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PROCEEDINGS OF THE STATIONARY SOURCE COMBUSTION SYMPOSIUM

Volume III

Field Testing and Surveys

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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PROCEEDINGS OF THE STATIONARY SOURCE COMBUSTION SYMPOSIUM

VOLUME III--FIELD TESTING AND SURVEYS

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Office of Research and Development
Washington, DC 20460

PREFACE

The Stationary Source Combustion Symposium was held on September 24-26, 1975, at the Fairmont Colony Square Hotel in Atlanta, Georgia. The symposium was sponsored by the Combustion Research Branch of E.P.A.'s Industrial Environmental Research Laboratory (IERL). The Combustion Research Branch has been involved in developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and improving equipment efficiency.

Dr. Joshua S. Bowen, Chief, Combustion Research Branch, was Symposium Chairman; Robert E. Hall, Research Mechanical Engineer, Combustion Research Branch, was Symposium Vice Chairman and Project Officer. The Welcome Address was delivered by Dr. John K. Burchard, Director of the Industrial Environmental Research Laboratory. Frank Princiotta, Acting Director of the Energy Processes Division of E.P.A.'s Office of Energy, Minerals, and Industry, was the Keynote Speaker.

The Symposium consisted of four Sessions:

Session I: Fundamental Research

Co-chairmen: Dr. Joshua A. Bowen
W. Steven Lanier, Research Mechanical Engineer, E.P.A., IERL, Combustion Research Branch

Session II: Fuels Research and Development

Chairman: G. Blair Martin, Chemical Engineer, E.P.A., IERL,
Combustion Research Branch

Session III: Process Research and Development

Chairman: David G. Lachapelle, Research Chemical Engineer,
E.P.A., IERL, Combustion Research Branch

Session IV: Field Testing and Surveys

Co-chairmen: Robert E. Hall
John H. Wasser, Research Chemical Engineer, E.P.A.,
Combustion Research Branch

These Session Chairmen have reviewed the transcriptions of the question and answer sessions, and, in addition, have worked with authors to clarify and revise presentations, where appropriate, and to make them clear and meaningful for these printed proceedings.

We are grateful for the cooperation of Marjorie Maws, Project Leader; Anita Lord, Symposium Administrator; and Margaret Kilburn, Program Director, of Arthur D. Little, Inc., who coordinated the symposium for E.P.A.

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SESSION IV

FIELD TESTING AND SURVEYS

R. E. Hall; J. H. Wasser
Co-Chairmen

THE EFFECT OF COMBUSTION MODIFICATION ON POLLUTANTS AND EQUIPMENT PERFORMANCE OF POWER GENERATION EQUIPMENT

by A. R. Crawford, E. H. Manny, M. W. Gregory and W. Bartok

Exxon Research and Engineering Company

Prepared for a Symposium

on

STATIONARY SOURCE COMBUSTION

Sponsored by

Combustion Research Branch
Industrial Environmental Research Laboratory
U.S. Environmental Protection Agency

Fairmont Colony Square Hotel
Atlanta, Georgia
September 24-26, 1975

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Several key findings have been determined from an analysis of the gaseous emission data. The new B&W burner equipped boiler emitted 35% less NO_x under normal firing and over 50% less NO_x under full load, modified firing operation than was emitted from an identical boiler with normally equipped burners. Tangentially fired boilers equipped with overfire air ports emitted about 20% less NO_x than similar boilers when tested under normal firing operation. Modified firing using overfire air ports and low excess air resulted in an average of over 40% additional reduction in NO_x emissions at full load, for a reduction of over 50 percent over boilers not equipped with overfire air ports. Mixed fuel fired boiler NO_x emission levels increased as the % of coal in the coal-oil or coal gas mixture increased, but not linearly. NO_x emissions from a 50 MW (MCR) gas turbine on a 3% O_2 basis were about 375 PPM at full load, 400 PPM at peak load, with reductions to about 325 and 250 PPM at 50% and 20% of full load respectively. All PPM values given in this report are corrected to a 3% O_2, dry basis.

Only relatively minor differences have been observed in particulate mass loadings under "low NO_x" firing conditions. Unburned carbon in the fly-ash, which was observed to increase in previous studies, especially on front wall and horizontally opposed fired boilers, was found to decrease on most of the boilers tested in this program. Particle size distribution, which could affect electrostatic precipitator collection efficiency, was found to be the same for "low NO_x" operation as for baseline conditions.

In 300-hour sustained runs, no major differences in corrosion rates have been observed for low NO_x firing compared to normal operation. Long term tests measuring actual furnace wall tube wastage are needed to confirm this finding. As in previous studies, no significant changes in boiler efficiency have been observed due to "low NO_x" mode of operation.

In the continuation of this program we will add sampling and analytical capabilities for measuring sulfates, nitrates, HCL, HC_n and hazardous and toxic materials. This will include POM as well as metallic elements. Also, further testing will be carried out to relate slagging tendency to furnace temperatures, to explore the potential use of antislagging additives, and to define the potential of combustion control for wet-bottom and waste fuel fired boilers.

1. INTRODUCTION

Exxon Research and Engineering Company has been conducting field studies under EPA sponsorship on the application of combustion modification techniques to control pollutant emissions from utility boilers. The emphasis in these studies has been on controlling NO_x emissions without adverse side-effects. These cooperative field studies have been conducted using a mobile sampling analytical system supplied by Exxon.

Under EPA Contract No. CPA 70-90 (1), significant reductions of NO were achieved for gas and oil-fired boilers using combustion modification techniques in limited field testing, without attempting to optimize the technology. The principal modifications investigated consisted of minimizin excess air, staged air/fuel introduction, flue gas recirculation, varying boiler load, and varying air preheat temperature. Also, as part of this study, it was possible to achieve significant reductions in NO_x emissions for two of the seven coal-fired boilers tested, through the combination of low excess air with staged firing.

Because of the difficulty of controlling NO_x emissions from coal fired boilers, in the subsequent EPA-sponsored Exxon study (Contract No. 68-02-0227) (2) the emphasis shifted to a more detailed investigation of emission control for coal-fired utility boilers, again in cooperation with boiler owner-operators and manufacturers. These field studies on twelve coal-fired units representative of the current design practices of the major U.S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley-Stoker) have produced very promising results. It was possible to achieve reductions in NO_x emissions ranging between about 30% and 50%, without apparent adverse side-effects. In addition to gaseous emissions measurements the studies included particulate mass loading and unburned combustible measurements, accelerated furnace corrosion probing, determination of boiler efficiency, and observations of changes in boiler operability, in particular slagging, fouling, and flame problems.

Based on the successful results of the above work, the Environmenta Protection Agency and the Electric Power Research Institute decided to jointly fund the present Exxon field study. The scope of the work has been broadened to determine the effects of combustion modification techniques on the control of pollutant emissions and on the performance of fossil fuel fired power generation equipment. In this field program, coal-fired, mixed-fuel fired and waste fuel-fired boilers are studied, in addition to short-term tests on stationary gas turbine and I.C. engine equipment. There remains continuing emphasis in this work on coal fired utility boilers.

The objective of the present study is to develop improved pollutant control techniques for coal fired utility boilers, and explore the application of such techniques to emissions control from mixed and waste-fuel fired combustion equipment, as well as to obtain preliminary field data on other power generation combustion equipment. Boilers selected for the program are being tested in cooperation with electric utilities and boiler manufacturers. Approaches aimed at improved NO_x control, such as coal fired boilers constructed with overfire air ports, and improved burner design are being explored. Potential adverse side-effects of combustion modifications are being studied in more detail than previously. Thus, in addition to the usual emission measurements (including pollutants, stable combustion products and unburned combustibles), both particulate mass and size distribution measurements are being made under normal and low NO_x modes of boiler operation. The effect of combustion modifications on the collectability of particulates will be evaluated by making precipitators of one or two units to be tested, and the SO_2/SO_3 ratio is being determined under normal and low NO_x operating conditions.

As previously, the effect of combustion modifications on boiler efficiency and operability is being determined. Special attention is being paid to the determination of potential furnace water wall corrosion resulting from staged firing. For this purpose, the results of 300-hour sustained corrosion runs will be compared with actual tube wastage measurements on at least one coal-fired utility boiler operated under low NO_x conditions for a six-month period.

2. FIELD STUDY PLANNING AND PROCEDURES

This section discusses the major steps involved in field study planning and the testing methods used to obtain emission, corrosion and performance measurements. Field study planning steps included selection of representative power generation equipment (with participation of EPA, EPRI, equipment manufacturers and equipment operators) and designing an effective test program strategy. Methods of gaseous emission testing were quite similar to those used in Exxon's "Systematic Field Study" (1). Particulate sampling, corrosion probing and performance measurements were an expanded version of those used in Exxon's previous field studies (2). Boilers firing coal, coal-oil and coal-gas mixed fuel were tested as was an oil fired, utility sized, gas turbine. In addition, particulate size distribution samples were taken and SO_2/SO_3 measurements were made using standard wet chemical methodology.

2.1 Selection of Power Generation Combustion Equipment

This program provides for the testing of utility boilers (coal fired, mixed fossil fuel fired and waste fuel fired) utility sized gas turbines and a large, stationary IC engine. To date, testing has been completed on four coal fired boilers, two mixed fuel (coal-oil and coal-gas) fired boilers and a oil fired gas turbine.

The successful selection of boilers representing current design practices was the result of a cooperative planning effort by Exxon Research, EPA, EPRI and boiler manufacturers (Combustion Engineering, Babcock and Wilcox, Riley Stoker and Foster Wheeler). The process of developing boiler selection criteria, reviewing boiler manufacturers list of boilers meeting the criteria, selecting a tentative list of boilers for detailed field meetings and final selection and scheduling of test programs has been described previously (2).

Design factors were the prime consideration in selecting boilers in the current field test program after other criteria such as size, operating flexibility, boiler measurement and control capability, etc. had been met. Boilers representing the current design practices of all four utility boiler manufacturers were desired. However, coal fired boilers designed with overfire air ports or specially designed burners for NO_x emission control were particularly desired. We were fortunate to obtain the cooperation of the boiler operators of three tangentially fired (2 coal, 1 coal-gas mixed fuel) boilers with overfire air ports and a wall fired boiler retrofitted with special low NO_x burners. We were not successful in obtaining the cooperation of the utility company which operates the only front-wall, coal fired boiler in the United States equipped with overfire air ports.

The design and operating features of the six coal or mixed fuel fired boilers tested to date in the current program are summarized in Table 2-1. Four boilers are tangentially fired (ranging in size from 130 MW to 800 MW) and two are wall fired (a rear-wall fired 125 MW unit, and a horizontally opposed firing 270 MW capacity unit). These boilers have been selected for field studies at the recommendation of their respective manufacturers as representative of current design practices and/or because of special designed NO_x reduction capabilities or programs.

2.2 Test Program Strategy

The up-to-date, comprehensive information obtained in field meetings provided the necessary data for Exxon to develop detailed, run-by-run proposed test program plans for review by all interested parties. Each test program, tailored to take full advantage of the particular combustion control flexibility of each boiler, was comprised of three phases: (1) short test-period runs, (2) a 1-3 day sustained "low NO_x" run and (3) 300-hour sustained "low NO_x" and normal operation runs. Thus the strategy used for field testing coal-fired boilers consisted first of defining the optimum operating conditions for NO_x emission control, without apparent unfavorable side effects in short-term statistically designed test programs. Second, the boiler was operated for 1-3 days under the "low NO_x" conditions determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs were made under both baseline and modified ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons were exposed on corrosion probes in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating the boiler under the reducing conditions associated with staged firing results in increased furnace water tube corrosion rates. Particulate samples were obtained under both baseline and "low NO_x" conditions. Engineering information on boiler operability, e.g., on slagging problems, and data related to boiler performance were also obtained.

Statistical principles (as discussed in more detail in our "Systematic Field Study" (1)) provided practical guidance in planning the Phase 1 test programs; i.e., how many, and which test runs to conduct, as well as the proper order in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could have been made. Our subsequent studies (2) illustrate these principles applied to a field test program conducted on a wall fired boiler.

Table 2-1

Summary of Coal and Mixed Fuel Fired Boilers Tested

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel(c) Burned	MCR (MW)	No. of Burners	Test Variables	No. of Test Runs
1.	Tennessee Valley Authority	Widows Creek - 5	B&W	RW	C	125	16	4	27(d)(e)
2.	Southern Electric Generating Company	E. C. Gaston - 1	B&W	HO(g)	C	270	18	5	37(d)(e)
3.	Alabama Power Company	Barry - 2	CE	T(f)	CG	130	16	6	38
4.	Potomac Electric Power Company	Morgantown - 1	CE	T	CO	575	40	5	27
5.	Salt River Project	Navajo - 2	CE	T(f)	C	800	56	4	36(d)(e)
6.	Public Service Company of Colorado	Comanche - 1	CE	T(f)	C	350	20	4	30(d)(e)
									195

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

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

(c) C - coal, CG - coal-gas mixed, CO - coal-oil mixed

(d) Particulate tests performed on these boilers

(e) Corrosion probe tests performed on these units

(f) Overfire air ports

(g) Special low NO_x emission burners

2.3 Gaseous Sampling and Analysis

The sampling and analytical system used in this program to obtain reliable gaseous emission data in field tests has been described in detail (1,2). A schematic drawing of the sampling system is provided in Figure 2-1. The gaseous species analyzed are also indicated on this diagram. Table 2-2 tabulates the instruments contained in the Exxon Analytical Van according to manufacturer, operating technique employed, and measurement range capabilities. This system has been used for over five years to obtain reliable field test data with a minimum of operating difficulties.

A major consideration in obtaining reliable gaseous emission data is to insure that the sample gas is virtually moisture free. Moisture in the sample gas can influence the readings obtained by certain instrumentation. This problem has been avoided effectively in the Exxon sampling system by passing the sample gases through a refrigerated water knock-out coil. Recently, permeation-type drying tubes* (Permatubes) have become available for removing moisture in gas sampling systems without changing the concentrations of other gases. For the present study, therefore, permatube driers were added to the Exxon sampling train as an addition to the refrigerated knock-outs to insure the maximum drying capabilities for the gaseous emission sampling system. This system has proven to be very effective in obtaining dry sample gases.

Concurrent with the present program, Exxon Research and Engineering Company conducted an investigation under contract to EPA (Contract No. 68-02-1722) to "Determine the Magnitude of the Stratification of Gases in the Ducts of Fossil Fuel Fired Power Plants." The results of this investigation showed that stratification of the gases in the ducts does indeed exist and that meaningful "average" emission values can be obtained only by multiple probe sampling of the inner 50% of the duct. Also, average emission data obtained in this manner would be within plus or minus 10 percent of values prevailing in adjacent ducts on the same boiler, perhaps with the exception of oxygen (O_2) the concentration of which may be influenced by leaks.

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* Manufactured by Perma Pure, Inc., Oceanport, N.J.

FIGURE 2-1

EXXON RESEARCH TRANSPORTABLE SAMPLING
AND ANALYTICAL SYSTEM

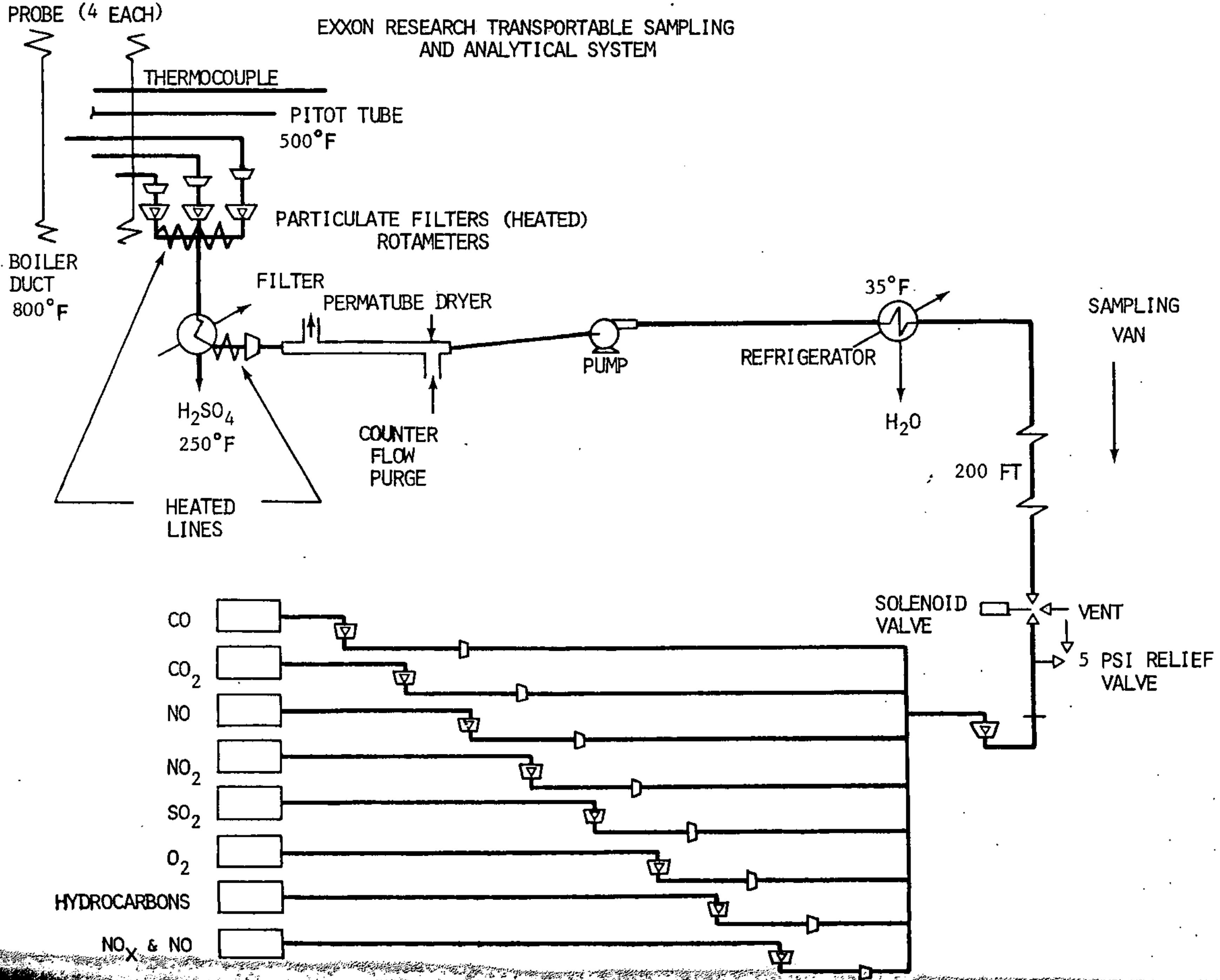


TABLE 2-2

CONTINUOUS ANALYTICAL INSTRUMENTS IN EXXON VAN

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive Infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm 0-23,600 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm
Thermo Electron		
NO/NO_x	Chemiluminescent	0-2.5 ppm 0-10.0 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm 0-10,000 ppm

The findings of this stratification study verify the design principles utilized by the Exxon sampling system for obtaining representative gaseous emission data. In the Exxon system, samples are taken from zones of "equal areas" in the flue gas ducts. At least two probes are installed in each flue gas duct, or a minimum of four are used when there is only one large flue duct on the boiler. Each of the probes is comprised of three stainless steel sampling tubes (short, medium and long) reaching to the mid-point of zones of equal area in the depth of the duct. Thus, a minimum of six sampling points per duct or 12 per boiler are provided, assuring representative gas samples.

A complete range of calibration gas cylinders in appropriate concentrations with N_2 purge and zeroing gas for each analyzer is installed in the system. Instruments are calibrated daily before each test and in-between tests if necessary, assuring reliable, accurate results.

2.4 Particulate Sampling

Combustion of fuel in utility boilers normally is accomplished in multiple burner arrays of several different firing patterns, such as, front wall, horizontally opposed, tangential, cyclone, etc. Air for combustion is supplied by forced draft fans in pressurized boilers or by both forced and induced draft fans in balanced draft boilers. On the average, excess combustion air in the utility industry varies between 15 to 25% and the air is admitted to the burners in a highly turbulent fashion and in sufficient quantities (as above) to assure complete combustion of the fuels. Combustion air and flame temperature are also maintained as high as possible to improve combustion efficiency.

Recently, with the advent of NO_x emission regulations, combustion processes have been modified to promote less intense combustion conditions so that operation at lower NO_x emission levels is possible. This has been accomplished by lowering and optimizing excess air levels, staging the combustion process and re-adjustment of burner dampers to decrease turbulence. Lowering excess air increases flame temperatures, aiding combustion, but tends to limit the amount of oxygen available for the combustion process. Potentially, this factor directionally increases the probability of burnout problems. Staging the combustion pattern, where the majority of the burners are operated at sub-stoichiometric conditions and the remaining air is introduced either through inactive burners or "overfire air ports" to complete the combustion process, can have similar, major effects. In the latter, available oxygen is limited in the initial combustion phase, flames are lengthened, and there is less turbulence due to the slower, diffusive mixing of air and fuel. Thus, staging the combustion pattern potentially can increase unburned combustibles. Modifications to the combustion process for NO_x emission control may also affect the amount and character of the particulate matter emitted from the boiler.

Accordingly, this field test program included investigations of potentially increased particulate emissions and changes in flyash particle size distribution in pulverized coal fired utility boilers. Measurements were made of particulate mass loading and flyash particle size distribution in tests both at "base" and optimized "low NO_x" operating conditions. The objective of this effort was to determine the extent of potential adverse side effects of "low NO_x" combustion modifications on particulate emissions by comparing total quantities, percent unburned carbon, and changes in particle size distribution with comparable data obtained under normal or baseline operating conditions. Data of this type is needed for an evaluation of potential adverse affects on electrostatic precipitator performance.

Measurements of flyash resistivity, which are also needed for assessing affects on precipitator performance, were beyond the scope of the present program.

Two Joy Manufacturing Company, and two Aerotherm Accurex High Volume, EPA type particulate sampling trains complying with EPA Method 5 requirements (3) were used to obtain particulate mass loading data. These trains have been modified to incorporate a Brink, multistage cascade impactor in the heated sampling box for the determination of particle size distribution. This arrangement permits particle size distribution determinations outside of the boiler under isokinetic sampling conditions.

2.5 Furnace Corrosion Probe Testing

Under certain conditions, pulverized coal fired boilers are subject to wastage of the furnace wall tubes. Normally, this type of corrosion is experienced in areas where a localized reducing environment might exist adjacent to the midpoint of furnace sidewalls near burner elevations where flame impingement could occur. To counteract such effects, normal practice is to increase the excess air level so that an oxidizing atmosphere prevails at these locations, and to increase the fineness of pulverization, so that the oxidation of the pyrites in the coal is completed before these species can come into contact with the furnace wall tubes. For new boilers, a design improvement consists of increasing the separation between the burners and the sidewalls, thus minimizing potential impingement problems. Several mechanisms have been postulated for this type of corrosion which appears to be associated with the formation of pyrosulfates from the coal ash (at 600-900°F), and iron sulfide, or SO_3 from the pyrites.

Combustion modifications for NO_x emission control are generally most effective at low excess air or substoichiometric air supply conditions in the flame zone, i.e., under conditions that are potentially conducive to furnace tube wall corrosion. The need for investigating the effects of modified firing operations on furnace tube wall corrosion has been recognized and preliminary investigations have already been conducted by Exxon Research and Engineering Company under EPA Contract No. 68-02-0227. Details and results of these investigations have been reported previously (2).

In the above program, the approach used for obtaining corrosion rate data was to expose corrosion coupons installed on the end of probes inserted into available openings located near "vulnerable" areas of the furnace under both baseline and "low NO_x" firing conditions. Coupons were fabricated of SA 192 carbon steel, the same material used for furnace wall tubes. Exposure for 300 hours at elevated coupon temperatures of 875°F (above normal furnace tube metal temperature of about 600°F) was chosen in order to deliberately accelerate corrosion so that "measurable" values could be obtained. Coupons were also mild acid pickled to remove any existing oxide coating prior to exposure to eliminate any potential differences due to surface conditions. The major conclusion of these investigations was that no major differences in corrosion rates were found for coupons exposed to "low NO_x" firing conditions compared to similar coupons subjected to normal operation. Corrosion rates on the coupons, however, were considerably higher than would be expected in a furnace wall tube due to the severe exposure conditions employed to obtain "measurable" values.

The approach used in obtaining corrosion rate data in the current program was similar to that of the prior program, but with several significant differences. First, corrosion coupons, which are all fabricated and machined in the same manner, are no longer mild acid pickled but, instead, are merely dipped in acetone and air dried prior to weighing to remove any existing oil used in machining. Second, and most important, coupon temperatures have been reduced to approximately the metal temperatures of the existing furnace wall tube in which they are exposed in an effort to more closely approximate actual furnace conditions. Third, in the current program, three coupons are installed on each probe in an effort to increase the amount of available data compared with only two in the prior program. Although this does not materially affect test conditions, more information is obtained from each probe. Time of exposure (300 hours) was held the same as for the prior program in order to eliminate potential differences in corrosion rates due to this factor.

Figures 2-2 and 2-3 show details of the corrosion probes used in this and the prior study. Our probes are based on a design supplied by Combustion Engineering. Essentially, the design consists of a "pipe within a pipe," where the cooling air from the plant air supply is admitted to the ring-shaped coupons exposed to furnace atmospheres at one end of the probe, through a 3/4-inch stainless steel tube roughly centered inside of the coupons. The amount of cooling air is automatically controlled to maintain the desired set-point temperature of 875°F for the coupons. The cooling air supply tube is axially adjustable with respect to the corrosion coupons, so that temperatures of both coupons may be balanced. To simplify the presentation, thermocouples mounted in each coupon are not shown in Figures 2-2 and 2-3. Normally, one thermocouple is used for controlling and the other one for recording temperatures. Also, as noted above, a third coupon is used on the end of the probe which is not shown in Figure 2-3. The cooling air travels backwards along the 2-1/2-inch extension pipe and discharges outside of the furnace. Thus, the cooling air and the furnace atmosphere do not mix at the coupon location.

2.6 Boiler Performance

Low NO_x modification techniques result in less intense combustion conditions which tend to increase burnout problems. Potentially this mode of operation increases the amount of unburned combustibles which could have an adverse effect on boiler efficiency. Particulate dust loading tests therefore were run for each major test at baseline and "low NO_x" operation and the samples were analyzed for unburned carbon. Boiler efficiency was then calculated, using the ASME Abbreviated Efficiency Test heat loss method, and the results compared to evaluate the side effects of low NO_x firing. The results are discussed in section 3.4.

FIGURE 2-2

CORROSION PROBE
DETAIL OF 2-1/2" IPS EXTENSION PIPE AND END PLATE
(OUTSIDE OF FURNACE)

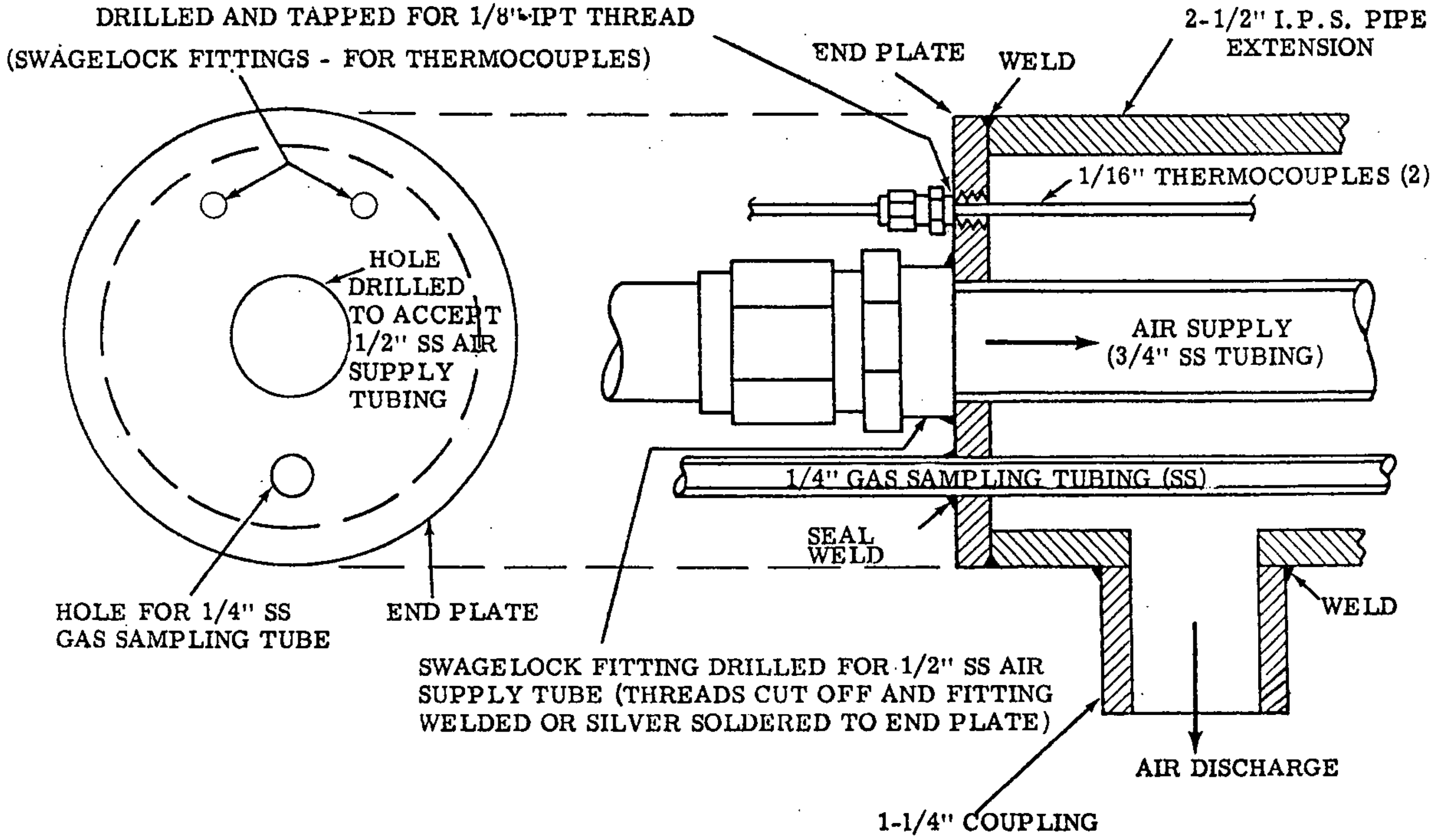
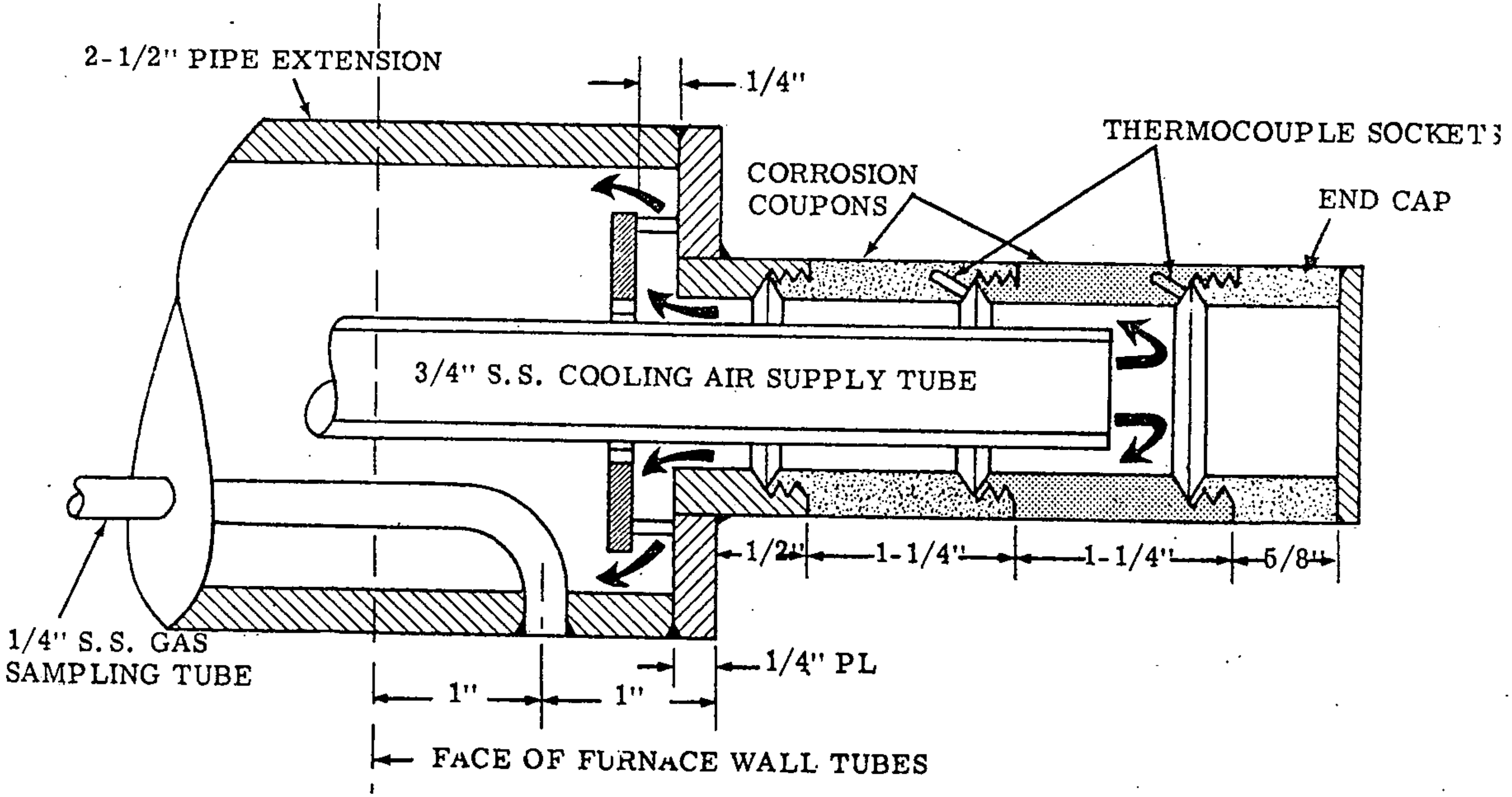


FIGURE 2-3

CORROSION PROBE
DETAIL OF CORROSION COUPON ASSEMBLY
(INSIDE OF FURNACE)



3. FIELD TEST RESULTS AND DISCUSSION

The field test results obtained on individual coal fired boilers under a variety of operating conditions, are presented in four parts. These parts consist of gaseous emission measurements, flue gas particulate loadings measured upstream of particulate collector equipment, corrosion probing data obtained in accelerated furnace fire-side water-tube corrosion tests, and estimated boiler performance. Gaseous emission data and most of the particulate emission data were obtained under normal, as well as modified firing operation. As discussed before, particulate loadings of the flue gas were determined only under conditions corresponding to baseline and "low NO_x" operation, for purposes of comparison on the relative effect of modified combustion operation on flue gas particulate loadings in coal combustion. Similar considerations apply to the sustained, 300-hour corrosion tests, which had as their objective the determination of whether staged firing of coal accelerates furnace water tube corrosion rates.

The gaseous emission data obtained under baseline and modified firing conditions at various load levels are presented first. Throughout this report, NO_x concentrations are expressed as ppm, adjusted to three percent O_2 in the flue gas, on a dry basis.

In addition to the results obtained in testing coal fired boilers, this section also presents the gaseous emission data on two mixed fuels (coal-gas and coal-oil) fired units, and an oil fired gas turbine.

3.1 Gaseous Emission Results for Individual Power Generation Combustion Units

Test programs were conducted on 6 coal fired boilers consisting of a rear-wall fired, an opposed-wall fired and four tangentially fired boilers. Two of the tangentially fired boilers were equipped to fire mixed fuel, one on coal and gas and the other on coal and oil. Typical cross-sectional diagrams for these types of boilers are shown in Appendix A. Table 2-1 lists each boiler by station and number, boiler manufacturer, type of firing, fuels burned, full load MW rating, and number of burners. In addition, the number of operating test variables included in each test program and the number of completed test runs are shown.

In presenting the results and discussion for each of these combustion units, we will first briefly describe the unit and the reason for its selection; second, summarize the key operating variables tested (load, excess air level, staged firing patterns, etc.) and resulting % O_2 and PPM NO_x emission data for each test run according to the program experimental plan; and third, present figures to aid in discussing analysis of test results. Major conclusions and overall findings will be presented in Section 4.

3.1.1 Field Test Results - Widows Creek, Boiler No. 5

Tennessee Valley Authority's Boiler No. 5 at the Widows Creek Station was the first boiler to be tested in our current field test program. A major reason for including this boiler in the test program was to obtain short-term (300 hour) corrosion data using Exxon corrosion probes which will be correlated with six month corrosion data based both on tube wall thickness measurements and coupon weight measurements provided by TVA. In addition, it provided TVA with an opportunity to compare their newly acquired test van with our sampling and analytical system. It also gave us the first opportunity to test our improved gaseous sampling conditioning system, our SO_2/SO_3 wet chemical analytical system and our new stratification probes.

Widows Creek Unit No. 5 is a 125 MW, 16-burner, rear-wall, pulverized coal fired Babcock and Wilcox boiler. Although the boiler was originally rated at 140 MW, full load is currently considered to be 125 MW. It has a single, dry-bottom furnace with a division wall. The 16 burners are arranged with four burners in each of four rows. Each row is fed with coal from a separate pulverizer, designated "A" for the top row through "D" for the bottom row. The burners are numbered 1 through 4 on each row from left to right when facing the rear wall (see Figure 3-2).

Table 3-1 contains a summary of the key operating and emission data from the 27 short-period test runs conducted on this boiler. Table 3-2 presents these results according to the test program experimental design. The four operating variables included in the test program were gross load (125 and 100 MW), excess air level (normal and low), secondary air register setting (60% and 20% open) and burner firing pattern (S_1 through S_9). The emission data shown on Tables 3-1 and 3-2 are average % oxygen and ppm NO_x (3% O_2, dry basis). Four probes, each containing short, medium and long sampling tubes were positioned at the centers of 12 equal areas in the flue gas ducts upstream of the air preheaters and downstream of the primary superheater. Composite gas samples from each probe were analyzed in turn over four complete cycles, resulting in 16 measurements of each gaseous component on each test run.

Figure 3-1 contains a plot of ppm NO_x (3% O_2, dry basis) vs. average % stoichiometric air to active burners. Least squares lines have been fitted to the data points for normal firing at 125 MW, normal firing at 100 MW and staged firing at 125 MW. Test run numbers are shown within the symbols which indicate different operating conditions. The test runs for the firing patterns that produced the

Table 3-1

Summary of Operating and Emission Data - Widows Creek, Boiler No. 5
(125 MW, Front Wall, Pulverized Coal Fired)

Date and Run No.	Operating Conditions				Flue Gas Measurements		
	Gross Load (MW)	Firing Pattern (Burners on Air Only)	Sec. Air Registers (% Open)	Excess Air Level	% O_2	PPM NO_x (3% O_2)	% Stoich. Air to Active Burners
9/25-1	105	S_1-None	60	Normal	5.4	603	134
2	118	S_1-None	60	Low	3.2	502	117
3	120	S_1-None	20	Normal	3.5	574	119
4	121	S_1-None	20	Low	3.2	548	117
9/26-1A	121	S_1-None	60	Normal	4.0	597	123
5	121	$S_2-(A_1A_4)$	60	Low	3.0	486	101
6	117	$S_3-(C_1C_4)$	60	Low	4.8	639	113
7	119	$S_4-(B_1B_4)$	20	Low	3.6	517	105
8	120	$S_5-(D_1D_4)$	20	Low	3.6	580	105
9/27-9	115	$S_5-(D_1D_4)$	60	Low	3.4	598	104
10	110	$S_4-(B_1B_4)$	60	Low	4.0	521	108
11	112	$S_3-(C_1C_4)$	20	Low	4.1	474	108
12	120	$S_2-(A_1A_4)$	20	Low	3.2	468	102
10/2-13	102	S_1-None	60	Normal	5.5	660	135
14	98	S_1-None	60	Low	3.0	462	116
15	98	S_1-None	20	Normal	5.4	667	134
16	97	S_1-None	20	Low	2.1	381	110
10/3-17	99	$S_6-(A_1A_4D_1D_4)$	60	Low	3.2	365	88
18	100	$S_7-(A_1A_4B_2B_3)$	60	Low	3.0	374	87
19	99	$S_8-(A_1A_4B_1B_4)$	20	Low	3.3	316	88
20	100	$S_9-(A_1A_2A_3A_4)$	20	Low	5.3	305	100
10/4-21	99	$S_9-(A_1A_4A_3A_2)$	60	Low	4.5	329	94
22	100	$S_8-(A_1A_4B_1B_4)$	60	Low	4.4	368	94
23	100	$S_6-(A_1A_4D_1D_4)$	20	Low	4.3	421	93
24	101	$S_7-(A_1A_4B_2B_3)$	20	Low	3.3	302	88
10/7-1B	125	S_1-None	60	Low	2.4	409	112
10/8-1C	125	S_1-None	60	Low	2.5	441	113

Table 3-2

Test Program Experimental Design - Widows Creek No. 5

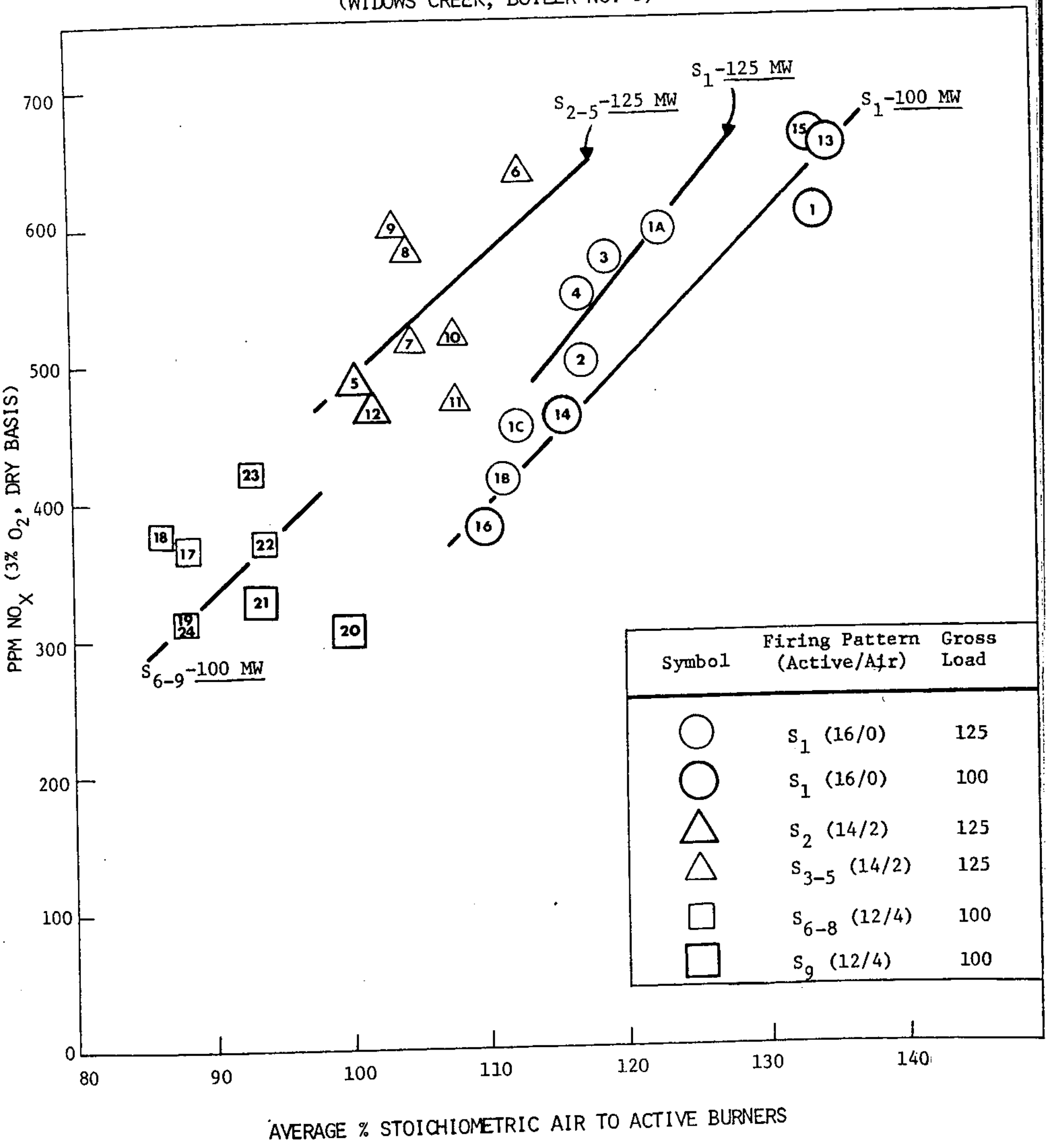
(Run No., Average % O_2 and Average PPM NO_x Emissions (3% O_2, Dry))

	L_1-Full Load (125 MW)				L_2-Reduced Load (100 MW)			
	A_1-Normal Air		A_2-Low Air		A_1-Normal Air		A_2-Low Air	
Secondary Air / Firing Pattern	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open
S_1-16 Firing Coal	(1A) 4.0%-597	③ 3.5% 574	② 3.2% 502	④ 3.2% 548	⑬ 5.5%-660	⑮ 5.4% 667	⑭ 3.0% 462	⑯ 2.1% 381
S_2-14 Firing Coal (A_1A_4 Air Only)	(1B) 2.4%-409 (1C) 2.5%-441		⑤ 3.0% 486	⑫ 3.2% 468	① 5.4%-603			
S_3-14 Firing Coal (C_1C_4 Air Only)			⑥ 4.8% 639	⑪ 4.1% 474				
S_4-14 Firing Coal (B_1B_4 Air Only)			⑩ 4.0% 521	⑦ 3.6% 517				
S_5-14 Firing Coal (D_1D_4 Air Only)			⑨ 3.4% 598	⑧ 3.6% 580				
S_6-12 Firing Coal ($A_1A_4D_1D_4$ Air Only)							⑰ 3.2% 365	㉓ 4.3% 421
S_7-12 Firing Coal ($A_1A_4B_2B_3$ Air Only)							⑱ 3.0% 374	㉔ 3.3% 302
S_8-12 Firing Coal ($A_1A_4B_1B_4$ Air Only)							㉒ 4.4% 368	⑲ 3.3% 316
S_9-12 Firing Coal ($A_1A_2A_3A_4$ Air Only)							㉑ 4.5% 329	⑳ 5.3% 305

FIGURE 3-1

PPM NO_X (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(WIDOWS CREEK, BOILER NO. 5)



lowest NO_x emission levels among staging patterns with two burners on air only, S_2, and four burners on air only, S_9, are indicated by the larger traingles and larger squares, respectively.

Baseline NO_x emissions calculated from the least squares regression lines for 120% stoichiometric air were 567 ppm and 506 ppm at 125 and 100 MW, respectively. These results are about 100 ppm lower than the results obtained in our previous field test program on "sister" boiler No. 6. This difference is probably due to the different coals fired and the fact that the inside walls of No. 5 furnace were much cleaner (less ash deposit) than the furnace walls of No. 6 boiler when it was previously tested.

Operation under low excess air conditions reduced NO_x emissions as shown by the least squares line plotted on Figure 3-1. A reduction of 10% in % stoichiometric air to active burners (i.e., 120% to 110%) reduced NO_x emissions by 21% under both full load (567 to 447 ppm) and 100 MW load (493 to 388 ppm) under normal, 16 burner firing operation.

Reducing gross load from 125 to 100 MW (20% reduction) with normal excess air, 16 burner firing resulted in lowering calculated NO_x emissions from 567 ppm to 493 ppm (13% reduction) at 120% stoichiometric air. Since the actual excess air level was increased during reduced load operation, actual NO_x emissions were higher during reduced load, "normal" air operation than under normal air, full load operation.

