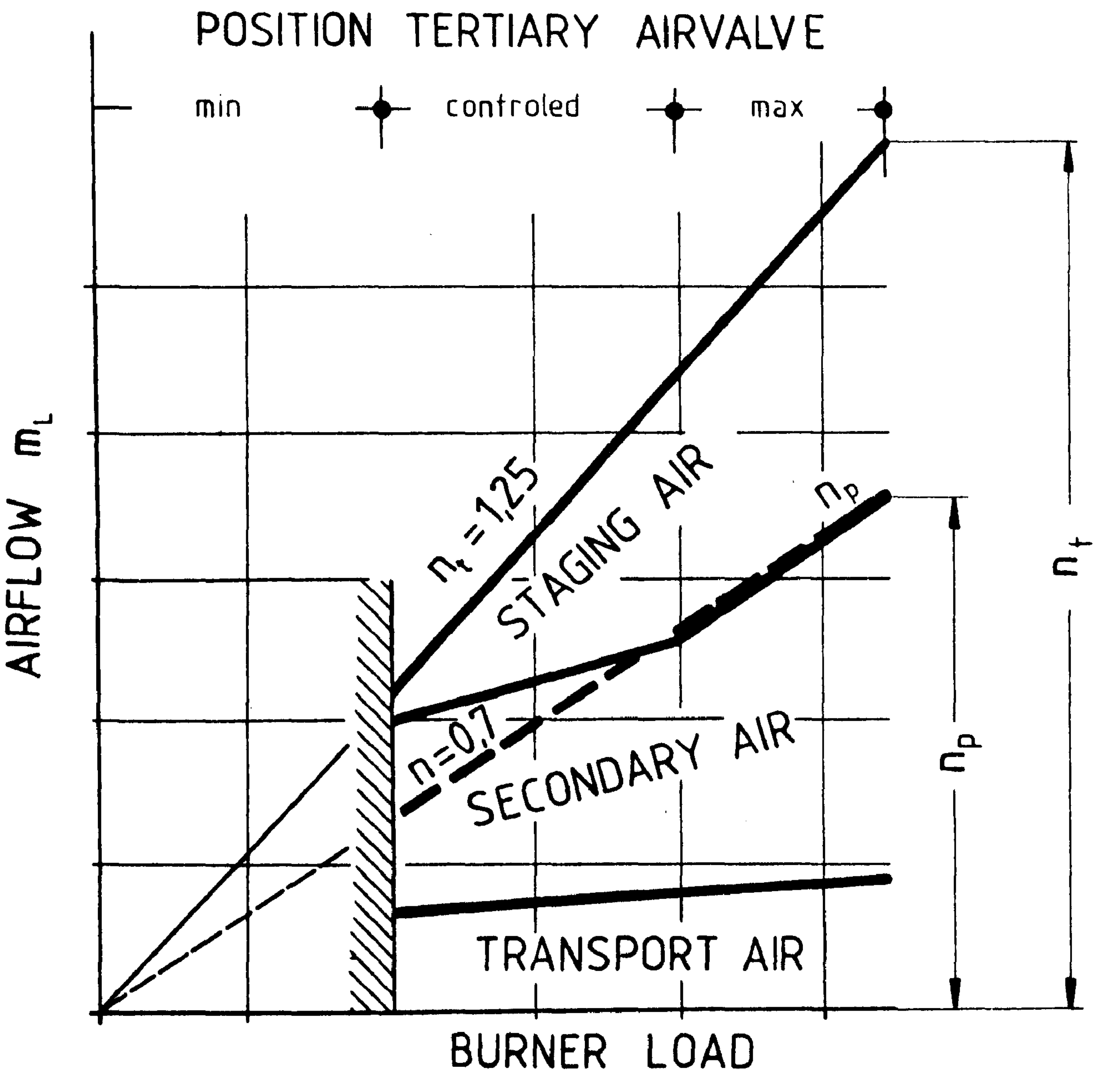



**Figure 5. Air Flow Distribution as Function of Burner Load (Control Procedure).**

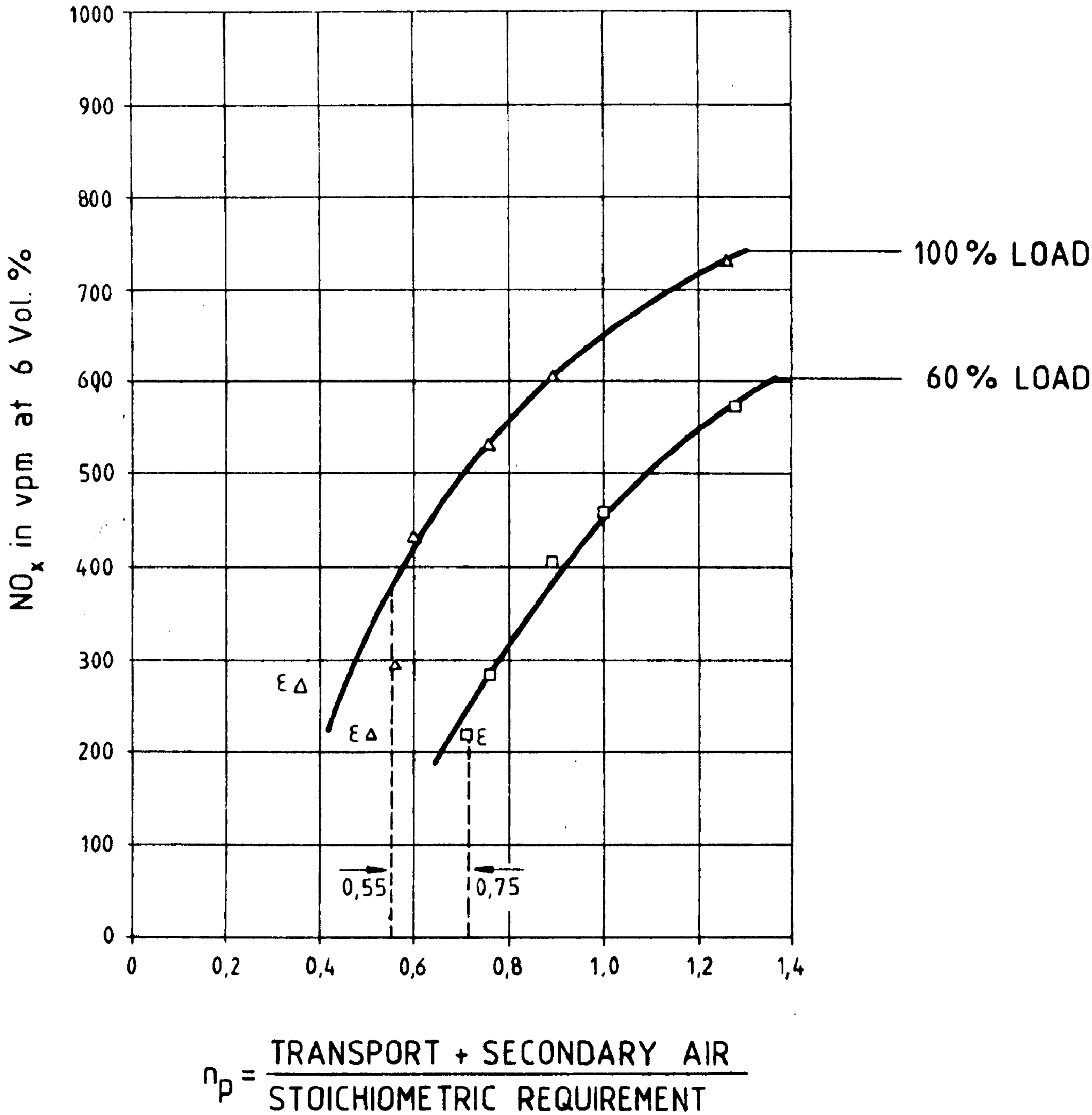



**Figure 6. Optimized Pilot Burner, NO-Emission as Function of Primary Zone Stoichiometry (np).**

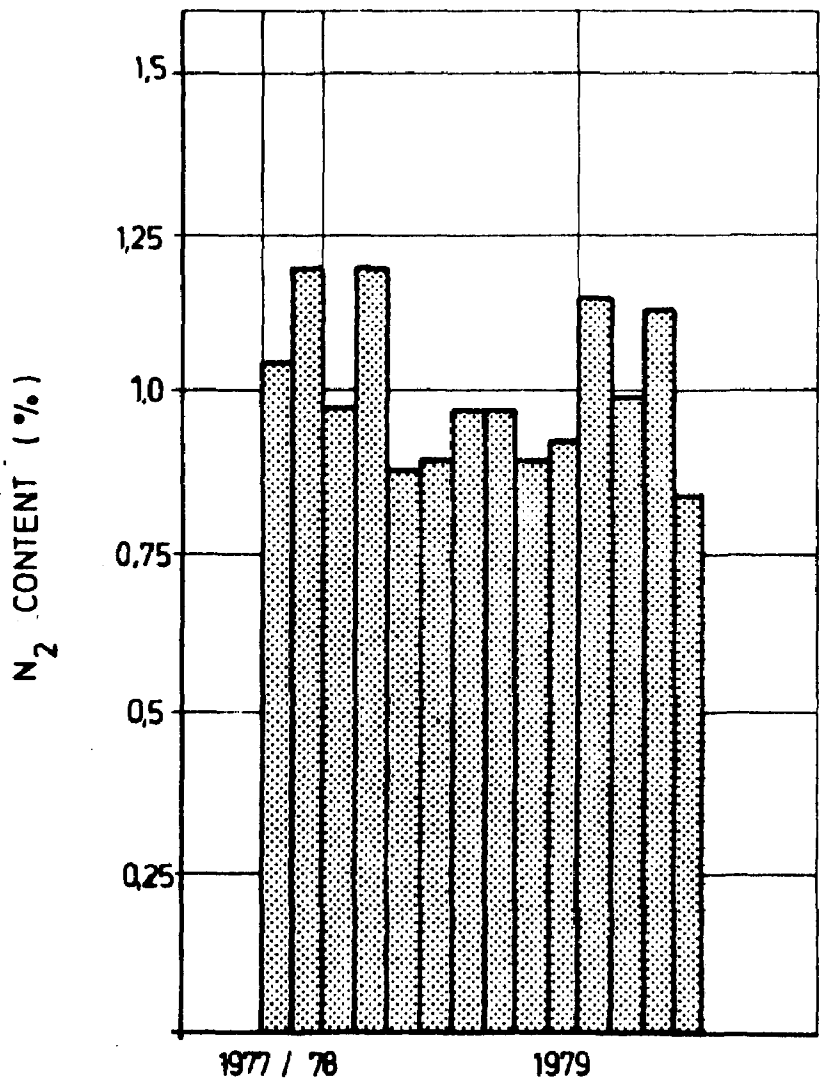
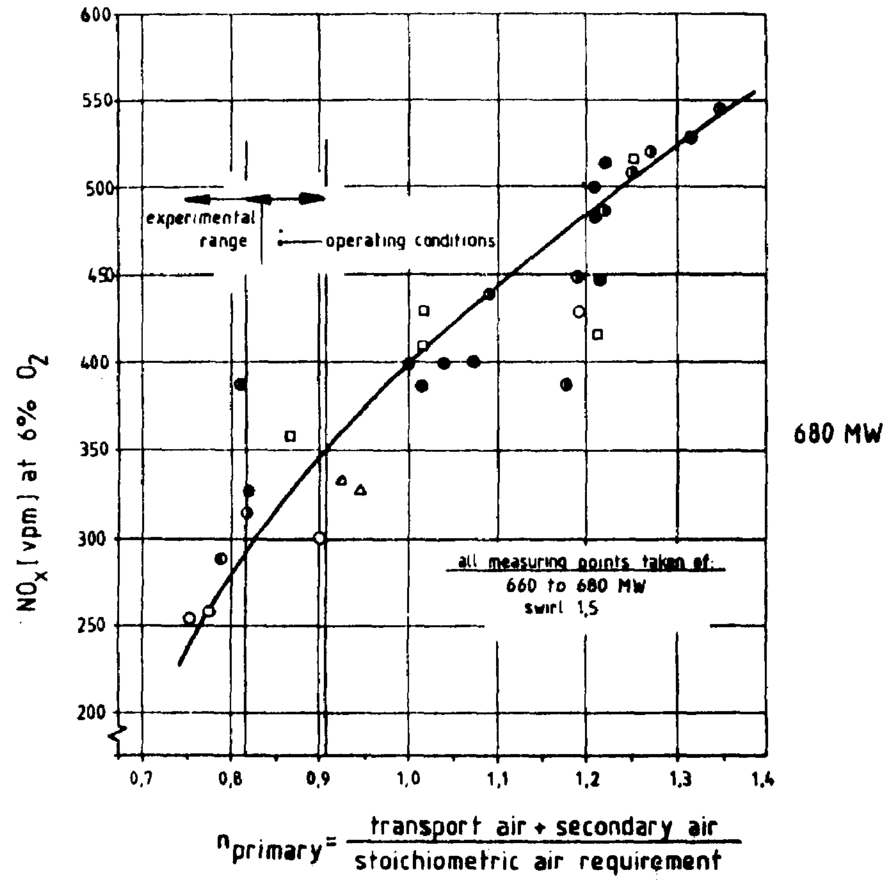



Figure 7. Variation of Coal Nitrogen Content with Time.




| $O_2$-content of flue gas(VOL%) | 4-4,5 | 4,5-5 | 5-5,5 | 5,5-6 | 6-7 | 7-9 |
|---|---|---|---|---|---|---|
| symbols | ○ | ◐ | ◑ | ● | □ | △ |