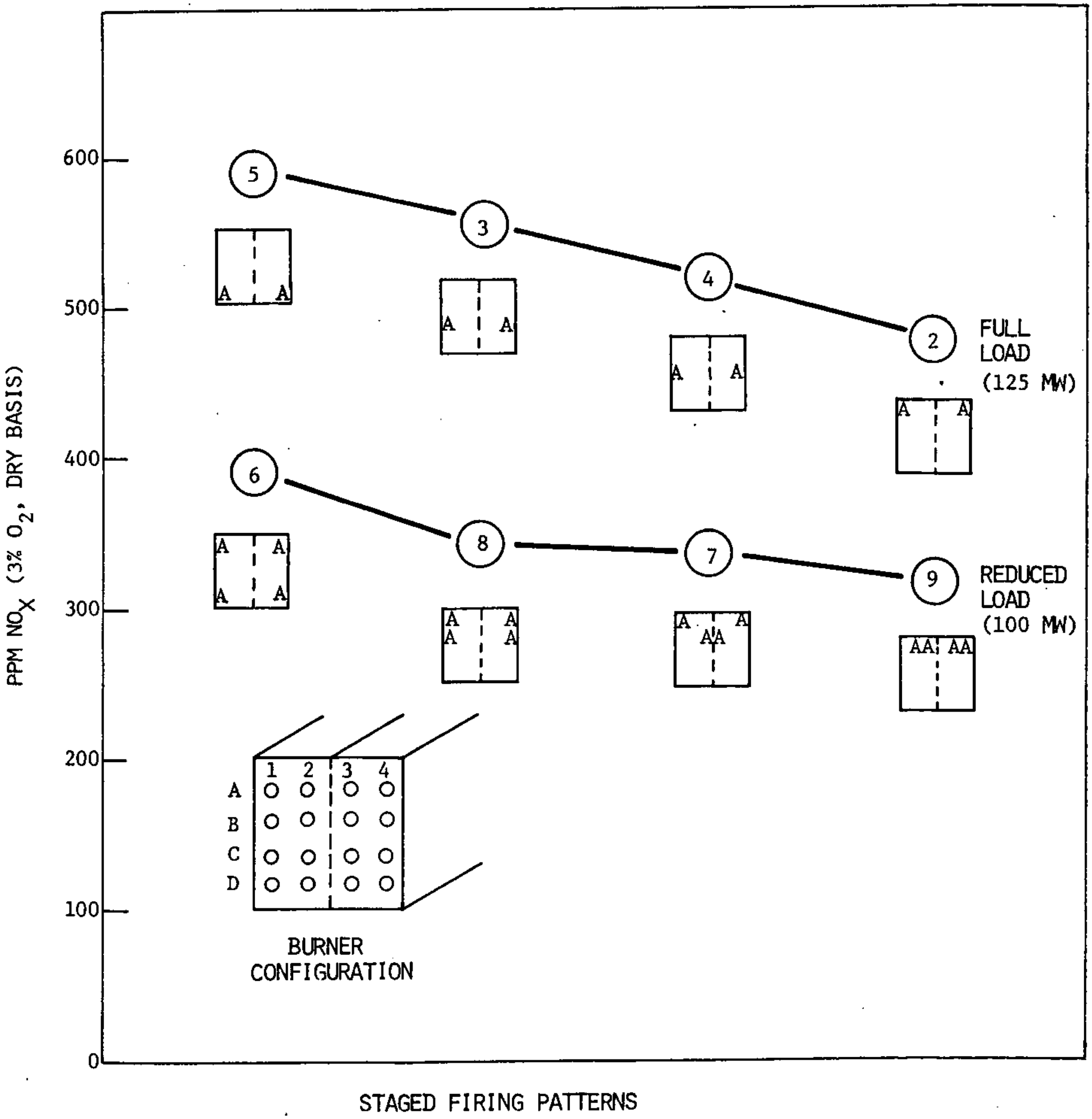
Staged firing test runs were conducted only at low excess air levels. This procedure was used to allow us to test additional staged firing patterns within the same test period, and to concentrate on low excess air operation that produces minimum NO_x emission rates. The minimum level of excess air was determined by acceptable CO emissions (less than 200 ppm) and normal stack appearance.

Four staged firing patterns were tested at 125 MW load with two burners on air only (14 active burners). The lowest average NO_x emissions were measured with top row outer burners on air only (477 ppm using S_2). The next lowest average NO_x emissions were measured with next to top row wing burners on air only (519 ppm using S_4) while S_3 and S_5 staged firing patterns with next to bottom and bottom row wing burners on air only produced an average of 557 and 589 ppm NO_x emissions, respectively. Thus, there was a consistent pattern of decreased NO_x emissions as the "air only" burners were shifted from "underfire" air on the bottom row to "overfire" air on the top row of burners as shown by the top line of Figure 3-2. Reducing secondary air register settings from 60% open to 20% open on the active burners

FIGURE 3-2

NO_X EMISSIONS VS. STAGED FIRING PATTERNS

(WIDOWS CREEK NO. 5 UNIT)



consistently resulted in lowered NO_x emissions on all 4 firing patterns with an average reduction of 9%. The best operating combination of register setting and staged firing (test run No. 12) produced an average NO_x emission level of 468 ppm which was 22% lower than the 597 ppm under actual base level operation (test run 1A).

Four staged firing patterns were also tested at 100 MW load with 4 burners on air only (12 active burners). The lowest average NO_x emission level (317 ppm) was measured with the top row of burners (fed from A mill) on air only (S_9). The next to best NO_x level (338 ppm) was measured when operating with A_1, B_2, B_3, and A_4 burners on air only, (S_7). Staged firing pattern S_8 (A_1, A_4, B_1 and B_4 burners on air only) produced NO_x emissions slightly higher than firing pattern S_7, while firing pattern S_6 (A_1, A_4, D_1 and D_4 burners on air only) produced the highest average ppm NO_x emission level of 393 ppm among the 4 burners off firing patterns. Reducing secondary air register settings from 60% open to 20% open on active burners reduced NO_x emissions by an average of 6% over these 4 firing patterns. The best combination of staged firing pattern (S_9) and air register setting (test run No. 20) produced a 305 ppm NO_x emission level or about 49% below full load, baseline operation. The average NO_x emission levels for staged firing patterns 6-9 are plotted on Figure 3-2.

Two factors appear to be responsible for lower NO_x when operating with secondary air register settings of 20% open on the active burners. The first one is that the overall level of excess air can be lowered, and the second is that operating in this way allows lower substoichiometric air supply to the active burners.

The test results obtained from boiler No. 5 were about as expected based on the results obtained on the previously tested No. 6 unit and other front-wall fired boilers. Each of the 4 operating variables, load, excess air level, secondary air register setting and firing pattern has a significant effect on NO_x emission levels. From a full load, base level NO_x emission level of 567 ppm (120% stoichiometric air), low excess air operation reduced NO_x emissions by about 12% to 502 ppm. Reducing load by 20% to 100 MW reduced NO_x emissions by 13%. Low excess air, staged firing at full load reduced NO_x emissions to as low as 468 ppm when secondary air registers were closed to 20% open. Low excess air, staged firing at reduced load (100 MW) reduced NO_x emissions to as low as 305 ppm with A mill burners on air only and closed down secondary air registers. The most effective staged firing patterns are those that maximize the amount of "overfire" air across the burner area.

3.1.2 Ernest C. Gaston, Boiler No. 1
(Southern Electric Generating Company)

Southern Electric Generating Company's Boiler No. 1 at the Ernest C. Gaston Station, was the second boiler to be tested in our current field test program. The major reason for selecting this boiler is that it has been retro-fitted with newly designed, low NOx emission burners. These burners, designed by Babcock and Wilcox, produce a limited turbulence, controlled diffusion flame. They are designed to minimize the amount of fuel and air mixed at the burner to that required to obtain ignition and to sustain combustion of the fuel. Figure 3-3 presents a line diagram of the dual register pulverized coal burners installed in Boiler No. 1.

Gaston Units No. 1 and 2 are 270 MW, 18-burner, horizontally opposed, pulverized coal fired Babcock and Wilcox boilers. Two division walls divide each furnace into 3 equal compartments, each having six burners arranged 3 high in both the front and rear walls of the furnace. The furnace is 60 feet wide, with a volume of 139,500 cubic feet and a total wall area of 25,732 square feet. Six pulverizers (each with 36,000 pounds capacity) feed coal to 3 burners each as shown in Figure 3-4. The maximum continuous rating of each boiler is 1,700,000 pounds of steam per hour. Steam design pressure at superheat outlet is 2,075 PSIG at 1000°F. Steam design pressure at reheater outlet is 495 PSIG at 1000°F. Steam temperature controls includes flue gas recirculation into the furnace and spray attemperators for primary superheat and reheater.

Table 3-3 contains a summary of the key operating and emissions data. Table 3-4 presents these results according to the test program experimental design. The five operating variables (and experimental levels tested) included in the test program were:

1. Gross load (full load (270 MW), 250 MW and 190 MW to 205 MW).
2. Excess air level (high, normal and low).
3. Secondary air register setting (30, 50, 70 and 100% open).
4. Tertiary air register setting (50 and 100% open).
5. Firing pattern (all burners firing, 1 top mill off, 2 top mills off).

The emission data shown in Tables 3-3 and 3-4 are average % oxygen and PPM NO_x (3% O_2, dry basis). Four probes, each containing short, medium and long sampling tubes were positioned near the centers of 12 equal areas in the flue gas ducts between the economizer and the air preheaters.

FIGURE 3-3

BABCOCK AND WILCOX DUAL REGISTER PULVERIZED COAL BURNER

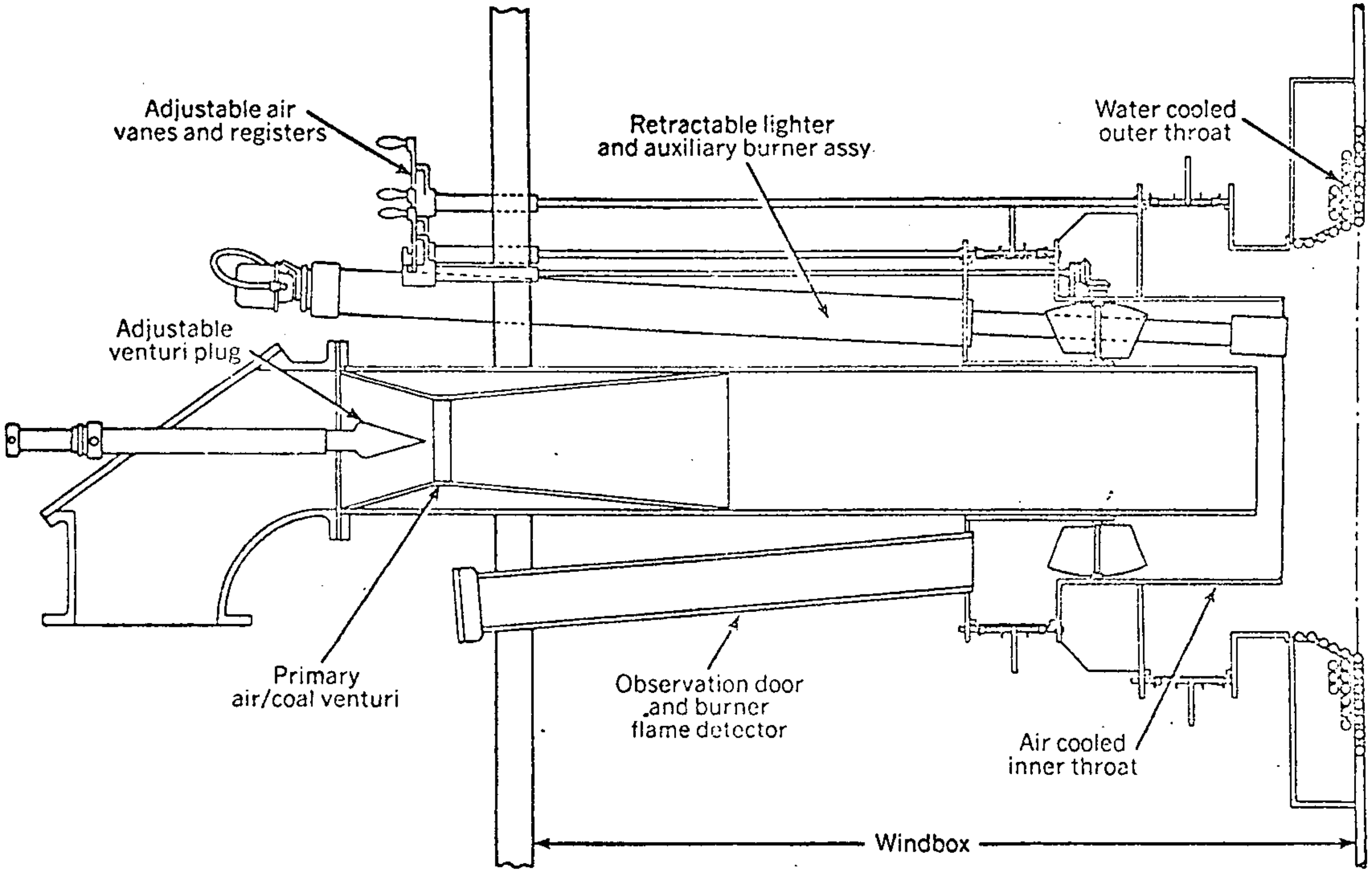
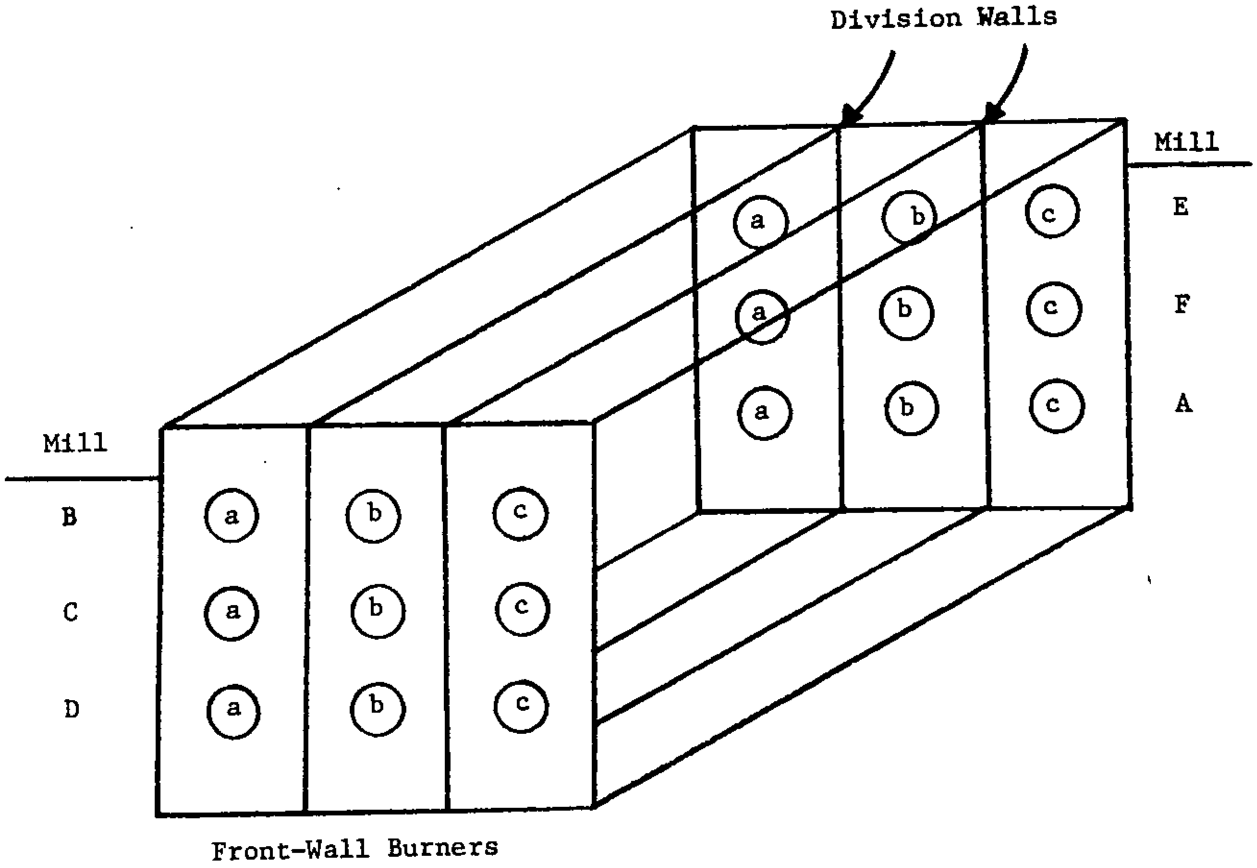


FIGURE 3-4

MILL-BURNER CONFIGURATION

(E.C. Gaston Boilers No. 1 and 2)



Composite gas samples from each probe were analyzed and recorded in turn over four complete cycles, resulting in 16 measurements of each gaseous component in each test run. The level of excess air on "low" excess air test runs was established as the minimum excess air level operation that would not produce over 200 PPM CO emissions.

Figure 3-5 is a plot of PPM NO_x (3% O_2, dry basis) vs. average % stoichiometric air to active burners. The numbers within the plotted symbols identify the run number from which the data were obtained. Least squares, linear regression lines were calculated from the data points representing normal firing (S_1) at 270 MW, normal firing at 205 MW, staged firing (S_2 - top mill burners on air only on front or rear wall) at 250 MW and staged firing operation (S_3 - top mill burners of front and rear wall on air only) at 190 MW.

Base-line NO_x emissions calculated from the least squares regression lines shown on Figure 3-5 for 120% stoichiometric air were 363 PPM and 279 PPM at 270 and 205 MW, respectively on Boiler No. 1 using the new low NO_x burners. Thus, a load reduction of 24% resulted in a 23% reduction in NO_x emissions. From a full load, base level NO_x emission level of 389 PPM (125% stoichiometric air), low excess air operating reduced NO_x emissions by about 29% to 278 PPM. Three staged firing patterns were tested: E mill burners on air only (S_2), E and B mill burners on air only (S_3) and B mill burners on air only (S_4). Low excess air, staged firing at 250 MW reduced NO_x emissions to as low as 240 PPM with B mill burners on air only (S_4). Low excess air, staged firing at a lower load of 190 MW reduced NO_x emissions to as low as 182 PPM with both E and B mill burners on air only (S_3). Analysis of secondary air register setting vs. NO_x shows that the lowest NO_x level was reached when the register setting is approximately 70% open with lower and higher settings give higher NO_x levels.

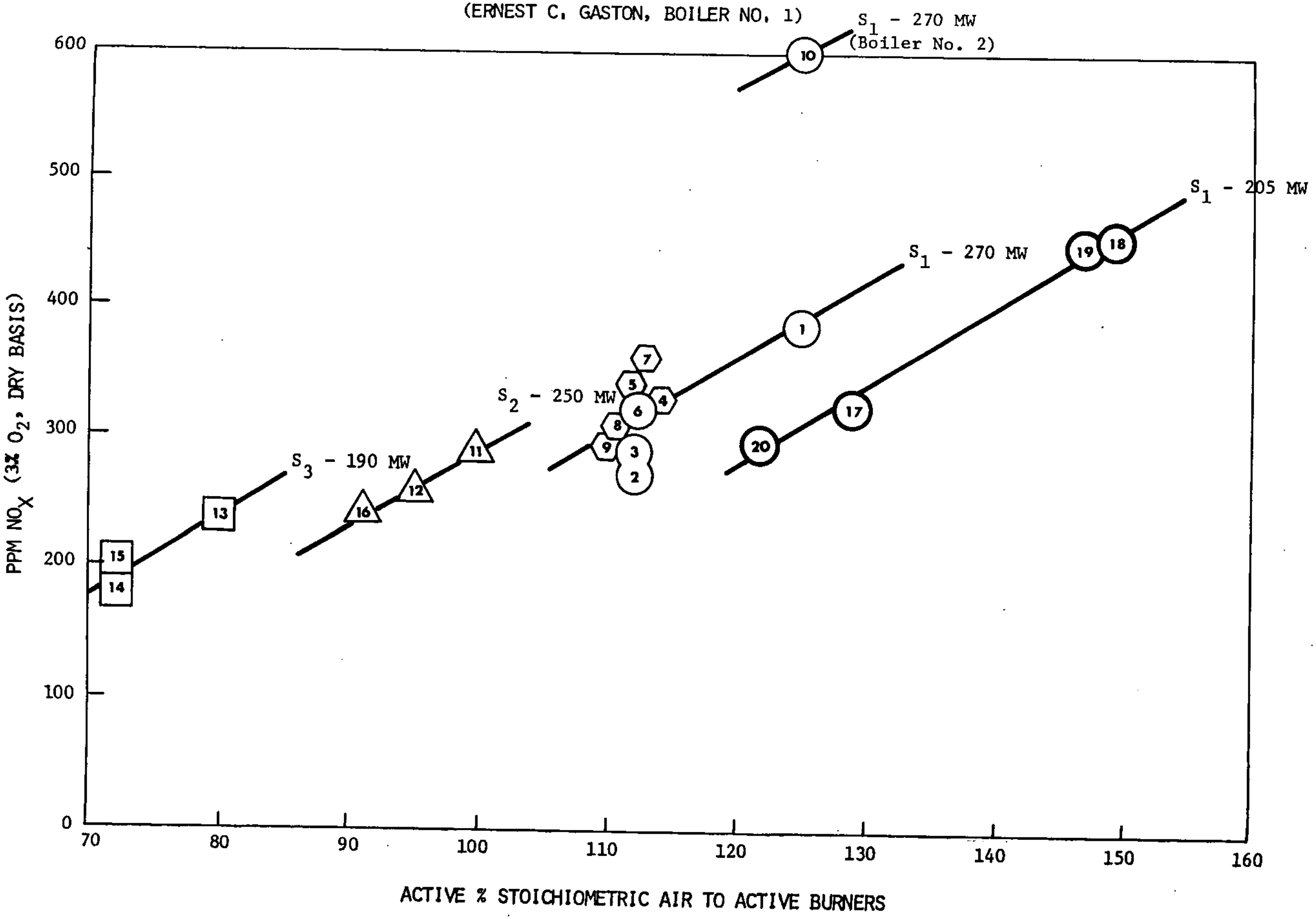
NO_x measurements on Boiler No. 2 when operated at full load of 270 MW, averaged 595 PPM at 24% excess air. Boiler No. 1 when operated at full load of 270 MW, averaged 387 PPM at 24% excess air. Therefore, the new dual register burners used in Boiler No. 1 reduced NO_x emission levels (35% reduction) significantly, compared to conventional Babcock and Wilcox burners.

A short term set of experimental runs were conducted to determine the effect of reduced pulverizer air temperature on NO_x emissions. At the normal operating temperature of 170°F, average NO_x emission measured 361 PPM (3.0% O_2) while at a reduced temperature of 140°F, average NO_x emissions measured 313 PPM (2.9% O_2). Thus, a 12% reduction in NO_x emissions resulted from the use of lowered pulverizer air temperature. Further experimentation would be necessary to determine if the reduced temperature operation would result in mill operating problems and to validate these results over a longer time period with a variety of coals and pulverizer settings.

FIGURE 3-5

PPM NO_X (3% O_2, DRY) VS. % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(ERNEST C. GASTON, BOILER NO. 1)



3.1.3 Navajo Station, Boiler No. 2
SALT RIVER PROJECT

Navajo Unit No. 2 is a twin furnace, 800 MW, Combustion Engineering Boiler. The two cell furnace has a volume of 465,500 cu. ft., width of 83 ft. 6-3/4 in. and front to rear length of 40 ft. 10-1/4 in. Maximum continuous rated primary steam flow is 5,400,000 lb./hr., at 1005°F, with a reheat steam flow of 4,850,000 lb./hr. at 1003°F. The normal fuel fired is Black Mesa Sub-Bituminous coal with a higher heating value of 10,725 BTU/lb., 10.4% ash, 10.3% moisture, 38% volatile material and 41.4% carbon content. At maximum continuous rating, 652,000 lb./hr. coal if fired and a furnace efficiency of 88.77% is expected. 7 pulverizers feed 56 burners arranged to fire at 7 different levels. Overfire tilting air ports are located above the top row of burners. Main steam pressure is 3590 lbs./sq. in. at the superheater outlet.

Table 3-5 contains a summary of the major operating variables and flue gas measurements for each of the 36 test runs completed on Navajo No. 2 Unit. Operating variables included in the experimental program were gross load, excess air level, burner tilt, and firing pattern. Average % oxygen and ppm NO_x (3% O_2, dry basis) are shown for each test run. Table 3-6 presents a summary of emission data (run no., % O_2, ppm NO_x) arranged according to the experimental design. Figures 3-6 through 3-9 have been constructed to aid in the analysis of these data.

Figure 3-6 is a plot of ppm NO_x (3% O_2, dry basis) vs. average % oxygen measured in the flue gas for all test runs conducted at full load with normal firing (S_1). Lines have been drawn to show the effect of excess air level on NO_x emission levels for +25°, +10 to +15°, 0° and -10 to -15° burner tilts. The effect of overfire cooling air (about 10% open) has no beneficial NO_x reduction effect when the burners are tilted up 25°. However, as the burners are tilted towards horizontal levels, the separation distance between the overfire cooling air and bulk flames increases and improved NO_x reductions are apparent. Operating with burner tilts at -10 to -15° produced higher NO_x emission levels than 0° tilt operation. The least squares, regression line calculated from the 7 test runs conducted at +10 to +15° burner tilt, (ppm NO_x = 118 + 51% O_2) showed an average reduction of 51 ppm NO_x for each reduction in flue gas oxygen content.

Figure 3-7 is a plot of ppm NO_x (3% O_2, dry basis) vs. % oxygen for the test runs conducted at full load with overfire air dampers 100% open (S_7). The least squares, regression line calculated from the 8 test runs conducted with +10 to +15° burner tilt (ppm NO_x = 90 + 54% O_2) showed an average reduction of 54 ppm NO_x for each 1% reduction in flue gas oxygen content. The average ppm NO_x emission level for the 5 S_7 test runs conducted at the lowest excess air level (3.5 to 3.8% O_2) was 282 ppm or 17% below the 341 ppm NO_x level for comparable excess air S_1 test runs.

TABLE 3-5

SUMMARY OF OPERATING AND EMISSION DATA - NAVAJO STATION - BOILER NO. 2

Date and Run No.	Operating Conditions							Flue Gas Measurements	
	Gross Load (MW)	Excess Air Level	Burner Tilt	Firing Pattern:				% O_2	PPM NO_x (3% O_2)
				Symbol	Overfire Air		No. Active Burners		
					% Open	Tilt			
5/29/75									
3	803	Normal	+10°	S_1	10	Horiz.	56	4.9	366
5/30/75									
6	802	Low	+10°	S_1	10	Horiz.	56	4.0	335
4	801	Low	Horiz.	S_1	10	Horiz.	56	4.2	309
5	797	Low	-15°	S_1	10	Horiz.	56	3.8	314
6A	800	Low	+25°	S_1	10	Horiz.	56	3.8	411
3A	799	Normal	+25°	S_1	10	Horiz.	56	4.8	492
1	798	Normal	Horiz.	S_1	10	Horiz.	56	4.9	343
6/2/75									
11	795	Normal	+10°	S_4	25	+10°	56	4.0	332
13	795	Normal	+10°	S_5	50	+10°	56	3.9	310
15	795	Normal	+10°	S_6	75	+10°	56	3.8	293
17	795	Normal	+10°	S_7	100	+10°	56	3.6	288
6/3/75									
18	802	Low	+10°	S_7	100	+10°	56	3.6	282
16	798	Low	+10°	S_6	75	+10°	56	4.0	289
14	799	Low	+10°	S_5	50	+10°	56	3.6	326
12	798	Low	+10°	S_4	25	+10°	56	3.6	328
6/4/75									
7A	800	Normal	+10°	S_1	10	+10°	56	5.2	378
6/5/75									
8	800	Low	+10°	S_2	10	+10°	48	3.6	259
8A	800	Low	+10°	S_1	10	+10°	48	3.6	298
7	800	Normal	+10°	S_2	10	+10°	48	5.0	318
7B	800	Normal	+10°	S_1	10	+10°	56	5.2	383
21	798	Normal	Horiz.	S_7	100	Horiz.	56	5.4	329
19	795	Normal	-15°	S_7	100	Horiz.	56	5.2	346
20	798	Low	-15°	S_7	100	Horiz.	56	3.5	271
22	795	Low	Horiz.	S_7	100	Horiz.	56	3.8	289

TABLE 3-5 (Continued)

SUMMARY OF OPERATING AND EMISSION DATA - NAVAJO STATION - BOILER NO. 2

Date and Run No.	Operating Conditions							Flue Gas Measurements	
	Gross Load (MW)	Excess Air Level	Burner Tilt	Firing Pattern:				% O_2	PPM NO_x (3% O_2)
				Symbol	Overfire Air		No. Active Burners		
					% Open	Tilt			
6/6/75 3B	802	Normal	+10°	S_1	10	+10°	56	5.4	416
17A	806	Normal	+10°	S_7	100	+10°	56	5.2	354
18A	802	Low	+10°	S_7	100	+10°	56	4.2	291
6/18/75 3C	803	Normal	+10°	S_1	10	+10°	56	5.4	385
6/19/75 18B	808	Normal	+12°	S_7	100	+10°	56	4.4	349
6/20/75 18C	808	Normal	+11°	S_7	100	+10°	56	4.6	346
6/24/75 18D	305	Low	+25°	S_7	100	+10°	32	4.6	349
2A	792	Normal	-10°	S_1	10	+10°	56	3.9	332
6/26/75 3D	785	Normal	+10°	S_1	10	+10°	56	4.8	346
18E	798	Low	+10°	S_7	100	+10°	56	3.7	280
23	565	Normal	+10°	S_1	10	+10°	48	5.3	350
6/27/75 24	565	Normal	+30°	S_1	10	+10°	40	5.0	404

Figure 3-6

PPM NO_x (3% O_2, Dry Basis) vs. % Oxygen

(Navajo No. 2 Boiler - Full Load, Normal Firing)

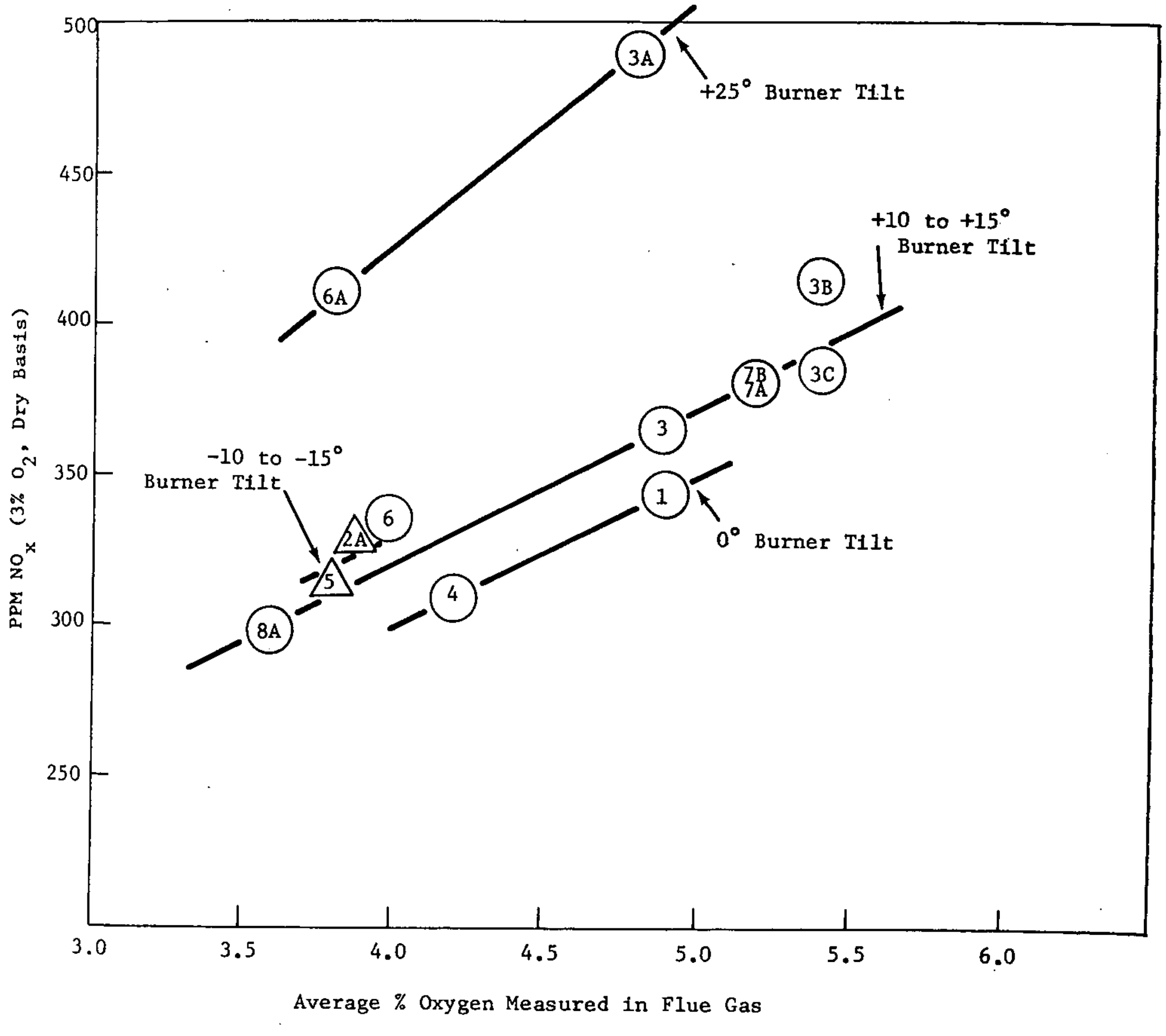


Figure 3-7

PPM NO_x (3% O_2, Dry Basis) vs. % Oxygen

(Navajo No. 2 Boiler - S_7, Overfire Air Dampers 100% Open)

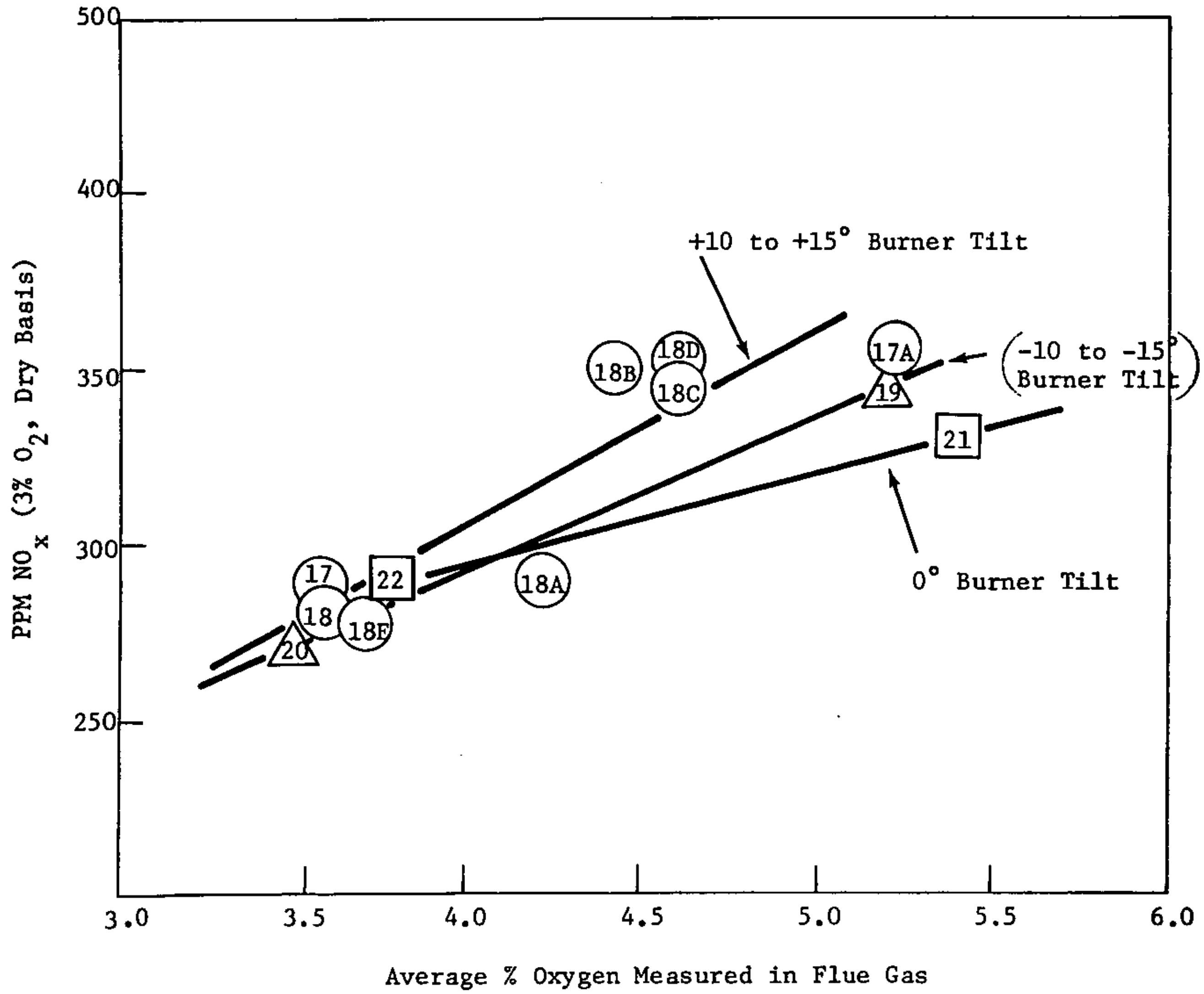


Figure 3-8 is a plot of ppm NO_x vs. % oxygen for the S_2, S_4, S_5 and S_6 staged firing test runs. The least squares line labeled S_7 from Figure 3-7 has been drawn on Figure 3-8 for comparison purposes. Short lines parallel to the S_7 line have been drawn through the average data for S_4, S_5 and S_6 test runs. The lowest NO_x emissions resulted from test runs No. 7 and No. 8 conducted with the top tier of burners on air only (S_2) and cooling air through the overfire air registers. The beneficial effect of increasing overfire air register openings from 25% (S_4), 50% (S_5) to 75% (S_6) is apparent from examination of Figure 3-8. However, Figure 3-9 has been constructed to present the effect of changing overfire air register settings more directly. Only test runs conducted with approximately equal excess air levels (3.6 to 40% O_2) and burner tilts (+10° to +15°) are shown on Figure 3-9 so that the effect of overfire air settings on NO_x emission rates can be easily seen. Average ppm NO_x levels (and overfire air register openings) decrease from 330 (25% OFA) to 318 (50% OFA) to 290 (75% OFA) to 283 (100% OFA).

Table 3-6 below has been developed so that the effect of boiler load on NO_x emission levels can be estimated. The first 5 columns provide data on the 3 test runs conducted at reduced loads of 565 to 305 MW. The fifth column lists NO_x levels for full load operation at comparable excess air levels and burner tilts from Figure 3-6. The last column indicates the % reduction in NO_x levels obtained at the reduced loads.

TABLE 3-6

REDUCED LOAD TEST DATA

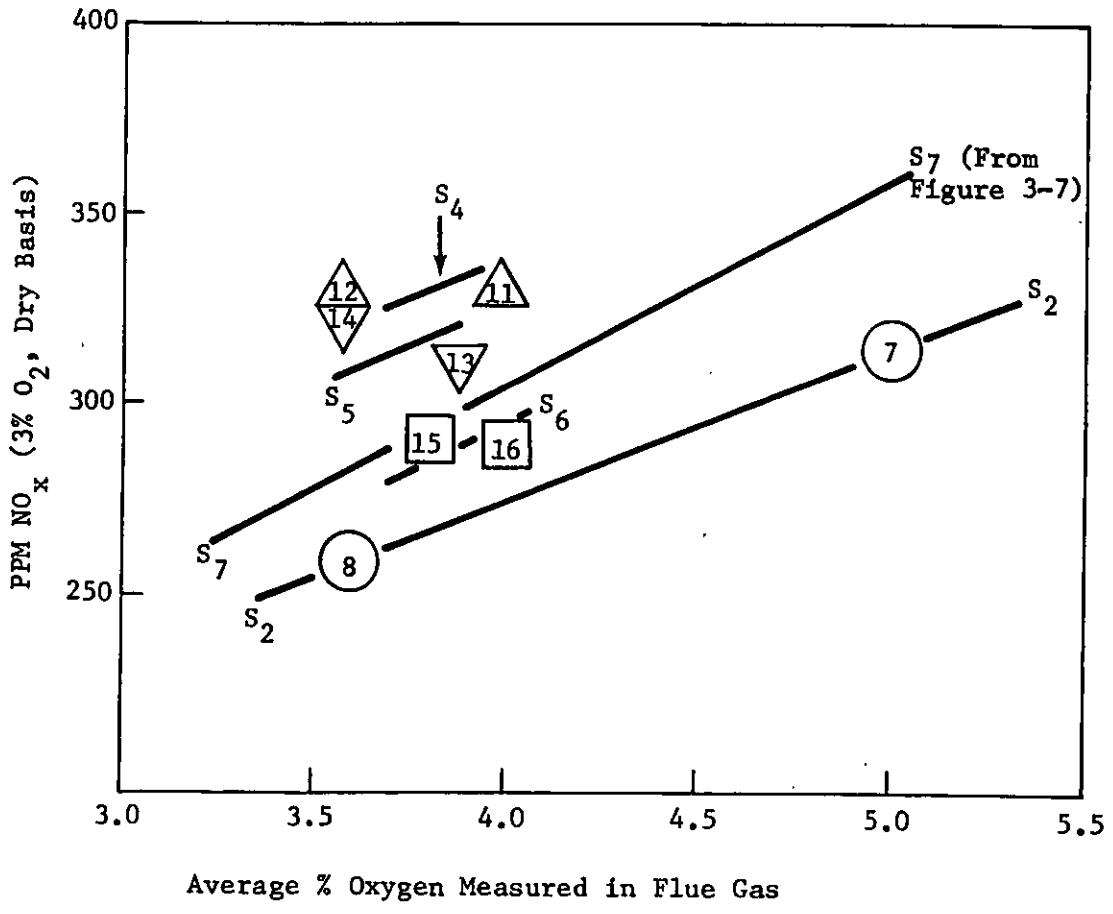
Run No.	Gross Load (MW)	Burner Tilt	% O_2	ppm NO_x	Full Load NO_x	% Reduction
23	565	+10°	5.3%	350	388	10
24	565	+30°	5.0%	404	506	20
18D	305	+25°	4.6%	349	474	26

Thus, a 29% reduction in load resulted in a 10 to 20% reduction in NO_x emission levels and a 52% reduction in load resulted in a 26% reduction in NO_x emission level.

Figure 3-8

PPM NO_x (3% O_2, Dry Basis) vs. % Oxygen

(Navajo No. 2 Boiler - S_2-S_7 Staged Firing)



[illegible]

TEST PROGRAM EXPERIMENTAL DESIGN - RUN NO., % O_2, PPM NO_x
(NAVAJO NO. 2 UNIT - FULL LOAD (795-808 MW)

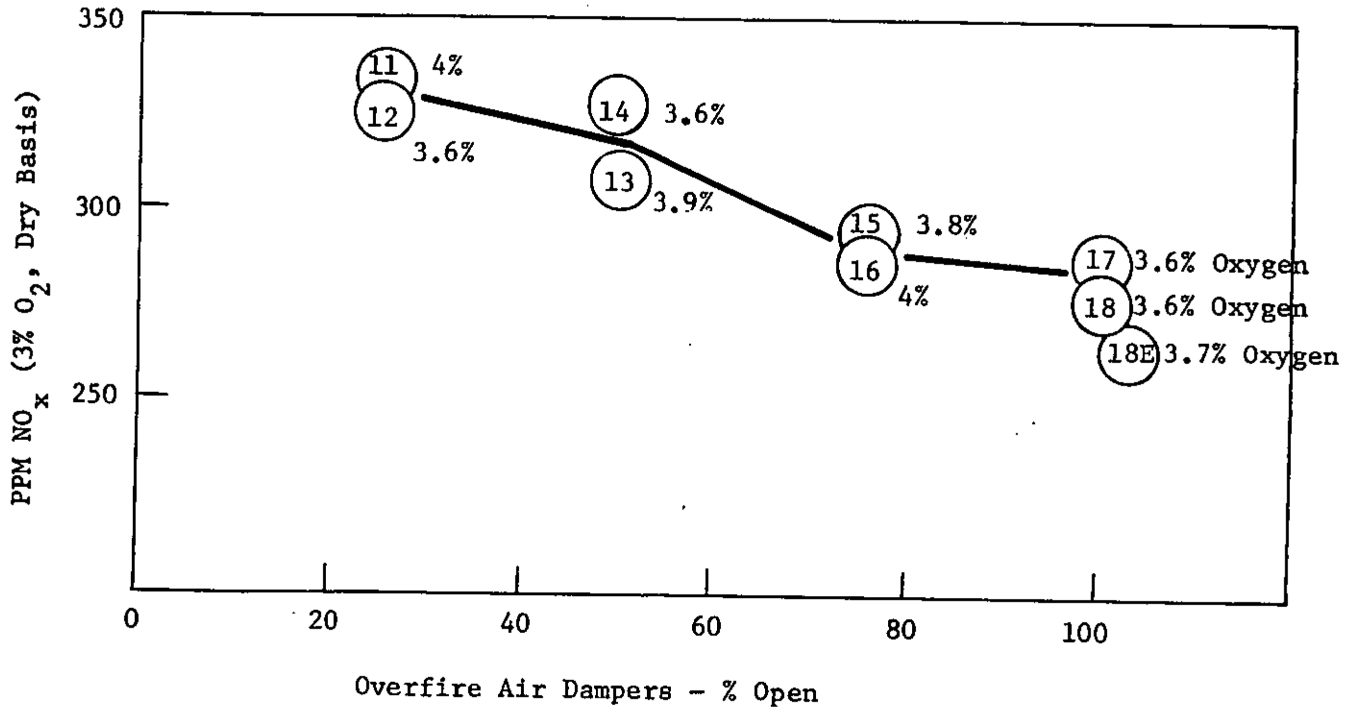
	Burner Tilt \ Firing Pattern	S_1-Normal Firing	S_2-Top Row Air Only	S_4-* 25% OFA	S_5-* 50% OFA	S_6-* 75% OFA	S_7-* 100% OFA
A_1- Normal Excess Air	T_1 -10° to -15°	(2A) 3.9% 332					⑲ 5.2% 346
	T_2 Horiz.	① 4.9% 343					㉑ 5.4% 329
	T_3 +10° to +15°	(3B) 5.4% 416 (3C) 5.4% 385 ③ 4.9% 366 (3D) 4.8% 346 (7A) 5.2% 378 (7B) 5.2% 383	⑦ 5.0% 318	⑪ 4.0% 332	⑬ 3.9% 310	⑮ 3.8% 292	(17A) 5.2% 354 (18B) 4.4% 349 (18C) 4.6% 346 (18D) 4.6% 349
	T_4 +25°	(3A) 4.8% 492					
A_2- Low Excess Air	T_1 -15°	⑤ 3.8% 314					⑳ 3.5% 271
	T_2 Horiz.	④ 4.2% 309					㉒ 3.8% 289
	T_3 +10° to 15°	⑥ 4.0% 335 (8A) 3.6% 298	⑧ 3.6% 259	⑫ 3.6% 328	⑭ 3.6% 326	⑯ 4.0% 289	⑱ 3.6% 282 (18A) 4.2% 291 ⑰ 3.6% 288 (18E) 3.7% 280
	T_4 +25°	(6A) 3.8% 411					

* Overfire air registers were set at 25% open for S_4, 50% open for S_5, 75% open for S_6 and 100% open for S_7.

Figure 3-9

PPM NO_x vs. Overfire Air Dampers - % Open

(Navajo No. 2 Boiler - Full Load)



3.1.4 Comanche Station, Boiler No. 1
Public Service Co. of Colorado, Pueblo, Colorado

Comanche Unit No. 1 is a single furnace, tangentially fired, Combustion Engineering Boiler. It was selected for this program because it conforms to modern design practices and has overfire air ports (OFA) over the top level of burners for NO_x emissions control. The furnace has a volume of 238,000 cu. ft., width of 45 ft. 4 in. and front to rear length of 40 ft. Maximum continuous rated primary steam flow at 2500 $lb./in^2$ is 2,534,000 lb./hr. at 1005°F with a reheat steam flow of 2,155,000 lb./hr. at 1005°. A Wyoming sub-bituminous coal is fired with nominal values of 8,250 BTU/lb., 5.2% ash, 0.57% sulfur, 29% moisture, 32.4% fixed carbon and 33.4% volatile matter, and an ash fusion temperature of 2150°F. At maximum continuous rating (350 MW), 428,000 lb./hr. coal is fired and a furnace efficiency of 84.65% is predicted. Five pulverizer feed 20 burners firing at 5 levels (designated "A" for the top and "E" at the bottom).

This unit was the first pulverized coal fired boiler designed by Combustion Engineering to have overfire air ports (through extended windboxes) for reduced nitrogen oxides emission levels. It also has a hot electrostatic precipitation for particulate collection.

Table 3-8 contains a summary of the major operating variables and flue gas measurements for each of the 30 test runs completed on Comanche No. 1. Operating variables included in the experimental program were overfire air damper settings (closed to 100% open and horizontal to -15° tilt), burner nozzle tilt (horizontal to -26°), secondary air register settings (22-40% open auxiliary and 100% open coal registers) and boiler load (316 to 340 MW).

Several operating limitations were experienced due to load, weather and boiler conditions. July and August are peak load demand months and thus only normal load variations were treated. Only normal excess air operation was used due to maximum ID fan capacity (economizer section blockage) and plant operating management's desire to avoid possible slagging problems (previously encountered) that might be caused by low excess air operations. Burner tilts are normally operated at -20° from the horizontal to avoid high steam outlet temperature and to reduce excess air level variations between flue gas economizer outlet ducts to a minimum. Thus, the burners were not tilted above horizontal. Secondary air register settings at full load are varied automatically to maintain a 4.5 to 5.0 in. H_2O furnace to windbox differential by varying auxiliary register settings, while the coal air registers are maintained 100% open. Thus, if the overfire air registers are opened from 5% (closed) to 50% open, the auxiliary air registers automatically close to 22 to 26% open from about 50% open. Maximum gross load during our test period was 320 to 340 MW due to limited ID fan capacity mentioned above and poorer than normal coal (up to 7% ash instead of 5% ash content). However, in spite of these limitations most of the objectives of the test program have been accomplished satisfactorly due to the excellent cooperation and assistance of plant personnel.

Table 3-8 contains average flue gas measurements of percent O_2 and ppm NO_x (3% O_2, dry basis) for each test run. Flue gas samples were taken from the centers of 6 equal areas from each of the two ducts ("A" and "B") between the economizer and the hot-side precipitator. Sixteen measurements were made of each gaseous component during each 32 minute "steady state" test run.

Figure 3-10 is a plot of ppm NO_x (3% O_2, dry basis) vs. burner nozzle tilt (degrees from horizontal). The number within the symbols indicate the test run. Straight lines have been drawn through the data points obtained from similar firing patterns to indicate the relationship between NO_x emission levels and burner tilts. Baseline operations (normal firing pattern with OFA ports closed) resulted in 410 PPM NO_x when operating normally at -15° to -20° burner tilts. Horizontal burner operation reduced NO_x emissions by 18% to 336 PPM, (Run 5) while lowering burner nozzle tilts to -26° increased NO_x emissions to 448 PPM (Run 3), or 9% above baseline operation.

Operation of the overfire air registers, as expected, had a large effect on NO_x emission levels. The three lines on Figure 3-10 drawn through data from S_1 operation (closed OFA ports), S_3 (25% open OFA ports) and S_4 (50% open OFA ports), respectively, indicate the reduction of NO_x emission levels as OFA port registers are opened. Figure 3-11 is a plot of PPM NOx emissions vs % open OFA registers for the data from test runs conducted at the normal operating range of -15 to -20° burner nozzle tilts. The solid line drawn through these data points indicates that NO_x emissions are reduced sharply from 407 PPM with overfire air ports closed (5% open for cooling) to 358 PPM with OFA ports 25% open to 289 PPM with 50% open OFA ports to a level of 264 PPM NO_x emissions when operating with 75 or 100% open OFA ports. Thus a 36% reduction in NO_x emissions levels from baseline operations was obtained through the use of overfire air ports. Additional improvements would be expected with low excess air operation and raised burner nozzle tilts closer to a horizontal position.

Excess air levels were maintained within "normal" levels during the entire test period at Public Service Company's request to avoid possible slagging problems. Consequently, test run average flue gas O_2 measurements varied within the narrow range of 3.5% to 4.4% making meaningful NO_x vs O_2 correlations difficult. However, as commonly found in tangentially fired boilers, average O_2 measurements (and NO_x measurements) from one duct (A) were consistently lower than average O_2 measurements (and NO_x measurements) from the other duct (B) on each test run. This situation provided a means for correlating NO_x levels with O_2 levels within test runs. Figure 3-12 is a plot of ppm NO_x vs O_2 data by flue gas duct for test runs 22 through 31. O_2 measurements in Duct B averaged 2.2% higher than in Duct A, while NO_x measurements in Duct B were 27 PPM higher than in Duct A. Although these lines cannot represent the full NO_x reduction potential of low excess air operation, they indicate directionally the improvements that should be obtainable.

TABLE 3-8

PHASE I EXPERIMENTAL TEST PROGRAM-COMANCHE NO. 1

Date And Run No.	Firing Pattern				Burner Nozzle Tilt	Excess Air Level	Secondary Air Reg. Aux/Coal (% Open)	Gross Load (MW)	NO_x (3% O_2, Dry Basis)	Avg. % O_2
	No. of Burners		Over Fire Air							
	Firing Coal	Air Only	% Open	Tilt						
7/14/75										
1	S_1-20	None	Closed	Horiz.	-14°	Normal	40/100	340	391	3.9
3	S_1-20	None	Closed	Horiz.	-26°	Normal	40/100	334	448	4.0
5	S_1-20	None	Closed	Horiz.	Horiz.	Normal	40/100	340	336	3.7
7	S_2-20	None	10%	Horiz.	-16°	Normal	37/100	340	373	3.8
7/15/75										
9	S_3-20	None	25%	-15°	-17°	Normal	35/100	335	355	4.1
11	S_4-20	None	50%	-15°	-17°	Normal	30/100	335	306	4.2
13	S_5-20	None	75%	-15°	-17°	Normal	27.5/100	333	261	3.7
15	S_6-20	None	100%	-15°	-18°	Normal	26.5/100	332	266	3.5
7/16/75										
2	S_1-20	None	Closed	-15°	-16°	Normal	38/100	332	404	3.8
4	S_1-20	None	Closed	-15°	-18°	Normal	40/100	331	417	4.0
17	S_3-20	None	25%	-15°	-26°	Normal	36/100	331	383	4.0
18	S_3-20	None	25%	-15°	Horiz.	Normal	36/100	332	308	4.0
7/17/75										
6	S_1-20	None	Closed	-15°	-16°	Normal	38/100	335	405	3.7
7/18/75										
20	S_3-20	None	25%	Horiz.	-17°	Normal	29/100	323	362	3.9
8	S_1-20	None	Closed	Horiz.	-20°	Normal	36/100	323	428	3.8
21	S_3-20	None	25%	Horiz.	-23°	Normal	33/100	321	364	3.9
19	S_3-20	None	25%	Horiz.	-4°	Normal	32/100	322	332	4.0
7/21/75										
22	S_4-20	None	50%	Horiz.	Horiz.	Normal	26/100	322	280	4.0
23	S_4-20	None	50%	Horiz.	-15°	Normal	22/100	321	316	4.2
24	S_4-20	None	50%	Horiz.	-25°	Normal	22/100	316	326	4.4
7/22/75										
25	S_4-20	None	50%	Horiz.	-15°	Normal	22/100	322	268	4.2
26	S_4-20	None	50%	Horiz.	-18°	Normal	24/100	321	284	4.1
7/23/75										
27	S_4-20	None	50%	Horiz.	-20°	Normal	23/100	321	245	3.8
7/24/75										
28	S_4-20	None	50%	Horiz.	-21°	Normal	22/100	322	259	3.8
7/25/75										
29	S_4-20	None	50%	Horiz.	-19°	Normal	24/100	321	289	4.4
7/29/75										
30	S_1-20	None	Closed	Horiz.	-20°	Normal	37/100	325	380	3.7
31	S_4-20	None	50%	Horiz.	-20°	Normal	27/100	322	271	3.9
7/30/75										
32A	S_4-20	None	50%	Horiz.	-15°	Normal	26/100	323	273	3.9
32B	S_4-20	None	50%	Horiz.	-15°	Normal	26/100	324	275	3.9
33	S_1-20	None	Closed	Horiz.	-15°	Normal	37/100	324	389	3.9

FIGURE 3-10

PPM NO_X (3% O_2 BASIS) VS BURNER TILT

(COMANCHE NO. 1 UNIT)

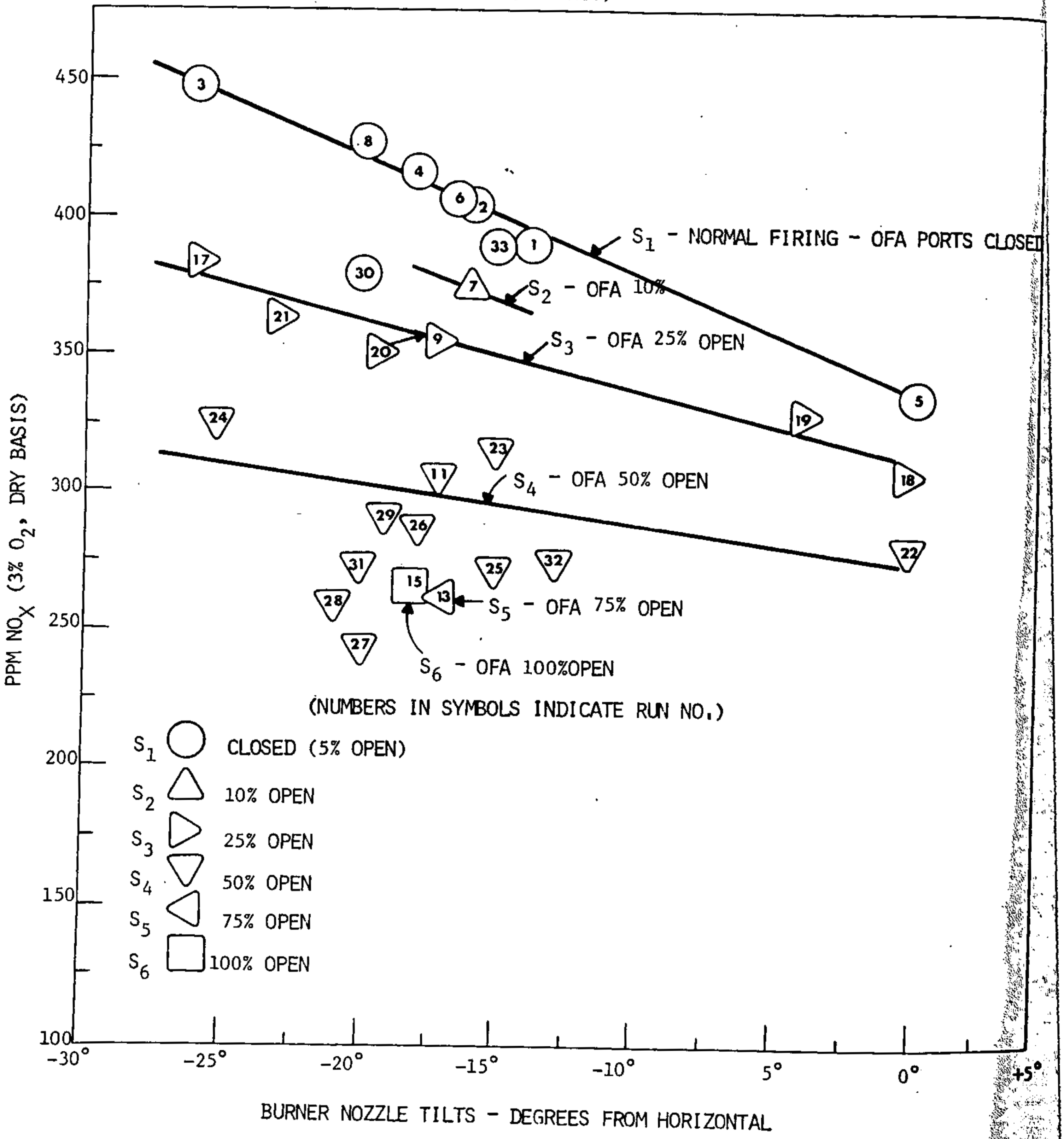


FIGURE 3-11

PPM NO_X (3% O_2 BASIS) VS OFA - % OPEN

(COMANCHE NO. 1 UNIT - -15° TO -20° BURNER TILT)

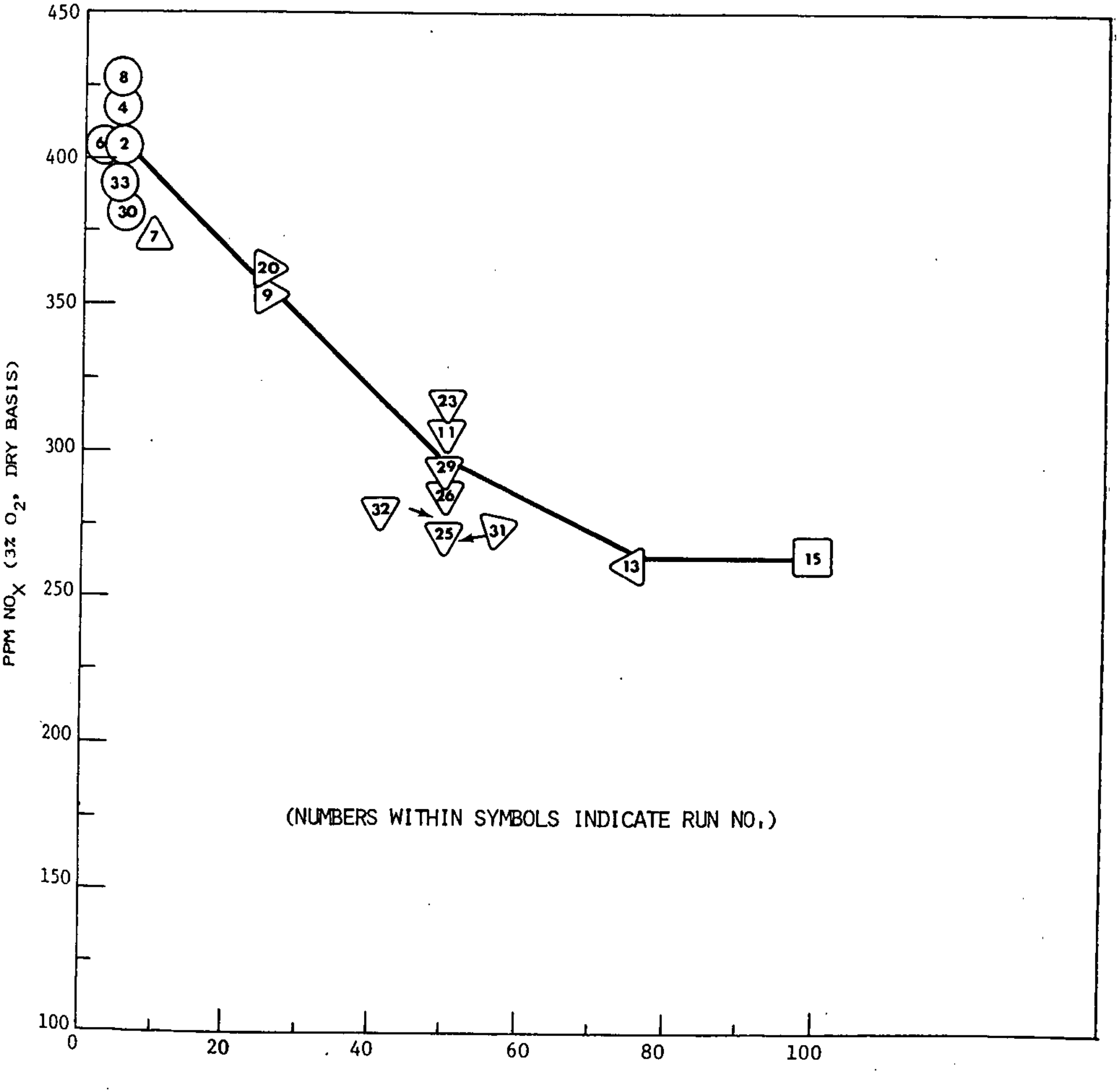
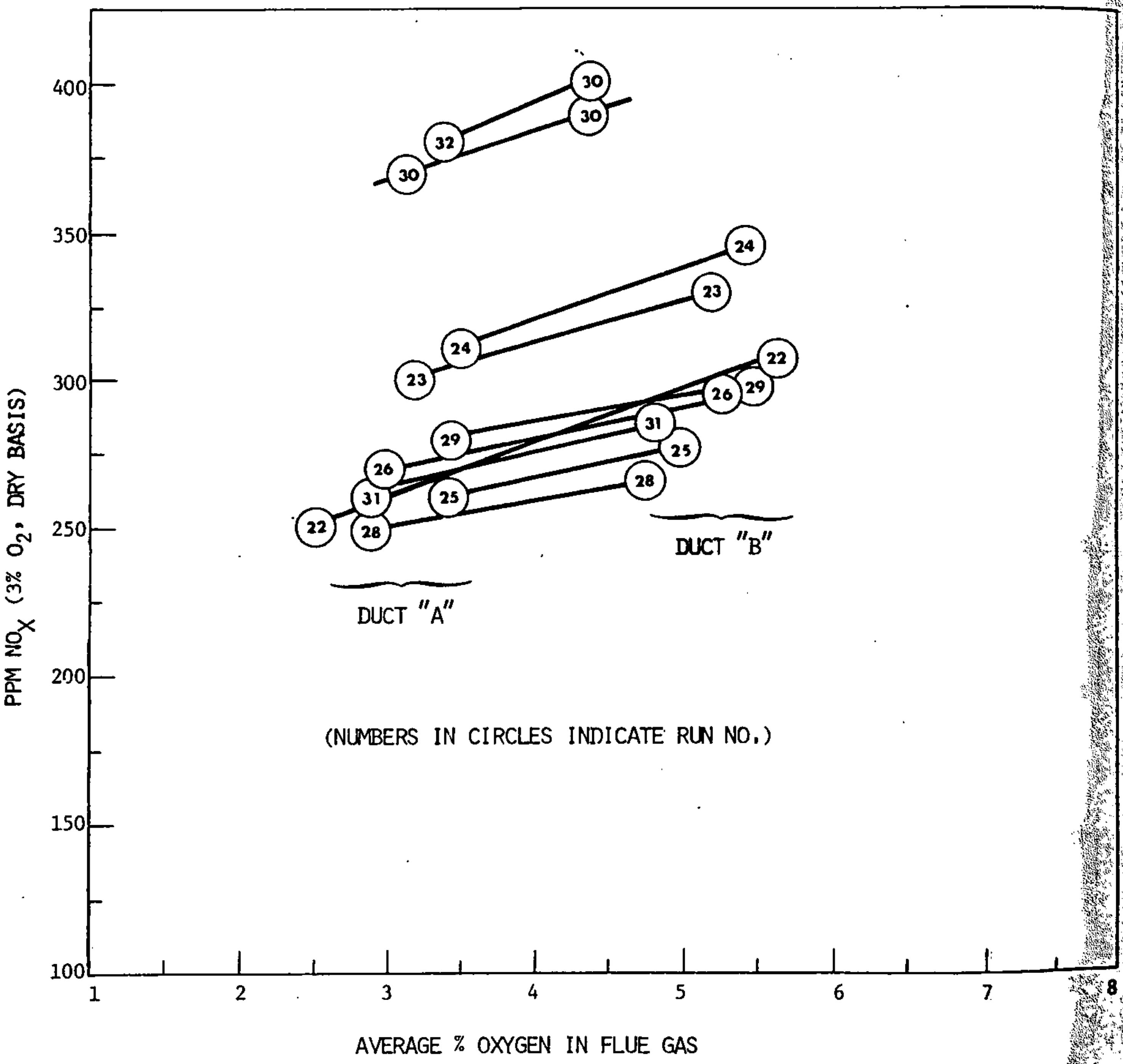


FIGURE 3-12

PPM NO_X (3% O_2 BASIS) VS % OXYGEN

(COMANCHE NO. 1 UNIT-S_4-50% OFA PORTS)



3.1.5 Barry Station, No. 2 Unit (Alabama Power Company)

Alabama Power Company's Boiler No. 2 at the Barry Station was the third boiler to be tested in our current field test program. There were two major reasons for selecting this boiler. First, it is one of very few boilers that has been retrofitted with overfire air ports for NO_x emission control. The second reason for selecting this boiler was that it is capable of firing gas (up to 40% of full load), coal and mixed fuel firing. To the best of our knowledge this is the only United States boiler with these combined capabilities. Figure 3-13 is a side elevation view of the unit.

Barry Station, Unit No. 2 is a natural circulation, balanced draft boiler which fires coal through four elevations of tilting tangential fuel nozzles. Each elevation of burners is fired by a pulverizer. The steam capacity at maximum continuous rating is 900,000 lbs/hour main stream flow with a superheat outlet temperature and pressure of 1000°F and 1875 PSIG, respectively. Superheat and reheat temperatures are controlled by burner tilt and water spray desuperheating. The furnace is 38 feet 2 inches wide and 28 feet 1¼ inches in depth. Two wind boxes (upper and lower) feed secondary air through 10 compartments (4 coal and 6 auxiliary) located at the four corners of the furnace. Vertical burner spacing is 4' 11" from center line to center line between elevations 1 to 2 and 3 to 4 with 7' 6" spacing between elevations 2 and 3. Overfire air ports were designed to supply about 20% of total air through new ducts located at each corner at 8 feet above the upper fuel zone as well as through the top two compartments of the upper windbox.

The experimental program was planned to produce required emission and operating information on this unusually flexible boiler from a minimum number of test runs. The program was divided logically into three experimental blocks, one at full load and two at reduced loads. The prime objectives of the full load (130 MW) block were to obtain baseline and modified combustion NO_x emission levels while firing 100% coal (Alabama and Illinois) as well as mixtures of gas and coal up to the maximum gas firing capability of the boiler under both normal and overfire air operation. Test runs to evaluate the effect of excess air level, burner nozzle tilt and secondary air register settings were also included in the full load block. The major objective of the reduced load block at 95 MW was to compare the NO_x reduction effectiveness of overfire air port operation with modified staged operation (top row of burners on air only). 95 MW is the maximum load capability of the boiler with the top mill off. To obtain information on NO_x emissions while firing 100% gas, test runs were conducted at the maximum load possible (55 MW) while firing gas only.

Figure 3-13

UNIT SIDE ELEVATION
ALABAMA POWER CO., BARRY NO. 2

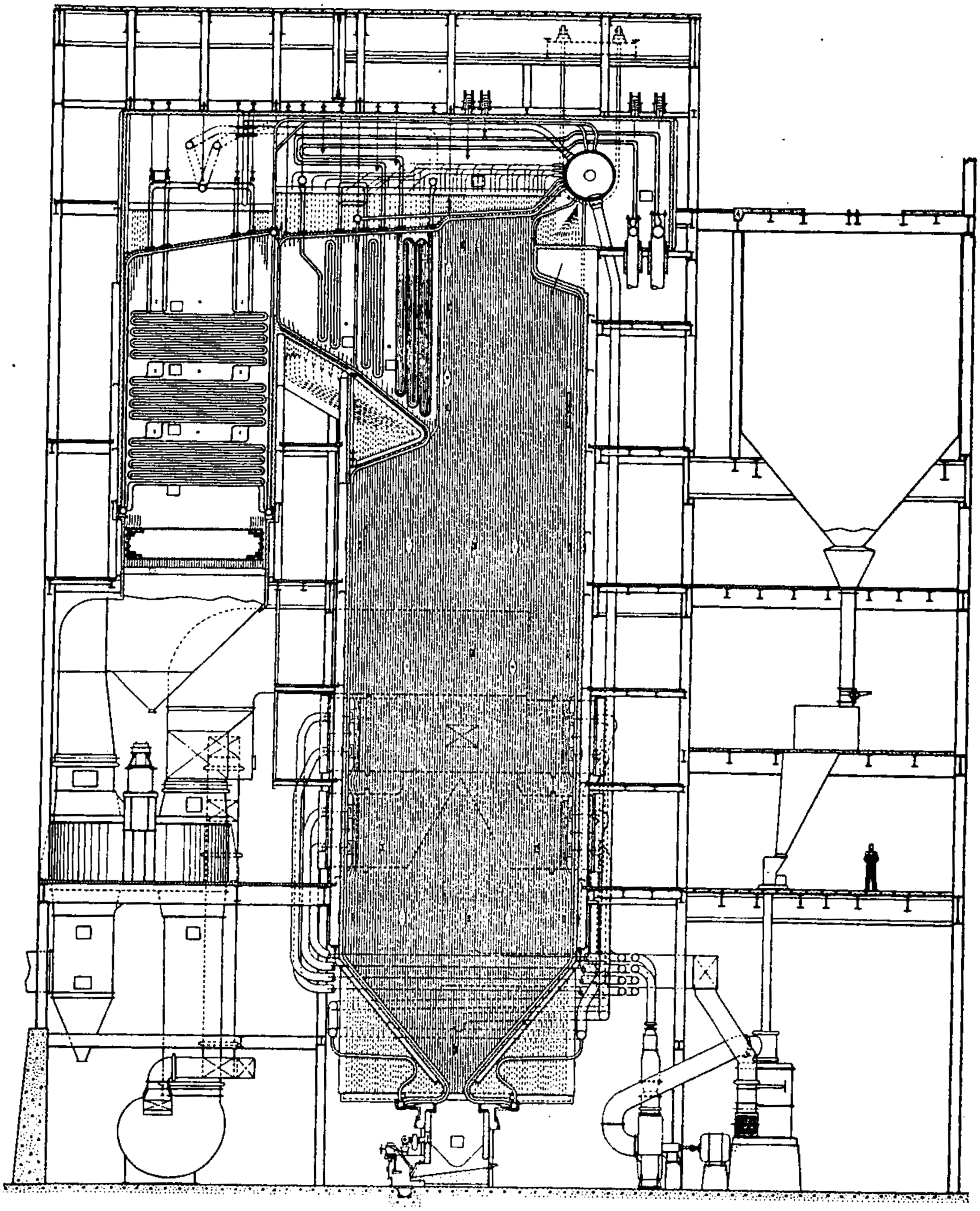


Table 3-9 contains a summary of the key operating and emission data for the 37 short-period test runs completed on this unit. Table 3-10 presents the average ppm NO_x emissions (3% O_2, dry basis) and % oxygen measurements for each test run according to the test program experimental design. The six operating variables (and experimental levels tested) included in the test program were:

1. Gross load (130 MW-full load), 95 MW and 55 MW)
2. Fuel fired (Alabama coal, Illinois coal, mixed fuel and natural gas)
3. Excess air level (normal and low)
4. Firing patterns (all coal levels firing with NO ports closed, 50% open and 100% open; top row coal off with NO ports closed and 50% open)
5. Burner tilt (horizontal, 20° up and 20° down)
6. Secondary air register setting (coal/auxiliary air at 30/100 and 100/50 % opening)

Full Load Test Data Results - Barry No. 2 Unit

Analysis of the NO_x emission data from the full load test block reveals several significant findings:

1. Full load, baseline operation (normal firing of all 16 burners, down or horizontal burner nozzle tilt and normal secondary air register settings) produced an average NO_x emission level of 341 ppm (3% O_2, dry basis) while firing 100% coal.
2. Staged firing using the special overfire air ports reduced NO_x emissions by 10 to 20% from baseline operation at equal excess air levels. 100% open overfire air ports produced lower NO_x emissions than 50% open operation.
3. Excess air level was the most significant single operating variable affecting NO_x emission levels. NO_x emissions were reduced through low excess air operation by 43% to 196 ppm under normal (S_1) firing operation, by 39% under staged firing operation, S_2 (50% open overfire air ports) and by 29% under staged firing operation S_3 (100% open overfire air ports). The solid regression lines on Figure 2 indicate the relationship between ppm NO_x and average % oxygen in the flue gas for these three firing patterns while firing 100% coal and operating with horizontal or down burner tilts and normal secondary air register settings.
4. Normal secondary air operation (30% open coal air and 100% open auxiliary air registers) produced an average of about 10% lower NO_x emissions than reversed secondary air operation (100% coal air and 50% open auxiliary air registers) when firing 100% coal.

Table 3-9

Summary of Operation and Emission Data - Barry, Boiler No. 2
(130 MW, Tangential Pulverized Coal Fired)

Date and Run No.	Boiler Operating Conditions									Average Gaseous Emissions		
			Firing Pattern									
				Burners				2nd Air Reg % Open				
	Gross Load (MW)	Excess Air Level	Mills Off	No. on Coal	No. on Air	OFA Ports % Open	Burner Tilt	Coal	Aux	Fuel Fired	% O_2	PPM NO_x (3% O_2 Dry)	Opacity (%)
2/12/75			*			**							
1	131	Normal	S_1-None	16	0	5	-17	30	100	Alab. Coal	4.92	365	--
2	130	Normal	S_2-None	16	0	50	-17	30	100	Alab. C	4.78	294	--
3	128	Normal	S_3-None	16	0	100	-17	30	100	Alab. C	4.69	265	--
4	129	Low	S_3-None	16	0	100	-17	30	100	Alab. C	3.82	189	55-60
5	129	Low	S_2-None	16	0	50	-17	30	100	Alab. C	3.54	182	50-70
6	126	Low	S_1-None	16	0	5	-17	30	100	Alab. C	3.14	196	55-70
2/13/75													
25	95	Normal	S_1-None	16	0	5	-2	30	100	Ill. C	7.29	452	50-60
7	93	Normal	S_2-None	16	0	50	-2	30	100	Ill. C	7.12	411	50-60
8	93	Low	S_2-None	16	0	50	-2	30	100	Ill. C	4.82	253	60-75
11	93	Normal	S_5-"A"	12	4	50	-2	30	100	Ill. C	6.81	272	60
12	95	Low	S_5-"A"	12	4	50	-2	30	100	Ill. C	4.31	192	60-70
9	94	Normal	S_4-"A"	12	4	5	-2	30	100	Ill. C	7.11	330	50-60
10	95	Low	S_4-"A"	12	4	5	-2	30	100	Ill. C	4.59	212	60-70
26	130	Normal	S1-None	16	0	5	-2	30	100	Ill. C	5.36	345	60-75
2/19/75													
21	130	Normal	S_1-"A"	12	0	5	-2	30	100	Kty. + .4Gas	3.94	168	60
22	128	Normal	S_2-"A"	12	0	50	-2	30	100	Kty. + .4G	4.65	184	55-70
23	132	Normal	S_3-"A"	12	0	100	+1	30	100	Kty. + .4G	4.94	182	55-65
24	130	Low	S_3-"A"	12	0	100	+1	30	100	Kty. + .4G	3.66	143	50-60
27	133	Normal	S_1-"C"	12	0	5	+1	30	100	Kty. + .4G	4.48	206	50-60
28	130	Normal	S_2-"C"	12	0	50	+1	30	100	Kty. + .4G	5.14	186	60
29	130	Low	S_3-"C"	12	0	100	+1	30	100	Kty. + .4G	5.03	184	60
30	128	Normal	S_3-"C"	12	0	100	+1	30	100	Kty. + .4G	4.91	190	60

* "A"-top mill through "D" bottom mill feeding the bottom row of burners.

** Overfire air "NO" ports are about 5% open for cooling when in a "closed" position.

Table 3-9 (Continued)

Date and Run No.	Boiler Operating Conditions										Average Gaseous Emissions		
	Gross Load (MW)	Excess Air Level	Firing Pattern				Burner Tilt	2nd Air Reg % Open		Fuel Fired	% O_2	PPM NO_x (3% O_2 Dry)	Opacity (%)
			Mills Off	Burners		OFA Ports % Open		Coal	Aux				
				No. on Coal	No. on Air								
2/20/75													
17	131	Low	S_1-None	16	0	5	+1	30	100	Kty. + 0.2G	4.94	218	70
18	128	Low	S_1-None	16	0	5	+1	30	100	Kty. + 0.2G	4.15	198	75
19	132	Low	S_2-None	16	0	50	+1	30	100	Kty. + 0.2G	4.75	212	70
20	134	Low	S_3-None	16	0	100	+1	30	100	Kty. + 0.2G	4.57	191	--
15	58	Normal	S_1-ABCD	0	0	5	+9	30	100	Gas	9.19	122	--
16	56	Low	S_1-ABCD	0	0	5	+6	30	100	Gas	7.32	97	--
13	54	Normal	S_1-A,B	8	0	5	+9	20	50	Kty. Coal	8.77	284	80-100
14	55	Low	S_1-A,B	8	0	5	+9	20	50	Kty. Coal	6.93	254	65-80
2/21/75													
31	133	Normal	S_1-None	16	0	5	+1	30	100	Kty. Coal	4.26	314	--
32	131	Normal	S_1-None	16	0	5	+20	30	100	Kty. Coal	4.00	320	--
33	135	Normal	S_1-None	16	0	5	-20	30	100	Kty. Coal	3.88	273	--
34	134	Normal	S_1-None	16	0	5	0	100	50	Kty. Coal	3.80	299	--
35	132	Low	S_2-None	16	0	50	0	100	50	Kty. Coal	4.03	233	55-70
37	128	Low	S_2-None	16	0	50	-20	100	50	Kty. Coal	3.96	218	--
36	130	Low	S_2-None	16	0	50	+20	100	50	Kty. Coal	4.12	274	--
38	126	Normal	S_2-None	16	0	50	0	30	100	Kty. Coal	4.68	243	--

* Mills are designated "A" for the mill feeding the top row of burners thru "D", the mill feeding the bottom row of burners.

** Overfire air "NO" ports are about 5% open for cooling, when in a "closed" position.

Table 3-10

Test Program Experimental Design - Barry No. 2 Unit

(Run No., Average % O_2 and Average PPM NO_x-3% O_2, Dry Basis)

			L_1-Full Load-130 MW								L_2-95 MW		L_3-55 MW			
			F_1-Coal-Alabama		F_2-Coal-Illinois		F_3-.8 Coal 0.2 Gas		F_4-.6 Coal 0.4 Gas		F_2-Coal-Illinois		F_2-Coal-Kentucky		F_5-Nat'l. Gas	
		% Open	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low
S_1-Normal Firing: NO Ports Closed, 16 Burners Firing Coal	T_1-Hor. Burner Tilt	D_1-30Coal 100% Aux			㉖5.4% 345 ㉛4.3% 314		㉗4.5% 206		㉑3.9% 168		㉕7.3% 452		⑬8.8% 284	⑭6.9% 254	⑮9.2% 122	⑯7.3% 97
		D_2-100Coal 50 Aux				㉞3.8% 299										
	T_2-+20°	D_1-30Coal 100 Aux			㉜4.0% 320											
	T_3-20°	D_1-30Coal 100 Aux	①4.9% 365	⑥3.1% 196	㉝3.9% 273											
S_2-NO P. 1/2 Open 16-Coal	T_1-Hor.	D_1-30Coal 100Aux	②4.8% 294 *	⑤3.5% 182 *			㉘5.1% 186		㉒4.6% 184		⑦7.1% 411	⑧4.8% 253				
S_3-NO Ports 100% Open 16 Burners Firing Coal	T_1-Hor.	D_1-30Coal 100 Aux			㊳4.7 243		㉙5.0% 184	㉚4.9% 182	㉓4.9% 182	㉔3.7% 143						
		D_1-100Coal 50 Aux				㉟4.0% 233										
	T_2-+20°	D_2-100Coal 50 Aux				㊱4.1% 274										
	T_3--20°	D_1-30Coal 100 Aux	③4.7% 265	④3.8% 189		㊲4.0% 218 **										
S_4-Top Row Air 12 Burn.-Coal	T_1-Hor.	D_1-30Coal 100 Aux									⑨7.1% 330	⑩4.6% 212				
S_5-NO 1/2 Open Top Row Air 12 Burn.-Coal	T_1-Hor.	D_1-30Coal 100 Aux									⑪6.8% 272	⑫4.3% 192				

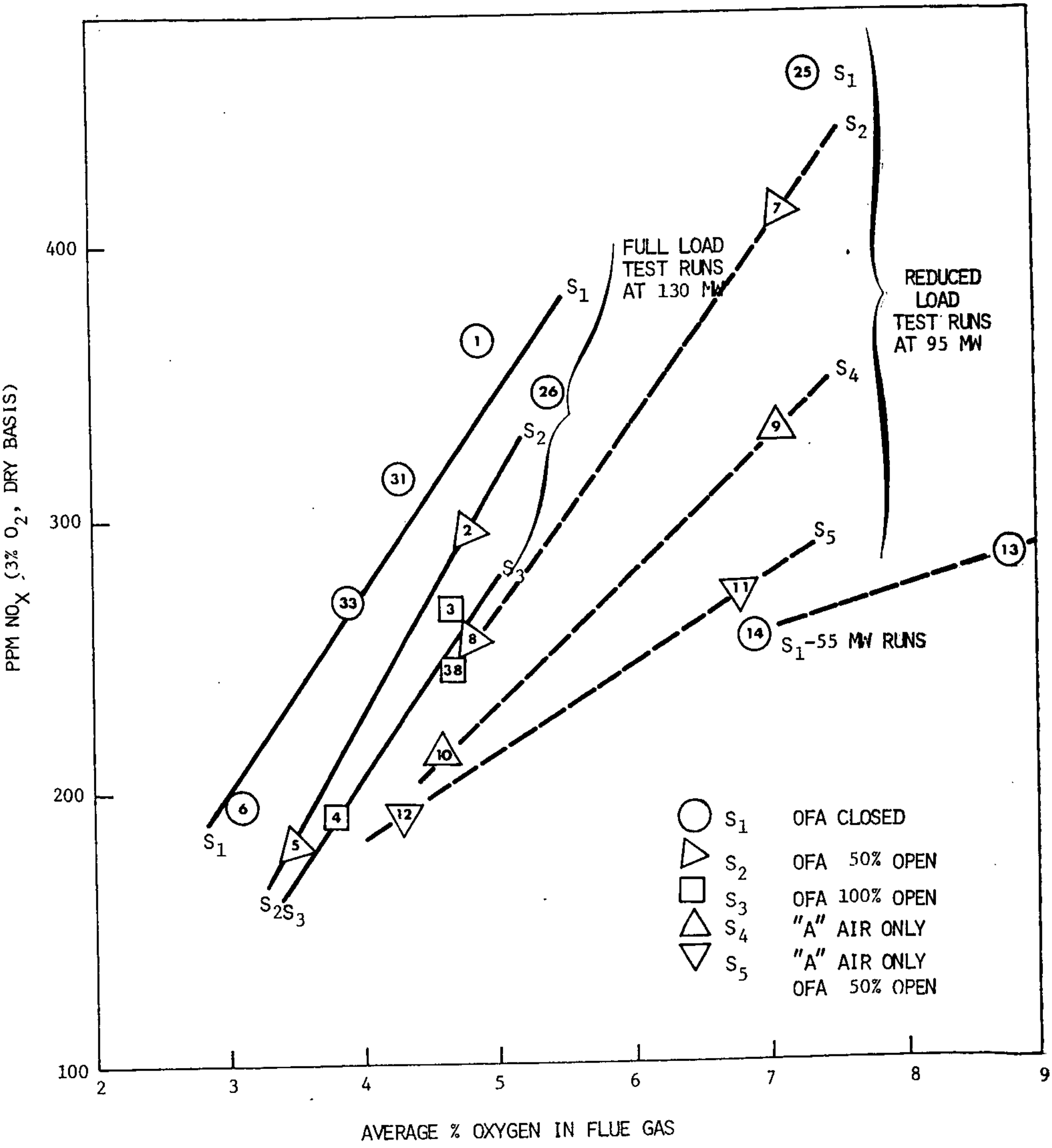
* Test runs 2 and 5: burner tilt -20°

** Test run 37: D_2 100 coal and 50 auxiliary air damper settings

FIGURE 3-14

PPM NO_X (3% O_2, DRY) VS % O_2 IN FLUE GAS

(100% COAL FIRED TEST RUNS - BARRY NO. 2 UNIT)



5. Burner nozzle tilt over the range of -20° to horizontal produced no consistent change in NO_x emission levels. However, raising burner nozzle tilts to +20° resulted in significantly higher NO_x emission levels. This effect can be explained by the fact that the overfire air directional dampers were fired at -11° and thus the effectiveness of staged combustion was reduced with raised burner tilts due to reduced separation of overfire air from the main combustion mixture.

6. Mixed fuel firing at full load reduced NOx emissions significantly. Figure 3-15 is a plot of ppm NO_x (3% O_2, dry) vs % coal in fuel for comparable full load test runs under normal firing, S1, and staged firing (S2 and S3) operations. Firing with 80% of the heat release from coal firing reduced NOx emissions by an average of 30% while firing with 60% coal resulted in an average of 32% NO_x reduction from 100% coal firing over the three firing patterns. Thus, within the range of full load, mixed fuel firing capability of this boiler, the data indicates that replacing coal with gas fuel lowers NO_x in the direction of full gas firing but the relationship is not linear. As discussed below at reduced load (55 MW), firing with 100% gas, reduced NO_x emissions from 269 to 110 ppm (60%) compared to 100% coal firing. A comparable linear relationship at full load would thus be a 12% reduction in NO_x emissions when firing 80% coal-20% mixture and a 24% reduction when firing a mixture of 60% coal-40% gas.

Reduced Load Tests

Earlier, we discussed the necessity for conducting two test program blocks at reduced load. The first block (comprising 7 100% coal fired test runs) was conducted in order to obtain information on the NO_x emission reduction effectiveness of staged combustion using overfire air ducts compared to modified staged combustion operation where the top tier of burners are on air only. Since the maximum capacity of the boiler with the top mill inactive is 95 MW, all of these runs were made at this load for comparative reasons. The second block (4 test runs) was conducted at the maximum load capacity of this boiler (55 MW) when firing with gas alone.

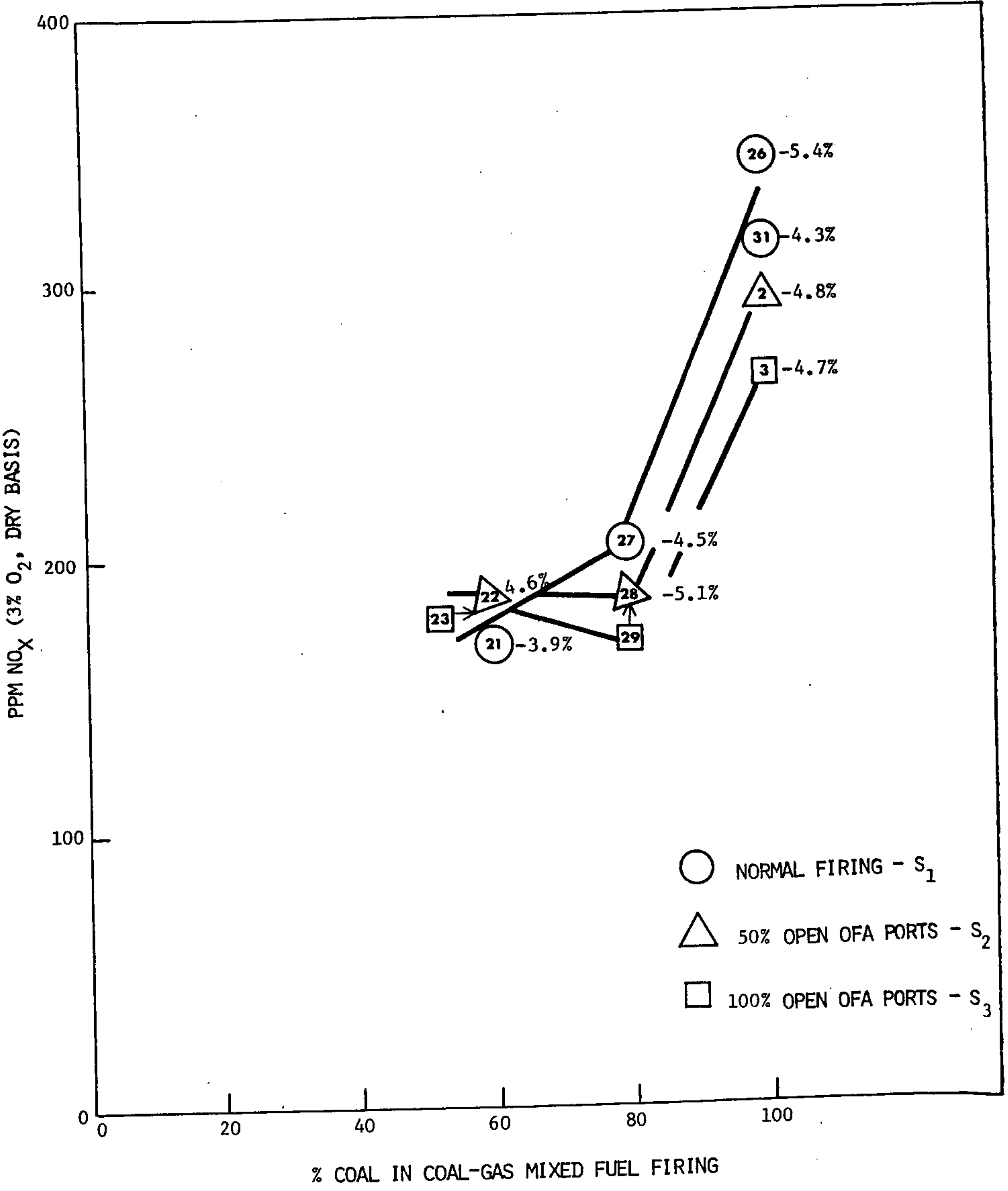
Reduced load test runs at 95 MW were conducted under normal, all burners firing operation and at three different staged firing operations: S_2, overfire air port dampers set at 50% open and all four levels of burners firing; S_4, overfire air port dampers closed (cooling air only) with top tier of burners on air only; and S_5, overfire air dampers 50% open and top tier of burners on air only.

The dashed lines on Figure 3-14, labeled S_2, S_4 and S_5 join the normal excess air and low excess air NO_x emission data points for each of these staged firing operations for visual comparison with the full load test results discussed above. These results cam be summarized as follows:

FIGURE 3-15

PPM NO_X (3% O_2, DRY) VS % COAL IN COAL-GAS MIXED FUEL FIRING

(BARRY NO. 2 UNIT-FULL LOAD TEST RUNS)



1. Baseline NO_x emissions were 452 ppm at the higher excess level required under reduced load operation.

2. Low excess air operation reduced NO_x emissions sharply in all three staged firing configurations compared to normal excess air levels as shown by the dashed lines in Figure 3-14.

3. As expected all three staged firing operations resulted in significantly lowered NO_x emission levels with the combined use of overfire air and top row of burners on air only producing the best results. Compared to the 95 MW, baseline NO_x emission level of 452 ppm, low excess air, S_2 operation (overfire air ports ½ open) reduced NO_x emissions by 44% (to 253 ppm); low excess air, S_4 (top burners on air only) operation reduced NO_x emissions by 53% (to 212 ppm) and low excess air, S_5 operation (50% open overfire air ports plus top row of burners on air only) reduced NO_x emissions by 58% to 192 ppm.

The second set of reduced load test runs (numbered 13 through 16) were designed to supply information on 100% gaseous fuel firing compared to 100% coal firing under both normal and low excess air operation. Under normal operation at 55 MW load, coal was fired through the bottom two rows of burners with relatively high excess air levels. Baseline NO_x emissions of 284 ppm were reduced to 254 ppm with low excess air operation. 100% gas firing operation produced 122 ppm NO_x under normal excess air levels and 97 ppm when using low excess air operation. Thus, at this low load, gas firing resulted in a 57% NO_x emission reduction under normal air operation and a 62% NO_x emission reduction under low excess air operation compared to 100% coal firing.

3.1.6 Morgantown, Boiler No. 1 (Potomac Electric Power Company)

Potomac Electric Power Company's, Boiler No. 1 at Morgantown, Md. was the fourth boiler to be tested in our current field test program. This boiler was selected, with the assistance of Combustion Engineering Company, because it represents modern design practices and has the capability of firing oil, pulverized coal or mixtures of the two fuels.

Morgantown Boiler No. 1 is a 575 MW, Combustion Engineering, tangentially fired, twin furnace boiler. Five pulverizers feed 40 burners arranged at 5 levels (A feeding top 8 burners to E feeding the bottom 8 burners). 32 oil burners are positioned at the four levels (8 per level) between the five pulverized coal burner levels, i.e., between A and B, B and C, C and D and D and E. The furnace has a volume of 292,600 cubic feet, a width of 63.15 feet and a length of 34.45 feet. Full load steam rate is 4,250,000 pounds/hour at 1005°F superheat temperature and 3810 PSIG pressure.

Table 3-11 contains a summary of the operating and emission data from the 27 test runs completed on the boiler. Table 3-12 presents these results arranged according to the test program experimental design. The five operating variables (and experimental levels) included in the test program were:

1. Gross load (full load - 575 MW, and reduced load - 300 MW)
2. Excess air level (normal, low and high)
3. Fuel mixture fired (100% coal to 100% oil)
4. Burner tilt (horizontal, +15°, -15°)
5. Firing pattern (normal firing - S_1, and staged firing - S_2)

Flue gas measurements of average % O_2 and ppm NO_x (3% O_2, dry) are included in Table 3-11 as well as the calculated % stoichiometric air to the active burners. The flue gas sampling system consisted of four probes, each containing short, medium and long sampling tubes positioned at the centers of 12 equal areas in the ducts between the economizer and the air heaters. Composite gas samples from each probe were analyzed and recorded in turn over four complete cycles, resulting in 16 measurements of each gaseous component in each test run.

Three figures have been constructed using identical coordinate scales to aid in visual analysis of the data. Figure 3-16 is a plot of ppm NO_x (3% O_2, dry basis) vs % coal (heat release basis) in the coal-oil mixed fuel firing for test runs conducted at full load under normal firing conditions (no overfire air). Figure 3-17 is a plot of test runs conducted under full load, staged firing (air only at top pulverized coal burner level) operation. Figure 3-18 is a plot of test runs conducted at reduced load (about 300 MW) under both normal and staged firing operation. The

TABLE 3-11

SUMMARY OF OPERATING AND EMISSION DATA - MORGANTOWN STATION, BOILER NO. 1

(575 MW, Pulverized Coal and/or Oil Tangentially Fired)

	Operating Conditions								Flue Gas Measurements		
					Firing Pattern(1)						
						Mills on:					
Date and Run No.	Gross Load (MW)	Excess Air Level	Fuel Fired - % Coal/% Oil	Burner Tilt		Coal	Air	No. of Oil Burners	% O_2	PPM NO_x (3% O_2)	% Stoich. Air to Active Burners(2)
3/14- 1	576	Nor.	22/78	-2°	S_1	A,C	None	21	4.4	458	125
2	576	Low	22/78	-2°	S_1	A,C	None	21	2.1	386	110
3	576	Nor.	22/78	0°	S_2	C,E	A	21	4.6	375	102
4	575	Low	22/78	0°	S_2	C,E	A	21	3.3	310	94
5	576	Low	22/78	+13°	S_2	C,E	A	21	3.4	334	94
6	584	Low	22/78	-12°	S_2	C,E	A	21	3.1	314	94
3/18- 7	576	Nor.	45/55	0°	S_1	A,B,C,D	None	18	4.5	525	126
8	576	Nor.	45/55	+15°	S_1	A,B,C,D	None	18	4.7	553	128
9	576	Nor.	45/55	-15°	S_1	A,B,C,D	None	18	4.7	568	128
3/19-7A	576	Nor.	49/51	0°	S_1	A,B,C,D	None	17	4.7	577	128
10	576	Low	49/51	0°	S_1	A,B,C,D	None	17	2.8	502	115
11	576	Nor.	49/51	0°	S_2	B,C,D,E	A	17	4.5	465	101
12	576	Low	49/51	+1°	S_2	B,C,D,E	A	16	3.1	423	94
3/20-13	578	Nor.	73/27	+1°	S_1	A,B,C,D,E	None	10	4.4	593	125
3/21-14	572	Low	72/28	+2°	S_1	A,B,C,D,E	None	10	3.4	511	119
15	572	Nor.	74/26	+2°	S_2	B,C,D,E	A	10	4.7	403	102
17	570	Nor.	93/7	+2°	S_1	A,B,C,D,E	None	2	4.9	552	129
18	572	Low	93/7	+2°	S_1	A,B,C,D,E	None	2	3.8	549	121
3/25-19	303	Low	0/100	0°	S_2	None	A	16	5.1	165	105
20	300	High	0/100	0°	S_2	None	A	16	4.2	149	99
21	300	High	20/80	0°	S_2	B	A	14	5.4	246	107
22	306	High	50/50	0°	S_2	B,C	A	8	5.4	300	107
25	301	High	100/0	0°	S_1	A,B,C,D	None	0	6.5	544	144
26	314	Low	100/0	0°	S_1	A,B,C,D	None	0	6.3	515	142
3/26-21A	298	Nor.	5/95	0°	S_1	A	None	16	5.9	247	138
22A	300	Nor.	43/57	0°	S_1	A,D,E	None	8	6.9	408	148
24	300	Nor.	62/38	0°	S_1	A,D,E	None	6	6.8	460	147

(1) Firing Pattern: S_1 - Normal Firing, S_2 - Overfire Air Staged Firing; 5 Mills (A at top three E on bottom).
(2) Based on simplifying assumption that air flows to each burner are equal.