**Figure 8. Retrofit Burner, $NO_X$ Emission as Function of Primary Zone Stoichiometry (np).**

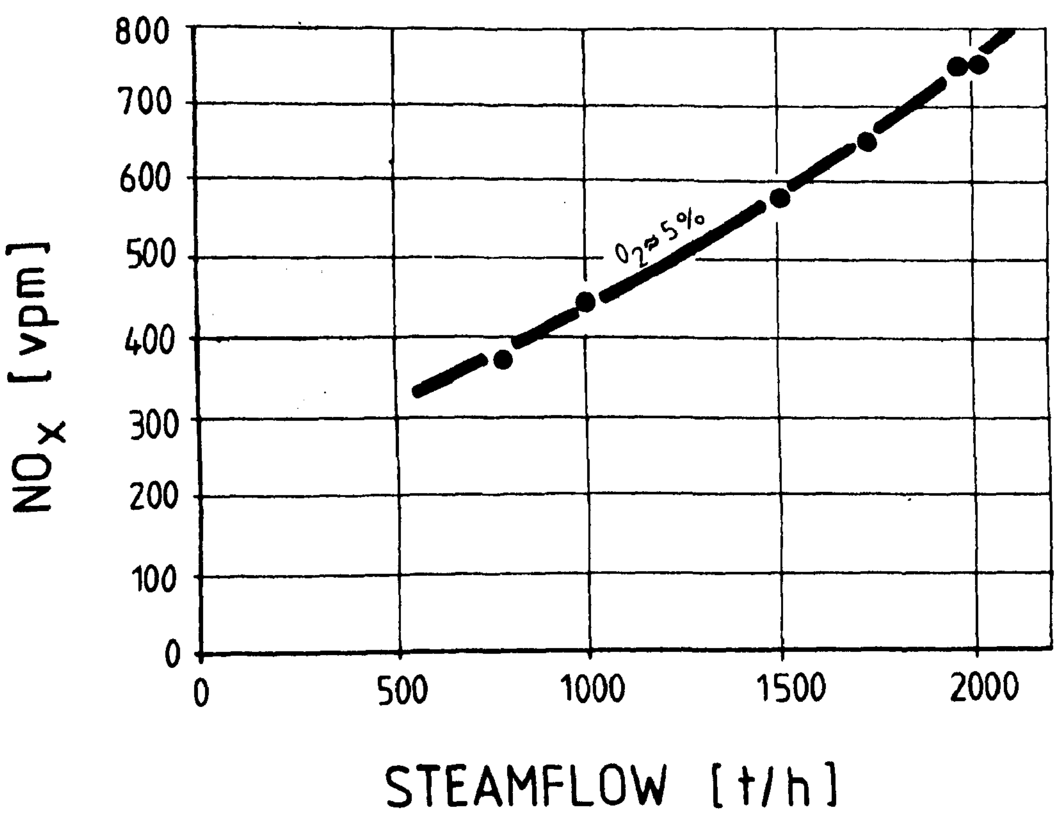



**Figure 9. $NO_x$ - Emission as Function of Boiler Load (Unstaged).**

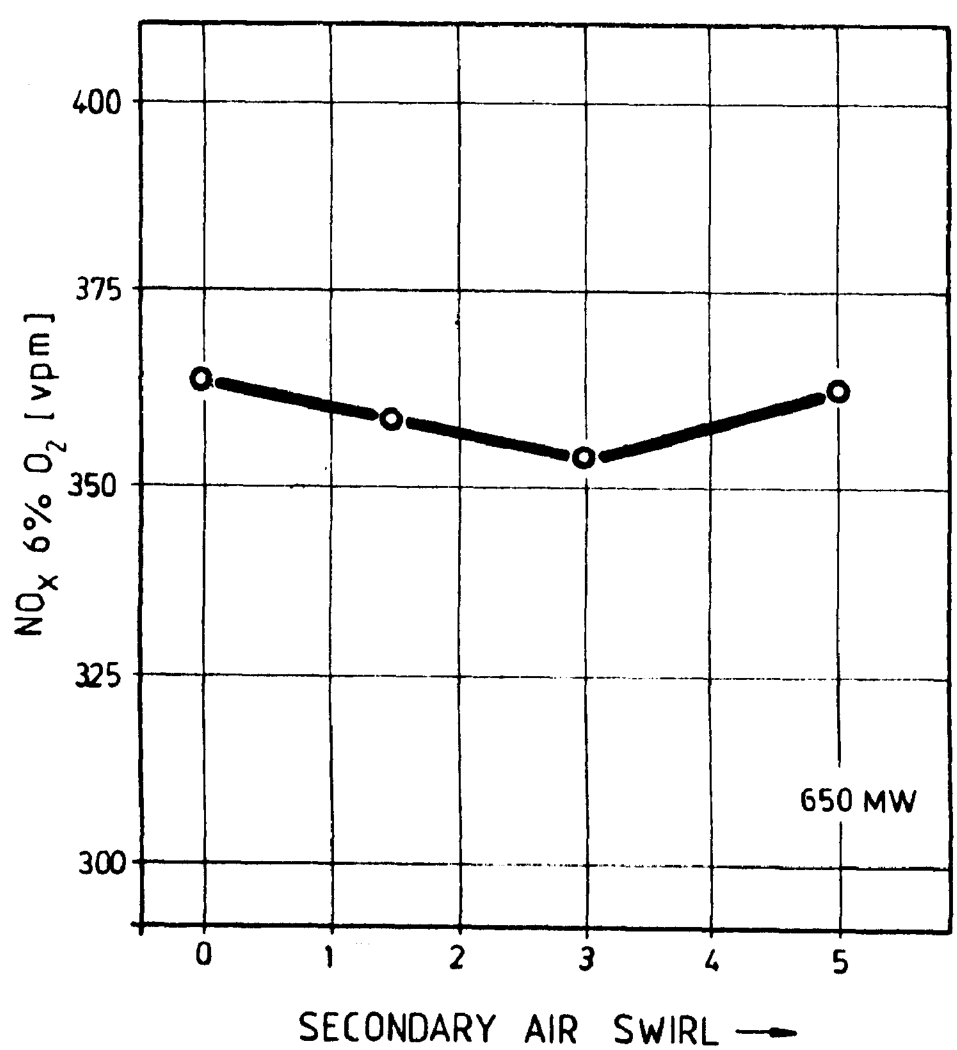