TABLE 3-12

TEST PROGRAM EXPERIMENTAL DESIGN - MORGANTOWN BOILER NO. 1

(Run No., Average % O_2 and Average PPM NO_x - 3% O_2, Dry Basis)

			L_1 - Full Load (575 MW)				L_2 - Reduced Load (300 MW)				
			F_1 - 93% C 7% O *	F_2 - 73% C 27% O	F_3 - 45% C 55% O	F_4 - 22% C 78% O	F_1 - 100% C 0% O	F_2 - 63% C 37% O	F_3 - 50% C 50% O	F_4 - 20% C 80% O	F_5 - 0% C 100% O
S_1 - Normal Firing Pattern	A_1 - Normal Excess Air	T_1 - Hor. Tilt	⑰ 4.9% 552	⑬ 4.4% 593	⑦ 4.5% 525	① 4.4% 458	㉕ 6.5% 544	㉔ 6.8% 460	(22A) 6.9% 408		(21A) 5.9% 247
		T_2 - +15° Tilt			⑧ 4.7% 553						
		T_3 - -15° Tilt			⑨ 4.7% 568						
	A_2 - Low Air	T_1 - Hor. Tilt	⑱ 3.8% 549	⑭ 3.4% 511	⑩ 2.8% 502	② 2.1% 386	㉖ 6.3% 515				
S_2 - Staged Firing	A_1 - Nor. Air	T_1 - Hor. Tilt		⑮ 4.7% 403	⑪ 4.5% 465	③ 4.6% 375			㉒ 5.4% 300		⑲ 5.1% 165
	A_2 - Low Excess Air	T_1 - Hor. Tilt			⑫ 3.1% 423	④ 3.3% 310					⑳ 4.2% 149
		T_2 - +15° Tilt				⑤ 3.4% 334					
		T_3 - -15° Tilt				⑥ 3.1% 314					

* Fuel fired - % coal and % oil on heat release basis.

Figure 3-16

PPM NO_x vs % Coal in Coal/Oil Mixed Fuel Firing

(Full Load, Normal Firing Pattern)

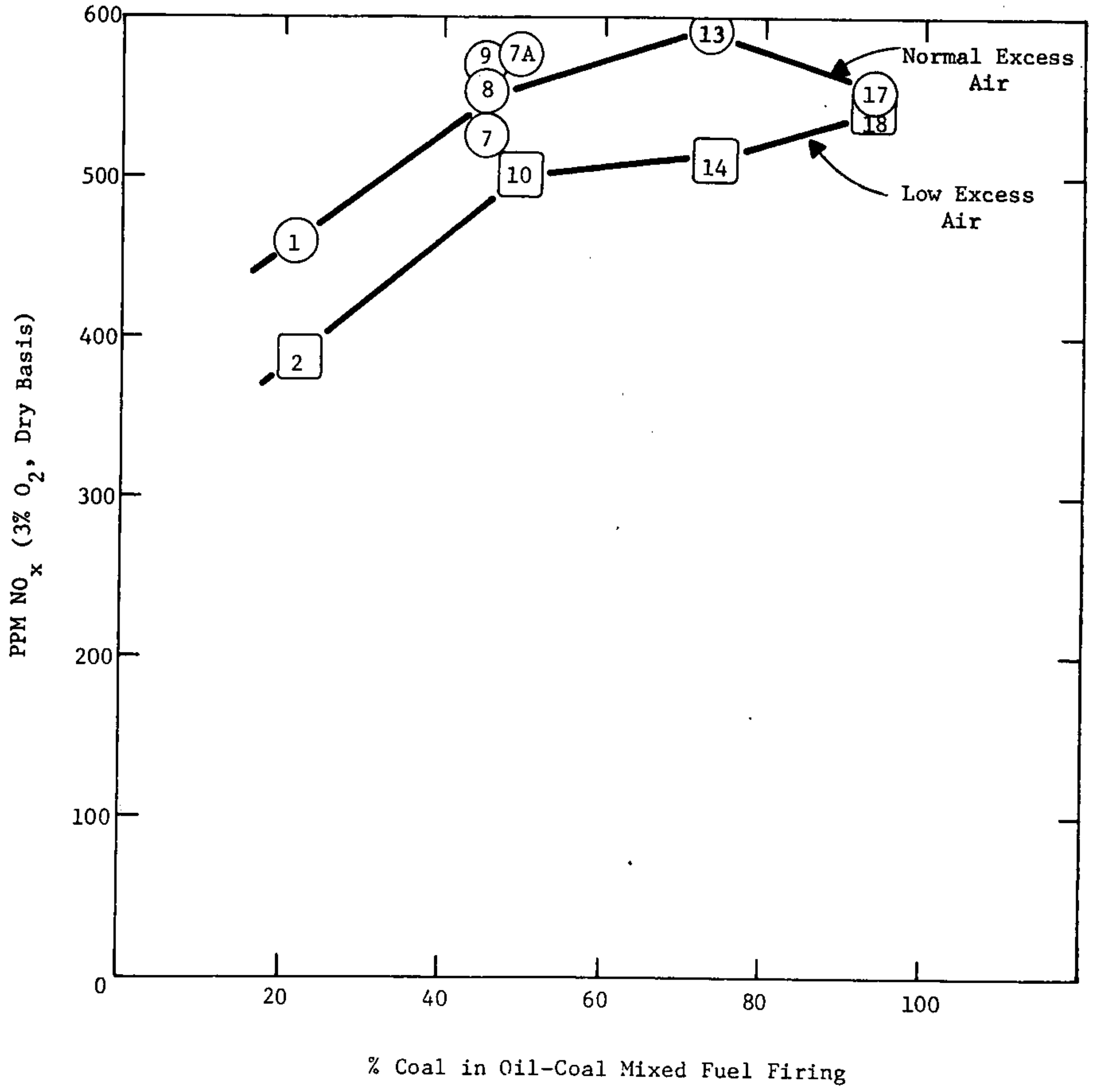


Figure 3-17

PPM NO_x vs % Coal in Coal/Oil Mixed Fuel Firing

(Full Load, Staged Firing Pattern)

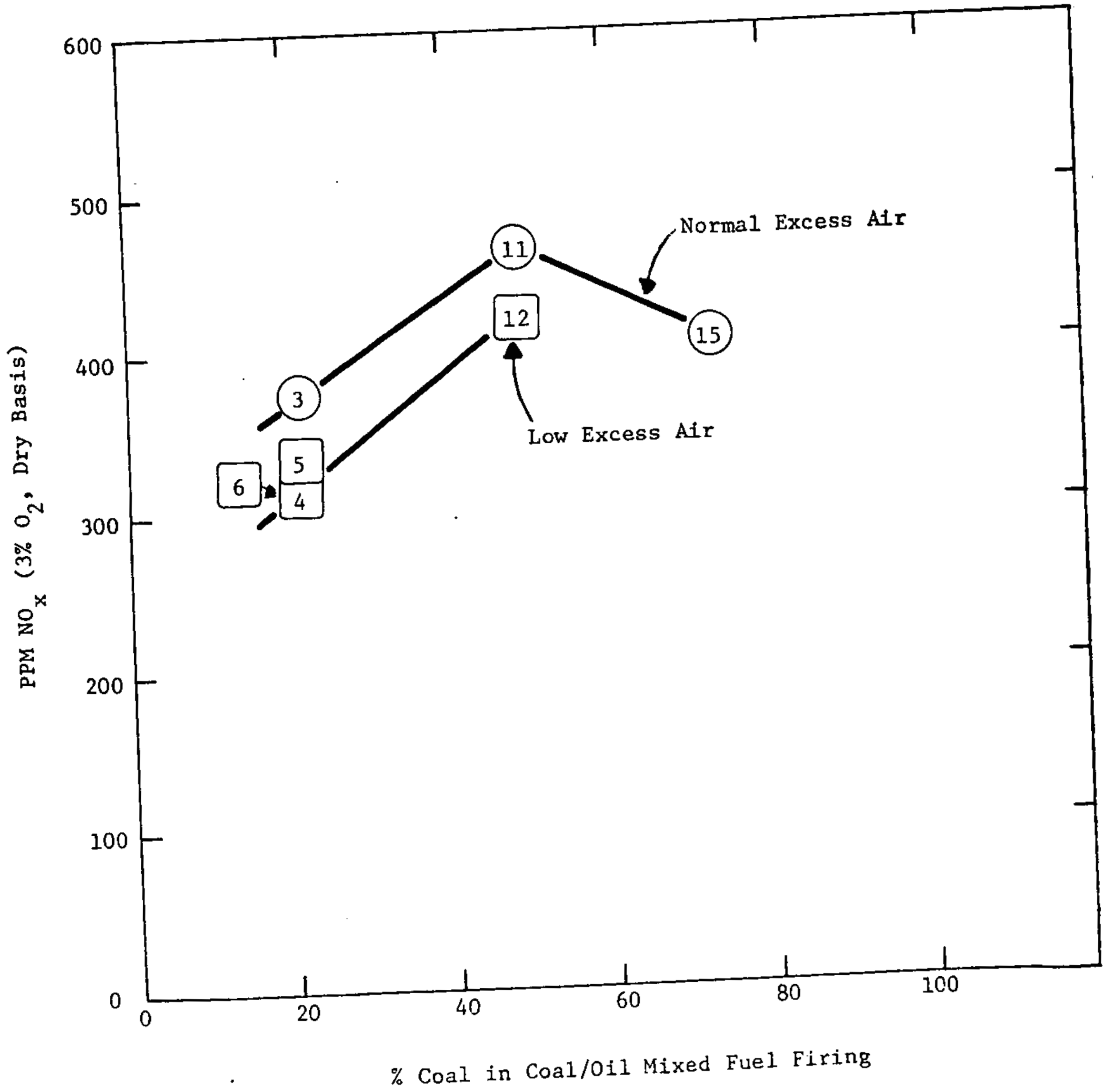
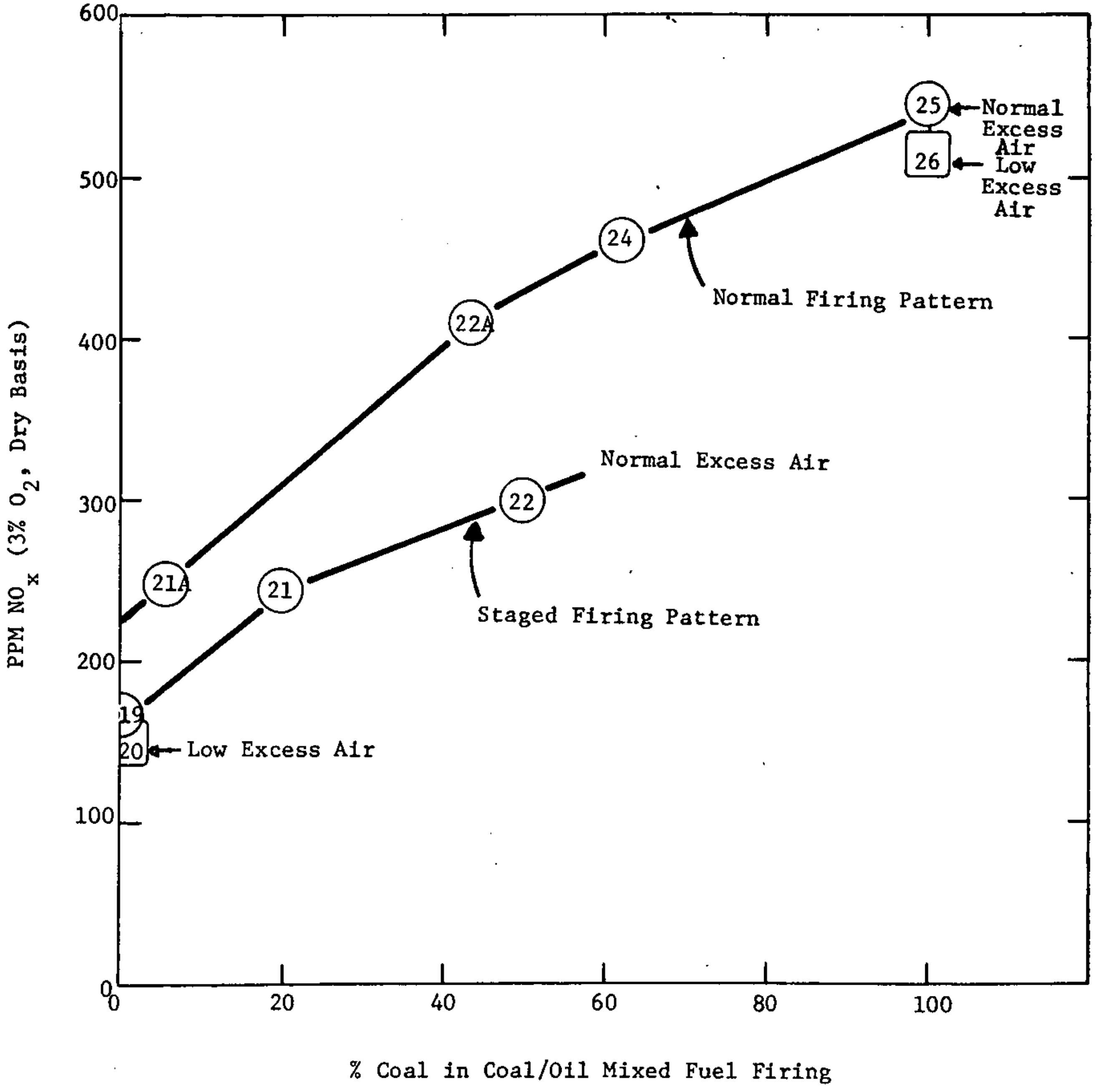


Figure 3-18

PPM NO_x vs % Coal in Coal/Oil Mixed Fuel Firing

(Reduced Load - Normal and Staged Firing)



numbers shown within circles (normal excess air operation) or squares (low excess air operation) indicate test run identification numbers. The conclusions reached from analysis of the data are summarized in the following paragraphs.

Low excess air operation (established by the maximum level of CO emissions (200 ppm) from any single probe) consistently reduced NO_x emissions compared to normal excess air operation. Under full load (575 MW) operation the average reduction in NO_x emissions was 10% under normal firing operation and 18% under staged firing operation. At reduced load (300 MW), reductions of 5 and 10% were experienced under normal firing and staged firing, respectfully. Lines have been drawn through the normal excess air and low excess air test run data on Figures 3-16 and 3-17 to facilitate this comparison.

Staged firing operation (top mill burners on air only) produced substantially lower NO_x emission levels than normal firing operation (top mill burners firing coal) under both full load and reduced load operation over a wide range of mixed fuels. Reductions of 18%, 19% and 32% were experienced at full load when firing with mixed fuels containing 22% coal, 49% coal and 73% coal, respectively, under normal excess air, staged firing operation compared to normal excess air, normal firing operation. The combination of low excess air and staged firing resulted in further improvements. At reduced load (300 MW), NO_x emission reductions of 26 to 40% were obtained through staged firing operation compared to normal firing operation.

Changing coal burner nozzle tilts had a minor effect on NO_x emissions when firing mixed fuels since the oil burners were fired in a horizontal position. Horizontal burner tilts resulted in about 6% lower NO_x emissions than 15° up or down tilting burners.

Reduced load operation (300 vs 575 MW) resulted in lowered NO_x emissions. However, the size of the reduction was highly dependent upon the amount of oil in the coal-oil mixture fired. While firing mostly coal (93% at full load and 100% at reduced load), NO_x emissions were reduced an average of only 4%. However, reducing load while firing 22 to 55% oil in oil/coal mixtures, reduced NO_x emissions by 26% under normal firing and 35% under staged firing.

NO_x emission levels generally increased with increased % coal in mixed fuel firing. Figure 3-18 shows this trend over almost the full range of fuel mixtures under normal firing operation at reduced load. A straight line through the NO_x data point from test run 25 (100% coal firing) and the NO_x data points for test run 21A (5% coal firing) does not pass through the NO_x data points for intermediate mixtures of coal-oil fuel. Thus, test run 22A (43% coal - 57% oil fired) emitted 13% higher NO_x emissions and test run 24 (62% coal - 38% oil fired) produced 9% higher NO_x emission than would be expected from a linear relationship calculated from 100% coal and 100% oil firing. Figure 3-16 shows a pronounced variation from a linear relationship for mixed fuel firing over the range from 22% coal to 93% coal. Increasing the percentage coal in the coal-oil mixture from 22% to 45 or 49% resulted in significantly increased NO_x emission rates (over 100 ppm) but little change in NO_x emission rates occurred with further increases in the % coal fired. Unfortunately, during the test period, this boiler had limited fuel burning capability, and therefore, full load test runs on 100% coal or 100% oil could not be run. Only 21 of the 32 oil burners were operational due to mechanical problems, and therefore, 22% of the heat release had to be supplied from coal. At the same time, coal supplies were short and some coal handling equipment could not be operated. Consequently, operating management limited the length of time that high coal mixtures could be burned as well as the maximum coal content of the mixed fuel.

In summary, we have found that most of the operating variables included in the experimental program had significant effects on NO_x emission levels. Low excess air operation reduced NO_x emissions by about 10% for a wide range of oil-fuel mixtures at full and reduced load. Staged firing operation resulted in 20 to 30% NO_x emission reductions over a wide range of coal/oil fuel mixtures. Combined low excess air and staged firing operation reduced NO_x by 30 to 40%. Tilting burners over the range of +15° to -15° produced minor changes in NO_x levels with horizontal levels producing the lowest NO_x emission levels. Increasing the proportion of coal in simultaneous oil/coal firing increased NO_x emission levels non-linearly under both normal and staged firing operation. The NO_x emission level increase was higher in changing from 0% to 50% coal, than the NO_x emission increase when changing from 50% to 100% coal fuel. It is possible that such behavior is exhibited because of the relative contributions of thermal NO_x and fuel NO_x to the total emissions.

3.1.7 Morgantown, G.E. No. 3 Gas Turbine (Potomac Electric Company)

Potomac Electric Company's G.E. Gas Turbine No. 3 is the first gas turbine to be tested in our current field test program. This General Electric model MS 7001 B Gas Turbine is of modern design and has a maximum continuous rating of 50 MW and a peak output of 54 MW. It fires No. 2 distillate oil and is not equipped for water injection.

Flue gas samples were taken from the centers of four equal rectangular areas from each of two stacks and from the centers of each of the stacks in order that possible stratification could be measured and to obtain representative flue gas samples. 12 to 18 measurements were recorded during the 15 to 20 minute duration of each test run.

TABLE 3-13

SUMMARY OF OPERATING AND EMISSION DATA - MORGANTOWN STATION, G.E. GAS TURBINE NO. 3

Date and Run No.	Operating Conditions			Flue Gas Measurements		
	Gross Load (MW)	Fuel Flow (GPM)	Exhaust Temp. (°F)	% O_2	PPM NO_x (Dry Basis)	
					15% O_2	3% O_2
4/1/75						
1	10	33	621	17.9	82	247
2	25	47	640	17.3	108	322
3	48	74	905	15.2	125	376
4	54	81	980	14.7	133	398

Table 3-13 contains a summary of the major operating and emission data obtained from this test program. Figure 3-19 presents the PPM NO_x (dry basis) vs Gross Load (MW) data on both a 3% and a 15% O_2 correction basis. As expected, the NO_x emission level increases with load, but not very sharply up to the peak load of 54 MW.

Measured gaseous concentration stratification was very low from the stacks of this gas turbine. For example, the maximum variation in the 18% oxygen measurements in run number 1 was 17.8 to 18.0%. The major causes of low stratification was the high velocity of the flue gas through the long path of ductwork (about 130 feet) in the switchback silencer and the location of the sample tubes four diameters from the nearest upstream disturbance.

intermediate mixtures of coal-oil fuel. Thus, test run 22A (43% coal - 57% oil fired) emitted 13% higher NO_x emissions and test run 24 (62% coal - 38% oil fired) produced 9% higher NO_x emission than would be expected from a linear relationship calculated from 100% coal and 100% oil firing. Figure 3-16 shows a pronounced variation from a linear relationship for mixed fuel firing over the range from 22% coal to 93% coal. Increasing the percentage coal in the coal-oil mixture from 22% to 45 or 49% resulted in significantly increased NO_x emission rates (over 100 ppm) but little change in NO_x emission rates occurred with further increases in the % coal fired. Unfortunately, during the test period, this boiler had limited fuel burning capability, and therefore, full load test runs on 100% coal or 100% oil could not be run. Only 21 of the 32 oil burners were operational due to mechanical problems, and therefore, 22% of the heat release had to be supplied from coal. At the same time, coal supplies were short and some coal handling equipment could not be operated. Consequently, operating management limited the length of time that high coal mixtures could be burned as well as the maximum coal content of the mixed fuel.

In summary, we have found that most of the operating variables included in the experimental program had significant effects on NO_x emission levels. Low excess air operation reduced NO_x emissions by about 10% for a wide range of oil-fuel mixtures at full and reduced load. Staged firing operation resulted in 20 to 30% NO_x emission reductions over a wide range of coal/oil fuel mixtures. Combined low excess air and staged firing operation reduced NO_x by 30 to 40%. Tilting burners over the range of +15° to -15° produced minor changes in NO_x levels with horizontal levels producing the lowest NO_x emission levels. Increasing the proportion of coal in simultaneous oil/coal firing increased NO_x emission levels non-linearly under both normal and staged firing operation. The NO_x emission level increase was higher in changing from 0% to 50% coal, than the NO_x emission increase when changing from 50% to 100% coal fuel. It is possible that such behavior is exhibited because of the relative contributions of thermal NO_x and fuel NO_x to the total emissions.

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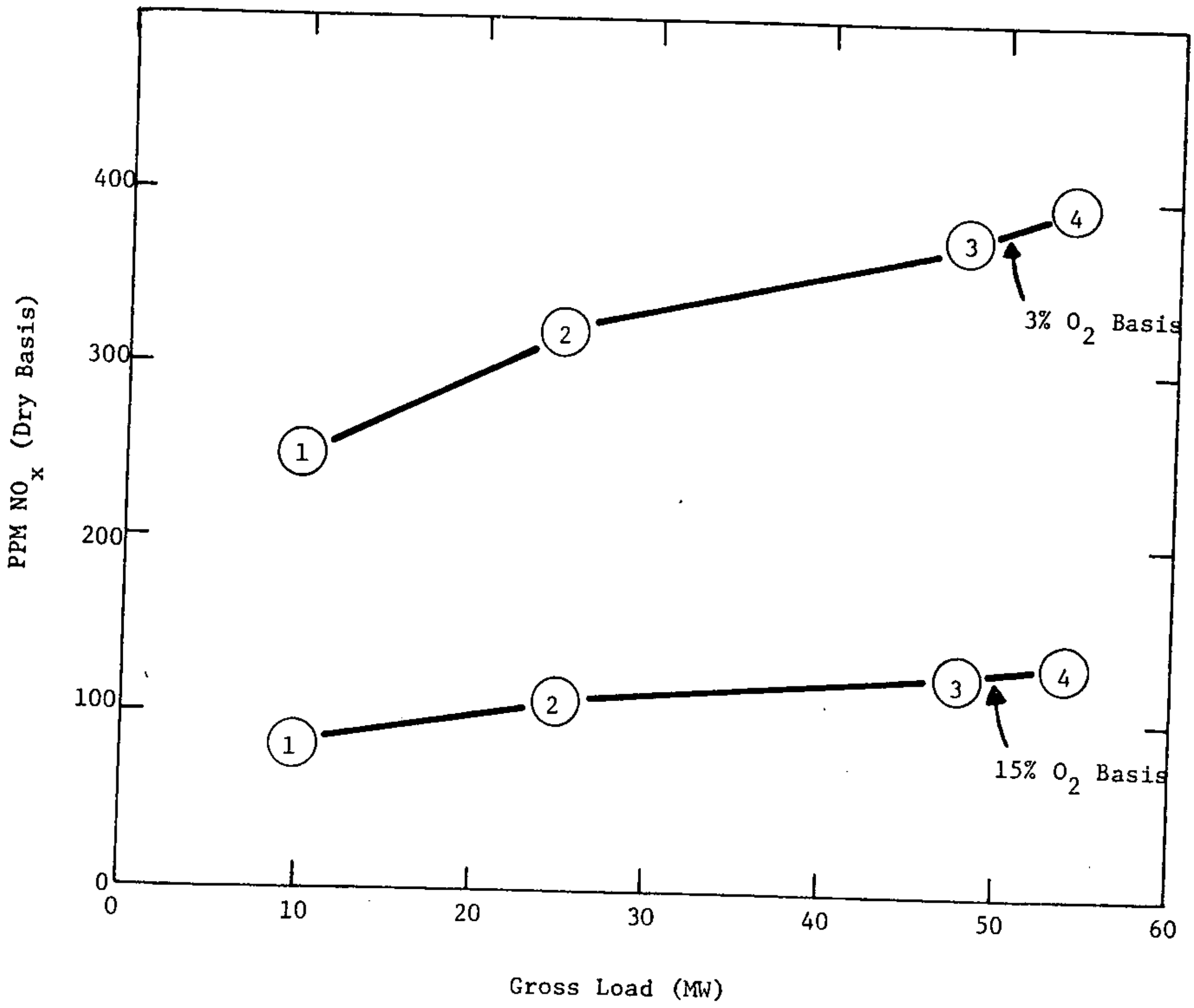
Figure 3-19

PPM NO_x (3% and 15% O_2, Dry Basis) vs Gross Load (MW)

(Morgantown No. 3 Gas Turbine)



3.2 Particulate Emission Results

As mentioned in section 2.5, the manner in which the combustion process occurs using known modifications to limit "NO_x" emissions has a very real tendency to increase burnout problems. Potentially, burnout problems could adversely affect particulate emissions which, as a consequence, could decrease precipitator collection efficiency. Marginal boiler installations as a result, therefore, might find it difficult to comply with existing Federal or State particulate emission regulations under "low NO_x" operating conditions. Accordingly, the objective of this investigation was to obtain sufficient data to afford a comparison of the effects of "low NO_x" firing techniques on particulate emissions by comparing measurements of total quantities, percent unburned carbon, and particle size distribution with similar data obtained under baseline operation. Particulate emission test results obtained in this program are summarized in Tables 3-14, 3-15, 3-16 and 3-17. The data appear to be reliable and consistent within the accuracy of this type of testing. An assessment of any adverse side effects of "low NO_x" operation is possible by a comparison of the differences in emission values tabulated in the above tables between baseline and "low NO_x" operation.

In our previous field study (2), some "side effects" were noted with "low NO_x" firing in that total quantities of particulate tended to increase but the increases did not appear to be significant and the effects, if any, appeared to be minor. Results obtained in the current program, as exhibited in Table 3-14, showed a similar tendency for particulate loading to increase on two boilers but, interestingly, the other two boilers tested exhibited a decrease in dust loading under low NO_x operation. Again, however, the differences are relatively minor and probably of little consequence. An increase in total particulates would tend to have an adverse effect on electrostatic precipitator efficiency in meeting Federal or State emission standards. Conversely, decreases would make it easier to meet standards.

Carbon loss or unburned combustibles is another potential side effect of "low NO_x" operation. As indicated in section 2.5, this could be the result of the tendency toward incomplete combustion or burnout problems. Any increase in unburned carbon as a consequence of "low NO_x" combustion modifications affecting the complete utilization of the fuel fired, obviously, would have a corresponding decreasing effect on boiler efficiency. An assessment of the magnitude of this potential "side effect" is provided from the data tabulated in Table 3-14 by comparing the percent carbon on the particulate between baseline and low NO_x operation. Referring to Table A, it may be noted that the carbon content of the particulate, in most cases, decreased under "low NO_x" operating conditions. This differs from the findings in

TABLE 3-14

PARTICULATE EMISSION TEST RESULTS

Utility	Test No.	Firing Condition	Av. Gr/SCF @ Std. Cond.	lb./10^6 BTU	Grams/ 10^6 cal.	Reqd. Efficiency to Meet 0.1 lb./ 10^6 BTU	% Carbon on Particulate	Coal Ash Wet, %	HHV BTU/lb. Wet
TVA	1B	Base**	4.46	5.32	9.58	98.12	13.04	14.64	11,281
	1C	Base**	4.45	5.33	9.59	98.12	9.11	18.27	10,258
	12C	Low NO_x	3.80	4.56	8.21	97.81	6.21	12.30	10,622
	12D	Low NO_x	3.55	4.26	7.67	97.65	8.08	12.30	10,622
So. Elec. Gen. Co.	28A	Base	4.93	6.18	11.12	98.38	2.69	15.00	11,690
	28B	Base	4.55	5.70	10.26	98.25	1.09	15.00	11,690
	29	Base	3.80	4.72	8.50	97.88	1.69	16.06	11,461
	30	Base	3.78	4.75	8.55	97.89	2.01	13.28	11,398
	26	Low NO_x	4.46	5.48	9.86	98.18	5.65	12.12	11,752
	27A	Low NO_x	4.68	5.75	10.35	98.26	3.37	9.84	11,632
	27B	Low NO_x	6.02	7.39	13.30	98.65	4.08	9.84	11,632
Salt River Project	3B	Base	3.17	4.27	7.69	97.66	.92	11.49	10,210
	2A	Base	3.48	4.27	7.69	97.66	1.79	5.94	11,068
	3D	Base	1.93	2.50	4.50	96.00	1.98	6.04	11,186
	18B	Low NO_x	4.95	6.26	11.27	98.40	.80	11.49	10,210
	18C	Low NO_x	5.35	6.85	12.33	98.52	1.16	6.62	10,780
	18E	Low NO_x	2.36	2.87	5.17	96.52	1.53	6.04	11,186
Pub. Ser. Co. of Colorado	30	Base	2.56	3.11	5.60	96.79	.66	*	*
	33	Base	2.59	3.18	5.72	96.86	.55		
	27A	Low NO_x	1.85	2.26	4.07	95.58	.46		
	27B	Low NO_x	2.41	2.94	5.29	96.60	.18		
	34	Low NO_x	1.96	2.34	4.21	95.73	.50		
	35	Low NO_x	2.02	2.41	4.34	95.85	.59		

* Analyses not available at this time

** Normal firing but at lower than normal excess air levels

Table 3-15

Public Service Company of Colorado
Comanche Station - Pueblo, Colorado
Boiler No. 1

Particle Size Distribution, Wt.%

	Base		Low NO_x			
Test No.	30	33	27A	27B	34	35
>2.5μ*	82.18	81.38	77.4	83.84	82.41	79.29
2.0μ	8.73	9.5	11.31	9.53	7.04	7.76
1.5μ	1.96	2.05	2.71	1.62	2.29	2.48
1.0μ	2.49	2.79	3.17	1.86	2.9	3.73
0.5μ	2.94	2.89	2.94	2.1	3.52	4.45
<0.5μ	1.70	1.39	2.49	1.05	1.85	2.13

* Includes probe and cyclone.

the previous program where increases were noted for "low NO_x" firing conditions, especially in front wall and horizontally opposed fired boilers. There is also an indication that particulate carbon content may decrease slightly under "low NO_x" conditions in tangentially fired boilers. The differences in the data, however, are not statistically significant and more information would be required to firm up this point. Carbon losses in boilers fired with Western coals, as in prior findings, have again been noted to be very low, attesting to the easy burnability of these coals. The effect of the changes in unburned combustibles on boiler efficiency is discussed in section 3.4 and is shown to be relatively minor.

Investigations into potential changes in particle size distribution was included in the current program in an effort to determine whether there might be any adverse side effects with "low NO_x" firing. Potentially, changes in the fine particle sizes could materially affect electrostatic precipitator collection efficiency which in borderline cases might inhibit compliance with emission standards. Tables 3-15, 3-16 and 3-17, respectively summarize the particle size distribution data developed in this study. Test data were obtained upstream of the electrostatic precipitators using a Brink multi-stage cascade impactor incorporated in an EPA type particulate sampling train, as described in section 2.5. Cut-off points in the Brink impactor were 2.5, 2.0, 1.5, 1.0, 0.5 and 0.25 microns. Particle size distribution data reported in Tables 3-15, 3-16 and 3-17 include all material collected in the probe and the cyclone in the distribtuion fraction greater than 2.5 microns. Comparing the data in Tables 3-15 and 3-16, it may be seen that there are no significant differences in particle size distribution between "low NO_x" and baseline operation for the two boilers tested. In Table 3-17, however, major increases are indicated for the smaller size fractions with "low NO_x" firing which would adversely affect precipitator collection efficiency on the boiler tested. The significance of the latter data, however, is open to serious question, first, due to the relatively small size of the sample obtained in these tests in the Brinks impactor and, second, because of the problems with leaks in the sampling equipment prevalent in these tests which were rectified in later tests. More particle size distribution data which are in the process of being developed are needed to resolve this question.

3.3 Corrosion Probing Results

In the current program significant changes were made in the conditions for obtaining corrosion rate data in an effort to better relate rates obtained on corrosion probes to actual furnace wall tube corrosion. In the prior investigation, corrosion rates averaged approximately 50 mils per year with considerable scatter between high and low values. Apparently, these high rates were influenced by the high exposure temperature of 875°F and the mild acid pickling of the coupons prior to exposure which it is now believed resulted in high initial corrosion. In this program, coupon temperatures were controlled at temperatures approximating the furnace tube temperature (about 725°F) and the acid pickling procedure was eliminated. As a result corrosion rates obtained (discussed later), were considerably lower and more consistent in value. All other test procedures were kept the same, i.e., probes were installed through openings as close as possible to vulnerable furnace areas, exposure was maintained the same at approximately 300 hours, coupons were removed, cleaned ultrasonically with glass beads, re-weighed and corrosion rates calculated all in accordance with prior procedures established for these tests. Total weight loss data were converted to corrosion rates on a mil per year basis using the combined inner and outer coupon areas previously found to give most consistent results, coupon material density and exposure time.

Corrosion rates have been determined on 36 coupons installed on 12 probes (3 coupons/probe) in 6 boilers at three different generating stations firing pulverized coal. Additional tests have also been run at another pulverized coal fired power plant with 4 probes (12 coupons) but results are not yet available.

The data obtained in this program are tabulated in Tables 3-18, 3-19 and 3-20. Referring to these tables it may be observed that in most cases the corrosion rates obtained varied between approximately 10 and 15 mils per year. These rates are considerably lower than those obtained in the previous program under accelerated conditions but they are still an order of magnitude greater than the 1 to 3 mils per year corrosion which might be expected on actual furnace tubes, so prediction or relation of results obtained on probes to what might be expected in an existing furnace is still difficult. Data developed in the prior program averaged approximately 50 mils per year corrosion with considerable scatter in the data. The lower and remarkably more consistent rates obtained in this progam reflect the changes made in test procedures to more closely approximate actual furnace wall tube conditions.

Table 3-18

Tennessee Valley Authority, Widows Creek Station

Corrosion Rate Data

Boiler	Probe No. (1)	Firing Condition	Coupon Corrosion Rate, Mils/Year
Boiler No. 6 (North Side)	4	Base	10.2 (2) 12.0 14.6
Boiler No. 6 (South Side)	3	Base	9.7 (2) 11.6 11.1
Boiler No. 5 (North Side)	2	Low NO_x	12.5 (2) 13.4 18.8
Boiler No. 5 (South Side)	1	Low NO_x	11.7 (2) 13.4 15.1

(1) Probes located between A B burners, top & next to top rows, respectively.

(2) Coupons furthest into furnace.

Table 3-19

Southern Electric Generating Company, E. C. Gaston Station
Wilsonville, Alabama

Corrosion Rate Data

Boiler (1)	Probe No.	Firing Condition	Coupon Corrosion Rate, Mils/Year
Boiler No. 2 @ (IR No. 1)	3	Base	10.3 7.3 10.2 (2)
Boiler No. 2 @ (IR No. 10)	4	Base	8.0 6.3 6.0 (2)
Boiler No. 1 @ (IR No. 10)	2	Low NO_x	20.0 12.3 10.4 (2)
Boiler No. 1 @ (IR No. 1)	1	Low NO_x	10.1 (2) 7.1 11.4

(1) Probes inserted through slag blower ports in side walls about 8 feet above top burners and 12 feet from rear furnace corner.

(2) Coupons furthest into furnace.

Table 3-20

Salt River Project, Navajo Station
Page, Arizona

Corrosion Rate Data

Boiler (1)	Probe No.	Firing Condition	Coupon Corrosion Rate, Mils/Year
No. 1 (North Side)	1*	Base	62.8 32.0 21.3 (2)
No. 1 (South Side)	2	Base	15.1 10.6 13.2 (2)
No. 2 (North Side)	3*	Low NO_x	43.8 29.2 19.7 (2)
No. 2 (South Side)	4	Low NO_x	16.2 15.1 15.5 (2)

(1) Probes inserted through observation doors in side walls between B & C burner rows.

(2) Coupons furthest into furnace.

* Probes with damaged coupons.

Referring to Table 3-20 it may be noted that the coupons on probes No. 1 and No. 3 indicate higher corrosion rates than those on probes No. 2 and 4, respectively. Undoubtedly, this was due to some of the metal having been removed on these coupons in the disassembling procedure caused by the galling of the threads between coupons. The indicated rate of corrosion for these coupons, therefore, should be used with caution.

The major conclusion from these data is that no major differences in accelerated corrosion rates can be observed for coupons exposed to "low NO_x" firing conditions compared to those subjected to baseline or normal combustion.

A comparison of corrosion experienced in long term tests (6 months plus) on existing furnace tubes with corrosion probe data obtained in the same furnace is also of paramount importance, and therefore such information will be obtained in future tests.

3.4 Boiler Performance Results

The prior NOx field tests indicated a tendency for particulate carbon content to increase substantially under low NOx operating conditions, especially on front wall or horizontally opposed fired boilers. Potentially an increase in unburned carbon could result in lowered boiler efficiency but this adverse side effect did not materialize in the previous study because the debit, at least partially, was offset by the increased efficiency resulting from lower excess air operation at low NOx conditions. In this study the side effects of "low NO_x" operating techniques on boiler performance were investigated and evaluated for each major test where particulate data were obtained under baseline and optimum "low NOx" conditions. Control room board data and other pertinent information representative of each test run were recorded and boiler performance (efficiency) was calculated following the ASME Steam Generating Units, Power Test Codes using the Abbreviated Efficiency Test, heat loss method. Calculations were based on the assumption that fly ash and bottom ash combustible content were the same and unmeasured losses were 0.5 percent. An example of typical performance data and the calculations made are shown in ASME test forms in Tables 3-21 and 3-22.

Table 3-23 tabulates the boiler efficiency calculated for each test along with other pertinent boiler performance information. Differences in calculated boiler efficiency between baseline and "low NO_x" tests provide a comparison of any debit or credit accruing to "low NO_x" operating conditions. These comparisons, however, must be weighed against other confounding factors, such as, differences in coal ash content, coal BTU content, boiler load, excess air levels, carbon content on particulate, etc. for each test run. Boiler efficiency, in general, increases with load and decreases with increases in coal ash or unburned combustible content of the particulate.

Referring to Table 3-23, it may be noted that there are no debits to "low NO_x" operation which decrease boiler efficiency materially. In fact, quite the opposite is indicated as reflected by the Tennessee Valley Authority and Salt River Project test data where increases in efficiency are evident under low NO_x firing due to decreases in uncombustible losses, lower coal ash, and excess air levels. Differences in boiler efficiency are also inconsequential with "low NO_x" operation where carbon losses increased substantially, as in the Southern Electric Company example. Here debits to low NO_x emission reduction techniques are offset by decreases in coal ash content and slightly lower excess air operating levels.

TABLE 3-21

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

SUMMARY SHEET

PTC 4.1-a (1964)

TEST NO. 1A BOILER NO. 6 DATE 4-18-72

OWNER OF PLANT TVA LOCATION Widows Creek

TEST CONDUCTED BY Esso Research & Engineering Co. OBJECTIVE OF TEST Boiler Performance DURATION 4 Hrs.

BOILER, MAKE & TYPE B&W Radiant RATED CAPACITY 125 MW

STOKER, TYPE & SIZE

PULVERIZER, TYPE & SIZE Type E BURNER, TYPE & SIZE

FUEL USED Bituminous Coal MINE COUNTY STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R. H. INLET	F	
7	STEAM TEMPERATURE AT R. H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.)(BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	88
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	372
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R. H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	15.87
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	912.1
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	0.66
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	11.6

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item 28} \times \text{Item 41})}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21})}{1000}$ + Item 30	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	14.4
33	O_2	% VOL	3.3
34	CO	% VOL	0.04
35	N_2 (BY DIFFERENCE)	% VOL	82.26
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt
37	MOISTURE	5.4
38	VOL MATTER	
39	FIXED CARBON	
40	ASH	
	TOTAL	
41	Btu per lb AS FIRED	11452
42	ASH SOFT TEMP.* ASTM METHOD	

	OIL	
51	FLASH POINT F*	
52	Sp. Gravity Deg. API*	
53	VISCOSITY AT SSU* BURNER SSF	
44	TOTAL HYDROGEN % wt	
41	Btu per lb	

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS	
43	CARBON	67.27
44	HYDROGEN	4.29
45	OXYGEN	
46	NITROGEN	
47	SULPHUR	0.77
40	ASH	15.87
37	MOISTURE	
	TOTAL	

	GAS	% VOL
54	CO	
55	CH_4 METHANE	
56	C_2H_2 ACETYLENE	
57	C_2H_4 ETHYLENE	
58	C_2H_6 ETHANE	
59	H_2S	
60	CO_2	
61	H_2 HYDROGEN	
	TOTAL	
	TOTAL HYDROGEN % wt	
62	DENSITY 68 F ATM. PRESS.	
63	Btu PER CU FT	
41	Btu PER LB	

	COAL PULVERIZATION	
48	GRINDABILITY INDEX*	-
49	FINENESS % THRU 50 M*	
50	FINENESS % THRU 200 M*	

64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL		0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		3.95
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		1.26
69	HEAT LOSS DUE TO RADIATION		0.002
70	UNMEASURED LOSSES		0.5
71	TOTAL		13.16
72	EFFICIENCY = (100 – Item 71)		86.84

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

TABLE 3-22

PTC 4.1-b (1964)

ASME TEST FORM

CALCULATION SHEET FOR ABBREVIATED EFFICIENCY TEST *Revised September, 1965*

OWNER OF PLANT TVA TEST NO. 1A BOILER NO. 6 DATE 4-18-72

30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15 } \ldots\ldots - \text{ ITEM 17 } \ldots\ldots}{1000}\right]$ = kB/hr			
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43: } 67.27}{100} - \left[\frac{\text{ITEM 22: } 0.1587 \times \text{ITEM 23: } 912.1}{14{,}500}\right] = 0.66$ NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.			
25	DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)} \times$ (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) $= \frac{11 \times \text{ITEM 32: } 14.4 + 8 \times \text{ITEM 33: } 3.3 + 7\left(\text{ITEM 35: } 82.26 + \text{ITEM 34: } 0.04\right)}{3 \times \left(\text{ITEM 32: } 14.4 + \text{ITEM 34: } 0.04\right)} \times \left[\text{ITEM 24: } 0.66 + \frac{\text{ITEM 47: } 0.77}{267}\right] = 11.6$			
36	EXCESS AIR† = $100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...			
	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = ITEM 25 11.6 × 0.24 (ITEM 13) − (ITEM 11) 372 − 88 = 790	790	$\frac{65}{41}$ × 100 =	6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37: } 5.4}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 − (ENTHALPY OF LIQUID AT T ITEM 11) 56] = 63.3	63.3	$\frac{66}{41}$ × 100 =	0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44: } 4.29}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 − (ENTHALPY OF LIQUID AT T ITEM 11) 56] = 452.5	452.5	$\frac{67}{41}$ × 100 =	3.95
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 0.1587 × ITEM 23 912.1 = 144.8	144.8	$\frac{68}{41}$ × 100 =	1.26
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	0.2	$\frac{69}{41}$ × 100 =	0.002
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ × 100 =	0.5
71	TOTAL	......	......	13.16
72	EFFICIENCY = (100 − ITEM 71)	......	......	86.84

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

Table 3-23

Summary of Boiler Performance Calculations

Company, Station	Boiler No.	Firing Mode	Test No.	Load, MW	% O_2	NO , PPM (3% O_2)	Coal, % Ash	% Carbon on Particulate	Boiler Efficiency, %
Tenn. Valley Authority, Widows Creek	5	Base *	1B	128	2.4	409	14.64	13.0	86.6
		Base *	1C	124	2.5	441	18.27	9.1	86.2
	5	Low NO_x	12C	125	2.5	412	12.30	6.2	87.7
		Low NO_x	12D	125	2.5	412	12.30	8.1	87.3
So. Electric Generating Company, E. C. Gaston	2	Base	28A	272	4.2	584	15.00	2.7	89.8
		Base	28B	272	4.2	584	15.00	1.1	90.1
		Base	29	268	4.1	572	16.06	1.7	89.9
		Base	30	270	4.3	606	13.28	2.1	89.2
	1	Low NO_x	26	270	3.9	349	12.12	5.7	89.2
		Low NO_x	27A	268	3.9	316	9.84	3.4	89.6
		Low NO_x	27B	268	3.9	316	9.84	4.1	89.8
Salt River Project, Navajo	2	Base	3B	799	4.8	492	11.49	0.9	89.0
		Base	2A	792	3.9	332	5.94	1.8	89.6
		Base	3D	785	4.8	346	6.04	2.0	89.6
	2	Low NO_x	18B	808	4.4	349	11.49	0.8	89.2
		Low NO_x	18C	808	4.6	346	6.62	1.2	89.5
		Low NO_x	18E	798	3.7	280	6.04	1.5	89.7

• Normal firing but at lower than normal excess air levels

Overall, it is concluded that no major differences in boiler operating efficiency result due to "low NO_x" emission firing techniques. Stated another way, reducing NO_x emissions in a utility boiler need not occur at the expense of increased energy costs.

4. CONCLUSIONS

In this section of the paper we present our conclusions from gaseous emission measurements, particulate emissions (mass and size distribution), corrosion test data and boiler operating performance.

4.1 Gaseous Emission Measurements

In section 3.1 we have discussed the results obtained from each of the 7 individual power generation equipment combustors. In this section a summary of the conclusions obtained from the individual units will be presented as well as the conclusions to be derived by examining the overall correlations based on the results of the six coal fired boilers.

Table 4-1 presents a summary of the NO_x emissions for coal fired boilers under baseline and "low NO_x" operation for the 6 boilers completed so far in this program. Widows Creek No. 5 boiler is a rear wall (RW) fired unit; Ernest C. Gaston No. 1 is a horizontally fired unit (with newly designed low NO_x burners); while the last four units are tangentially fired (of which 3 are equipped with overfire air ports). Gaseous measurements of % O_2, PPM NO_x and PPM CO are listed for baseline operation, "low NO_x-I" (modified firing operation at full load) and "low NO_x-II" (modified firing operation at reduced load). Baseline PPM NO_x emission levels are listed at both actual excess air levels and (in parenthesis) the values calculated at 20% excess air for comparison purposes.

Both wall fired boilers (Widows Creek No. 5 and Gaston No. 2) under baseline operation produced NO_x emissions above the 0.7 lb./10^6 BTU Federal standard for new boilers. However, under modified firing operation both Widows Creek No. 5 (low excess air, staged firing) and Gaston No. 1 (low NO_x, Babcock and Wilcox burners) were able to meet the standard under full load operation. At reduced load (-20%) Widows Creek boiler No. 5 was able to lower NO_x emissions to as low as 305 PPM (49% less than base). Gaston No. 1 using the newly designed burners produced 35% less NO_x emissions than Gaston No. 2 under baseline conditions. Modified firing operation of Gaston No. 1 unit at full load and reduced load reduced NO_x emissions by 53% and 69%, respectively, compared to baseline operation with the normal burners.

The three tangentially fired boilers equipped with overfire air ports under full load, baseline operation (cooling air only) met the 0.7 lb./10^6 BTU NO_x standard while Morgantown No. 1 unit was slightly above the standard for new boilers. Modified firing using overfire air ports with low excess air resulted in 37 to 45% NO_x emission reductions while staged

Table 4-1

Summary of NO_x Emissions for Coal Fired Boilers

Boiler	Operating Mode (Gross Load - MW)	% O_2	NO_x Emissions ppm (3% O_2)	NO_x Emissions Lb. / 10^6 BTU	NO_x Emissions gm / 10^6 CAL	ppm CO (3% O_2)
1. Widows Creek No. 5 (RW)	Base - 125	4.0	597(567)*	0.79	1.43	29
	"Low NO_x - I" - 125	3.2	468	0.62	1.12	88
	"Low NO_x - II" - 100	5.3	305	0.41	0.74	285
2. Ernest C. Gaston No. 1 (HO) (Low NO_x Burners)	Base - 270	4.3	389(366)*	0.52	0.93	26
	"Low NO_x - I" - 270	2.4	278	0.37	0.64	65
	"Low NO_x - II" - 190	1.6	182	0.24	0.44	329
3. Navajo No. 2 (T) (Overfire Air Ports)	Base - 800	4.8	492(400)*	0.65	1.18	64
	"Low NO_x - I" - 802	3.6	282	0.38	0.68	330
4. Comanche No. 1 (T) (Overfire Air Ports)	Base - 323	4.0	417(370)*	0.55	1.00	27
	"Low NO_x - I" - 333	3.7	261	0.35	0.62	35
5. Barry No. 2 (T) (Overfire Air Ports)	Base - 130	4.9	341(250)*	0.45	0.82	22
	"Low NO_x - I" - 129	3.3	189	0.25	0.45	49
6. Morgantown No. 1 (T)	Base** - 570	4.9	552(534)*	0.73	1.32	21
	"Low NO_x***- I" - 572	4.7	403	0.54	0.96	20

* Baseline NO_x emissions calculated for 20% excess air

** Fuel burned = 93% coal, 7% oil

*** Fuel burned = 74% coal, 26% oil

firing reduced Morgantown No. 1 NO_x emissions by 27%. Comparison of normalized baseline NO_x emissions of these 3 boilers with the four tangentially fired boilers from our previous program (2) shows an 18% NO_x reduction due to cooling air.

The ranges of NO_x emissions measured under normal firing operation as a function of excess air level (% O_2 in flue gas) are shown in Figure 4-1. The code letters identifying the power station and boiler numbers are as follows:

Code Letters	Station	Boiler No.
WC	Widows Creek	5
M	Morgantown	1
C	Comanche	1
G	Ernest C. Gaston	1
N	Navajo	2
B	Barry	2

As discussed in section 3.1, excess air level had a significant effect on the level of NO_x emissions from each boiler under normal firing operation. These NO_x vs % O_2 relationships are shown in Figure 4-1. Witl the exception of Comanche No. 1 unit, (which had limited excess air level operating flexibility) the slopes (calculated by least squares) of these lines are fairly consistent. However, the average NO_x levels vary because of boiler size, type of firing, type and composition of coal fired, etc.

Figures 4-2 and 4-3 have been prepared to show the overall relationship between NO_x emission levels and excess air level (% O_2 in flue gas, on a consistent basis for normal firing and modified firing operation for the six coal fired boilers tested to date in this program.

Figure 4-2 is a plot of "normalized" NO_x emissions expressed as a % of baseline NO_x emissions (full load and 20% excess air) vs average % O_2 measured in the flue gas for normal firing conditions. The solid lines shown for each boiler are based on the least-squares, linear regression analysis of all full load, test runs made under normal firing operation (all burners firing coal and with closed overfire air ports). With the exception of the Comanche boiler mentioned above, all of the lines fit within a relatively narrow band.

Figure 4-3 is a plot of "normalized" NO_x emissions (expressed as a % of baseline NO_x emissions at full load and 20% excess air) vs average % oxygen measured in the flue gas for modified firing conditions. Thus, the ordinates are identical in Figures 4-2 and 4-3. However, the

FIGURE 4-1

PPM NO_X VS % OXYGEN IN FLUE GAS

(NORMAL FIRING - COAL FIRED BOILERS)

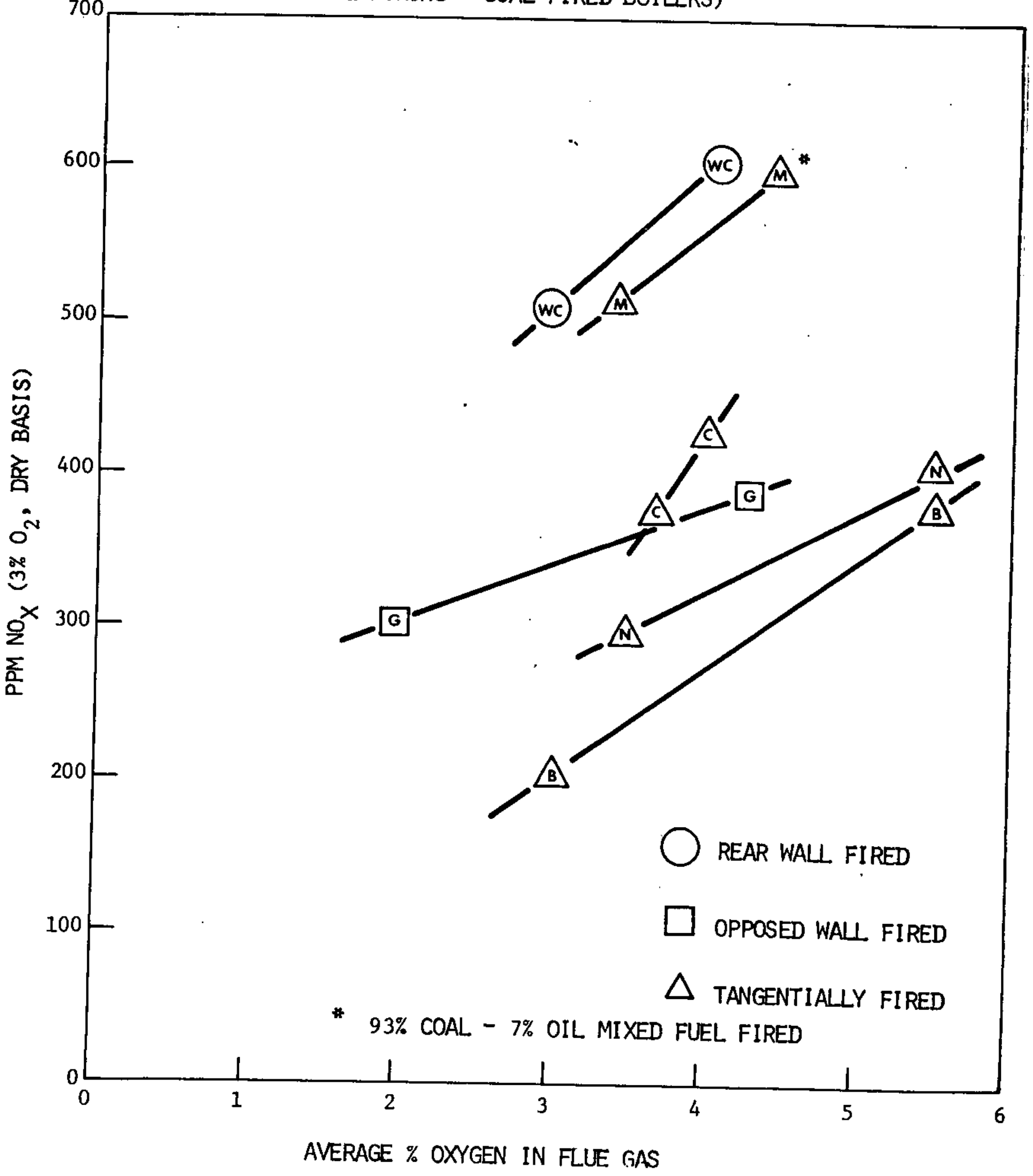


FIGURE 4-2

EFFECT OF EXCESS AIR LEVEL ON NO_X EMISSIONS UNDER NORMAL FIRING OPERATIONS

(COAL FIRED BOILERS)

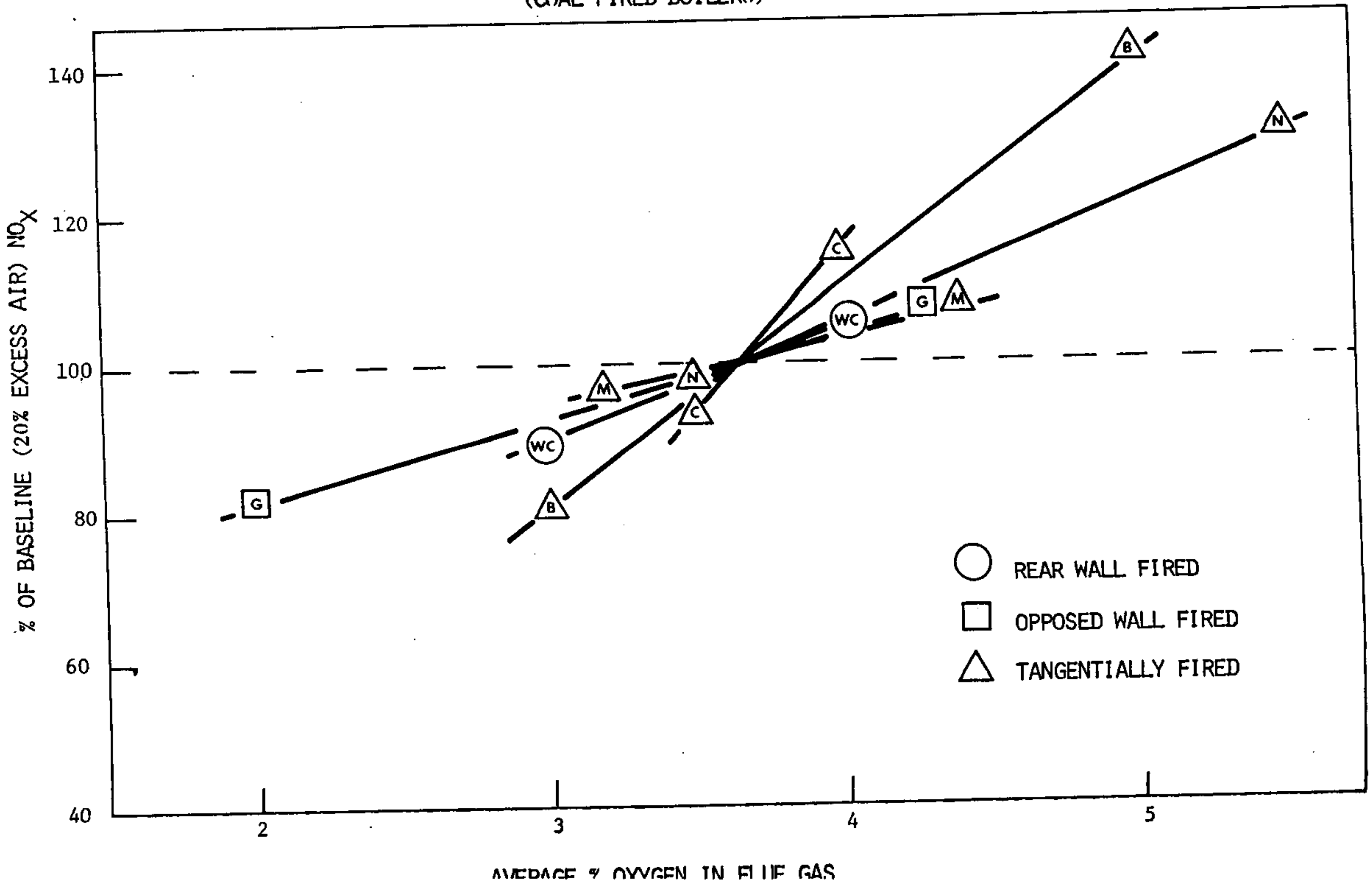
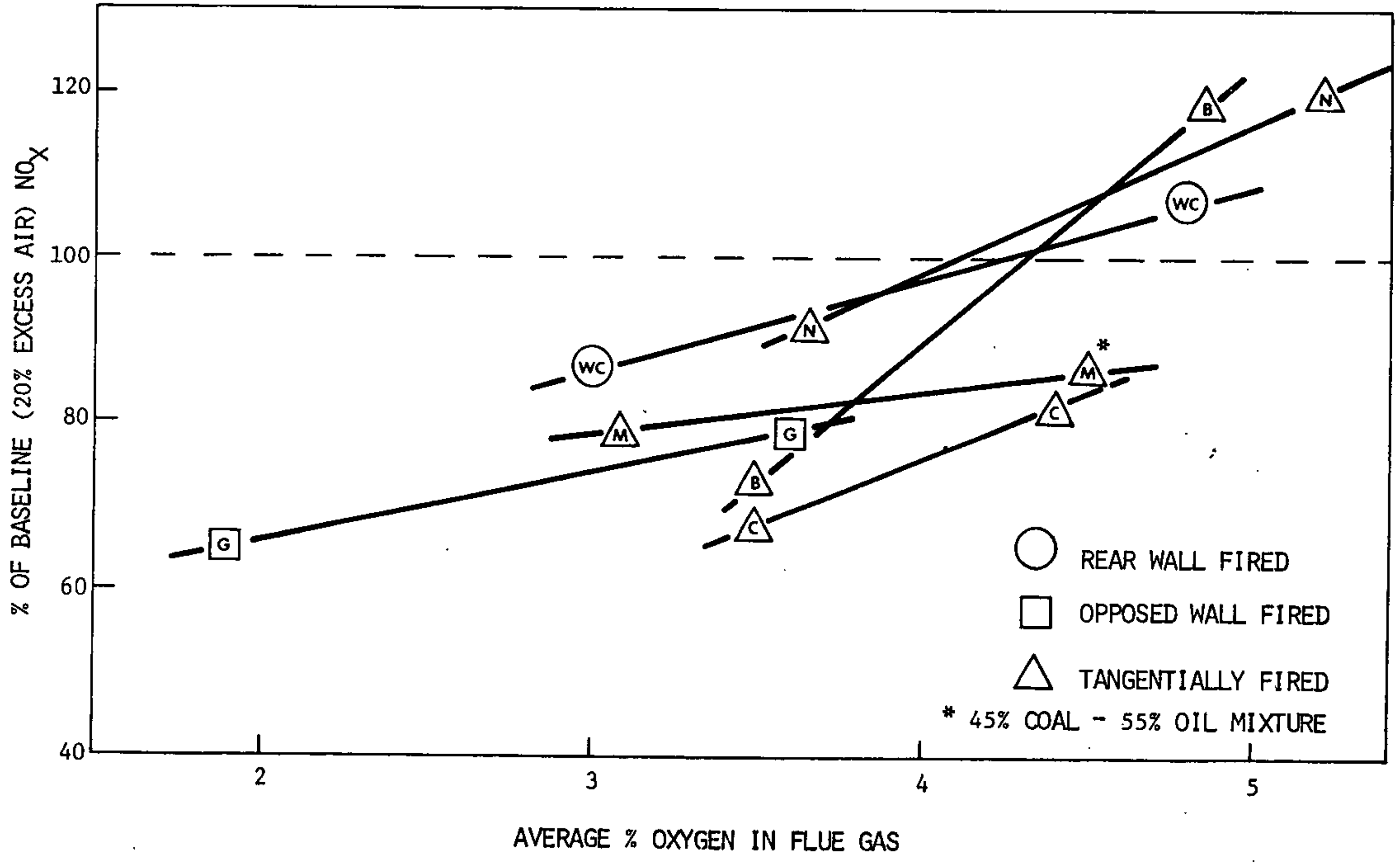


FIGURE 4-3

EFFECT OF EXCESS AIR ON NO_X EMISSIONS UNDER MODIFIED FIRING CONDITIONS

(COAL FIRED BOILERS)



least squares regression lines of Figure 4-3 do not necessarily pass through the 100% normalized NO_x point at 3.6% oxygen, as they must by definition in Figure 4-2.

Figure 4-3 indicates the importance of low excess air firing on NO_x emissions when operating under modified firing conditions such as staged firing. The slopes of these lines are very similar except for Morgantown No. 1 (which fired a mixture of coal and oil) and Barry No. 2 unit (with overfire air ports relatively far from the top row of active burners). It should be noted that all of the boilers tested had baseline NO_x emission rates above the normalized (20% excess air) levels used in Figure 4-3 and that optimized, modified firing operation generally produced lower NO_x operation than shown by the least squares lines. Thus, the improvement from low excess air, modified firing operation compared to actual baseline NO_x emission levels averaged 38% vs the 26% shown in Figure 4-3. An additional point to recall is that three of these boilers are equipped with overfire air ports which produced an 18% reduction of normalized baseline NO_x emission from the tangentially fired boilers tested in our last program (2).

Initial studies on mixed fuel fired boilers indicate that NO_x emission levels increased as the % of coal in the coal-oil or coal-gas mixture increased. However, the relationship was not linear. We plan to test additional units to firm up the relationship.

A large (50 MW rated) General Electric gas turbine has been tested under normal operating conditions while firing fuel oil. NO_x emissions were about 375 PPM at full load, 400 PPM at peak load (54 MW) with reductions to about 325 and 250 PPM at 50% and 20% of full load operation, respectively.

4.2 Side Effects of Combustion Modifications

As discussed in Section 3, the modified combustion techniques studied for controlling NO_x emissions have not produced major adverse side-effects in short-term, 300-hour sustained tests. In other words, furnace wall corrosion, particulate mass loading and size distribution, carbon on fly ash, and boiler efficiency have not changed significantly when comparing "low NO_x" operation with baseline conditions. Long-term demonstration is required to validate these conclusions.

5. REFERENCES

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3. Environmental Protection Agency, "Standards of Performance for New Stationary Sources," Method 5, Published in the Federal Register, December 23, 1971, Vol. 36, Number 247, p. 24888.

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APPENDIX A

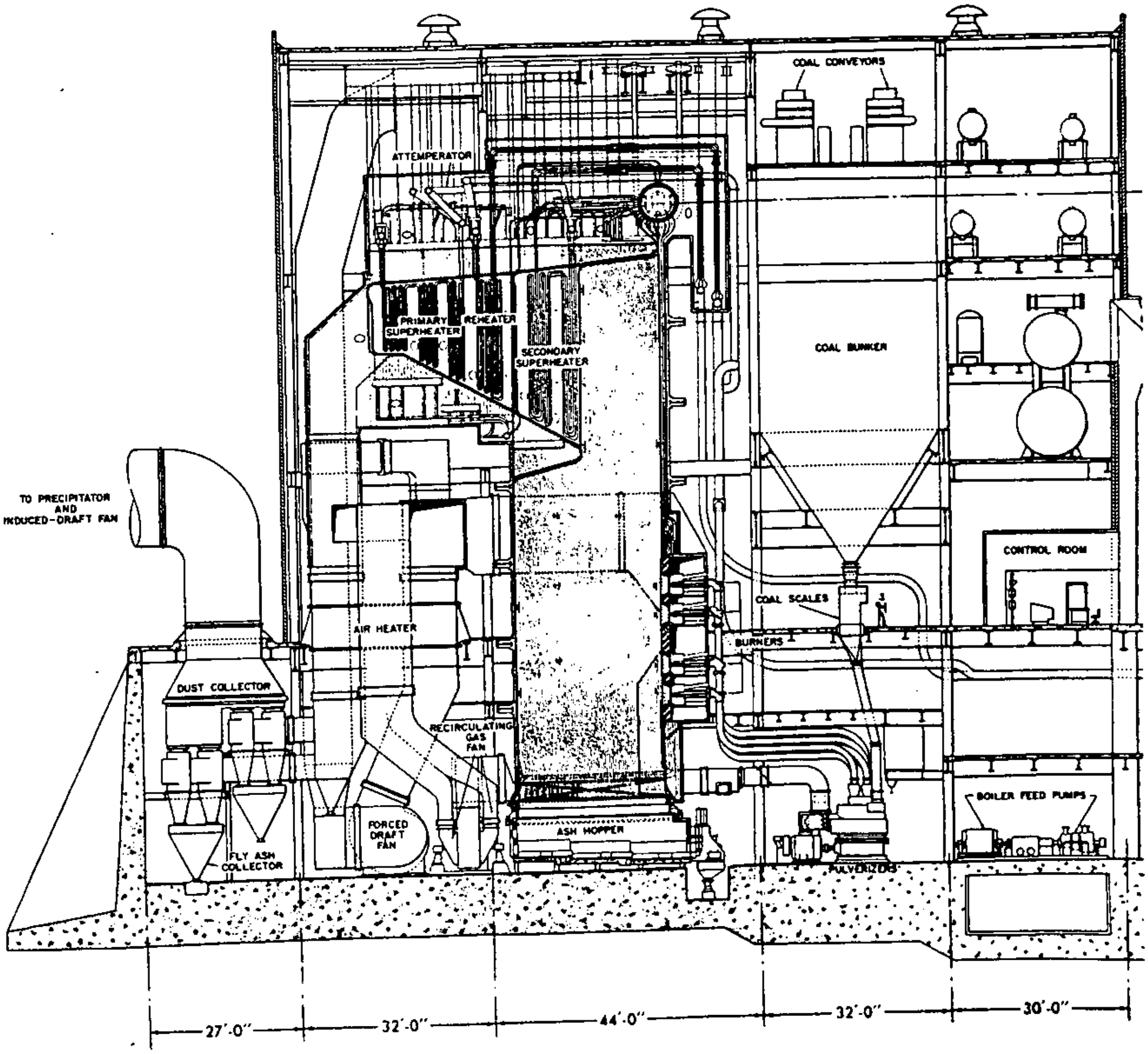
CROSS SECTION DRAWINGS OF TYPICAL UTILITY BOILERS

Typical utility boiler designs representative of the types of boilers tested in this program are shown in the cross sectional drawings in Figures 1 through 3 of Appendix A. Typical front wall and horizontally opposed and tangentially fired boilers are shown in Figures 1, 2 and 3, respectively.

APPENDIX A

FIGURE 1

TYPICAL FRONT WALL FIRED BOILER



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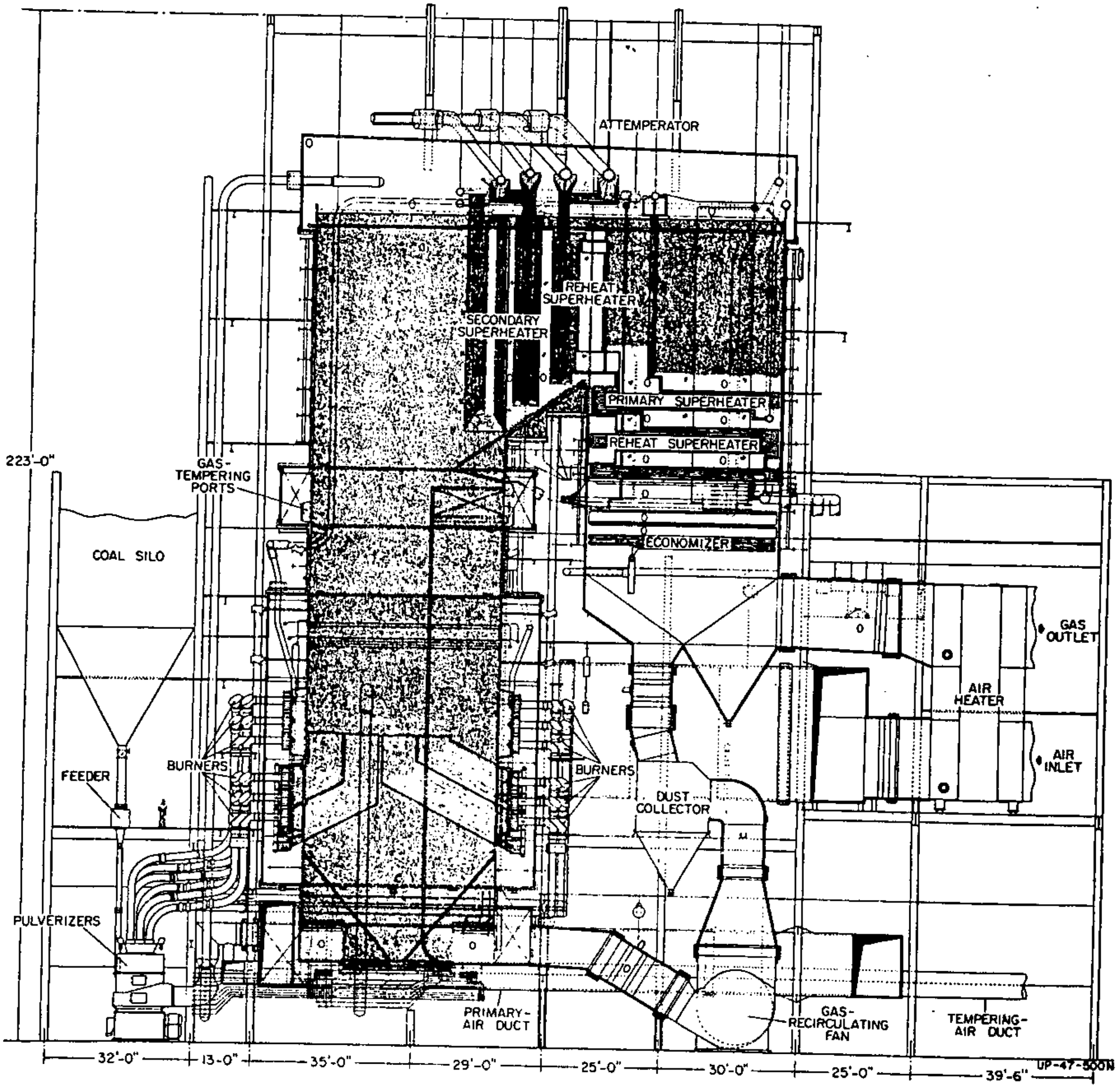
THE BABCOCK AND WILCOX COMPANY

APPENDIX A

FIGURE 2

TYPICAL HORIZONTALLY OPPOSED FIRED BOILER



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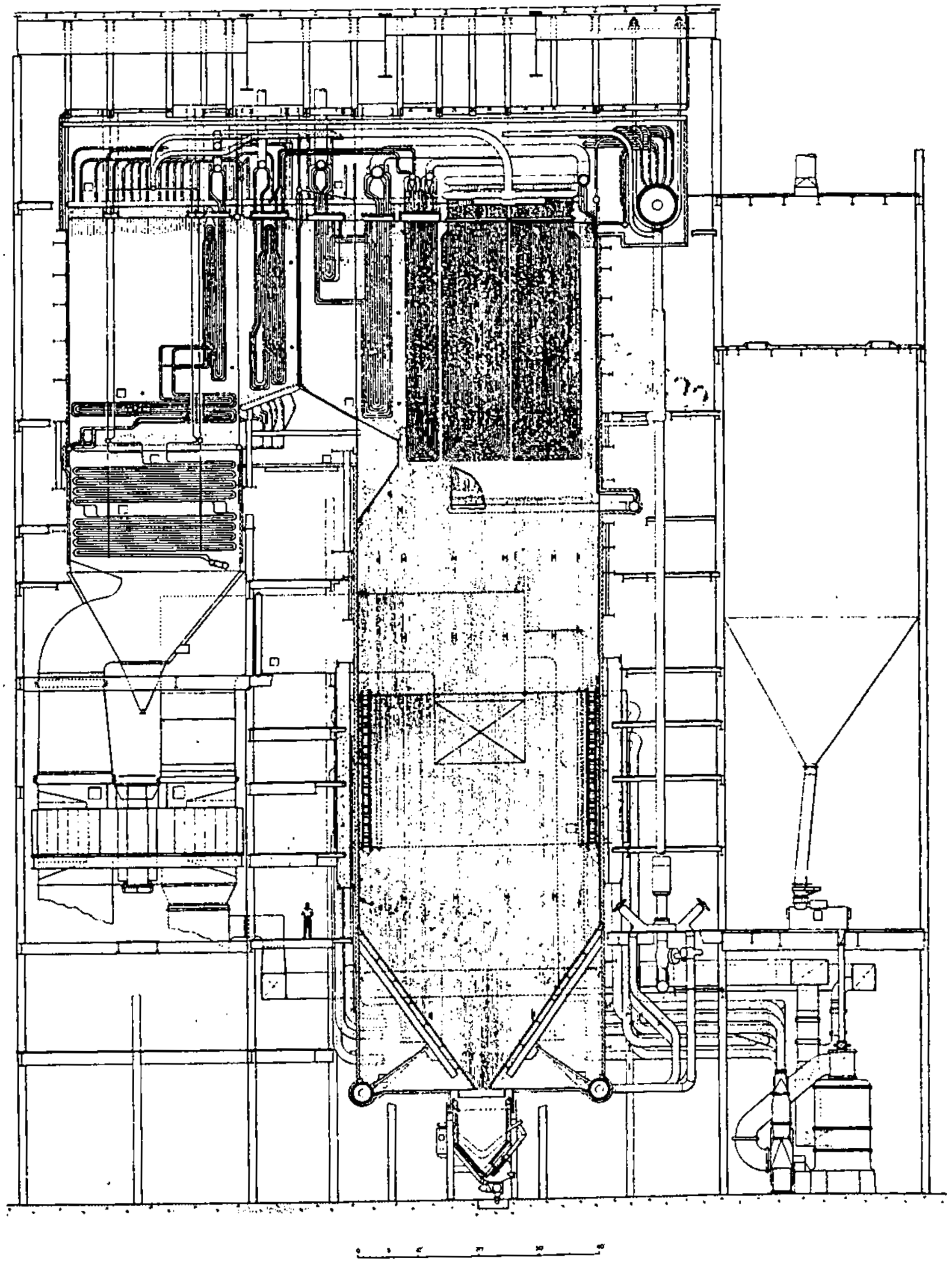
APPENDIX A

FIGURE 3

TYPICAL TANGENTIALLY FIRED BOILER



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APPENDIX B

CONVERSION FACTORS

ENGLISH TO METRIC UNITS

To Convert From	To	Multiply By*
BTU	Gigajoule, GJ	1.055 056 E-06
BTU/pound	Gigajoule/kilogram, GJ/kg	2.326 000 E-06
Pounds/BTU	Kilogram/gigajoule, kg/GJ	4.299 226 E-07
Pounds/hour	Kilogram/hour, kg/hr	4.535 924 E-01
Pounds/square inch	Megapascal, MPa	6.894 757 E-03
Tons (short)	Metric tons, t	9.071 847 E-01
Pounds	Kilogram, kg	4.535 924 E-01
Feet	Metre, m	3.048 000 E-01
Inches	Centimetres, cm	2.540 000 E+00
Inches	Metre, m	2.540 000 E-02
Cubic feet	Cubic metres, cm^3 Decimetre, dm^3	2.831 685 E-02 2.831 685 E+01
Gallons	Decimetre, dm^3	3.785 412 E+00
°Fahrenheit	°Kelvin, K	(°F + 459.67) 5/9

* Numbers expressed in power-of-ten notation using E ± xx to indicate the power of ten. For example:

$$1.055\ 056\ \text{E-06} = 1.055\ 056 \times 10^{-6} = .000001055056$$

8:30 a.m.
The Effect of Combustion Modification
on Pollutants and Equipment Performance
of Power Generation Equipment
Allen R. Crawford and Erwin H. Manny
Exxon Research and Engineering

Q: I would like to suggest that your glancing over the CO data was, I think, a little bit too cavalier. I realize that you were addressing yourself to NO_x primarily but when I see factors of 10 increase in carbon monoxide...I don't know much about your boilers but I do know a little bit about data. I think I'd be a little bit concerned about the "bean bag" effect. This is something I guess we see in every combustion system. In your table 4.1, you are talking about a reduction in NO_x of about 597 to 305 parts per million, but your CO goes up from 29 to 285. That is not a small increase. Would you comment?

A: CO level is probably our best indication of a poor combustion threshold. A very small change in percent O_2, below the threshold level, can increase CO levels tremendously. For example, we often have a condition in which changing flue gas oxygen from, say, 2% down to 1.6% can increase the CO level by 5 to 10 times or from a normal 25 ppm up to 250 to 500 ppm. Consequently, operating near the threshold level can produce widely varying CO levels. In actual "low NO_x" operation, increasing O_2 levels by 0.2 to 0.4% over the threshold level will in most cases reduce CO down to 100 ppm or lower without increasing NO_x levels significantly.

Q: It is also a question of the tradeoff. This is a question for the OAQPS people to answer, but is that increase in CO as important as the reduction in NO that you achieve?

A: Generally, in other combustion sources for which we have gathered data to set standards of performance, from what our Health Effects people at NERC in North Carolina say, it is much more important to control NO and hydrocarbons to lower levels than to control CO. You can have rather high CO levels. Of course, in terms of effects, at ground level, it is mass rated emissions that are important rather than concentration. But still, at these low concentrations you would not expect to even get near an ambient air quality standard at ground level for CO. Whether the CO level is 25, 50 to 100 ppm, it is relatively minor compared to the nitrogen oxides that are of much more concern. [Answered by Stan Cuffe of EPA.]

A: Thank you, Stan. Also, I might add that you mentioned hydrocarbons. Hydrocarbon emissions were so low on these tests that the values weren't reported in the tables. But, in general, they were only 1 or 2 parts per million.

Q: I haven't had a chance to read your paper too well, but I don't see any place where you have stated the sulfur levels of the coal which were being burned at these stations. That would make a significant difference as far as the corrosion data is concerned.

A: Right, this is important. This paper is an interim report. However, our final report will have complete gaseous information, as well as coal composition. We agree with your comment.

One other problem is that this data was a summary of very recent results, so all the coal analyses are not even in for the tests. But in the final report they will be. You can probably surmise from the location of the station what the approximate level of sulfur is in the coal. For those of you who are interested in relative effects of sulfur on the corrosion testing, I would like to refer you to a previous report that we published in 1974 on our previous studies, which covered a rather broad range of western, mid-western, and eastern bituminous coals as well as a lignite coal. One can use those results to relate the sulfur levels of the coals fired with the corrosion rates measured with the coupons. I think that would probably be a useful reference to look up.

Q: One thing I noticed between the data that was presented by TVA yesterday and yours today (it is flipping by kind of fast so I haven't had a chance to read the papers). TVA data looked as though it were taken after the ESP. Your particulate data, I would guess, was taken before, because you showed a percent efficiency required to meet a standard, which means that you were taking data upstream. Aside from the obvious that yours is going to be much higher in just total mass rate than theirs, the conclusion about whether more is going out or not...really, you have a classifying device in between there. So this could account for some of these differences in interpretation of results.

A: We took our particulate tests at the same location they did and, if you remember, TVA answered your question indicating that they have a mechanical collector. We tested ahead of the mechanical collector.

Q: Erv, there is a lot of data here, as a couple of people have said. Maybe I am just pulling something off the top, but I noticed that on the figures for Widows Creek #5, your so-called low NO_x run really has about the same NO_x level as the so-called base line. Whereas in TVA's data from yesterday on Widows Creek #5, they got about a 30% reduction in NO_x. So, is your so-called NO_x run really a low NO_x run or is it just base line all over again?

A: Well, it was really "low NO_x" type of operation because we were operating the boiler in a staging pattern. Unfortunately, the oxygen levels did turn out to be the same for both "baseline" and "low NO_x" operation. As Al pointed out, the stoichiometric air at the active burners with staged firing would be less than under baseline operation because we did have burners out of operation and on air only.

Q: As one of the few operators represented here at this symposium, I would just like to add a comment more than a question, and a plea for some of this longer term corrosion data. Corrosion is a very subtle phenomenon in a coal fire boiler. The often-mentioned difficulty is getting test candidates because of fears.

And these are very real conditions. We have had identical boilers, identical coal. One of them will corrode and one will not. It is a very complicated phenomenon, and long term data is needed.

A: You are right. This program is co-sponsored by EPRI. They have advertised in their newsletter asking for candidate boilers. So, if you or anyone else has a candidate boiler, please let us know. This type of testing is absolutely necessary. The corrosion probes were used because it was a short term, quick means of getting an indication. We won't really know the answer until we get more actual tube wall measurement data.

Q: Those are the kind of things I was going to say yesterday that were in our plans this coming fiscal year. We would like to initiate an extension of the corrosion work in terms of a long-term monitoring operation. The success of that program is going to depend very heavily on the host sites and just how intensive a program we can get underway. I think it is becoming very clear now that we certainly need to better quantify the effects of these combustion modifications on corrosion so that we are going to have all of the facts. I think the jury is still out on this thing right now, though.

A: I would like to make just one comment on corrosion. As you saw in our slides, the corrosion differences on coupons here were very, very nominal. On our previous program, we had considerable scatter. Whenever you do a corrosion probe test you recognize that it is not a precise thing. If you get the relatively consistent results such that we have obtained on the last program, then I think you are doing very well!

Q: In your tests where you mix coal and oil, I was wondering what was the basis for the percentage of coal and oil. Whether it was Btu's, weight, or just what?

A: Our basis was the Btu heat release for each fuel.

Q: In connection with the nitrogen, did you measure the nitrogen in the coal to see whether that was the contributing factor because you showed an appreciable reduction as you went to more oil? I was wondering if perchance that extra nitrogen was coming from the coal?

A: No coal data is given in the report that you have because we didn't have complete fuel analysis when it was written. But we do measure the nitrogen content and it will be included in the final report.

ANALYSIS OF GAS-, OIL- AND COAL-FIRED UTILITY BOILER TEST DATA

By:

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ANALYSIS OF GAS-, OIL- AND COAL-FIRED UTILITY BOILER TEST DATA

ABSTRACT

This study is being conducted by The Aerospace Corporation in response to a strong need that exists today for a reliable, useful analytical tool to guide combustion modifications in full-scale, multi-burner utility boilers to reduce NO_x emissions. In the light of today's understanding of the many processes controlling NO_x formation, such an analytical tool must necessarily be semi-empirical. To be reliable and directly useful it should take into account current understanding, yet be capable of verification with data from widely different, full-scale, multi-burner utility boilers.

Such a tool has been constructed, by use of a Zeldovich model for thermally generated NO_x, a unique model for the conversion of fuel-bound nitrogen and an approximate flow and mixing model first to generate an approximate NO_x prediction equation. The coefficients of this equation were then empirically improved by regression analysis of data from nearly 600 tests conducted on 16 full-scale, multi-burner utility boilers burning coal, oil or natural gas fuels in single wall, opposed and tangential configurations. Parametric analyses with the resulting semi-empirical equations show the independent effects on NO_x emissions of load, excess air, NO_x ports, burners out of service (number and location), combustion air temperature, boiler cooling rate, weight fraction of nitrogen in the fuel and combinations of these leading to NO_x emissions minima. Results can be used directly today as a tool to guide operating conditions and hardware modifications for significant reductions in NO_x emissions.

SECTION 1.

SUMMARY

A semi-empirical tool has been developed which can be useful in guiding development testing to reach practical minimum levels of NO_x emissions from utility boilers burning coal, oil or natural gas fuels. A detailed but approximate model describing the generation of NO_x in large multiple-burner boilers was used to generate a single equation which, if all of the processes involved were well known, would be capable of predicting NO_x emissions. This qualitative equation, of approximately the proper functional form, was then made quantitative by regression analyses of large samples of data from a total of 575 tests of full-scale coal-, oil- and natural gas-fired utility boilers.

The details of the development of the equation and results of application to oil- and gas-fired boilers have been reported in "Analysis of Test Data for NO_x Control in Gas- and Oil-Fired Utility Boilers", Report No. EPA 650/2-75-012, January 1975. This work formed much of the basis for the later analysis of coal-fired data. Since reduction of NO_x emissions from coal-fired boilers is of greatest interest today, and the results of that study have not yet been reported, this paper is directed primarily to coal-firing. A major modification to the previous work, which was necessary to adequately analyze coal-fired data, involved improvements to that part of the model describing the generation of NO_x from the conversion of fuel-bound nitrogen.

The data sample from coal-fired utility boilers used in this study showed that minimum emission levels between 250 and 350 ppm were achieved in each of the boiler firing types (tangential, opposed and single-wall), with acceptable levels of carbon monoxide emissions. In general, the lowest levels of NO_x emissions under full-rated load

from all of the boilers in the sample were achieved with low-combustion air (windbox) temperatures, with a high moisture coal involving a low temperature rise due to combustion (e.g., lignite) and/or with staged combustion by operating 20-25 percent of the burners on air-only and located in the highest levels of the burner array.

Parametric studies to explain and extend the effects of a number of significant parameters on NO_x emissions have indicated that levels less than 250 ppm can be achieved by combinations of combustion modifications which result in (1) reduction of the overall boiler excess air to about three percent excess oxygen, (2) reduction of the effective excess air in the active burner region to less than 80-85 percent of theoretical and (3) reduction of the maximum equilibrium combustion temperature to less than about 2200K (3500 degrees F). Results of the analyses are sufficiently general to indicate that a number of widely different physical modifications can achieve the above three objectives and result in further NO_x reductions.

Further testing is required under the operating conditions representing the minima in the test data used, as well as those representing further significant NO_x reductions as indicated by this study to assure the lack of, or to resolve, any undesirable side effects of operation under these conditions. Potential side effects include excessive emissions of other air pollutants, excessive loss in plant efficiency, unstable combustion and excessive tube wall corrosion or erosion rates. It is side effects such as these, rather than processes inherent to NO_x formation, that appear to represent the most likely limitations on ultimate NO_x reduction.

SECTION 2.

DATA ANALYSIS APPROACH

Nearly all technical problems which arise in existing systems generate a desire to achieve some sort of new operating condition or situation. If empirical solutions are not readily achieved, and if there is no great urgency to resolve the problem, the overall approach can proceed through a sequence of fundamental and applied research (and screening, developmental and full-scale testing) to an orderly solution. In each of these steps, experimental data of various kinds are needed to confirm the solutions of the preceding step and to feed back new information. If the urgency is great, however, all of these steps must be undertaken concurrently. In many such cases, the powerful tool of "cut-and-try", guided by semi-empirical analytical tools, has created a successful solution in the shortest possible time.

These semi-empirical tools are usually initiated by using current technology to develop a rough prediction model. If everything were known of these processes, experimental data would be necessary only to confirm the analysis. If this is not the case, at least a directly applicable, semi-empirical development tool can be generated by using full-scale data to correct the theoretical prediction model. The most comprehensive way to convert this imperfect analytical model to a semi-empirical development tool is to use the theoretical model as a correlation equation for "least squares fit" or regression analyses of full-scale data. Such computer analysis of large quantities of data, in which the significant independent parameters vary over wide ranges, can correct for deficiencies in the analyses and provide an equation which, at the very least, explains the existing data.

The problem of excessive NO_x emissions from utility boilers appears to be a classical one of the urgent type discussed above. There does not appear to be sufficient understanding of all aspects of the problem at this time to reasonably expect accurate prediction of NO_x emissions from full-scale, multiple-burner boilers, under all operating conditions, from fundamentals alone. Considering the extreme complexity but major significance of, for example, hydrocarbon/air/nitrogen combustion and of turbulent flow/reaction phenomena, it also appears that a fairly long, concentrated research effort may be necessary before these and other significant aspects of the problem are sufficiently well understood. It seems likely, therefore, that a semi-empirical engineering approach such as described above can be most expeditious in resolving the problem, at least for the immediate future. While it was not known how successful such an approach might be, The Aerospace Corporation undertook this effort with the assistance and funding of EPA's Combustion Research Branch, Industrial Environmental Research Laboratory, Research Triangle Park, N.C.

In general, the approach to development of this semi-empirical tool involved four steps: (1) development of a general, approximate model of NO_x generation in full-scale, multi-burner utility boilers; (2) development of a single equation from the model, consisting of a series of linear terms with only approximately determined coefficients, to predict NO_x emissions; (3) regression analyses of large quantities of widely varying data from utility boilers to improve the coefficients of the prediction equation; and (4) parametric analyses with the resulting equations, and verification with selected data, to show the effects of major variables influencing NO_x emissions.

A great deal of detail was involved in setting up the model and generating the prediction equation. Most of this detail is described in Reference 1, which reports the study of oil and natural gas fuels.

Figures 1, 2 and 3 show the gross mixing model and the various mixing zones established for the general wall-fired configurations, and Figures 3 and 4 show the subsequent modification for tangential boilers. Mixing in this model is of the so-called "tank-and-tube" type, where species mixing takes place instantly at the beginning of each zone and the resulting mixture then flows uniformly through the zone, generating NO_x. Although not within the scope of this project, a finite rate gasification and gas mixing model has been developed but, as of this writing, has not been incorporated in the model.

NO_x chemistry in the model includes a simple Zeldovich mechanism for thermally-generated NO_x and a largely empirical model for the conversion of fuel-bound nitrogen. The assumptions were made that "prompt NO" phenomena, and mechanisms for the destruction of NO_x, had only small effects on total NO_x emissions from these large boilers, compared to the generation of NO_x from the simple Zeldovich and bound nitrogen conversion mechanisms.

The rough prediction equation initially consisted of 22 terms describing thermal NO_x generation in the different mixing zones, one term to account for conversion of bound nitrogen and a constant. The 22 thermal NO_x terms were subsequently combined in various ways to eight terms. Each of these terms is calculated, in a computer program, from a number of highly non-linear functions but appears in the prediction equation only as a linear term with an approximately determined coefficient.

Further detail concerning the formulation of the model and the prediction equation can be found in Reference 1. A report (Reference 2) describing subsequent modifications, improvements and analyses for coal-fired boilers will be published later this year.

Table 1 summarizes the total data sample used in this study. Without a finite-rate gasification expression to account for this major physical difference between the coal, oil and gas fuels, it was considered necessary to analyze data with each of these fuels separately. The regression analysis had to be depended upon to correct the coefficients of the various zones representing series gasification and mixing for the actual degree of gasification and mixing in each of these zones.

Table 1 shows a total data sample of 575 test conditions with coal, oil and natural gas fuels. An additional 70 test conditions were also reduced and entered into the program, which involved attempts to shut off the combustion air, or secondary air, to some burners by closing the air registers. A great deal of effort was spent attempting to establish the degree of air leakage through these closed air registers. The effort was finally abandoned and these tests were deleted from the data sample. It appears that in some cases this leakage can be appreciable. Conclusions based on a significant fraction of data from tests with closed air registers can lead to significant errors. Overall, the effect of deleting these tests, representing only 11 percent of the total, was minor. For these same reasons, if at all possible, no data from any source was entered into the data sample if the air registers on some burners were partially closed while others were completely open. It is considered impossible to accurately estimate the distribution of combustion air to the various burners in such cases.

Analyses of the coals burned in the boilers of this study are reported in Reference 3. To minimize the work load in calculating equilibrium combustion temperatures and product species, the seven coal types fired were reduced to four more general coal types. The analyses of these synthesized coals are shown in Table 2.

SECTION 3.

RESULTS

Three types of results of this study are presented. Because of the lack of understanding of the mechanism of conversion of fuel-bound nitrogen to NO_x, the formulation and the validity of the term generated in this study to account for NO_x from this source are considered results of significant interest.

Secondly, the results of the parametric studies show the independent effects of some of the major variables affecting NO_x emissions. Many of these effects have been observed before and the results of this study serve only to confirm these previous observations and to lend credence to this approach. The detailed effects of two-stage combustion, burners-out-of-service and combustion air temperature in reduction of NO_x emissions in full-scale, multiple-burner boilers are considered significant new results and, therefore, primarily these parametric studies are discussed.

Finally, all of the results of the studies of coal-, oil- and natural gas-fired utility boiling data lead to some general conclusions regarding techniques for minimizing NO_x emissions from the two general sources: (1) conversion of fuel-bound nitrogen; and (2) thermal fixation of nitrogen in the air. Application of these techniques to boilers firing each of these fuels leads to practical conclusions regarding hardware modifications to yield minimum NO_x emissions.

Fuel-Bound Nitrogen Conversion

Details of the development of the model for bound nitrogen conversion will be available in the forthcoming report cited as Reference 2. Basically, many observers (e.g., References 4 through 8) have noted that: (1) the conversion efficiency of fuel-bound nitrogen to NO_x at a fixed level of excess air is some inverse function of the weight fraction of nitrogen chemically bound in the fuel; (2) the efficiency of conversion is directly proportional to the local air-fuel ratio; (3) the rate of nitrogen conversion is of the order of the hydrocarbon-air reactions themselves; and (4) the conversion efficiency appears to be a weak function (if at all) of local gas temperatures. These observations were used to postulate a simple model of the conversion process in which: (1) the conversion efficiency is inversely proportional (empirically to the two-thirds power) to the weight fraction of nitrogen in the fuel (ash- and moisture-free); (2) the conversion efficiency is linearly proportional to the local air-fuel ratio, with zero NO_x occurring at an air-fuel ratio where there is just sufficient oxygen present in the air to oxidize the carbon to carbon monoxide and the hydrogen (other than that already bound to oxygen in the moisture) to water; (3) the appropriate local air-fuel ratio is the average of that in the regions where the initial hydrocarbon reactions are taking place; and (4) the conversion efficiency is independent of the local temperature.

Figure 5 shows a plot of data available to this study from full-scale tests and some laboratory experiments relating conversion efficiencies at three percent oxygen to weight fraction of nitrogen in the fuel. Since the full-scale data may involve some thermally generated NO_x, the empirical curve shown in the figure was established to represent a lower bound of the full-scale data, but the curve represents actual data in the case of the controlled tests conducted in the laboratory. Much more data of this type are available (e.g., Reference 4) but not all of the appropriate test conditions were available to this study. In general, these additional data confirm a curve of the type shown.

The model for the conversion of fuel-bound nitrogen to NO_x used in this study is a simple linear function of the fraction of theoretical air available during the initial hydrocarbon reactions. The intercept is set by assumption (2) above, and the slope is determined by the weight fraction of nitrogen in the ash- and moisture-free fuel according to Figure 5. Figure 6 shows a plot of these curves for the four coal types and the low sulfur oil of this study.

The problem of calculating the efficiency of conversion of fuel-bound nitrogen to NO_x from the above model would now be quite simple and straightforward if the coal and oil gasification and the gas mixing rates in the active burner region were well known. In that case, the average local air-fuel ratio in the regions where the initial hydrocarbon reactions were taking place could be accurately determined and the average conversion efficiency calculated. Since development of these rates was not within the scope of this study, an approximate method was developed to take into account the effects of slow gasification rates of coal particles on conversion efficiency.

Observations on coal flames in boilers of various firing types indicate that luminous, reacting flames appear to extend 4.5 to 6.1 meters (15 to 20 feet) into the boiler from the burners. If the firing configuration is such that gross mixing between burner flows and bulk gases is forced to occur within that distance, then the average local air-fuel ratio in the region where the initial hydrocarbon reactions are taking place (including some further distance for gas mixing) would approximately be the average of all burner flows and bulk gases at that level. If such mixing does not occur within that distance, then the appropriate average would be that of the burner flows alone. Opposed and tangential firing configurations are both designed to force such mixing early. The opposed, coal-fired boiler in this study allows a maximum of about 4.3 meters (14 feet) for mixing within the burner flows before forced mixing with opposed burner flows begins. Mixing with bulk gases begins well before that, at least in the higher burner levels. The tangential configuration is designed to induce swirling bulk gases and more direct and early mixing of bulk gases with burner flows and between the burner flows.