**Figure 10. Retrofit Burner, Effect of Swirl on $NO_x$ Emission.**

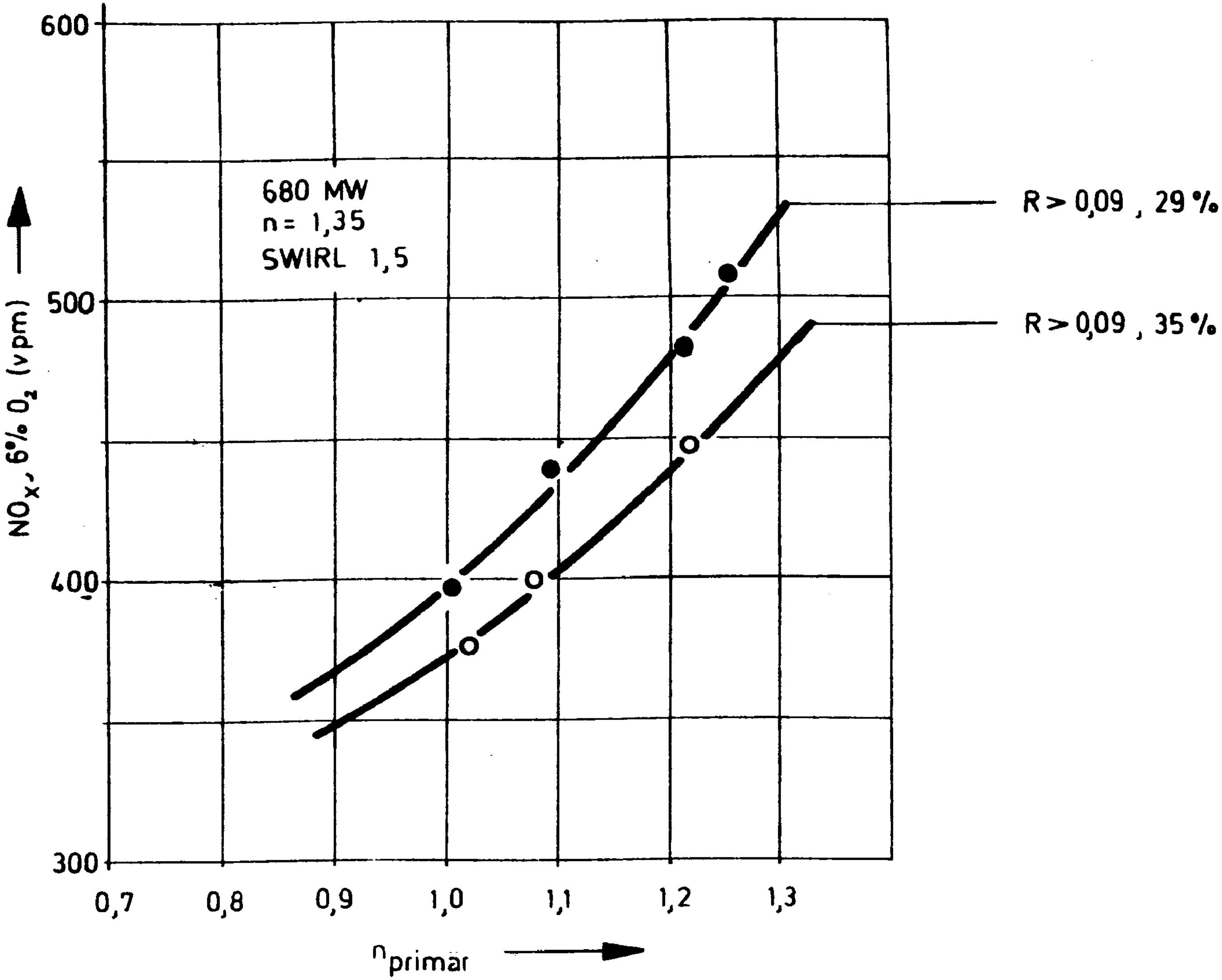



**Figure 11. Retrofit Burner, Effect of Coal Fineness on $NO_X$ Emission.**

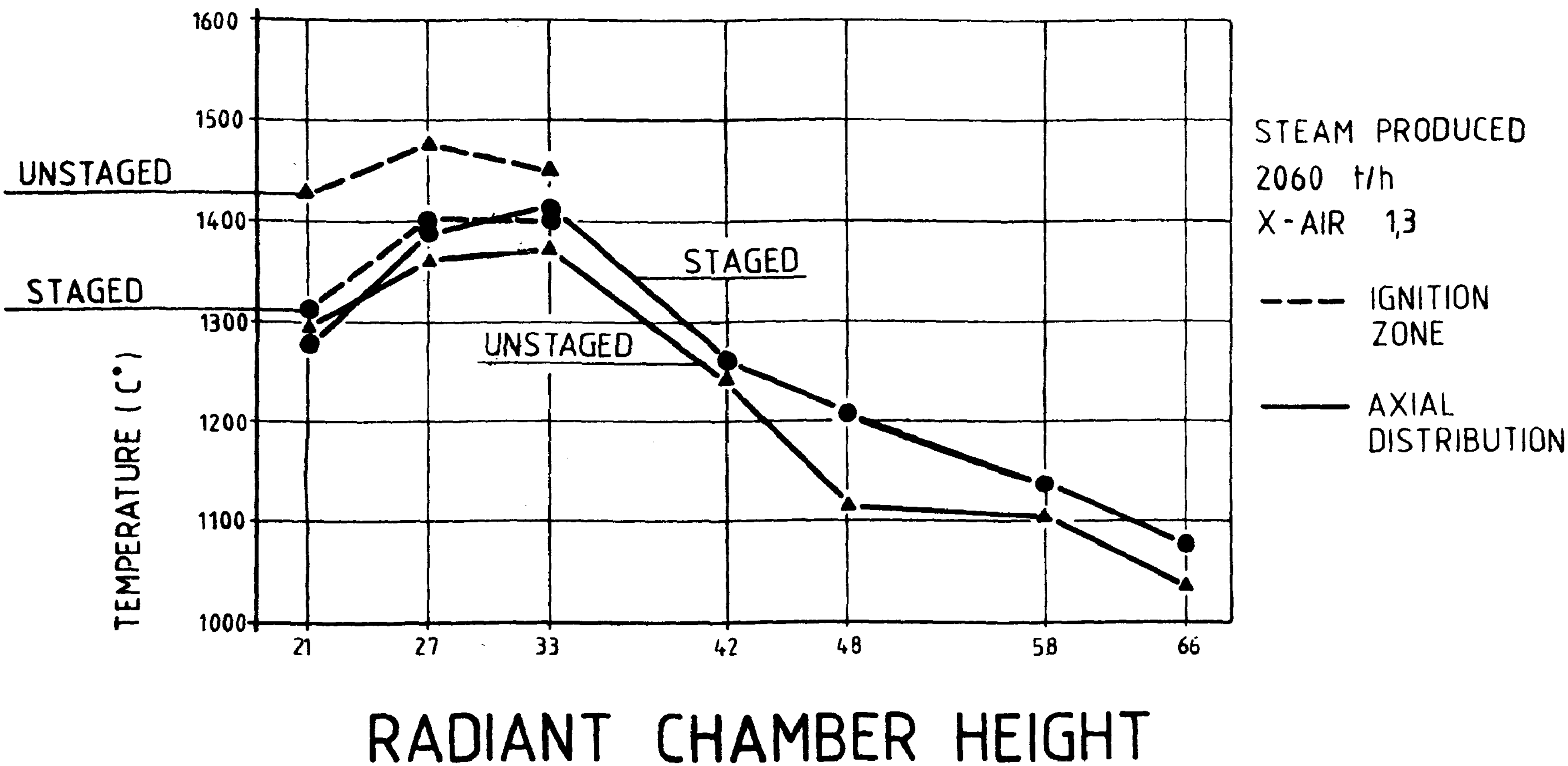