For the opposed and tangential boiler configurations the appropriate average air-fuel ratio for calculation of the fuel-bound nitrogen conversion efficiency at a given burner level was taken to be the average of all of the burner flows introduced into the boiler up to and including that burner level. The appropriate air-fuel ratio for all of the coal introduced into the boiler (the average for the region of the active burners) was then taken to be the average of all of the levels where fuel is being introduced. If all of the active burners, and none of the air-only burners, are located below some level (for example, all burners in the top row air-only and all burners below the top row active) then the average air-fuel ratio of the active burner region is equal to that of the burners. In the case where air-only burners are mixed with active burners the average air-fuel ratio is always higher than that of the burners. Since the efficiency of conversion of fuel-bound nitrogen has been observed to increase with the local effective air-fuel ratio, these higher average air-fuel ratios always increase the NO_x generated from the fuel nitrogen. In general, this accounts for the fact that, when air-only burners are mixed (vertically and/or horizontally) with active burners and gross forced mixing is early, some of the gasified fuel will initially react in local regions of high air-fuel ratio and generate higher levels of NO_x from fuel-bound nitrogen conversion. From the standpoint of NO_x generated from conversion of fuel-bound nitrogen alone, this latter case implies that minimum NO_x requires that air-only burners be located in the highest levels of the burner array.

Single-wall-fired boilers, however, involve no direct mechanism for creating this gross mixing. In boilers with small numbers of burners, and limited vertical distribution of the burner array, the array begins to resemble a single burner. In a single-burner configuration there is little or no mixing with bulk gases and, in fact, the transition from "burner flows" to "bulk gases" is even difficult to define. In the single-wall coal-fired boilers of this study, the burner flows at the lowest level can proceed, with little or no forced mixing with bulk gases, for 6.7 to 9.8 meters (22 to 32 feet) across the boiler. In this study, therefore, the average air-fuel ratio "seen" by the fuel in the initial reaction period was taken as that of the active burners, regardless of the locations of air-only burners in the burner array. Treating the conversion of fuel-bound nitrogen in single-wall burners in this manner implies that any effect of the vertical location of air-only burners in these boilers must result from effects on thermally-generated NO_x.

For purposes of regression analysis of the coal data sample, the NO_x contributed by conversion of fuel-bound nitrogen was calculated from the model and the mixing assumptions discussed above, and subtracted from the measured value of NO_x. The regression analysis, then, was conducted only on that portion of the NO_x assumed to be due to thermal mechanisms. Verification of this total approach will be discussed in the following subsection.

Results of Parametric Studies

Results of parametric studies with oil and natural gas fuels are presented and discussed in detail in Reference 1. Since NO_x reduction in utility boilers burning coal fuels is of greater interest today, primarily results related to coal burning will be discussed.

In developing the equation to be used for the parametric study of coal, the entire coal-fired data sample as shown in Table 1 was used in the regression analysis to establish the coefficients of the terms. The correlation coefficient for this data sample was 0.82. The resulting equation, then, is approximately applicable to any of the seven boilers in the sample and, if the sample is sufficiently typical of coal-fired boilers in general, could be considered applicable to any coal-fired boiler.

The most significant term in the equation is that describing the conversion of fuel-bound nitrogen. In all of the 186 tests in the coal-fired data sample of this study, conducted on seven widely different boiler geometries and firing types and involving four quite different coals, no data were found which indicated NO_x levels significantly below the level calculated from the bound nitrogen term. The same is true of the 139 test data samples on four boiler types fired with the single low-sulfur fuel oil. Therefore, the bound nitrogen term tends to represent a minimum NO_x level obtainable by the combustion modification techniques represented in the data sample. Since the bound nitrogen term is a function of the coal composition (primarily the weight fraction of chemically bound nitrogen in the ash- and moisture-free coal) and the effective fraction of excess air surrounding the coal particles while they are gasifying, these are the only parameters which can be controlled to minimize NO_x from this source.

The second most significant source of NO_x in the equation used for the parametric calculation is represented by the eight terms describing thermal NO_x generation in the region of the active burners. The majority of the analytical effort in this study was involved in establishing these terms to adequately represent thermal NO_x generation in this complex mixing and reaction region. These terms were all important in the study of NO_x from natural gas-fired boilers, of course, but will be seen to be much less significant with coal-fired boilers.

Finally, one other significant source of NO_x, with all fuels, is represented by the constant in the equation derived by the regression analyses. Parametric studies on the natural gas- and oil-fired data showed that this constant represented the thermal NO_x

generated in the region above (or downstream) of the active burner region (identified as the "NO_x Port Mixing" zone in Figure 2). Figure 7 shows a parametric calculation, from Reference 1, on the effects of large increases in NO_x port air flow on NO_x emissions with natural gas fuel. At very large values of NO_x port flow, when the entire active burner region should be generating no NO_x, the calculation becomes asymptotic to the approximate value of the constant. The only remaining region where significant NO_x could be generated, in such a case, is that zone above the active burners which is always at the level of excess air of the overall boiler. This is also the region where the final mixing of NO_x port air flow, or air flow from air-only burners in the top burner level, is mixed with fuel-rich combustion products coming from the active burner region below, forcing the local air-fuel ratio of these gases to cross stoichiometric from fuel-rich to the slightly fuel-lean mixture of the overall boiler.

Therefore, the three major sources of NO_x in coal-fired boilers in the study are: (1) the conversion of fuel-bound nitrogen in the boiler region where the initial hydrocarbon reactions are taking place; (2) thermally-generated NO_x in the complex mixing and reaction zones in the region of the active burners; and (3) the final mixing zone above the active burners. Figure 8 identifies these three sources in the data from TVA's sister boilers Widows Creek Units Nos. 5 and 6. The figure shows that the lower bound of these data rather closely follows the calculated line for the NO_x generated from conversion of the fuel-bound nitrogen for this coal type, confirming both the slope and the intercept. In general, the full-load NO_x data tend to follow a second straight line parallel to the bound nitrogen line and higher by about 146 ppm. This is the constant in the parametric equation for the combustion air temperature of this boiler and the combustion temperature rise of this coal. The thermal NO_x generated in the active burner region is represented by the large scatter of data (for different air-only burner combinations) approximately centered about theoretical air and added to the NO_x from the bound nitrogen and the constant terms. This region is enclosed by a Zeldovich-type function for a constant time.

A large number of parametric calculations were made to investigate various methods of reducing the NO_x generated from coal-firing in each of these regions. From the standpoint of practical, readily implemented combustion modifications represented in the data, only three significant "rules" were observed:

(1) Air-only burners should be located in the highest row(s) of the burner array. Figure 9 shows the parametric calculations of NO_x emissions when all burners in a given vertical level are operated air-only. While the effects vary in magnitude, all show that the top level is the appropriate location for air-only burners to minimize NO_x.

(2) Increasing the number of air-only burners, located in the top row(s) of the burner array, reduces NO_x from both fuel-bound nitrogen conversion and from thermal generation in the active burner region. This will be shown in subsequent composite figures.

(3) Within practical limits of overall boiler excess air and within the combustion modification techniques represented in the data, only those modifications which reduce the combustion gas temperatures in the final mixing zone reduce thermal NO_x from this region. Data in this sample show low NO_x emissions from this region under conditions of low-combustion air temperature, low-combustion temperature rise (lignite fuel) and/or long-combustion gas cooling time in the active burner region. Other techniques to reduce the temperature in this region, such as flue gas recirculation

and water spray, might also accomplish this same objective but were not evaluated in this study. It is possible that air pre-treatment need only be applied to the "overfire" air rather than to all of the combustion air.

The remaining figures show all of the available data on each of the different types of coal-fired boilers and coal types in this sample and the parametric calculations on the effects of the above three major parameters. This form of data confirmation was chosen because of the large number of significant variables which affect NO_x. Although the data sample of this study is relatively large, very little data can be found in which only a single major parameter was varied, with all others being held constant. In Figures 10 through 15 four calculated NO_x curves are shown, superimposed on the data: (1) the fuel-bound nitrogen curve; (2) the variation with numbers of air-only burners located in the highest levels of the burner array; (3) the same case as (2) but with the combustion air temperature reduced to 422K (300 degrees F); and (4) variation of overall boiler excess air with all burners active (fuel plus air). The latter calculation was made both to provide a comparison to case (2) of a configuration not involving the final mixing zone and to show the effects of not using the staged combustion (air-only burners) technique to reduce the excess air to the active burners. Since reduced boiler load does not represent a practical way to reduce NO_x emissions, considering the demand for electricity and the limited available capacity, all parametric calculations shown are for full-rated load operation.

Figure 10 shows the same TVA Widows Creek data as in Figure 8 with the four parametric curves superimposed. The available data show that NO_x levels as low as about 380 ppm (dry, at three percent O_2 overall boiler excess oxygen) were tested with no undesirable side effects (at least none noted in the field testing reported in Reference 3). Data lying below the curve for two-stage combustion (case 2) tended to represent low load and/or cases where high carbon monoxide emissions were measured. If the two-stage combustion curve could be reliably extrapolated that far, no limit on NO_x reduction would be observed per se. Of course, no data are available either to verify this NO_x extrapolation or to evaluate possible undesirable side effects. Reduction of combustion air temperature to 422K (300 degrees F) from about 606K (630 degrees F) at rated load substantially reduced the NO_x thought to be thermally generated in the final mixing zone, except at very low levels of excess air in the active burners. The curve representing "normal" operation (all burners active), with overall boiler excess air as the single variable, shows the large increases in NO_x thermally generated in the active burner region that are possible without two-stage combustion. All of the highest data points (greater than 600 ppm) shown in Figure 10, with excess air to the burners less than 115 percent of theoretical, result from burner configurations with two air-only burners located in the bottom level of the burner array.

Figure 11 shows the data and parametric calculations for Alabama Power's Barry Unit No. 4. This boiler is unique in the data sample because of the very low combustion air temperature (428K, 310 degrees F) at rated load. In this case, the parametric calculations for two-stage combustion and 422K (300 degrees F) combustion air temperature are represented by the single curve shown about 75 ppm above the bound nitrogen curve. This represents nearly a factor of two reduction in the NO_x generated in the final mixing zone from the previous case. The upper limit of the data and the parametric curve for normal operation (with no final mixing zone) appear to be little affected by this temperature reduction, although the three data points at the highest fraction of excess air appear to disagree with the parametric calculation. NO_x levels as low as 250 ppm were tested with no evidence of excessive CO emissions (less than 177 ppm).

Shown in Figure 12 is a very similar tangential boiler, Naughton Unit No. 3 of Utah Power and Light, firing a coal similar in equilibrium combustion temperature rise but operated with combustior air temperatures of about 667K (740 degrees F) (430 degrees F hotter than Barry No. 4 and 110 degrees F hotter than Widows Creek No. 5). The parametric calculations in this figure show evidence of higher levels of thermally generated NO_x in the active burner region, particularly when the excess air in the active burner region was less than theoretical. Unfortunately, no tests were conducted on either of the tangential boilers in this sample with air-only burners located at any vertical level other than the top level so it is difficult to confirm the degree of thermally generated NO_x originating in the active burner region. The thermal NO_x thought to originate in the final mixing zone is larger in this case (about 165 ppm) than in either the other tangential boiler (75 ppm) or the single-wall boiler (146 ppm). The parametric calculations indicate that the reduction in NO_x generated in the active burner region by the use of a few air-only burners located in the top levels of the burner array is more than offset, with these high-combustion air temperatures, by that generated in the final mixing zone (curve 2 is higher than curve 1, where they overlap). The data imply that these air-only burners are somewhat more effective than the calculations indicate. Operating conditions yielding total NO_x emissions levels as low as 236-266 ppm were tested, with measured CO emissions less than 91 ppm.

The parametric calculations thus far have shown the relatively strong effect of combustion air temperature on the total NO_x emissions. A further case of interest in this regard is the data from boilers firing coal type 1 (lignite - see Table 2). In this coal, the moisture content is so high that the combustion temperature rise is calculated to be more than 280K (500 degrees F) lower than the coals fired in the boilers discussed to this point. Thus, almost regardless of the combustion air temperatures involved, the NO_x emissions should result almost totally from conversion of the fuel-bound nitrogen. Figure 13 shows the parametric calculations for Dave Johnson Unit No. 2 of the Pacific Power and Light Company, which fired coal type 1. The parametric calculations for staged combustion (curves 2 and 3) do indeed closely parallel the bound nitrogen line. Unfortunately, of the 14 tests conducted on this boiler 11 involved fully or partially closed air registers and were therefore deleted from the data sample. The two tests involving air-only burners in the top levels of the burner array (showing excessively high carbon monoxide emissions) lie only slightly below the appropriate parametric calculation (curve 2) and right on the fuel-bound nitrogen curve. The one case shown in reasonable agreement with the parametric calculation for normal operation represents a configuration with air-only burners in the bottom level of the burner array. Data from the other 11 tests, involving closed air registers, tend also to verify the calculations but show a great deal of scatter above and below the calculated lines. Further confirmation of agreement between calculated NO_x levels and data for coal type 1 will be seen later in the application of the parametric calculation for a boiler which was not in the data sample used for regression analyses.

A case similar to the previous one is represented by Four Corners Unit No. 4 of the Arizona Public Service Company. Coal type 2 was fired in this boiler. The very high ash content of this coal also tends to reduce the equilibrium combustion temperature rise. Aerospace calculations indicate that this temperature rise is about

155K (280 degrees F) lower than those of coal types 3 and 4, but about 144K (260 degrees F) higher than that of coal type 1 (Johnson No. 2). Full-load combustion air temperatures in Four Corners No. 4 were about 580K (580 degrees F), representing a relatively nominal level. The boiler is very large (800 MW), with a divider wall, and a complicated burner array consisting of 54 burners arranged such that some burners are directly opposed and some are not. The potential mixing of the burner flows and bulk gases was considered sufficiently rapid that it was considered an "opposed" firing type (the only one of this type in the data sample).

Figure 14 shows the data and parametric calculations for this boiler. In this case, the data deviate considerably from the parametric calculations, particularly for the cases where the average excess air in the region of the active burners was greater than about 110 percent of theoretical. Below this level the data appear to be approaching the parametric calculation (curve 2) more closely. The agreement between the parametric calculations and the data is best, then, in the region of low NO_x emissions, where it is most important. The data in Figure 14 show that at least two operating conditions were tested which yielded 450 to 500 ppm NO_x emissions with CO levels less than 200 ppm. While this minimum level of NO_x tested seems quite high, no tests were conducted with burner excess air less than about 92 percent of theoretical.

The data shown in Figure 14 represent the only case of significant disagreement with the calculated NO_x levels found in this study. Unfortunately, in the data sample of this study, it also represents the only data available from boilers firing high ash coal. This boiler is also the largest in the data sample and has the largest number of burners arranged in the most complex burner array. There was not sufficient time to further investigate the causes of the disagreement between the calculated NO_x levels and the data. It is tempting simply to empirically increase the slope of the line describing NO_x from fuel-bound nitrogen conversion for this coal type but more data are needed to verify that the disagreement is indeed related to the coal type.

All of the parametric calculations shown in Figures 10 through 14 were conducted using the same NO_x equation, derived from regression analysis of all of the coal-fired data in the sample. With the exception of the very high NO_x levels (greater than 600 ppm) observed in the Four Corners No. 4 data, firing the very high ash coal, the parametric calculations are reasonably well substantiated by the data. To the extent that the boilers and coal types represented in these figures are typical of all coal-fired boilers and coal types, this equation might be applied with confidence to any other boiler or coal type, simply by entering the appropriate fuel characteristics and the operating characteristics and hardware of the boiler.

To test this hypothesis, data from Leland Olds Unit No. 1 of the Basin Electric Power Cooperative were held out of the sample used for regression analysis. This boiler was chosen because it appeared to represent one of the more complex cases. It was fired with coal type 1, the high-moisture lignite fuel with very low-equilibrium combustion temperature. The combustion air temperatures, however, are very high (780K, 950 degrees F) at rated load. Also, this boiler is of the opposed firing type in the bottom two levels but the top level (of three levels) has burners on only one wall. The burner configuration is also unique in that there are eight burners in each of the bottom two burner levels. It was considered that these unique features (the coal type, the combustion air temperature and the burner configuration) would represent a reasonably severe test of application of the NO_x equation derived semi-empirically from data from other boilers.

Figure 15 shows the calculations and data for this boiler. The data are perhaps in better agreement with the calculated NO_x levels than they were with the boiler data included in the sample used for regression analysis. The data show a rather distinct transition, from the lower NO_x level resulting from configurations with air-only burners located in the top levels of the burner array (curve 2) to the higher NO_x level associated with normal operation (curve 1), when the air-fuel ratio in the active burner region was about 105 percent of theoretical. In general, the agreement between the data and the calculation for this boiler, which was not in the data sample used to derive the calculation equation, is considered good.

General Conclusions from the Study of Coal-, Oil- and Natural Gas-Fired Data

The semi-empirical analytical tool developed in this study has proved to be of significant value in providing reasonable explanations for the effects of certain boiler operating and hardware parameters on NO_x emissions and for the NO_x emissions minima observed in the data. The greatest value of this tool, however, appears to lie in the direct, useful guidance which it provides for development testing which, with greater confidence, can be expected to yield minimum NO_x emissions. In particular, the approach discussed herein is the only known method, at this time, that the complex interactions between burners in full-scale, multiple-burner boilers can be taken into account adequately to point the way to practical, useful techniques for significant NO_x reduction.

In general, data contained within the sample of 575 tests on 16 boilers of the single-wall, opposed and tangential configurations firing four types of coal, a low-nitrogen (and sulfur) oil and natural gas indicate that NO_x minima as low as about 250, 130 and 110 ppm for the coal, oil and gas fuels, respectively, have already been demonstrated under full-load conditions. A possible exception to these low, demonstrated minima is the high-ash (25 percent) coal, which showed NO_x emissions no lower than 450 ppm, but insufficient data were available to determine if this truly represents the readily attainable minimum with this coal.

Parametric analyses, extrapolating from this base of existing data, indicate relatively straightforward, understandable and apparently practical further combustion modifications to affect further significant NO_x reductions. The only possibly inherent limit to NO_x reduction which can be deduced from the data of this study (alone) is related to the extremely fuel-rich initial combustion conditions required to completely eliminate the NO_x generated from conversion of fuel-bound nitrogen (55 to 65 percent of stoichiometric air). It is possible that the hydrocarbon flame itself cannot be supported under these very rich conditions, resulting in flame-out or combustion instability. Practical limits due to other undesirable side effects may also exist but data on these other effects were not contained in the sample of this study.

The general technique for minimizing NO_x emissions from the conversion of fuel-bound nitrogen involves maximum reduction of the air available for combustion in the local regions of the boilers where the solid or liquid fuel is gasifying and where the initial hydrocarbon reactions are taking place. Without major modifications to existing boilers, this implies the operation of large numbers of burners on air-only, and/or NO_x ports, located as high as possible in the boiler.

Techniques for minimizing thermally generated NO_x depend on the concentration of nitrogen in the fuel. In high-nitrogen fuels such as coal, the air available for combustion in the active burner region must be maintained as low as possible, at least until the initial hydrocarbon reactions are completed. This will also minimize NO_x

thermally generated in the active burner region. The remaining problem area, then, is in the boiler mixing zone where the remaining excess air must be added to the hot products of the earlier fuel-rich combustion to bring the total for the overall boiler up to about three percent excess oxygen. It is in this region that the local air-fuel ratio of the bulk gases must pass through the region of high thermal NO_x generation rates around stoichiometric as the remaining excess air is added. The data of this study indicate that techniques which reduce the gas temperature in this region (i.e., reduced combustion air temperature or low temperature rise due to combustion) are quite effective in minimizing NO_x thermally generated in this region.

If there is no nitrogen chemically bound in the fuel, as with natural gas, it is not necessary to maintain fuel-rich conditions in the early combustion regions. In fact, in order to avoid establishing mixing zones anywhere in the boiler where the air-fuel ratio must pass through the regions of high thermal NO_x generation rates, it appears most desirable to maintain air-fuel ratio conditions in natural gas burners well above that of the overall boiler, finally approaching the boiler air-fuel ratio at the latest possible moment through the use of fuel-rich burners in the top level of the burner array, or through the use of fuel-rich "NO_x ports". This concept has not been tested in full-scale utility boilers. Using more standard modifications, involving air-only burners and/or air-only NO_x ports, the remaining active burners can only be fuel-rich. With gaseous fuels, where the intimate air-fuel mixing in the burner flows is rapid, minimum NO_x emissions normally result from the same burner and NO_x port configurations which minimize NO_x emissions in coal-fired boilers (i.e., large numbers of air-only burners concentrated in the top levels of the burner array, open NO_x ports and reduced peak combustion temperatures).

Low nitrogen-bearing oil fuels represent an intermediate case between that of coal and natural gas. Clearly, if very low NO_x emissions are required, the NO_x resulting from conversion of even this low concentration of fuel-bound nitrogen must be eliminated. This means that the optimum combustion modifications must be the same as for coal-fired boilers. If, however, the level of NO_x emissions resulting from conversion of the fuel-bound nitrogen at air-fuel ratios somewhat above that of the overall boiler is acceptable, then the optimum natural gas configuration might be appropriate. The natural gas configuration would at least minimize thermally generated NO_x, leaving only the NO_x resulting from the conversion of some fraction of the fuel-bound nitrogen. Since liquid fuels require considerable time to vaporize and, therefore, intimate that air-vapor fuel mixing is slow compared to that of natural gas, the average, local air-fuel ratio surrounding the burning oil vapor can approximately be maintained air-rich simply by locating air-only burners at the lowest levels of the burner array (i.e., by maintaining air-rich bulk gases). All of the oil-fired boiler data analyzed in Reference 1 indicated that, within the range of the configurations tested, minimum NO_x emissions resulted from this latter case.

This entire study, of course, has concentrated on techniques for NO_x reduction alone. Many of the conclusions drawn from the parametric studies are extrapolations beyond the existing data (based on a reasonably sound model and reasonable agreement with the existing data). No analytical predictions, no matter how free of empiricism, are free of risk, particularly as the extrapolations from known data increase. The conclusions of this study need to be verified by test. In particular, these conditions need to be evaluated for undesirable side effects. Among the potentially harmful side effects which need to be evaluated, to determine limits on the maximum reduction of NO_x emissions, are: (1) excessive plant efficiency losses; (2) excessive emissions of other air pollutants; (3) excessive boiler wall corrosion or erosion rates; (4) combustion and flame instabilities; and (5) practical control of boiler operation and heat flux profiles. The questions of the effects of combustion modifications on plant efficiencies and on combustion instabilities are currently being addressed in a continuation of the subject study. At least within the data of this study, it appears that hydrocarbon, carbon monoxide and smoke emissions can be controlled to acceptable levels simply by maintaining the boiler overall excess air greater than about three percent excess oxygen in coal-fired boilers. No detailed data on the effects of combustion modifications on wall corrosion or erosion rates or on boiler controllability were available in this study.

ACKNOWLEDGEMENTS

The work reported in this paper was supported by the Combustion Research Branch, Industrial Environmental Research Laboratory (Research Triangle Park, N.C.) of the U.S. Environmental Protection Agency under Grants No. R802366 and R803283-01, R. E. Hall, Project Officer. Most of the coal-fired utility boiler test data in the sample of this study were obtained from the field testing of Exxon Research and Engineering Company, as reported in Reference 3, with some amplification by Mr. A. R. Crawford. Some additional data on the Widows Creek facility of the Tennessee Valley Authority were obtained from TVA, with the assistance of Dr. G. A. Hollinden and Mr. J. R. Crooks. All of the oil and natural gas data used in this study were obtained from records of the Los Angeles Department of Water and Power, with the direct assistance of Messrs. R. Toda, W. Pepper and R. Gentner. Sincere appreciation is acknowledged for the assistance of each of these organizations and personnel.

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FIRING TYPE	No. OF BOILERS	RATED LOAD, MW	No. OF BURNERS	NO_x PORTS	No. OF TESTS COAL	OIL	NAT GAS
SINGLE-WALL	1	105	18	NO	3	-	-
	2	125	16	NO	72	-	-
	2	180	16	NO	-	29	27
	2	240	12	NO	-	43	31
	1	260	16	NO	18	-	-
	1	340	16	NO	14	-	-
OPPOSED	2	240	12	YES	-	6	47
	2	350	24	YES	-	61	145
	1	800	54	NO	17	-	-
TANGENTIAL	1	330	20	NO	22	-	-
	1	360	20	NO	40	-	-
	TOTAL: 16			TOTALS:	186	139	250
				GRAND TOTAL:		575	

Table 1. Summary of total data sample

COAL TYPE	ULTIMATE ANALYSIS, % DRY C	 H	 O	 N	 S	 ASH	MOISTURE, % (Proximate)	HIGHER HEATING VALUE, Btu/lb
1-HIGH MOISTURE	63.6	4.5	19.2	0.90	0.70	11.1	32.0	7,200
2-HIGH ASH	58.8	4.7	9.3	1.3	0.90	25.0	10.5	8,900
3-NOMINAL	70.5	4.7	9.3	1.3	3.1	11.1	10.5	11,700
4-HIGH NITROGEN	72.3	4.7	9.3	1.7	1.7	11.1	10.5	11,700

Table 2. Analyses of coal types

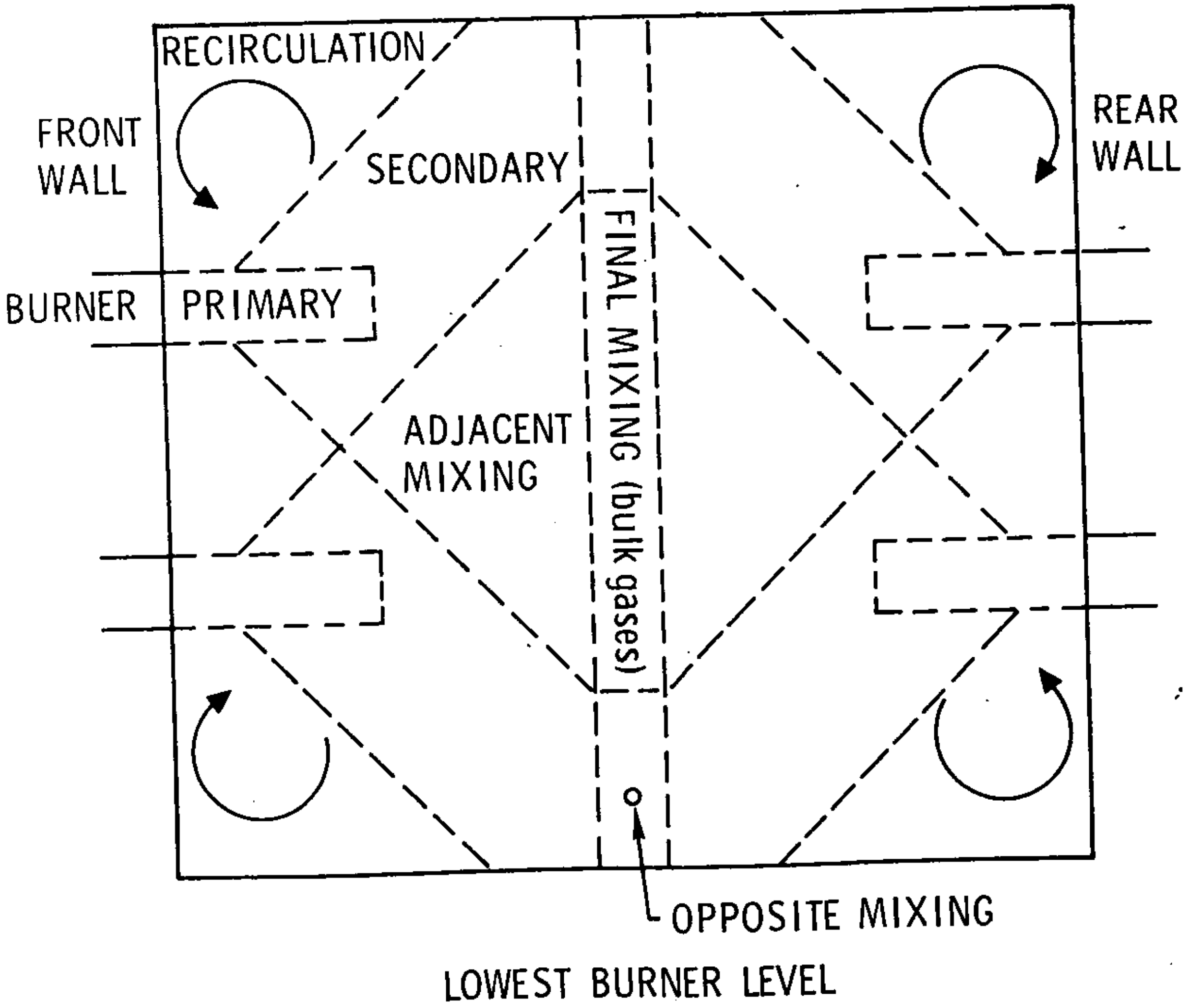

Figure 1. Schematic of mixing zone model--horizontal section at lowest burner level

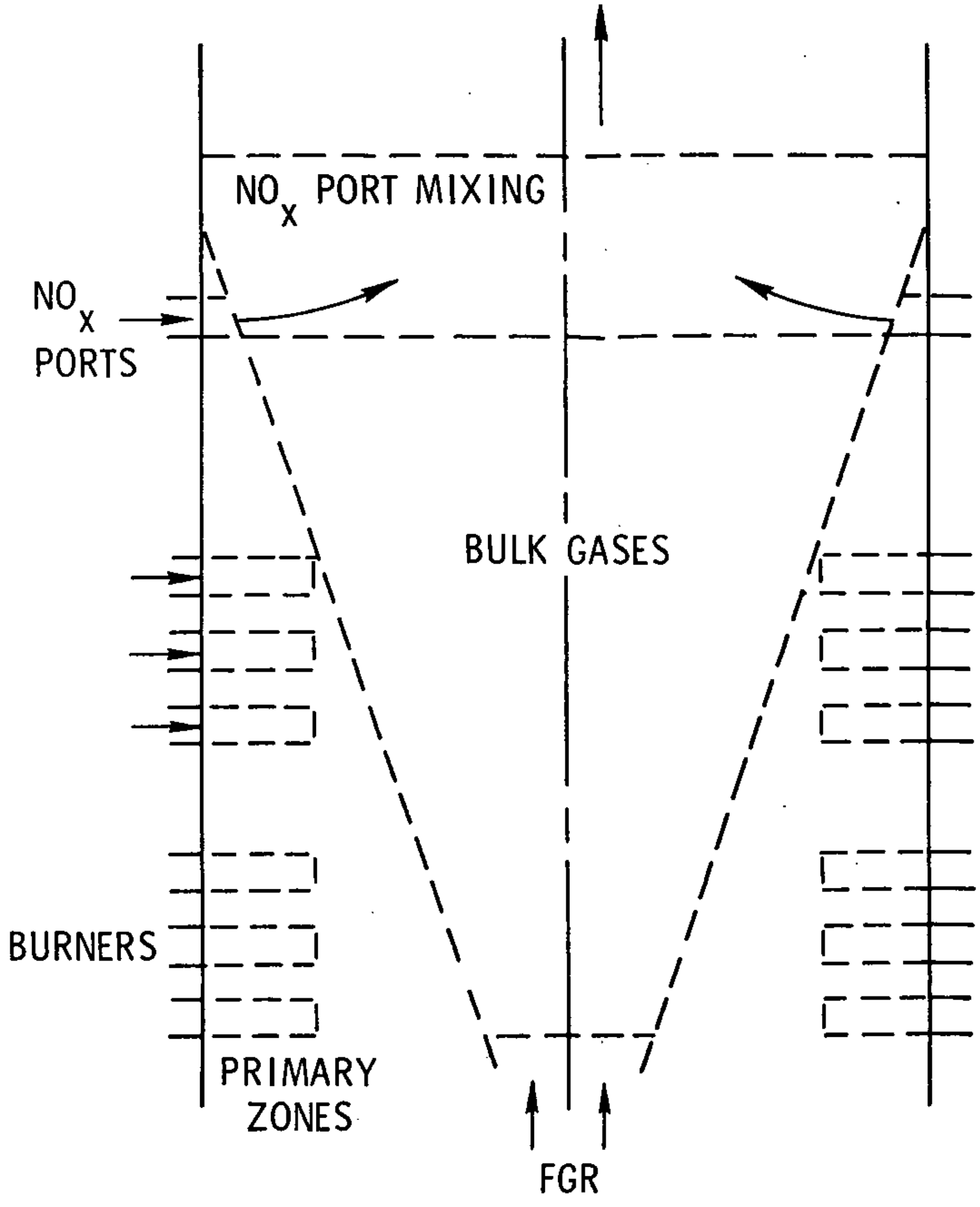

Figure 2. Schematic of mixing zone model--vertical section

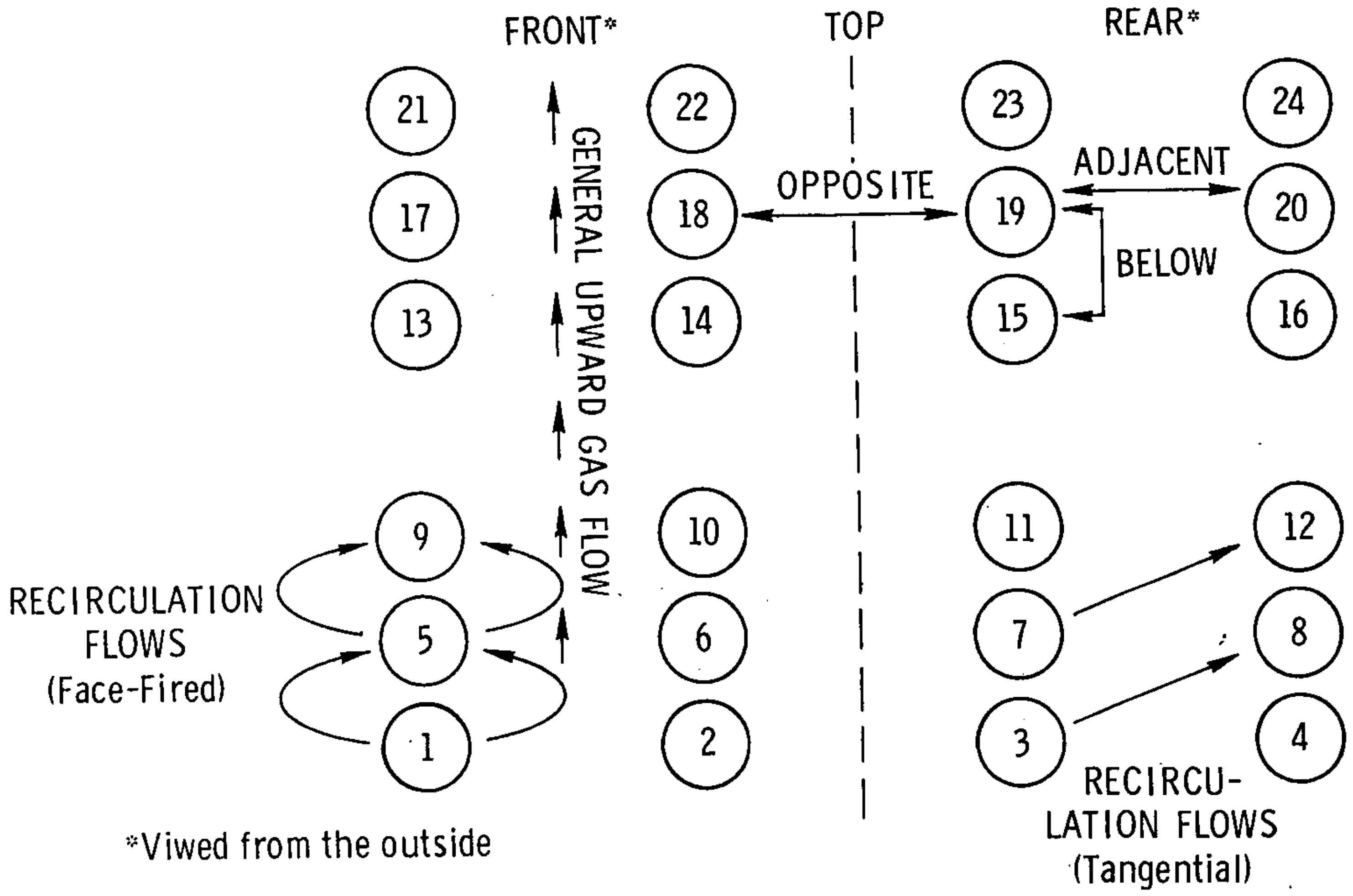

Figure 3. Mixing zone model--definition of burner configurations

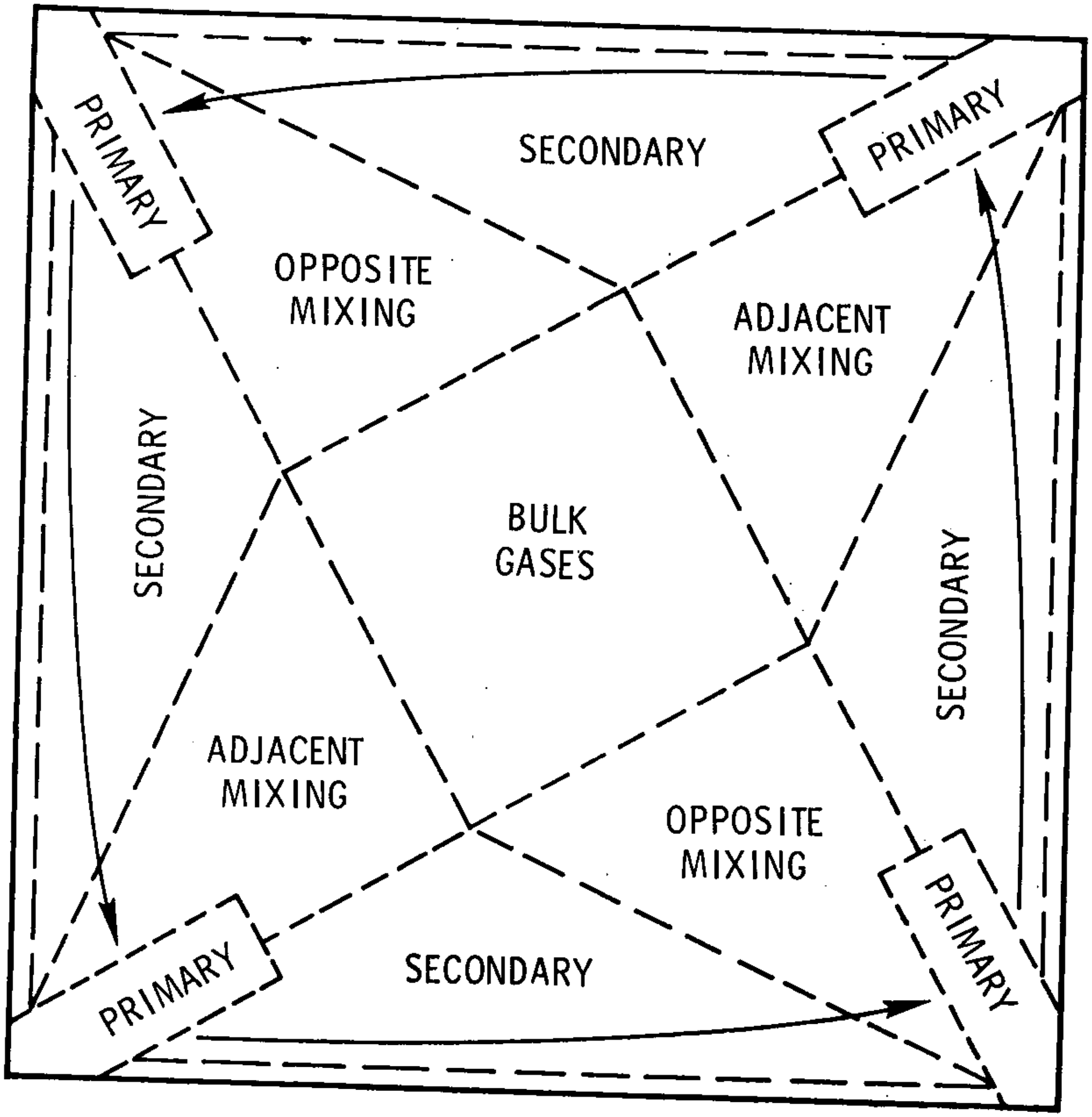

Figure 4. Schematic of mixing zone model for tangential boilers--horizontal section at lowest burner level

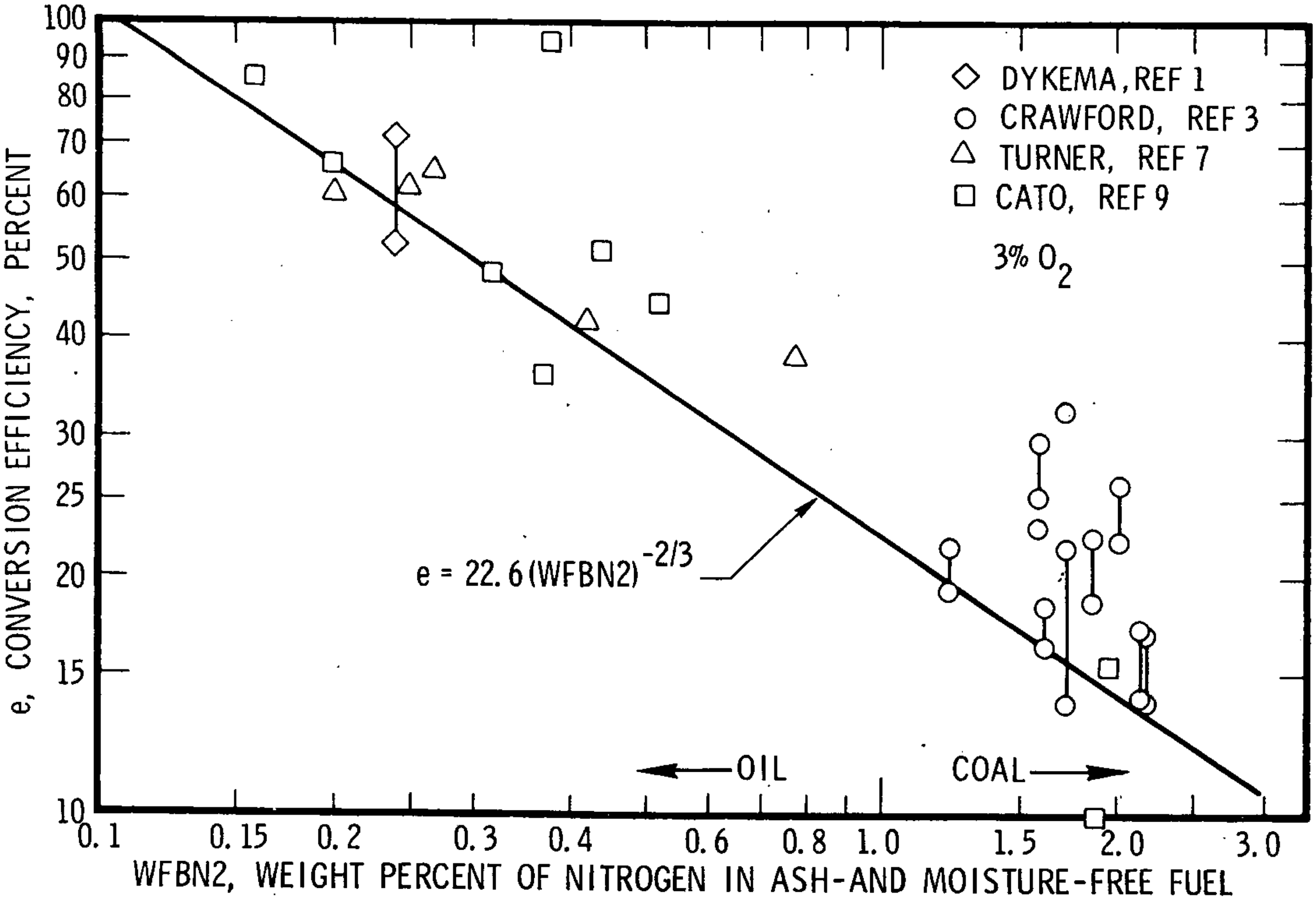

Figure 5. Variation of the efficiency of conversion of fuel-bound nitrogen to NO_x with the concentration of nitrogen in the fuel

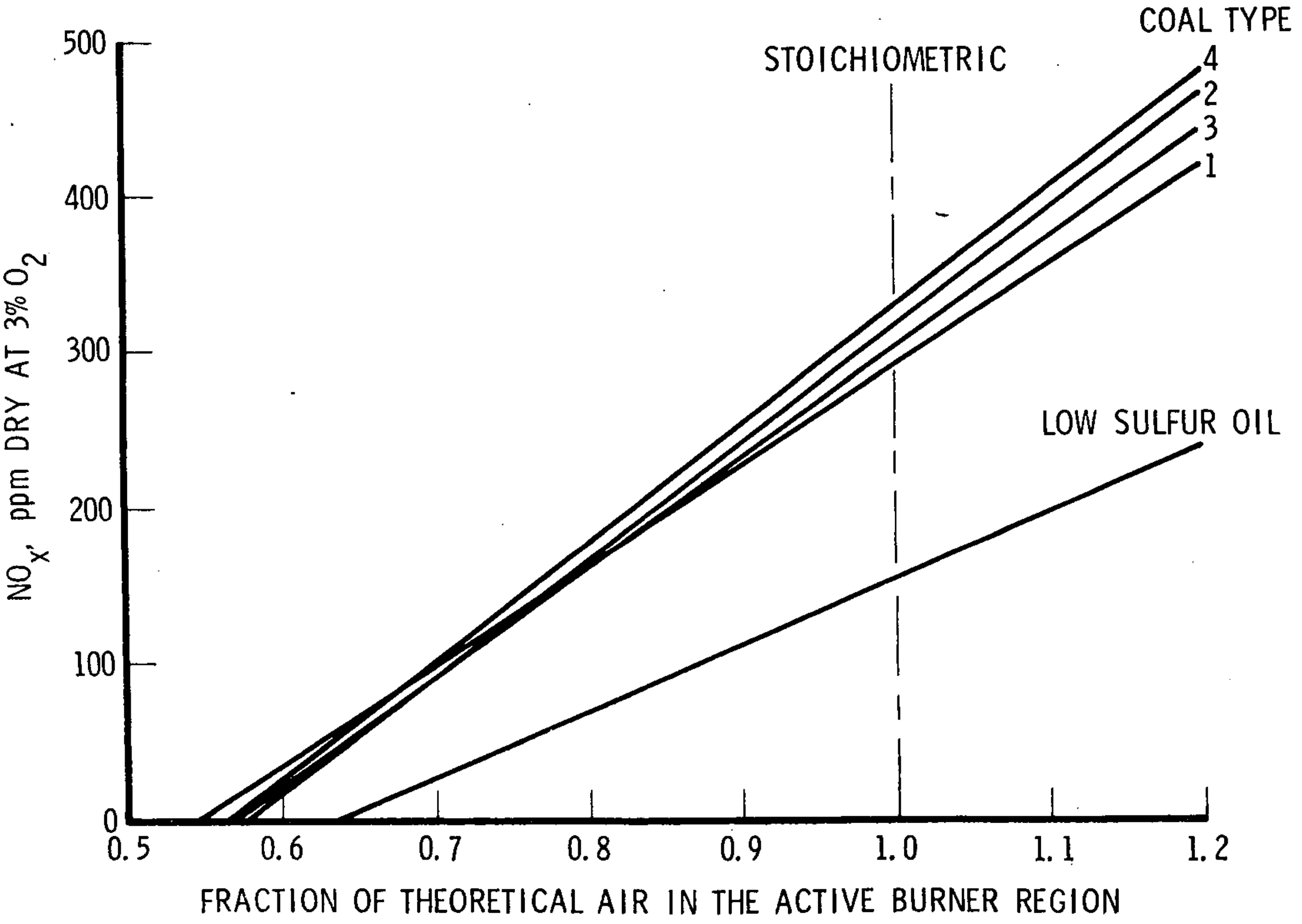

Figure 6. NO_x generated by conversion of fuel-bound nitrogen

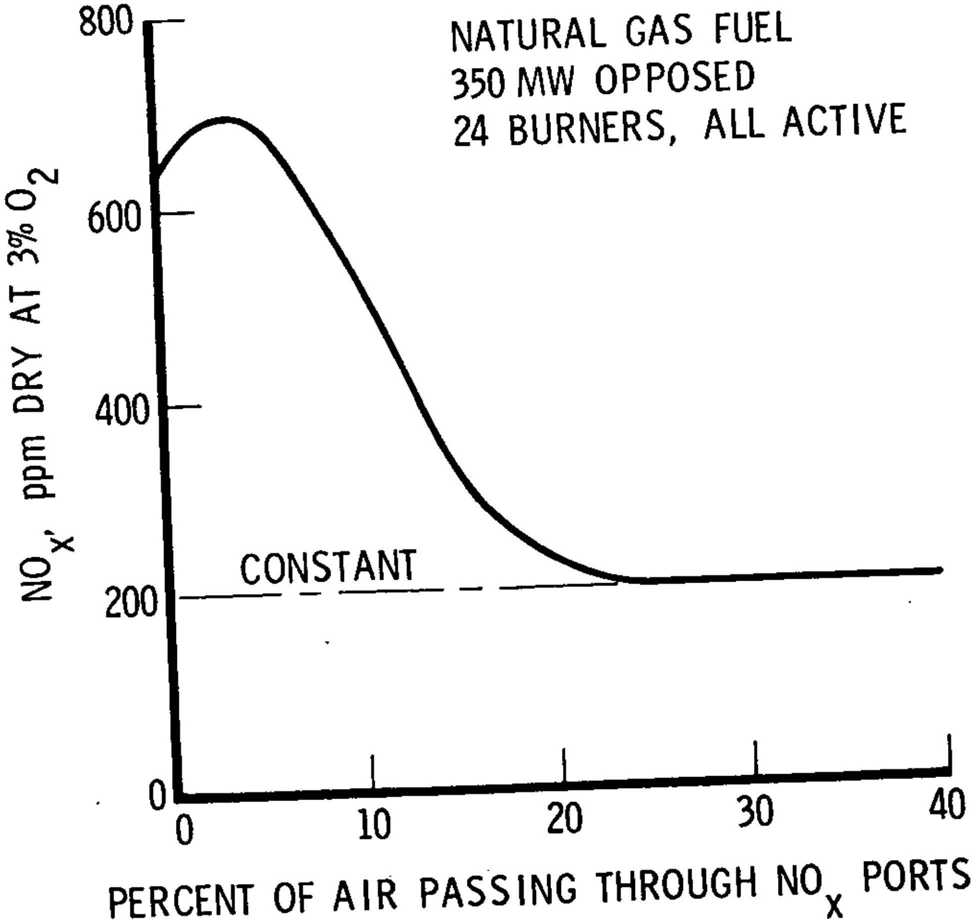

Figure 7. Limit on reduction of thermally generated NO_x by NO_x port flow alone

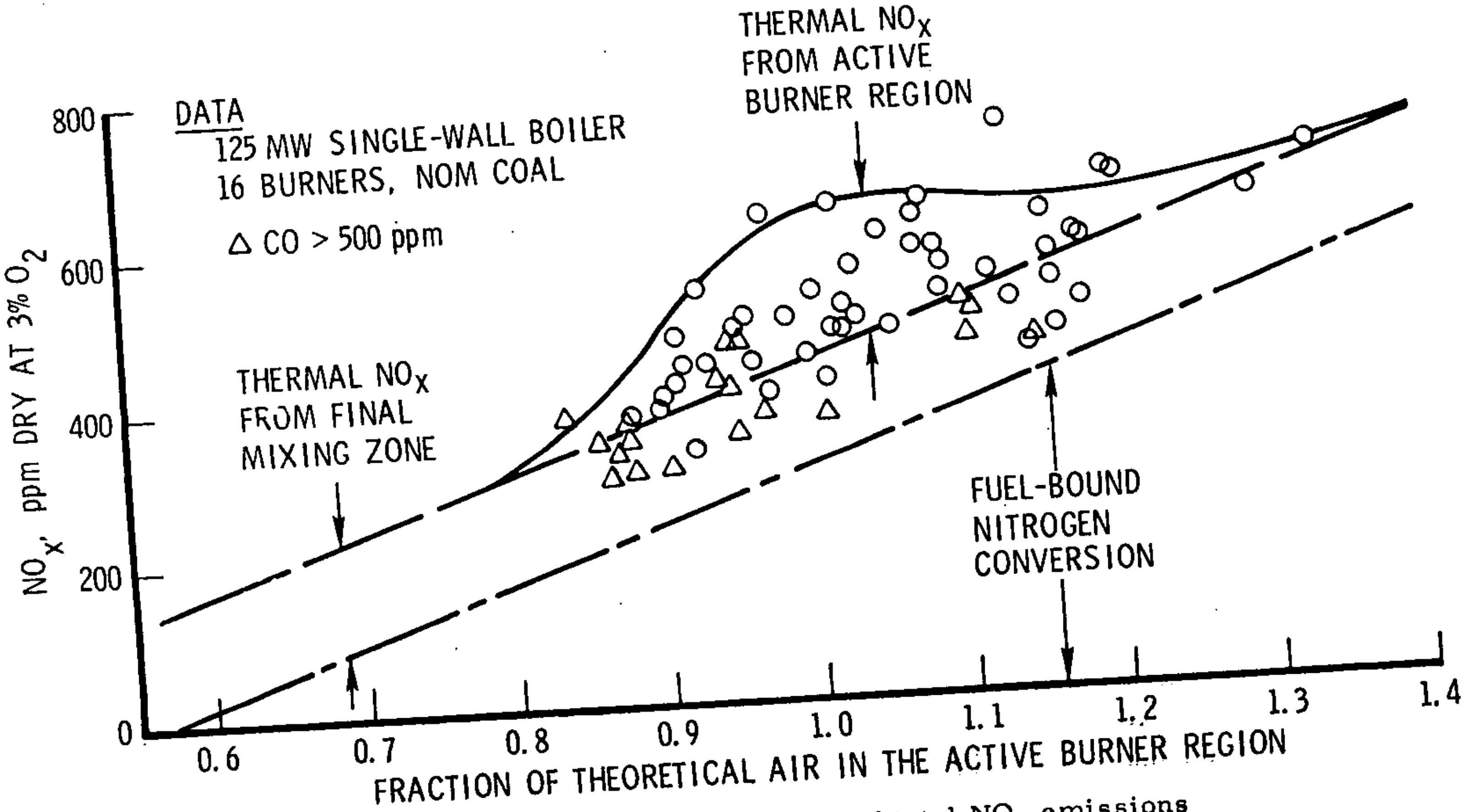

Figure 8. Schematic showing major sources of total NO_x emissions

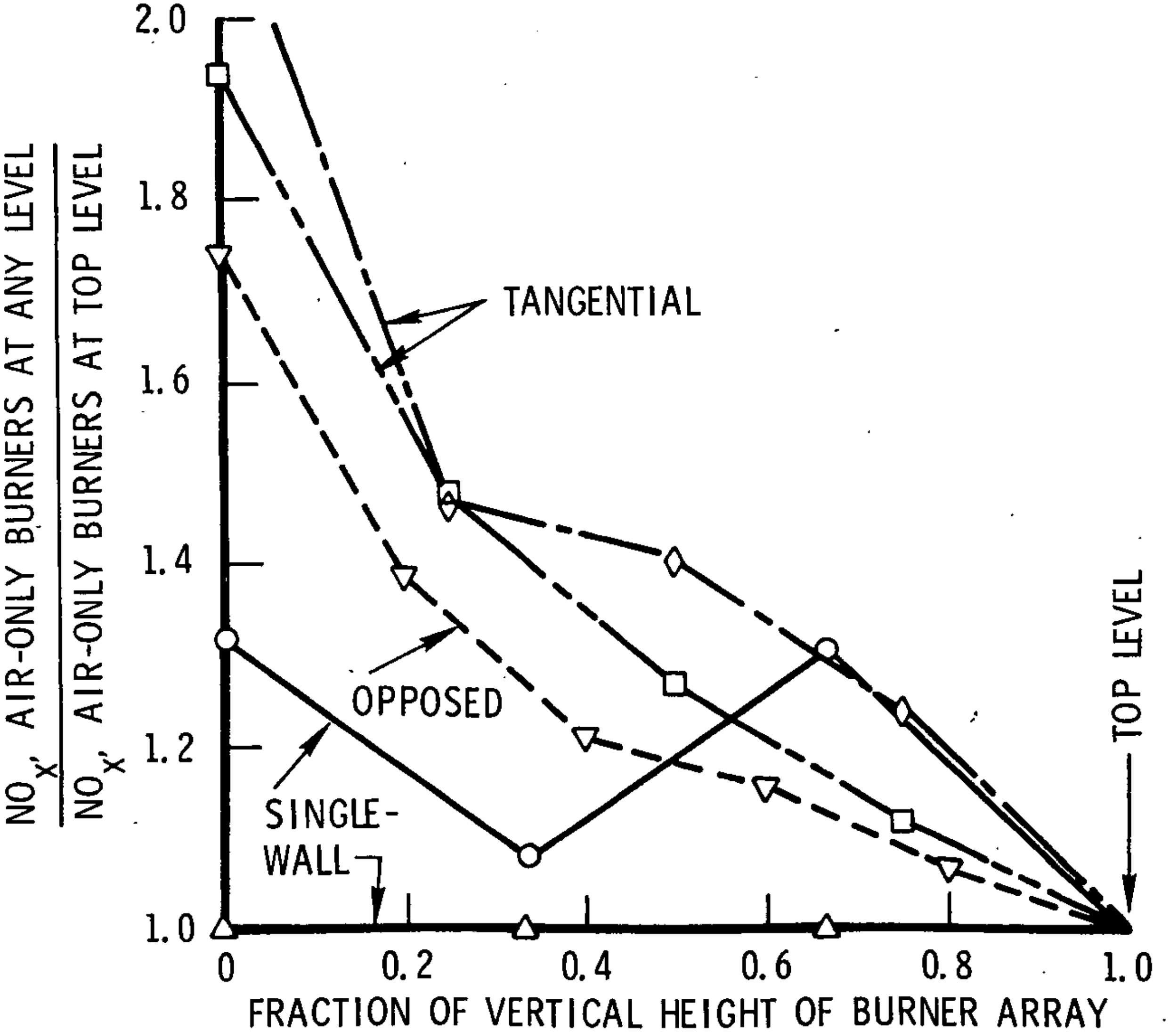

Figure 9. Results of parametric calculations on the effect of locating air-only burners at various vertical levels in the burner array

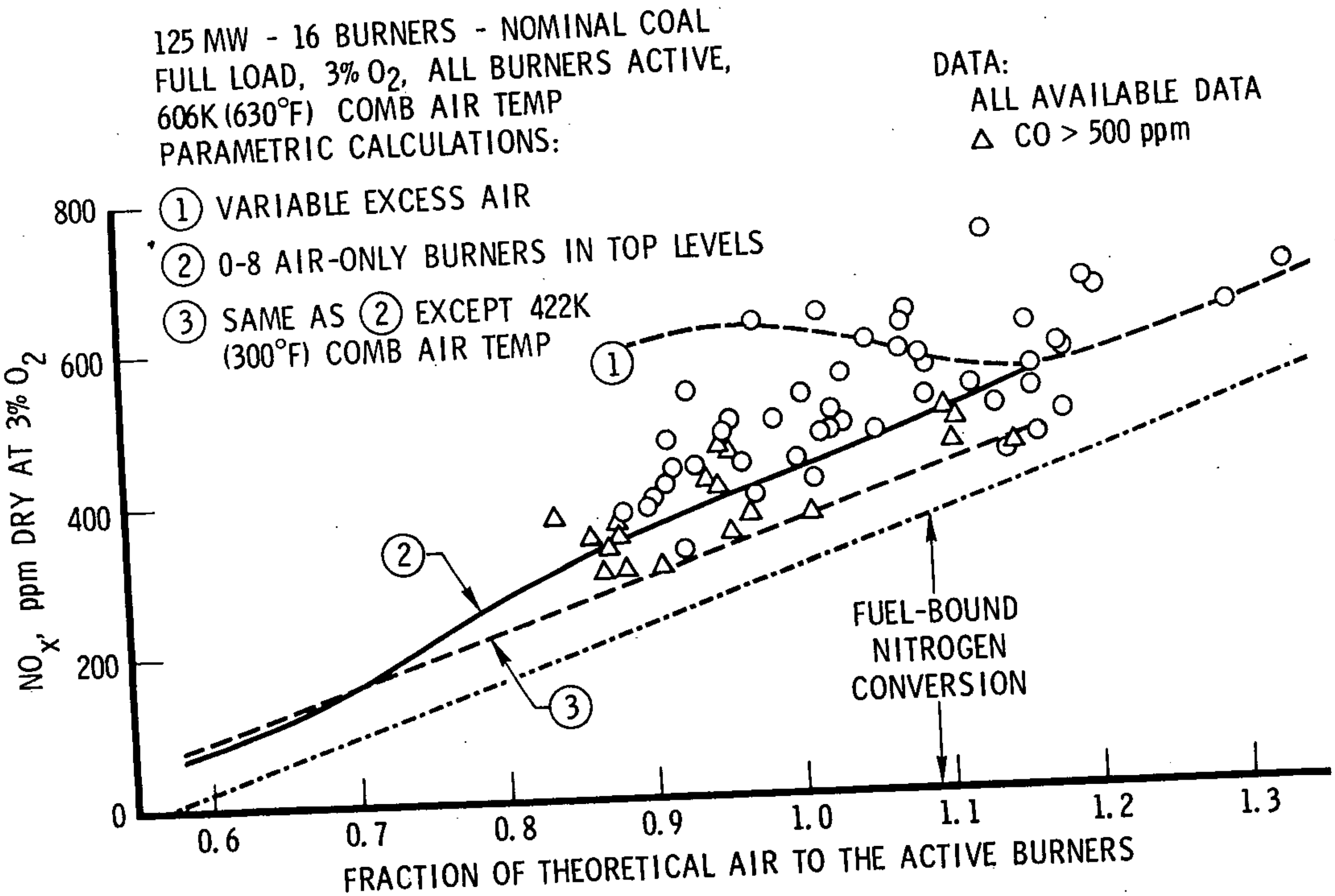

Figure 10. Typical single-wall boiler firing nominal coal type with typical combustion air temperature

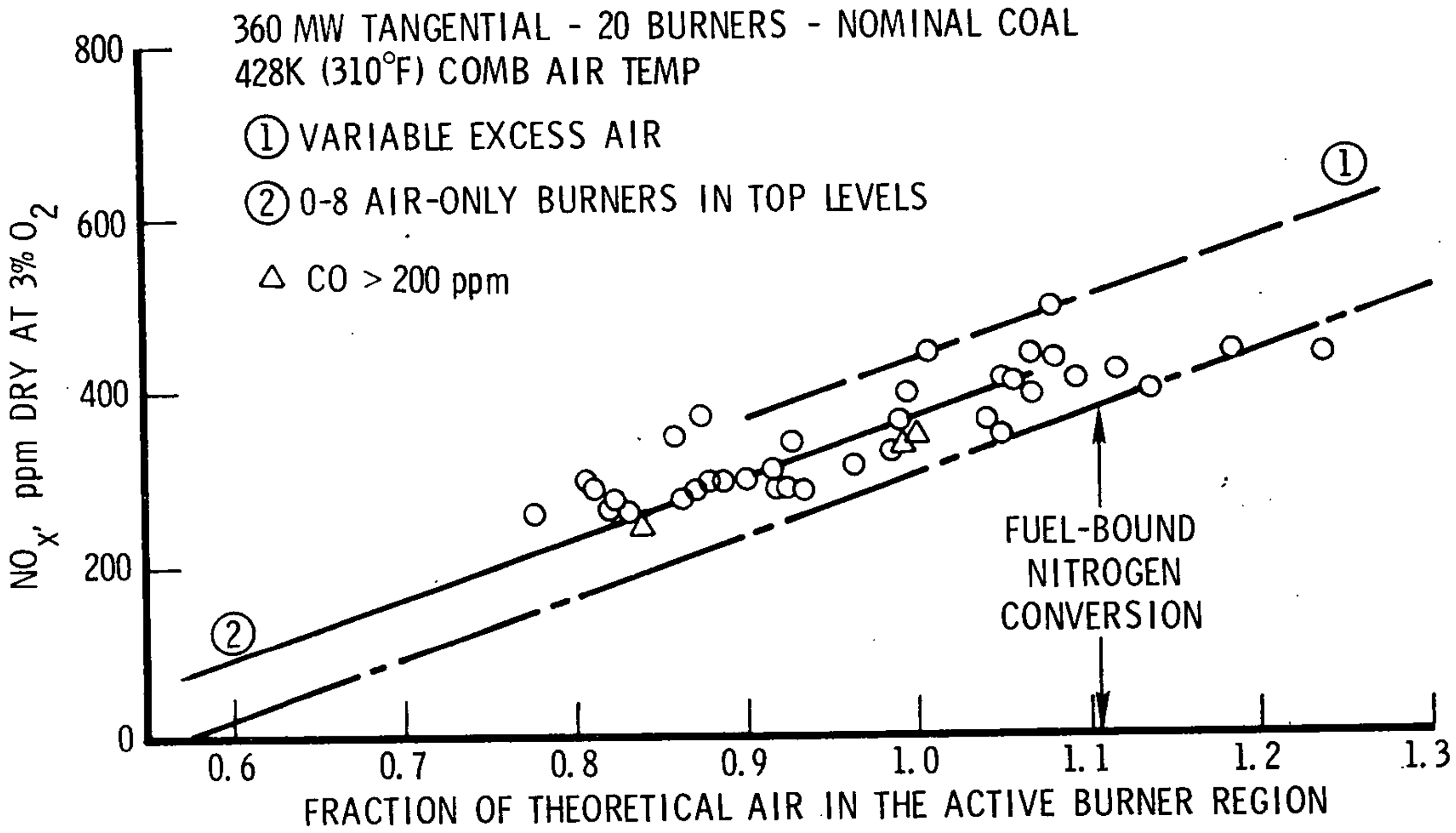

Figure 11. Effects of low combustion air temperature in a boiler firing a nominal coal

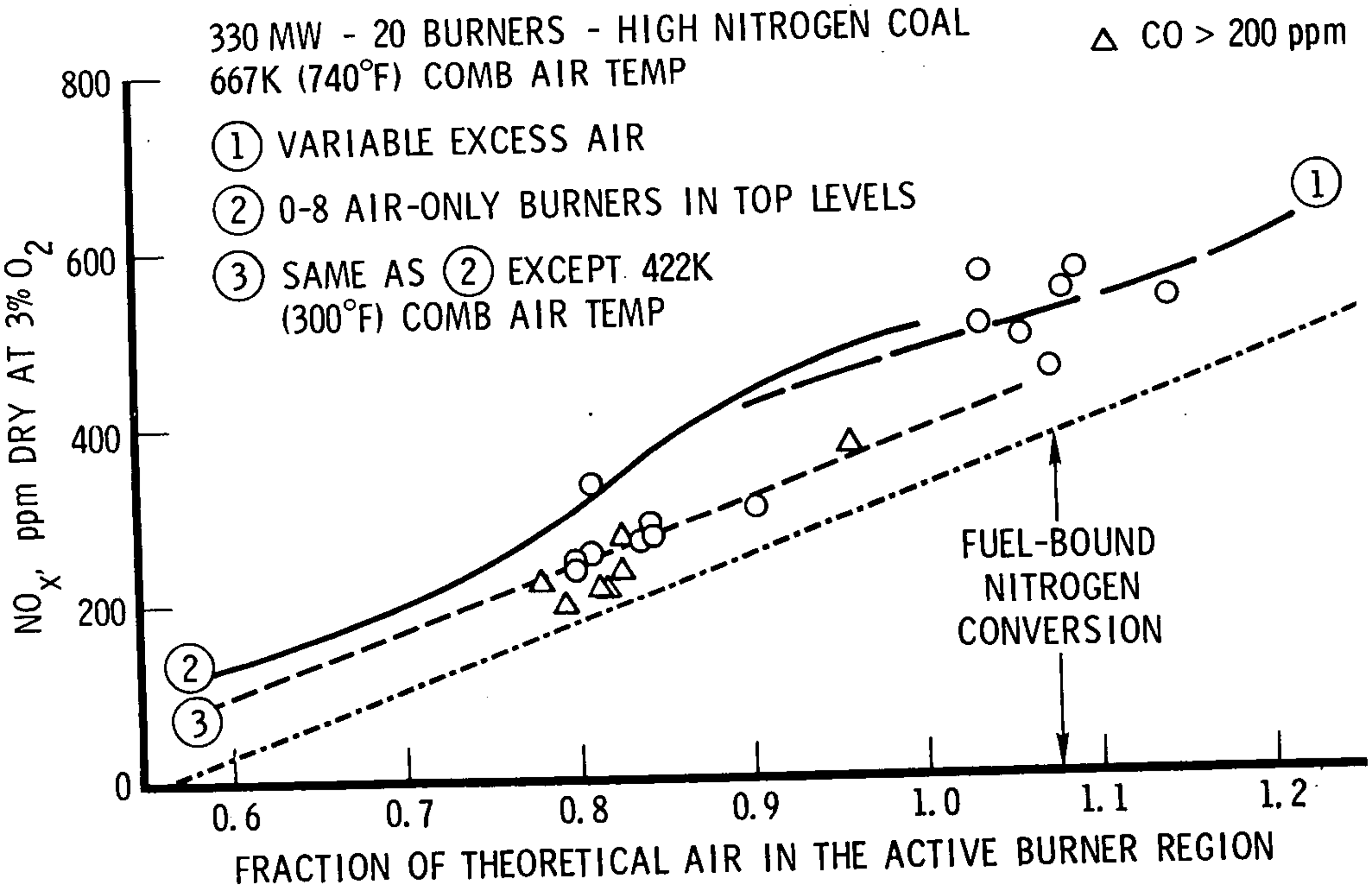

Figure 12. Effects of high combustion air temperature and high fuel nitrogen in a tangential boiler

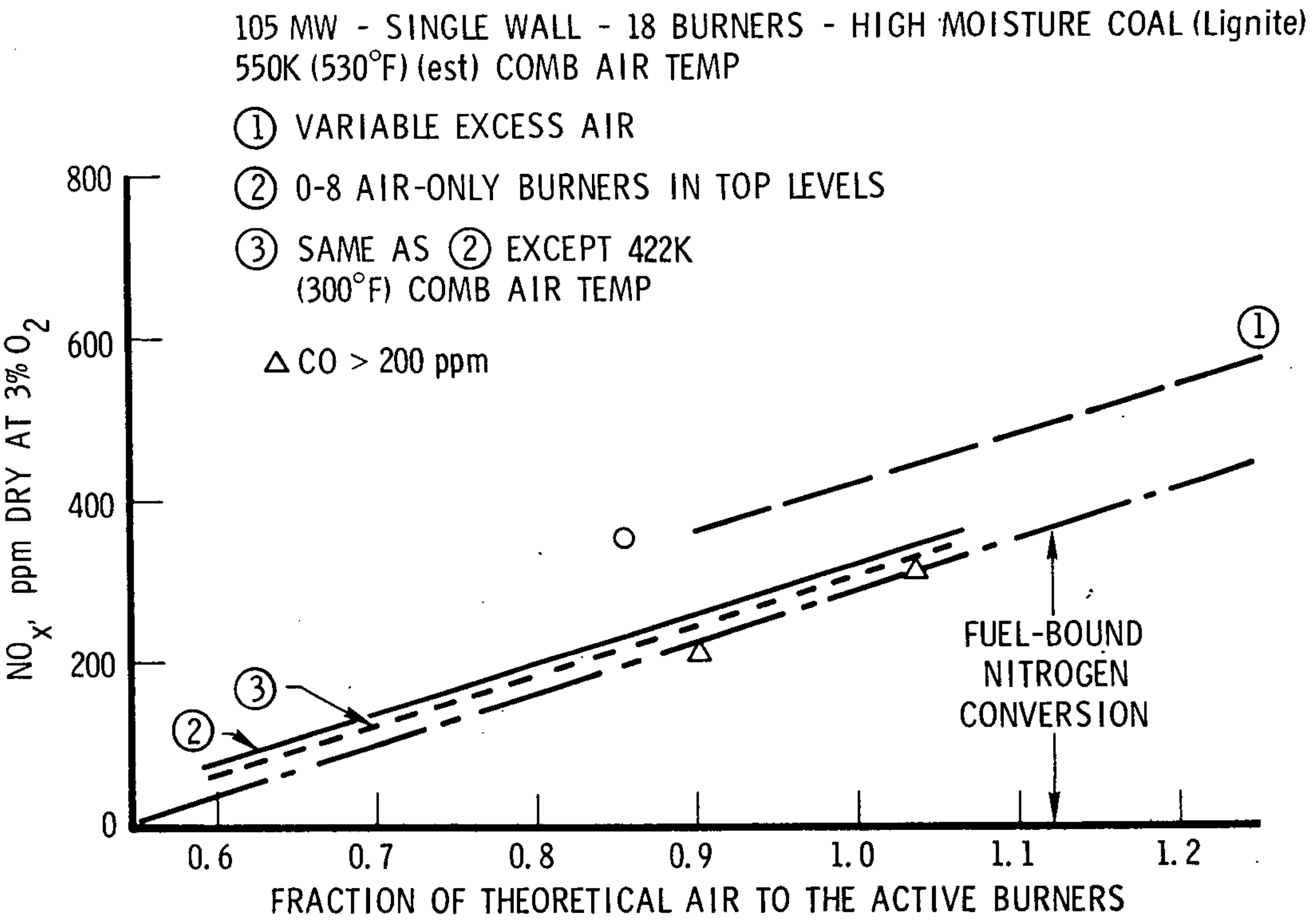

Figure 13. Effects of high moisture, low combustion temperature rise coal (lignite) with nominal combustion air temperature

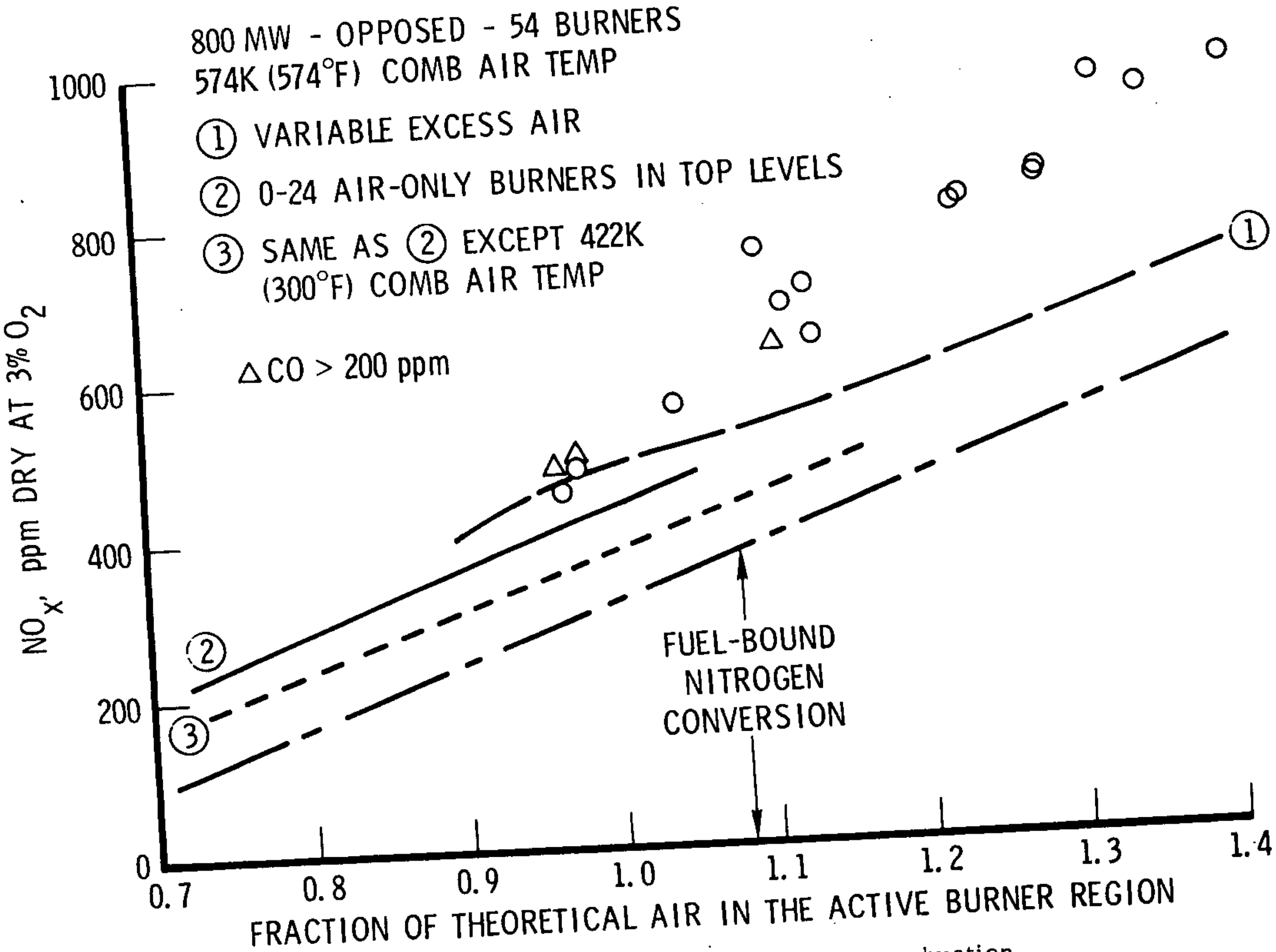

Figure 14. Effects of a high-ash coal with moderate combustion air temperature

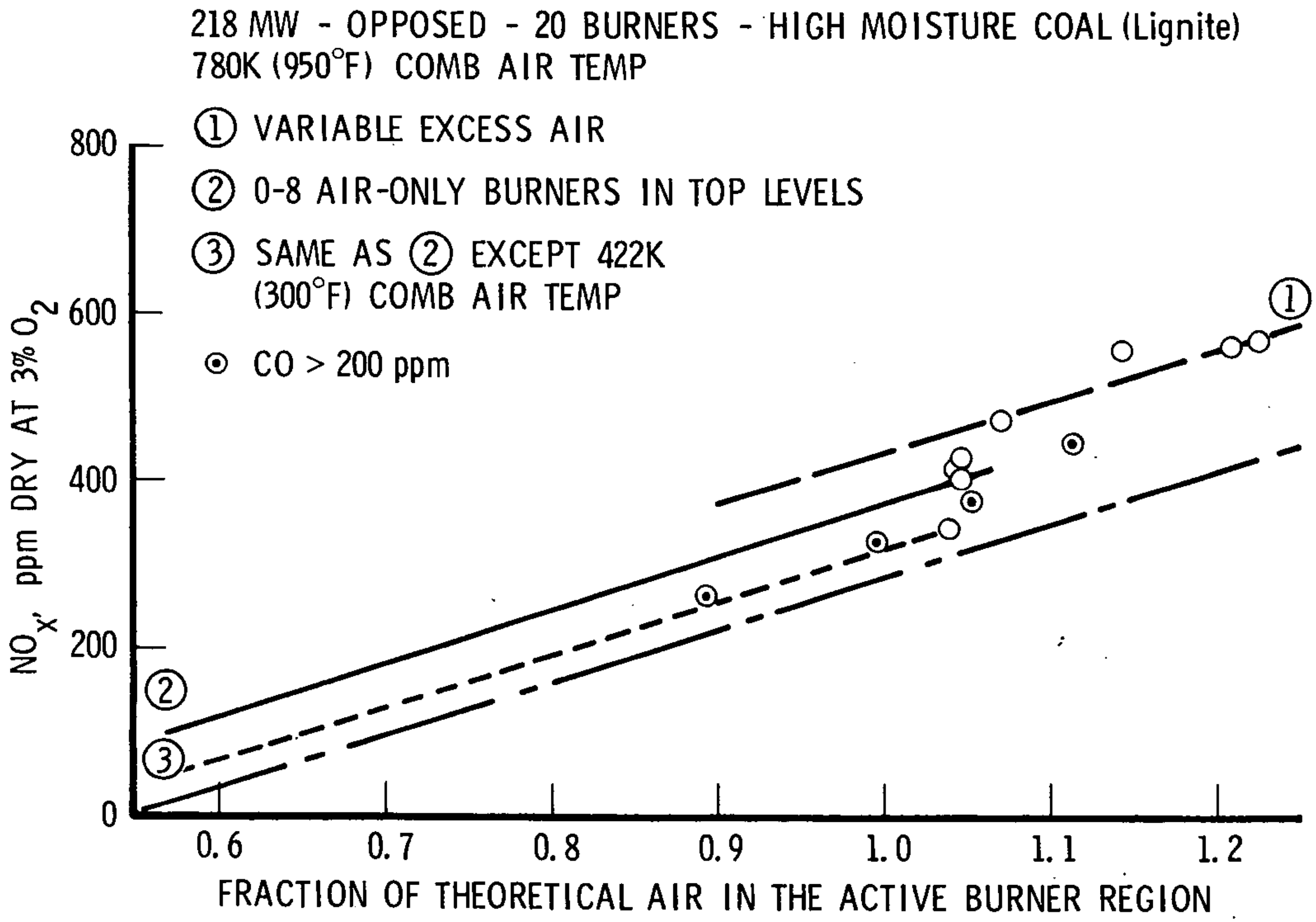

Figure 15. Parametric calculations for a boiler not in the data sample used to derive the equation

9:25 a.m.
Analysis of Gas -, Oil-and
Coal-Fired Utility Boiler
Test Data
O.W. Dykema and R.E. Hall

Q: In your rate equation for the thermal formation of NO_x, what rate constant did you use?

A: Each of the terms in the equation developed from the model, and those in the correlating equation, which represent increments of thermally generated NO_x in particular types of mixing zones, are based on an Arrhenius rate equation for NO_x formation. The pre-exponential constant is part of the coefficient of each of these terms. In the regression analyses of large quantities of data these constants are determined empirically. As a result, it is not necessary to select a rate constant and no particular effort was made to select one.

Q: Most of your parametric calculations and data appear to show NO_x levels linearly related to the excess air in the burners or in the active burner region, essentially parallel to the line for conversion of fuel-bound nitrogen. Why do we not see the non-linear maximum around stoichiometric typical of thermally-generated NO_x?

A: The typical rate equation for thermally generated NO_x is contained in eight of the terms in the equation used for the parametric calculations. If the calculations are linear with excess air in the burners, the NO_x contributions from the sum of these terms must be small, implying little thermally generated NO_x in the total. Of the 6 figures showing the parametric calculations and data for different boilers and coals, 4 represent cases of relatively low combustion temperatures, due either to low combustion air temperature or low combustion temperature rise (lignite and high-ash coals).

In these cases, it might be expected that thermally generated NO_x would be a small part of the total. In the other two cases, the non-linear effect of thermal NO_x mechanisms is apparent in the figures. In all cases, however, thermally generated NO_x is relatively small compared to that generated by conversion of the fuel-bound nitrogen in the coal.

Q: The data shown in your figure on the effect of excess air, and your related discussion, imply that the observed reduction of NO_x with reduction in excess air is due only to the appearance of CO, and the subsequent direct effect of CO on the NO_x. Do you mean to imply this?

A: No. The figure presented on the effect of excess air was included in the presentation here largely to illustrate an observation from the data with no conclusions intended. All of the parametric calculations and conclusions from this study involve excess air as an independent variable affecting NO_x. Throughout the study, however, there consistently appeared to be an additional effect of the appearance of CO on reduction of NO_x over and above that of excess air alone. One of the advantages of a symposium such as this, involving specialists representing all levels of research and development, is the opportunity for two-way communication. This observation on the apparent effect of the appearance of CO on NO_x reduction was offered here primarily to solicit comment, rather than to present a fact. That figure will probably not be included in the published proceedings.

INFLUENCE OF COMBUSTION MODIFICATIONS ON POLLUTANT EMISSIONS FROM INDUSTRIAL BOILERS

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FOR

STATIONARY SOURCE COMBUSTION SYMPOSIUM
ATLANTA, GEORGIA
SEPTEMBER 24-26, 1975

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INFLUENCE OF COMBUSTION MODIFICATIONS ON POLLUTANT EMISSIONS FROM INDUSTRIAL BOILERS

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ABSTRACT

The possibility of reducing the total nitrogen oxides emissions from existing industrial boilers by modifying the combustion process has been investigated during a field test program. The gaseous and particulate emissions from coal, oil, and natural gas fuels were measured both before and after the combustion modification. Data were taken on particulate size as well as concentration.

The principal combustion modification methods that were investigated were: reducing the excess combustion air, adding the combustion air in stages, recirculating flue gas, reducing the combustion air temperature, turning off the fuel (but not the combustion air) to one or more of the burners, tuning the burner, and resetting the burner registers.

All of the combustion modification methods were effective to varying degrees in reducing the nitrogen oxides emissions, and reductions of as much as 50% were obtained with several of the modifications. In most instances, the boiler efficiency was not degraded, although the particulate emissions increased by up to 50% in some cases. There was no substantive effect on the other pollutant emissions.

1.0 PROGRAM OBJECTIVE

Industrial combustion devices of all kinds contribute a large fraction of the total air pollution from stationary sources. Studies have found that as much as 40% of the stationary source nitrogen oxides emissions originate from devices such as industrial boilers (Refs. 1, 2). A similar figure was obtained for oxides of sulfur, while particulate emissions were more than 80%. Combustion modifications have been demonstrated for utility boilers which can reduce pollutant emissions without degrading boiler efficiency. Application of these modifications to industrial combustion devices, if successful, could have a profound impact on air quality and energy conservation.

It was the objective of this program of field testing to determine the gaseous, particulate, and toxic element emissions and the efficiency of industrial boilers ranging in capacity from 11 to 527 GJ/hr (10,000 to 500,000 lb of steam/hr), and to determine the reduction of emissions that could be achieved by modifying the combustion process in a systematic and controlled manner. An additional objective was to maintain or improve boiler efficiency.

The results of the field test program sought to establish what design and/or operational changes that boiler manufacturers and operators could make to reduce emissions and where future combustion research activities should be concentrated. The measurement of toxic emissions will be used to determine if industrial boilers as a class are a significant source of hazardous pollutants.

The program was conducted in two phases and this paper reports the results primarily of the Phase II, except for the results of the toxic element emission measurements which are not yet complete. Phase I was one year in duration and involved the selection of 47 representative industrial boilers for testing, construction of a mobile emissions measurement laboratory, and field testing of the 47 boilers for emissions with the boilers operating normally or with minor operating changes (Ref. 3).

The Phase II activities were of 14 months duration and involved the intensive testing of 19 boilers to measure the sensitivity of the emissions and boiler efficiency to combustion modifications that sometimes required retrofit of the boiler (Ref. 4). Examples of such combustion modifications were overfire air ports and flue gas recirculation.

In Phase I, the boilers were selected to reflect the prevailing geographical distribution of boilers and fuels throughout the continental United States. Consequently, the preponderance of test boiler sites was east of the Mississippi River. This criterion was used in Phase II also, although not as rigorously, since certain specific types of boilers were sought. The field test sites for both program phases are shown in Figure 1.

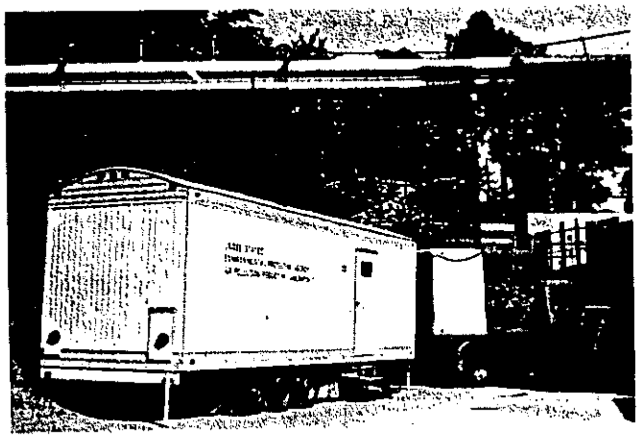
The following measurements were made:

Total nitrogen oxides
Hydrocarbons
Carbon dioxide
Carbon monoxide
Sulfur dioxide
Sulfur trioxide
Total particulates
Particulate size
Plume opacity
Boiler efficiency
Toxic elements

The emissions were measured with instrumentation contained in the 2.4 by 9.0 meter (8 by 29 ft) laboratory trailer of which exterior and interior views are shown in Figure 2. The gaseous emission measurements, except sulfur oxides, were measured with continuously reading analyzers located in the measurement console in the

Figure 1. Field Test Site Locations, Phases I and II.

Gas Emission
Measurement
Console



Mobile Laboratory
Truck and Trailer

Sulfur and Particulate
Measurement Area -
Wet Chemistry

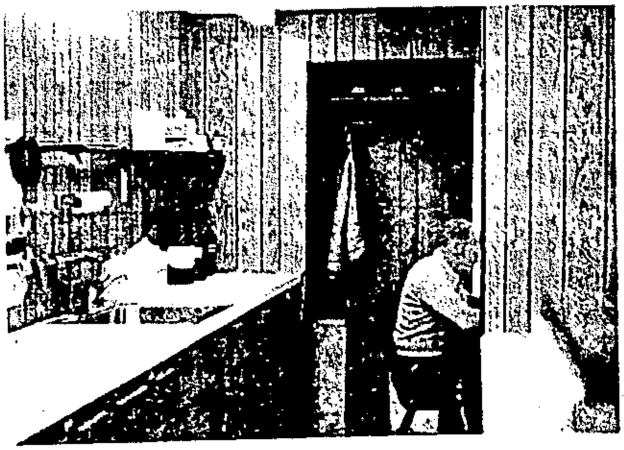


Figure 2. Interior and exterior views of mobile laboratory.

trailer. The particulate concentration, particulate size, and sulfur oxides concentration measurements were made with instrumentation prepared in the wet chemistry area of the laboratory and taken to the sample port. The weighing and titration were done in or near the laboratory.

The emission measurement instrumentation used for the program was that listed in Table I below. The operation of the instrumentation is discussed in detail in Reference 3.

Table I. EMISSION MEASUREMENT INSTRUMENTATION

Emission	Symbol	Measurement Method	Eqmt Manufacturer
Nitric oxide	NO	Chemiluminescent	Thermo Electron
Oxides of nitrogen	NOx	Chemiluminescent	Thermo Electron
Carbon monoxide	CO	Spectrometer (NDIR)	Beckman
Carbon dioxide	CO_2	Spectrometer (NDIR)	Beckman
Oxygen	O_2	Polarographic	Teledyne
Hydrocarbons	HC	Flame ionization	Beckman
Sulfur dioxide and trioxide	SO_2, SO_3	Absorption/ titration	KVB Equipment Co
Total particulate matter	PM	EPA Std Method 5	Joy Mfg Co
Particulate size	--	Cascade impactor	Monsanto
Smoke spot	K	Reflection	Research Appliance
Opacity	--	EPA Std Method 9	--

2.0 BASELINE TEST RESULTS

The objective of the baseline emission measurements was to establish the general level of emissions from industrial boilers as a class and to provide a base level from which to determine the effect on emissions of combustion modifications. The measurements of the total nitrogen oxides and solid (or filterable) particulate emissions at the baseline setting of the boilers before combustion modification are shown in Figures 3 and 4. Data from both Phase I and Phase II are included.

Nitrogen Oxides Emissions

The total nitrogen oxides emissions were found not to be significantly dependent upon boiler size, as is indicated in Figure 3. However, they were strongly dependent on the type of fuel being fired. This strong dependence is illustrated in Table II which shows the range and average concentration of nitrogen oxides.

Table II. RANGE AND AVERAGE EMISSIONS OF TOTAL NITROGEN OXIDES AT BASELINE AND LOW-NOx OPERATION

	Range	Average			
	Baseline	Baseline Operation		Low-NOx Operation	
Fuel Type	NOx g/GJ (ppm)	NOx g/GJ (ppm)	Excess O_2 %	NOx g/GJ (ppm)	Excess O_2 %
Coal	100-562 (164-922)	290 (475)	8.7	225 (369)	6.7
No. 2 Oil	36-101 (65-180)	67 (120)	5.5	59 (105)	4.0
No. 5 Oil	112-347 (200-619)	164 (293)	5.8	142 (254)	4.9
No. 6 Oil	107-196 (190-350)	151 (269)	5.3	121 (216)	4.9
Natural Gas	26-191 (50-375)	71 (139)	4.8	57 (111)	5.0

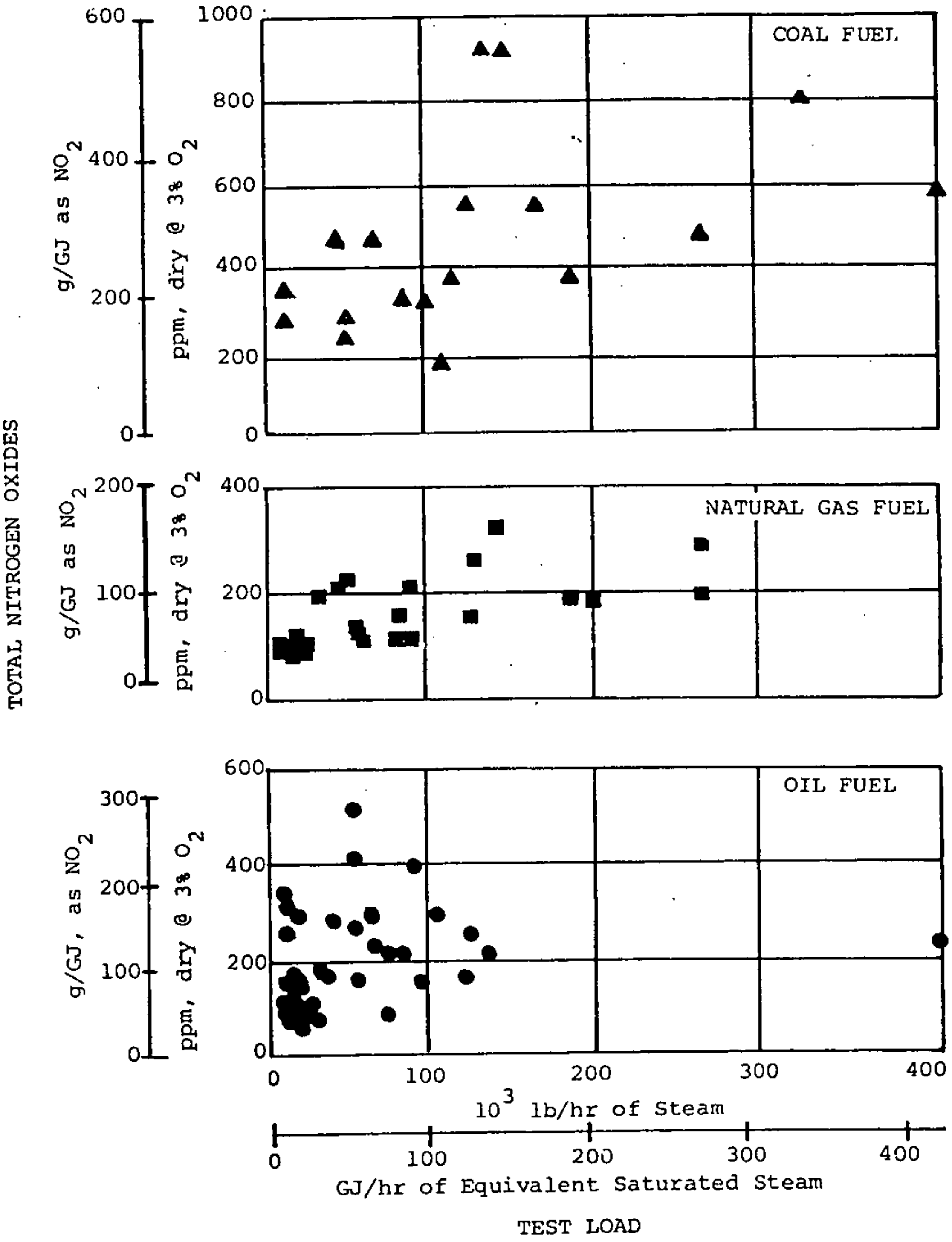


Figure 3. Total oxides of nitrogen emissions at baseload

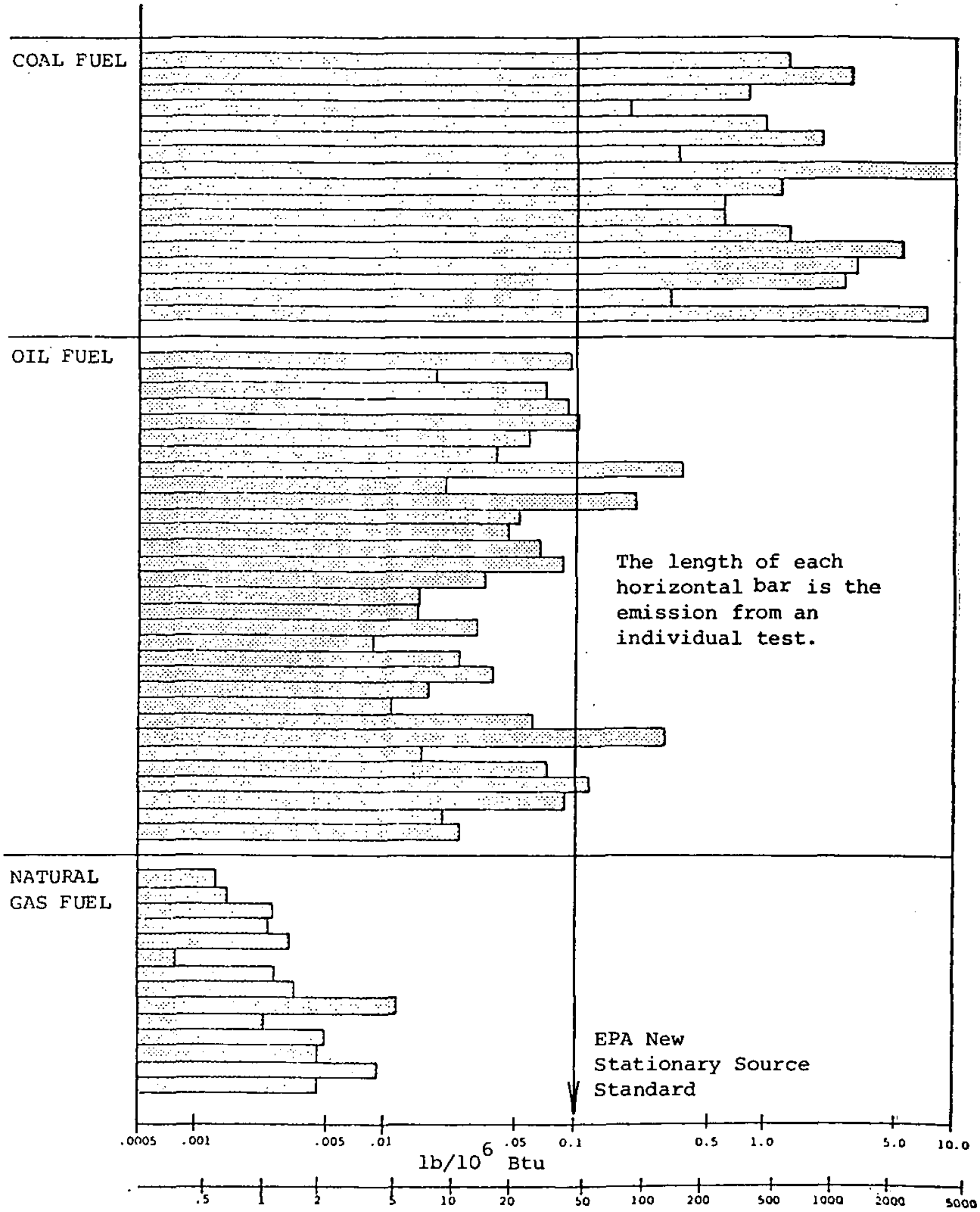


Figure 4. Solid particulate emissions at baseload.