**Figure 12. Retrofit Burner, Ignition Zone and Axial Temperature Distribution.**

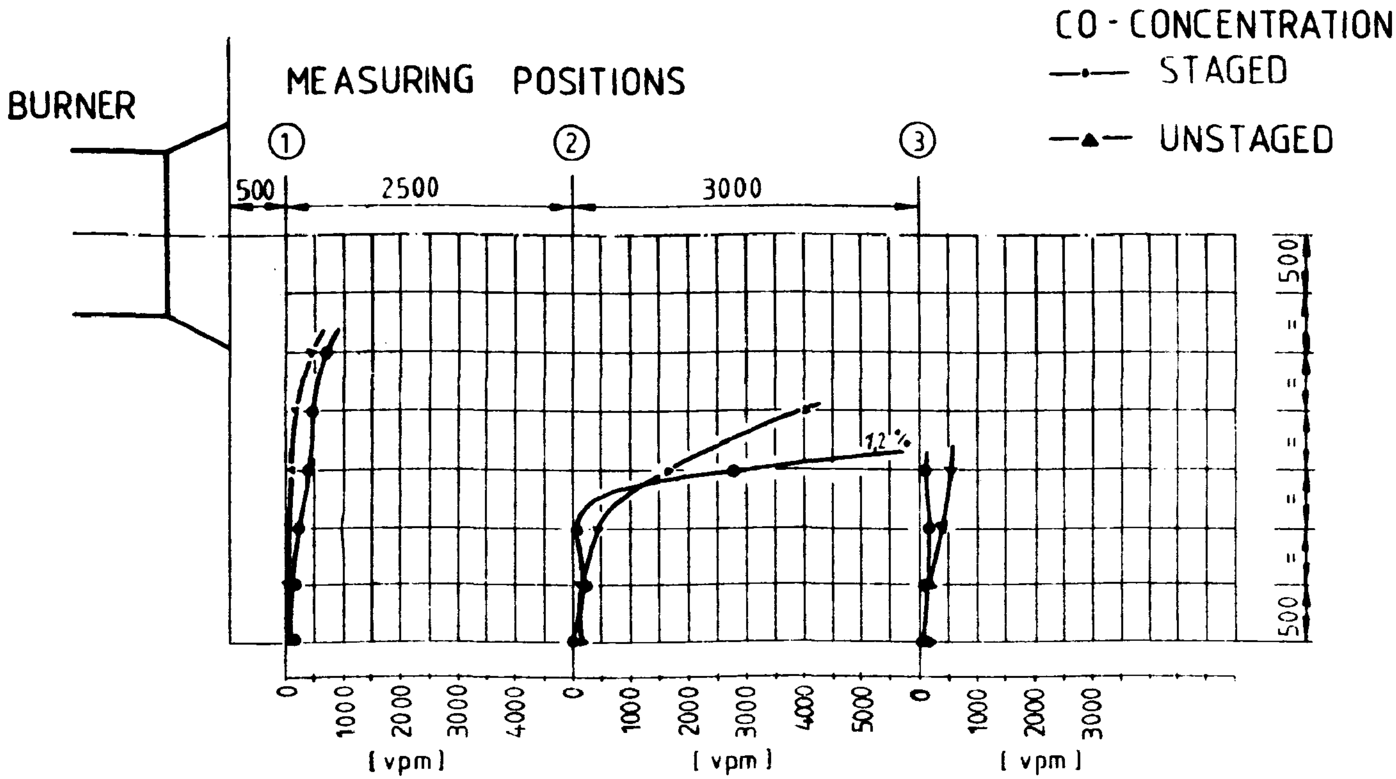



Figure 13. Retrofit Burner, In-Flame CO - Concentration Measurements.

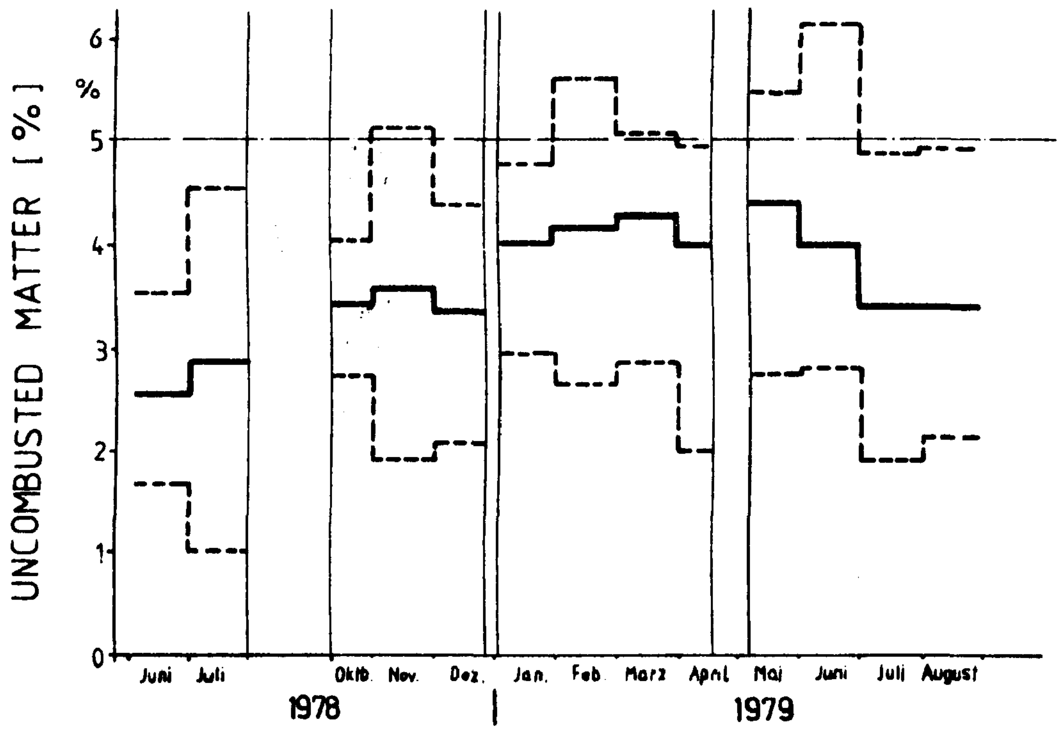



**Figure 14. Uncombusted Carbonaceous Matter in Fly Ash, Variation with Time.**

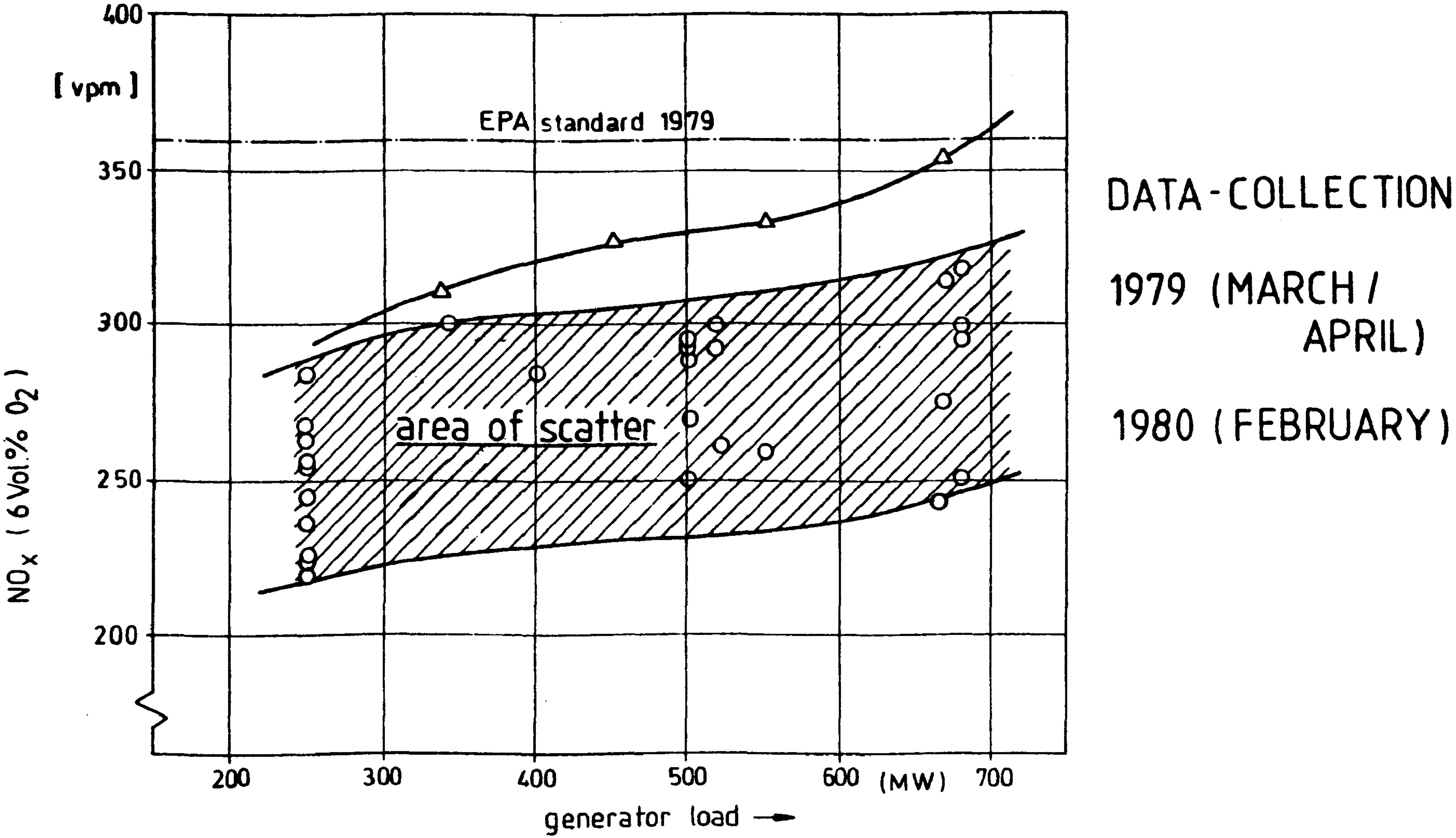



Figure 15. Retrofit Burner, Long Term Fluegas $NO_X$ Data as Function of Boiler Load.

## TECHNICAL REPORT DATA
*(Please read Instructions on the reverse before completing)*

| | | |
|---|---|---|
| 1. REPORT NO. | 2. | 3. RECIPIENT'S ACCESSION NO. |
| 4. TITLE AND SUBTITLE<br>Proceedings of the Joint Symposium on Stationary Combustion $NO_x$ Control. Vol. 1. Utility Boiler $NO_x$ Control by Combustion Modification | | 5. REPORT DATE<br><br>6. PERFORMING ORGANIZATION CODE |
| 7. AUTHOR(S)<br>Symposium Cochairmen: Robert E. Hall (EPA) and J.E. Cichanowicz (EPRI) | | 8. PERFORMING ORGANIZATION REPORT NO.<br>IERL-RTP-1083 |
| 9. PERFORMING ORGANIZATION NAME AND ADDRESS<br>See Block 12. | | 10. PROGRAM ELEMENT NO.<br>EHE624<br>11. CONTRACT/GRANT NO.<br>NA (Inhouse) |
| 12. SPONSORING AGENCY NAME AND ADDRESS<br>EPA, Office of Research and Development<br>Industrial Environmental Research Laboratory<br>Research Triangle Park, NC 27711 | | 13. TYPE OF REPORT AND PERIOD COVERED<br>Proceedings; 10/6-9/80<br>14. SPONSORING AGENCY CODE<br>EPA/600/13 |

15. SUPPLEMENTARY NOTES EPA-600/7-79-050a through -050e describe the previous symposium. IERL-RTP project officer is R.E. Hall, Mail Drop 65, 919/541-2477.

16. ABSTRACT The proceedings document the approximately 50 presentations made during the symposium, October 6-9, 1980, in Denver, CO. The symposium was sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, and the Electric Power Research Institute (EPRI), Palo Alto, CA. Main topics included utility boiler field tests; NOx flue gas treatment; advanced combustion processes; environmental assessments; industrial, commercial, and residential combustion sources; and fundamental combustion research. This volume relates to the use of combustion modification to control NOx emissions from utility boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

| a. DESCRIPTORS | | b. IDENTIFIERS/OPEN ENDED TERMS | c. COSATI Field/Group | |
|---|---|---|---|---|
| Pollution | Flue Gases | Pollution Control | 13B | |
| Combustion | Engines | Stationary Sources | 21B | 21K |
| Nitrogen Oxides | | Environmental Assessment | 07B | |
| Boilers | | | 13A | |
| Tests | | | 14B | |
| Assessments | | | | |

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|---|---|---|
| 18. DISTRIBUTION STATEMENT<br>Release to Public | 19. SECURITY CLASS (This Report)<br>Unclassified | 21. NO. OF PAGES<br>282 |
| | 20. SECURITY CLASS (This page)<br>Unclassified | 22. PRICE |

EPA Form 2220-1 (9-73)