The "Low-NOx Operation" column entries are the average of the emissions when the most effective combustion modification method for that particular fuel type was used. Coal-fueled boilers were the greatest emitters of total nitrogen oxides. All nitrogen oxides measurements cited in this paper in parts per million (ppm) have been normalized to dry at 3% excess oxygen.

The emissions levels at baseline for each test series are listed in Table III. Table III also lists the pollutant emission levels when the boiler was operated such that the total nitrogen oxides emissions were the lowest. The shaded areas denote tests where certain emissions were measured both before and after combustion modification. The column on the extreme right entitled "Test Type" indicates the particular combustion modification that produced the lowest nitrogen oxides emissions. For example, in Test No. 102, the lowest nitrogen oxides emissions occurred when the excess combustion air was reduced to its lowest level. In Test No. 104, the lowest total nitrogen oxides were found after the burner had been tuned. The meaning of the abbreviations and symbols used is given in Appendix A.

Solid Particulate Emissions

The solid particulate emissions were not at all dependent upon the boiler size, but were strongly dependent upon the fuel type, as Figure 4 shows. The emissions from oil and gas fuels were usually below the Stationary Source Standard of 43 g/GJ (0.1 lb/10^6 Btu) for boilers of greater than 265 GJ/hr, but the emissions from coal always were well above it. The solid particulate concentration includes only the solid particulate that was caught by a heated filter and not the condensible particulate that was condensed and collected in water-filled bubblers.

Table III. BOILER EMISSION MEASUREMENTS AT BASELINE AND LOW NOx TEST CONDITIONS (1)

						BASELINE TEST CONDITIONS AND EMISSIONS (1)								LOW NITROGEN OXIDES TEST CONDITIONS AND EMISSIONS (1)								
Test No. From-Thru	Loc. No.	Boiler Capacity GJ/hr (10^3lb/hr)	Test Fuel	Burner (1) Type	Burner No. Of	Test Load GJ/hr (10^3lb/hr)	Excess O_2 %	NOx (2) g/GJ (ppm)	CO_2 (2) %	CO (2) g/GJ (ppm)	HC (2) g/GJ (ppm)	SOx (2) g/GJ (ppm)	Solid Part. g/GJ (lb/MBtu)	Test Load GJ/hr (10^3lb/hr)	Excess O_2 %	NOx (2) g/GJ (ppm)	(2) CO_2 %	CO (2) g/GJ (ppm)	HC (2) g/GJ (ppm)	SOx (2) g/GJ (ppm)	Solid Part. g/GJ (lb/MBtu)	Test Type
101 only	1	31 (29)	NG	Ring	1	18 (17)	2.2	39.6 (77.7)	10.8	21 (67)	- -	- -	- -	Baseline Test Only Conducted								
102-103	1	31 (29)	#2	Steam	1	18 (17)	5.3	50.7 (90.3)	11.6	31 (90)	- -	188 (241)	7.31 (.017)	20 (19)	4.7	47.1 (84)	11.7	51 (150)	- -	- -	- -	LowAir
104-106	1	31 (29)	NG	Ring	1	25 (24)	0.9	38.0 (74.5)	11.2	152 (489)	- -	- -	- -	25 (24)	2.6	41.8 (81.9)	10.4	0 (0)	- -	- -	- -	BrTune
107-108	1	31 (29)	#2	Steam	1	26 (25)	2.7	47.7 (85)	13.2	139 (407)	- -	300 (384)	4.73 (.011)	25 (24)	3.8	48.3 (86.1)	12.5	38 (110)	- -	- -	12.0 (.028)	BrTune
109-110	27	106 (100)	NG	Ring	1	79 (75)	6.6	56.6 (111)	7.9	0 (0)	- -	- -	- -	82 (78)	2.4	77.5 (152)	9.3	0 (0)	2.5 (14)	- -	- -	BrTune
111-112	27	106 (100)	PS300	Steam	1	90 (85)	9.3	257 (458)	8.8	40 (116)	- -	488 (626)	26.2 (.061)	74 (70)	6.5	277 (494)	10.0	0 (0)	- -	- -	28.4 (.066)	BrTune
113-115	29	158 (150)	NG	Ring	2	127 (120)	5.3	78.5 (154)	8.0	0 (0)	22 (125)	- -	- -	Baseline was low NOx								
116-121	29	158 (150)	#6	Steam	2	126 (119)	5.0	165 (294)	11.8	0 (0)	6.8 (35)	- -	- -	74 (70)	6.0	99.3 (177)	9.8	3.4 (10)	2.9 (15)	- -	- -	BOOS LowLoad
122-125	28	74 (70)	NG	Ring	3	31 (29)	5.7	108 (211)	7.6	0 (0)	0 (0)	- -	- -	32 (30)	5.3	49.0 (96)	7.9	16 (50)	0 (0)	- -	- -	BOOS
126-130	28	74 (70)	#6	Steam	3	31 (29)	5.3	115 (205)	11.6	0 (0)	- -	- -	127.3 (.296)	30 (28)	4.9	101 (180)	11.6	9.5 (28)	- -	- -	- -	LowAir
131-133	31	274 (260)	Coal	Pulv.	4	137 (130)	7.4	563 (922)	11.8	0 (0)	- -	813 (956)	2279 (5.3)	66 (63)	7.5	378 (618)	11.8	0 (0)	- -	- -	- -	BOOS LowLoad
134-139	30	132 (125)	Coal	SpStk	4	87 (82)	6.2	196 (320)	12.8	0 (0)	-	947 (1114)	1312 (3.05)	51 (48)	7.4	119 (195)	11.8	15 (40)	- -	- -	- -	LowAir LowLoad
140-142	32	137 (130)	NG	Ring	1	81 (77)	7.1	81.6 (160)	8.0	62 (200)	- -	- -	- -	Baseline was low NOx								
143-148	32	127 (120)	NG	Ring	4	88 (83)	4.4	117 (230)	9.4	0 (0)	- -	- -	- -	65 (62)	4.4	74.5 (146)	9.0	13 (43)	- -	- -	- -	BOOS LowLoad
149-152	33	580 (550)	Ref. Gas	Spud	8	506 (480)	5.1	84.8 (146)	8.4	0 (0)	- -	- -	- -	506 (480)	3.9	53.8 (107)	9.4	80.2 (263)	- -	- -	- -	CombCyc BOOS
153-155	34	264 (250)	NG	Spud	1	206 (195)	2.6	96.4 (189)	11.4	100 (322)	6.9 (39)	- -	- -	157 (149)	4.4	64.8 (127)	9.2	18.9 (61)	7.61 (43)	- -	- -	VPH AirReg
156-159	13	528 (500)	Coal Oil	Pulv. Steam	6 3	422 (400)	8.6	216 (353)	8.6	0 (0)	- -	- -	1122 (2.61)	443 (420)	7.2	166 (263)	10.0	21 (76)	- -	- -	- -	BOOS LowAir
160-164	36	211 (200)	#2	Steam	1	72 (68)	4.4	57.8 (103)	11.2	0 (0)	0 (0)	- -	6.88 (.016)	63 (60)	6.3	39.3 (70)	10.4	0 (0)	0 (0)	- -	155 (.36)	Damper OFA
165-168	35	227 (215)	Coal	ChGrt	1	110 (104)	9.5	100 (164)	9.2	9.3 (25)	5.3 (25)	- -	133 (.31)	111 (105)	8.7	77.0 (126)	10.3	20 (55)	3.8 (18)	- -		LowAir
169 only	31	274 (260)	Coal	Pulv.	4	148 (140)	7.0	561 (918)	-	0 (0)	- -	- -	3014 (7.01)	Baseline Test Only Conducted								
170-175	20	84 (80)	#6	Steam	1	65 (62)	3.3	148 (264)	13.5	0 (0)	1.6 (8)	780 (1000)	31.8 (.074)	67 (63.5)	2.7	132 (236)	13.1	10 (30)	2.5 (13)	- -	24.1 (.056)	AirReg & LowAir
176-179	37	42 (40)	#6	Steam	2	34 (32)	4.3	109 (195)	12.6	0 (0)	2.9 (15)	815 (1045)	50.7 (.118)	34 (32)	4.0	97.6 (174)	12.1	8.5 (25)	0 (0)	- -	34.8 (.081)	LowAir
180-185	38	47 (45)	NG	Ring	1	42 (40)	1.9	112 (220)	9.4	0 (0)	1.8 (10)	- -	- -	41 (38.5)	2.9	52.0 (102)	8.4	11 (35)	- -	- -	- -	OFA
186-189	38	47 (45)	#6	Steam	1	39 (36.5)	3.0	183 (326)	11.0	0 (0)	- -	738 (946)	38.7 (.09)	39 (36.5)	2.9	97.0 (173)	11.8	19 (55)	3.9 (20)	- -	55.0 (.128)	OFA

Table III. (Continued) BOILER EMISSION MEASUREMENTS AT BASELINE AND LOW NOx TEST CONDITIONS(1)

				Burner		BASELINE TEST CONDITIONS AND EMISSIONS (1)								LOW NITROGEN OXIDES TEST CONDITIONS AND EMISSIONS (1)								
Test No. From-Thru	Loc. No.	Boiler Capacity GJ/hr (10^3 lb/hr)	Test Fuel	(1) Type	No. Of	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NOx(2) g/GJ (ppm)	CO_2(2) %	CO(2) g/GJ (ppm)	HC(2) g/GJ (ppm)	SOx(2) g/GJ (ppm)	Solid Part. g/GJ (lb/MBtu)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NOx(2) g/GJ (ppm)	(2) CO_2 %	CO(2) g/GJ (ppm)	HC(2) g/GJ (ppm)	SOx(2) g/GJ (ppm)	Solid Part. g/GJ (lb/MBtu)	Test Type
190-194	19	18.5 (17.5)	NG	Ring	1	14.8 (14)	3.2	30 (59)	10.0	3 (10)	0.9 (5)	-	-	14.3 (13.6)	2.8	8 (16)	10.2	37 (120)	13.3 (75)	-	-	FGP
195-199	19	18.5 (17.5)	#6	Steam	1	14.8 (14)	3.1	95 (169)	13.2	0 (0)	-	-	13.3 (.031)	14.8 (14)	2.4	61 (108)	13.	53 (155)	0.9 (5)	-	-	OFA
200-203	19	18.5 (17.5)	#6	Air	1	14.8 (14)	2.9	91 (162)	13.2	0 (0)	0 (0)	146 (187)	13.3 (.031)	14.8 (14)	2.3	65 (116)	13.6	6.8 (20)	0. (0)	-	-	FGR
204-206	19	18.5 (17.5)	NG + #6	Ring, Air	1	14.8 (14)	3.3	59 (111)	11.2	3 (10)	4.7 (25)	-	-	14.8 (14)	2.8	49 (92)	11.8	0 (0)	4.7 (25)	-	-	FGR
207-212	39	211 (200)	NG + RG	Spud	1	169 (160)	3.7	98 (192)	8.8	8 (25)	0 (0)	-	-	169 (160)	6.4	75 (147)	7.4	48 (155)	0 (0)	-	-	OPA

(1) An explanation of the abreviations and units used is given in Appendix A.

(2) The emissions of these species are reported as dry at 3% excess oxygen.

(3) The shaded areas denote tests where certain emissions were measured both before and after combustion modification.

Particulate Size

The size distribution of the particulate emissions was measured to determine the effect on size of fuel type, burner type, dust collectors, and combustion modification. Thirty tests on ten different boilers with and without combustion modification were conducted. Sixteen of the measurements that are listed in Table IV were made with oil fuel and 14 with coal fuel using a low-speed-flow type cascade impactor. In some instances soot was blown to include in the size measurements the soot that was deposited during the test.

Particulates having a diameter of 3 μm or less and listed in the sixth column are important because the "fine" particulates smaller than three microns in diameter are especially dangerous to public health (Ref. 5). The proportion of the particulate catch that was in the fine particulate range ran from about 30% to 80% for oil fuel. For coal fuel the proportion was less, about 20% to 33% with one instance of 65%.

Oil fuel also produced more particulates in the size range that causes reduced visibility and atmospheric haze than did coal. As expected, the particulates from coal were larger in aerodynamic diameter than were the particulates from oil.

Most of the oil fuel data evinced a large proportion of particulates in the fine particulate size range. Typically, two-thirds of the particulates were 3 μm or smaller in size. Test No. 162 was an exception, since only about 30% of the particulates were below 3 μm. This smaller number of fine particulates probably was due to the characteristics of the light No. 2 oil fuel. The light oil also had a lower total concentration of particulates.

The results of two pulverized coal-fired boilers are compared in Figure 5. The two upper curves are for Location Nos. 13 and 31, both of which fired pulverized coal. The coal was from

Table IV. DISTRIBUTION OF PARTICULATE SIZE

OIL FUEL

Test				Proportion of Total Weight of Catch				
No.	Location	Load GJ/hr (10^3lb/hr)	Burner or Oil Type	Particles Inhaled Then Exhaled <0.5 μm %	Particles In The "Fine" Particulate Size Range <3 μm %	Particles Reducing Visibility by Mie Scattering 0.4-0.7 μm %	Soot Included	Test Conditions
111	27	90 (85)	PS300	60	81	10	No	Baseline
121-9	29	76 (72)	No. 6	10	68	8	Yes	Baseline with light soot
121-10		76 (72)	No. 6	15	64	22	Yes	Baseline with light soot
121-11		76 (72)	No. 6	3	29	3	Yes	Baseline with light soot
130	28	32 (30)	No. 6	7	49	6	No	Baseline
162-36	36	65 (62)	No. 2	1	26	1	No	Baseline
171-6A	20	53 (50)	No. 6	40	73	3	Yes	Baseline
171-6B		53 (50)	No. 6	37	67	2	Yes	Baseline
171-8		54 (51)	No. 6	37	65	2	Yes	Baseline
170-5		68 (64)	No. 6	32	62	3	No	Higher Load
176-5	37	34 (32)	No. 6	32	58	1	No	Baseline
COAL FUEL								
139-5	30	87 (82)	SpStk	0.7	8	<1	No	Baseline, Upstream of Cyclone
156-2	13	422 (400)	Pulv.	2	30	3	No	Baseline, Downstream of Cyclone
166-3	35	116 (110)	ChGrt	11	24	6	No	Baseline, Downstream of Dust Collector
166-5		111 (105)		46	65	13	Yes	
166-6		111 (105)		25	33	3	Yes	
166-9		106 (100)		5	22	2	Yes	
166-11		116 (110)		5	24	4	Yes	
169-1	31	148 (140)	Pulv.				Yes	Baseline, Upstream of Dust Collector
169-2		148 (140)		1	26	1	Yes	Baseline, Downstream of Dust Collector
169-3		148 (140)		1	10	2	Yes	Baseline, Upstream of Dust Collector
169-4		148 (140)		1	50	3	Yes	Baseline, Downstream of Dust Collector
169-6		148 (140)		0.4	22	1	Yes	Baseline, Downstream of Dust Collector

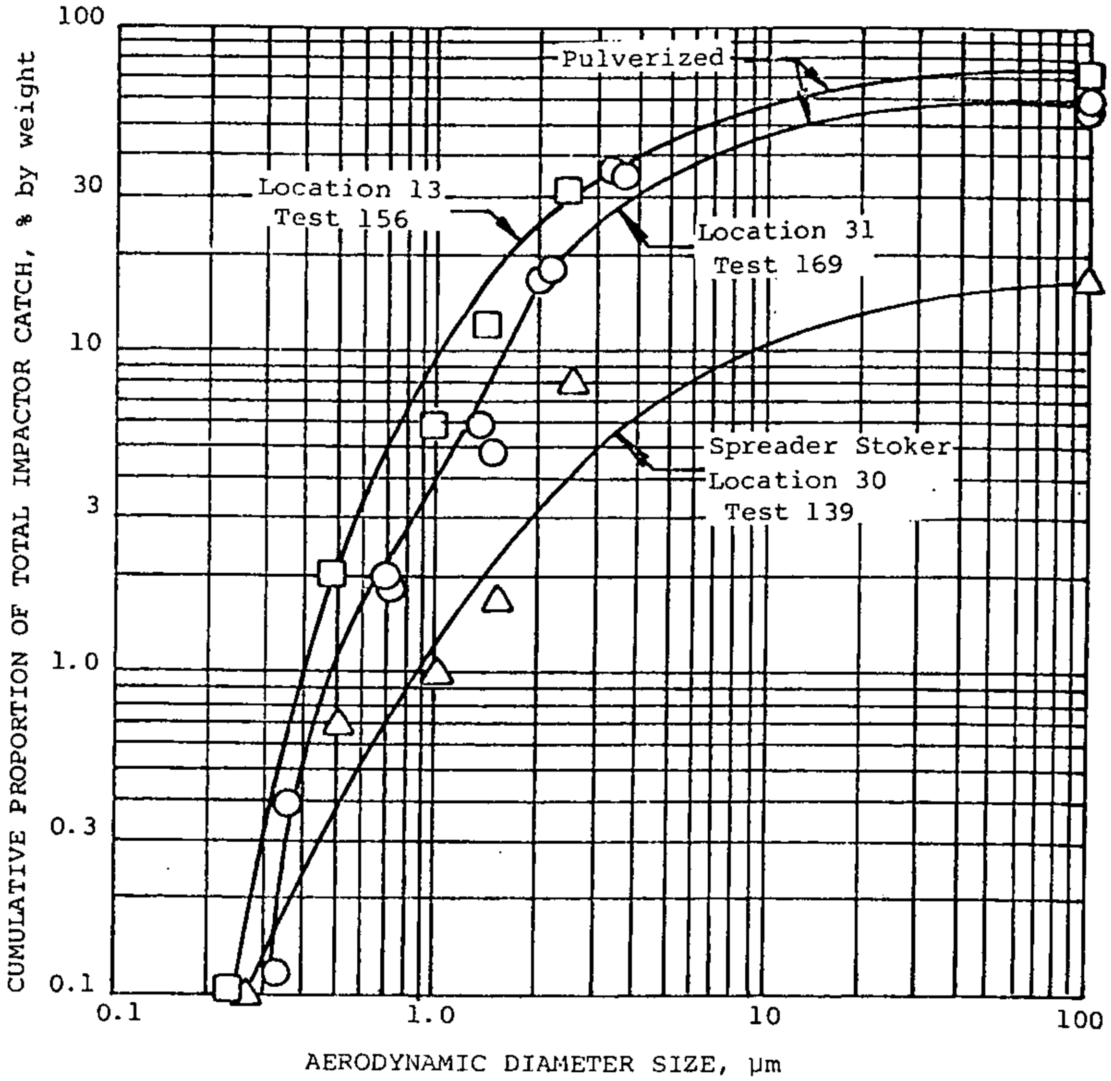


Figure 5. Baseline particulate size distribution, coal fuel

different sections of the country, but the coal particulate size distributions were similar. Figure 5 also illustrates the difference in size that was found for pulverized-fired and spreader stoker-fired boilers. The spreader stoker had a much lower proportion of the smaller sized particulates.

Hydrocarbon Emissions

Hydrocarbon (HC) emissions from both natural gas and oil fuels generally were in the zero to 14 g/GJ (zero to 75 ppm) range. The two highest baseline values measured were 35.4 and 101.8 g/GJ (200 and 575 ppm).

Carbon Monoxide Emissions

The baseline carbon monoxide (CO) emissions for industrial boilers were normally near zero, although in a few test cases the boilers were being operated with over 70 g/GJ (200 ppm) of carbon monoxide emissions.

Sulfur Oxides Emissions

The combined sulfur dioxide and sulfur trioxide emissions for coal- and oil-fired boilers ranged from near zero to as high as 1530 g/GJ (1800 ppm). Almost all of the sulfur present in the fuel appeared in the stack gases and the level of sulfur oxides emissions was directly proportional to the sulfur content of the fuel. An exception was when the sulfur content of the coal exceeded 2%. In these three cases the sulfur oxide content of the stack gas was below 100% conversion, indicating that about one-quarter of the sulfur was emitted in another form, e.g. retained in the fly ash or emitted as a sulfate in the flue gas.

Boiler Efficiency

Boiler thermal efficiencies were determined from heat loss calculations based on fuel composition and flue gas emissions measurements. Baseline efficiencies for coal-fired boilers ranged from 72% to 88% and averaged 81%. The oil-fired boilers exhibited efficiencies between 72% and 88% and averaged 83%. Gas-fueled boilers had efficiencies from 70% to 85% with an average of 81%.

One of the major factors affecting the efficiency of individual boilers was the excess oxygen level. A 1% reduction in excess O_2 generally improved efficiency by about 0.5%. Baseline efficiencies were also dependent upon the type of boiler equipment. Older boilers were generally in poorer physical condition and lacked efficiency-enhancing design features such as economizers and air preheaters. The larger-capacity boilers were more efficient than smaller units probably due to more efficient design. The type of burner had an influence on efficiency in the case of coal-fired units. Cyclone and pulverizer units had much higher efficiency levels than the chain grate and underfed stokers.

Furnace Design

Twenty firetube furnace boilers were tested during Phase I. Comparison of the test results showed no significant difference between nitrogen oxides emissions from firetube and watertube boilers when burning the same fuel (Ref. 3). The Phase II testing concentrated on watertube boilers only.

3.0 COMBUSTION MODIFICATION TEST RESULTS

During Phase II eleven methods of combustion modification were investigated. They are listed on Table V and the postulated effect of the modification of combustion which caused the lower nitrogen oxides emissions is tabulated in the column on the right of Table V. A total of 52 tests of the eleven combustion modification methods were run.

The effects of combustion modification on the total nitrogen oxides and solid particulate emissions and on the boiler heat loss efficiency are illustrated in Figures 6 and 7. The combustion modification effect graphs are divided into quadrants. The criterion for the "best quadrant" with solid particulate emissions is that the effect of the modification was to reduce the emissions of both the total nitrogen oxides and the particulates. In the "worst quadrant", both emissions increased. In the case of boiler heat loss efficiency, the best quadrant is when the total nitrogen oxides emissions decreased, but the efficiency increased.

In slightly over one-half of the cases (56%), when the nitrogen oxides were decreased the particulates were increased. In 22% of the tests, the emissions were in the best quadrant where both decreased. The effect on boiler efficiency was more favorable, for in over 60% of the instances the results were in or adjacent to the best quadrant. The effect of fuel is discussed in Reference 4.

Excess Combustion Air Reduction

A combustion modification method that offered ease of implementation, emission reduction, and efficiency increase was to lower the amount of excess air being fired. In about three-quarters of the instances when the excess air was reduced, the nitrogen oxides emissions decreased by up to 38% of the baseline level, and the efficiency increased, by up to 3 percentage points. Reducing the

Table V. COMBUSTION MODIFICATION METHODS AND EFFECTS

CATEGORY AND METHOD	EFFECT
1. Mixture Ratio Variation	
o Excess air level	o Varies the overall fuel/air mixture ratio
o Overfire air	o Creates local fuel/air ratio stratification by bypassing air and delays complete combustion
o Burners-out-of-service	o Creates local fuel/air ratio stratification by bypassing air and delays complete combustion
o Burner register adjustment	o Controls swirl level and the local rate of fuel/air mixing
2. Enthalpy Variation	
o Combustion air temperature	o Influences peak gas temperature level and duration
o Flue gas recirculation	o Reduces peak gas temperature level and duration
o Firing rate	o Affects fuel heat release rate per unit volume, and gas heat loss rate
3. Input Variation	
o Fuel oil temperature/viscosity	o Controls atomization characteristics; e.g., drop size and vaporization rate
o Fuel type switching	o Reduces sulfur and/or nitrogen oxides emissions from the fuel
o Burner tuneup	o Assures performance according to design specifications
o Fuel oil atomization method and pressure	o Controls local fuel/air mixing rates by varying drop size distribution and overall fuel spray shape

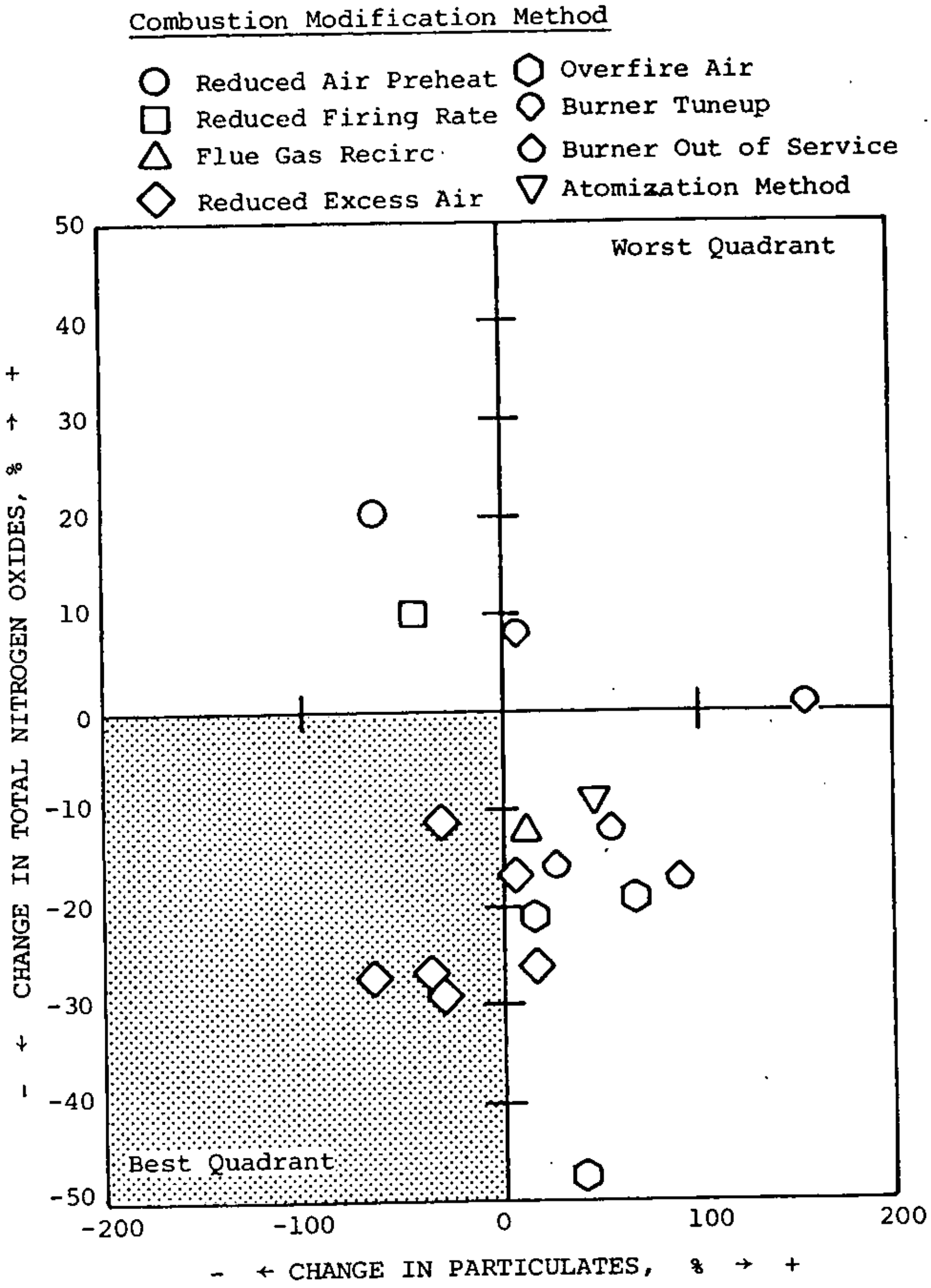


Figure 6. Effect of combustion modification method on total nitrogen oxides and solid particulate emissions.

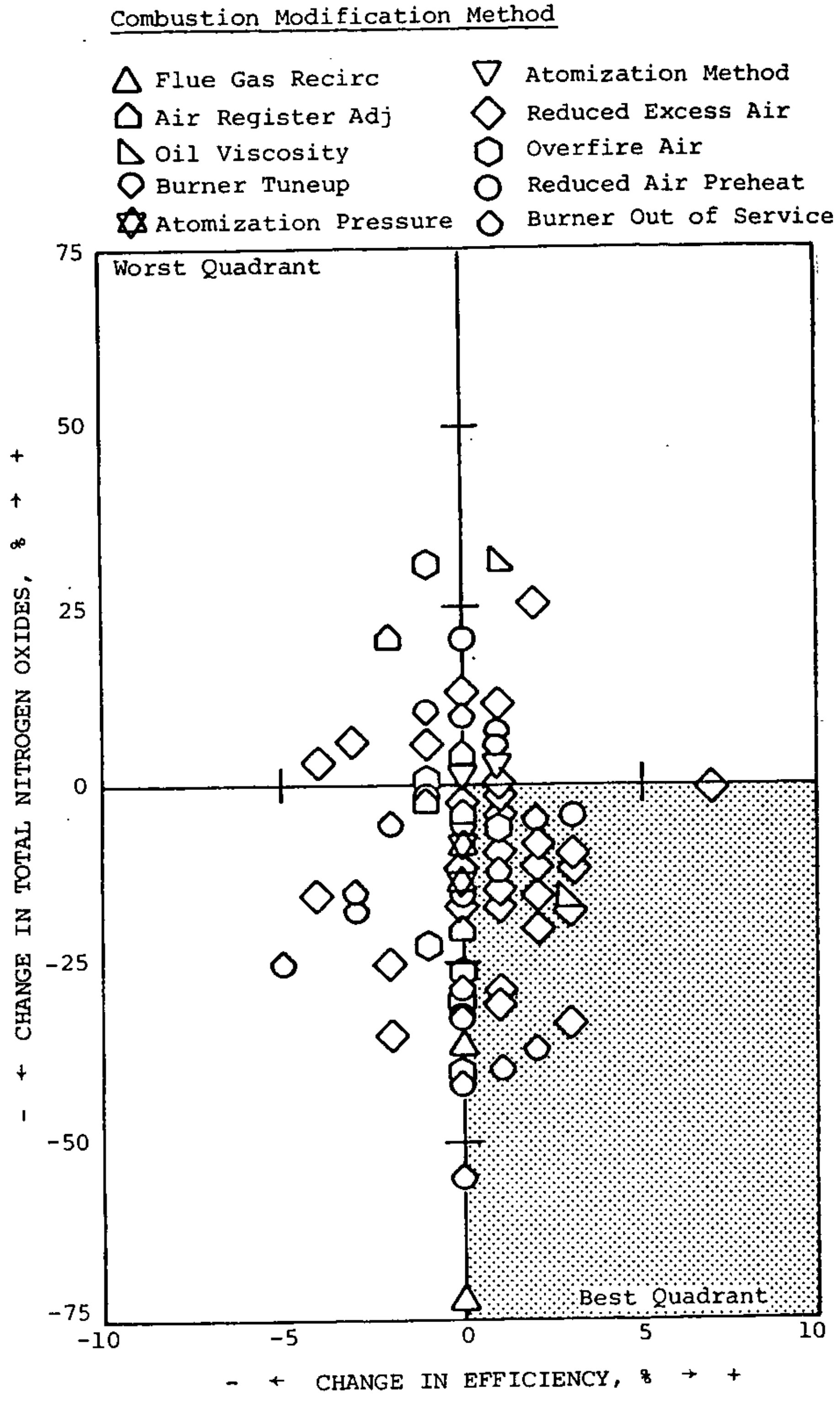


Figure 7. Effect of combustion modification method on total nitrogen oxides emissions and boiler efficiency.

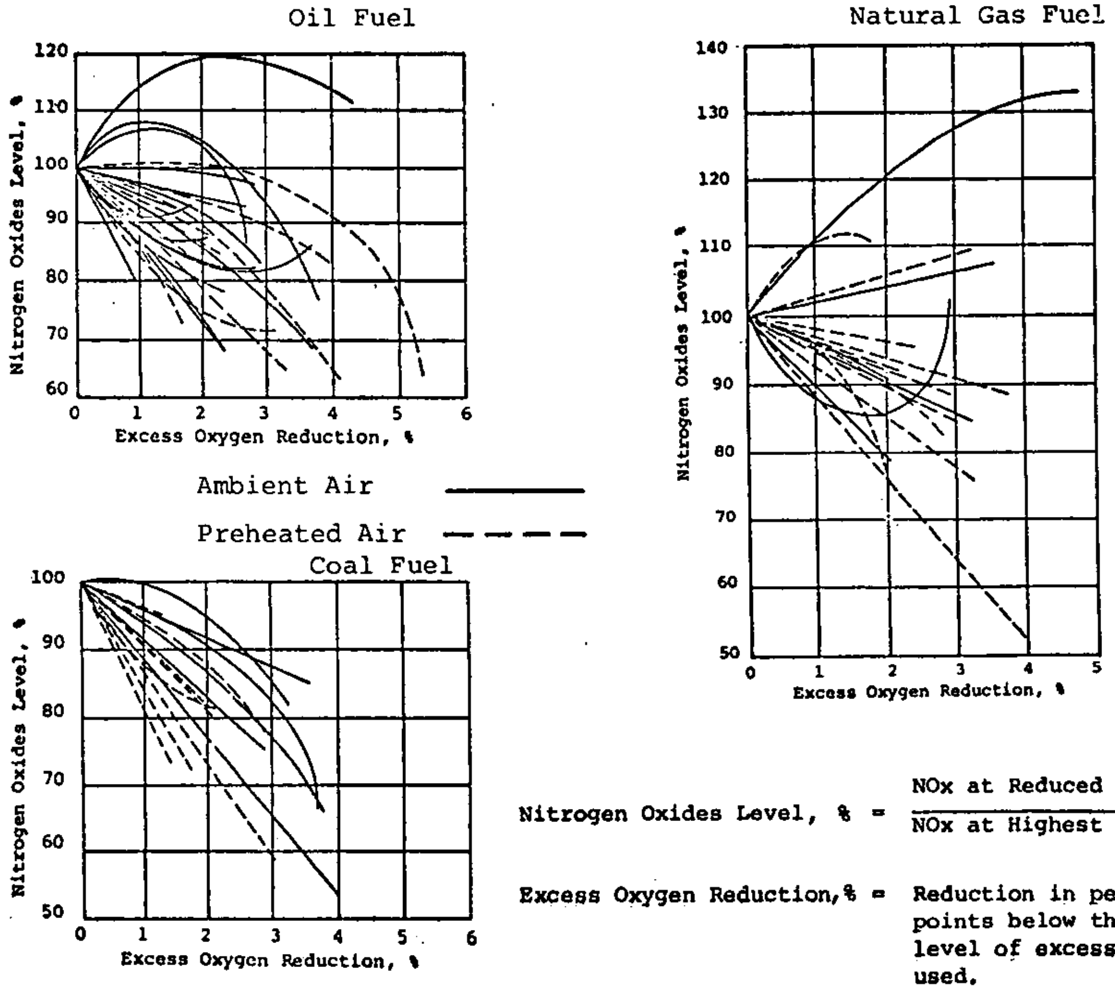
excess air suppressed the formation of thermal nitrogen oxides from all the fuels. The greater reductions for oil and coal fuels were due to the suppression of the conversion of fuel nitrogen to NOx also.

The effect of lowered excess air on the solid particulate emissions was to reduce them by up to about 15% with coal fuel and up to about 30% with No. 6 oil fuel. In only two cases out of six did the reduction of excess air cause less complete combustion and a slight increase in particulate emissions. The criterion for minimum excess air was the appearance of carbon monoxide in the flue gas. If the excess air had been further reduced to the point where the smoke number had increased significantly, the particulate emissions, then, would have increased.

The test results of changing the level of excess oxygen on the total nitrogen oxides emissions are depicted in Figure 8. The effect of reducing the excess oxygen was the greatest for coal fuel, causing a reduction in NOx level of about 12% for each one percentage point reduction in excess oxygen.

The oil fuel data for both heated and ambient temperature combustion air indicated a reduction in total nitrogen emission level of about 7% for each one percentage point reduction in excess oxygen. The reduction of the nitrogen oxides level from Nos. 5 and 6 fuel oils was about twice that from the No. 2 oil fuels.

The influence of the excess air/oxygen level on the nitrogen oxides emissions from natural gas-fueled boilers without preheated combustion air was varied. However, the preheated combustion air data evidenced a consistent decrease of emissions level of about 5% for each one percentage point reduction in the excess oxygen level. The variations in dependency were caused by the air-fuel premixing characteristics of the individual burners, the heat-absorbing characteristics of the furnace, differences in burner design, etc.



Nitrogen Oxides Level, % = $\frac{\text{NOx at Reduced } O_2}{\text{NOx at Highest } O_2} \times 100$

Excess Oxygen Reduction, % = Reduction in percentage points below the highest level of excess oxygen used.

Figure 8. Nitrogen oxides emission reduction due to a reduction in excess oxygen.

Staged Combustion

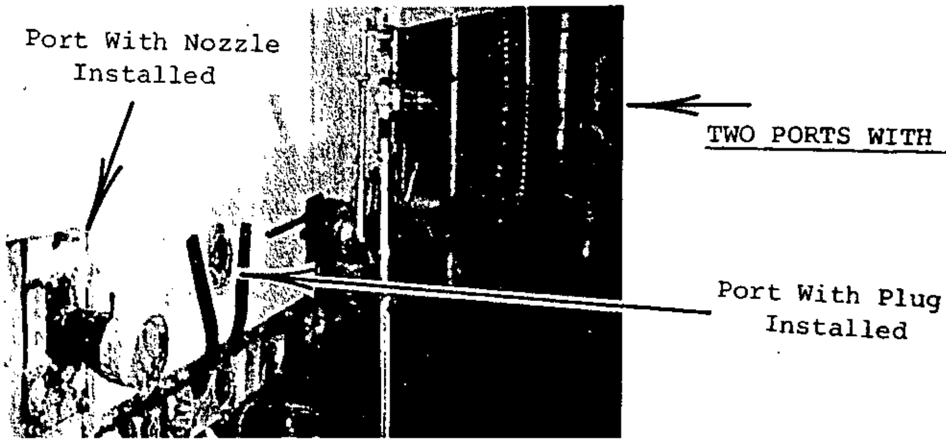
Nine tests were run where the combustion air was added in stages, three each on coal, oil, and gas fuels. In all but two cases, staging the air reduced the nitrogen oxides emissions by up to 47%. One exception was with natural gas fuel where the change was zero and the other was a spreader stoker where the nitrogen oxides emissions increased by 10%. In four cases, the boiler efficiency decreased up to three percentage points and in the other five cases it was unchanged.

Diverting some of the combustion air from the initial combustion zone at the burner and injecting it farther downstream from the burner had two principal effects on the formation of nitrogen oxides. Firstly, the combustion process was slowed down and the consequent delayed release of the heat of combustion resulted in a lower temperature for the products of combustion; thus, the formation of the thermal nitrogen oxides was suppressed. Secondly, less oxygen was available in the initial flame zone and this suppressed the formation of nitrogen oxides from the fuel nitrogen.

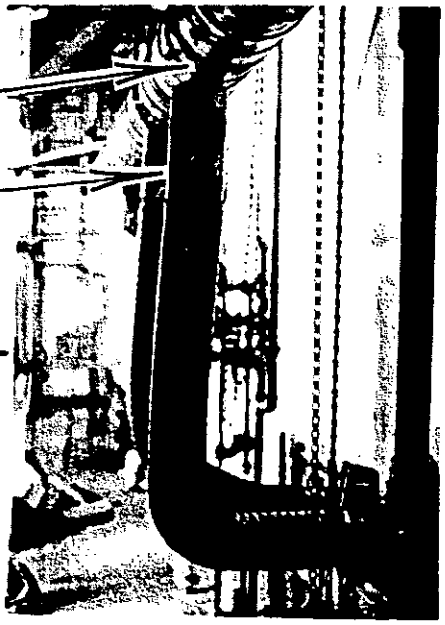
Three of the staged air tests were made with No. 6 oil fuel and in all cases the particulates increased, by 12% to 75%, as indicated in Figure 6. Apparently, delaying complete combustion increased the amount of unburned carbon in the flue gas.

During Phase II, two boilers were modified to allow adding part of the air downstream of the burner and five boilers were tested which had been manufactured with staged air capability.

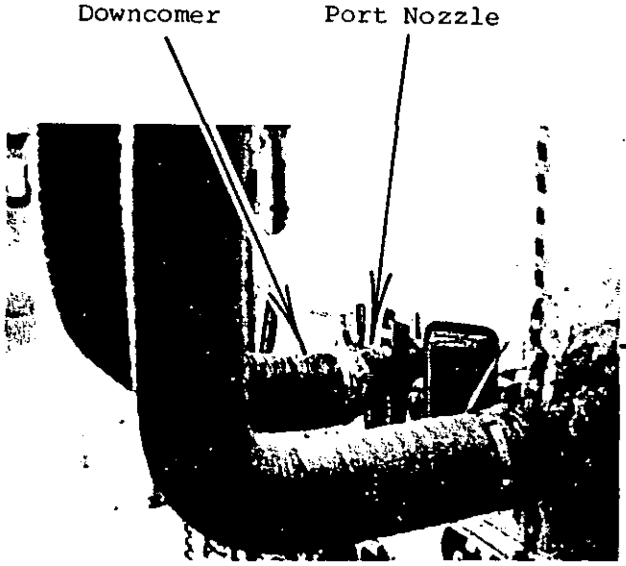
One of the staged air modifications is pictured in Figure 9 and diagrammed in Figure 10. A 36-cm diameter manifold pipe was run along each side of the boiler and was connected to a fan mounted on the floor. Four flexible fabric pipes were connected to the manifold and these could be connected to the five staged air ports that had been cut into the furnace side walls on each side.



TWO PORTS WITH DOWNCOMERS ATTACHE



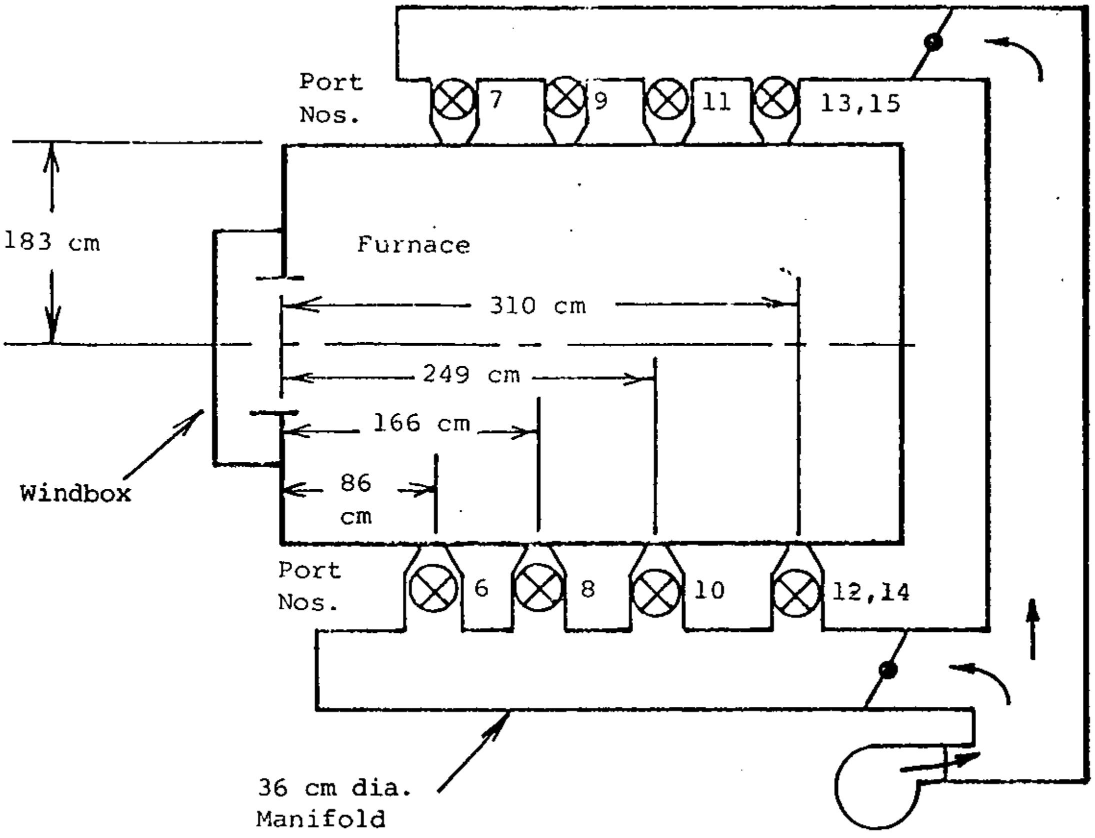
AIR SUPPLY MANIFOLD AND TWO DOWNCOMERS



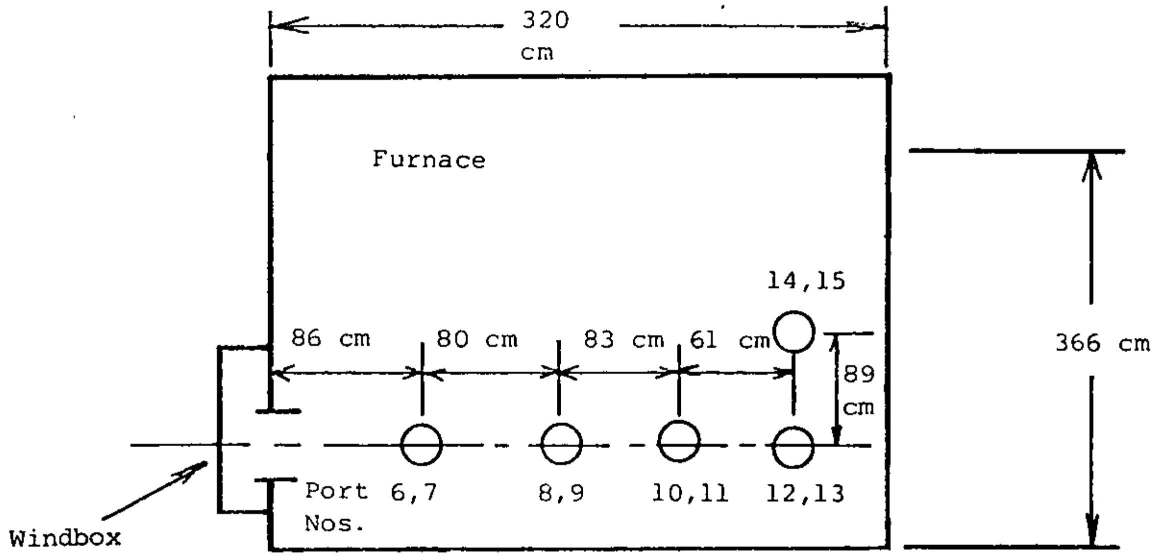
DETAIL OF ATTACHMENT OF DOWNCOMERS TO PORT NOZZLE

Figure 9. Staged combustion air installation at location No. 38.

Boiler Type: Combustion Engineering, balanced-draft, Type VU-10
Boiler Capacity: 47500 GJ/hr (45,000 lb/hr)
Burner Type: Single Peabody, steam atomized



(a) TOP VIEW



(b) SIDE VIEW

Figure 10. Schematic diagram of staged combustion air system installed at location No. 38.

The results of the tests on this boiler with natural gas fuel are presented in Figure 11. For comparison with what could be accomplished simply by reducing the amount of excess air through the burner, the effect on the nitrogen oxides emissions with no staged air ports open also is plotted. The data in Figure 11 indicate the following for gas fuel: (1) for the ports located along the burner axis [port nos. 6-13], the nitrogen oxides emissions exhibited little sensitivity to the location of staged air addition, (2) the staged air ports located above the burner axis [port nos. 14 and 15] were the most effective in reducing nitrogen oxides, (3) the nitrogen oxides reduction with staged air addition was a strong function of the relationship of the stoichiometric fuel-to-air ratio to the actual fuel-to-air ratio at the burner. This ratio is plotted on Figure 11 as theoretical air at the burner in percent.

The nitrogen oxides emissions were reduced from the baseline level of 112 g/GJ to 91 g/GJ simply by decreasing the excess air. They were reduced to about 80 g/GJ by staging the air through the middle ports. When the air was staged through the upper rear ports, Nos. 14 and 15, the NOx emissions were reduced to 52 g/GJ, for a total reduction of 54%. By trimming the combustion air it was possible to achieve this 54% reduction and limit the carbon monoxide emissions to 11 g/GJ. Less than 32 g/GJ (100 ppm) of carbon monoxide was the goal during the testing.

Some typical results of the staged air tests of this modified boiler with oil firing are shown in Figure 12. As with gas firing, the burner fuel-to-air ratios were the dominant parameter in correlating the nitrogen oxides emissions. Nitrogen oxides reductions to about 50% of the baseline level were obtained when the burner theoretical air was reduced from the baseline level of 114%

Test Load: 42 GJ/hr (40x10^3 lb/hr)
Fuel: Natural Gas
Test Nos. 180 and 183

Note: The excess oxygen level in the stack gas was held constant during all staged air tests.

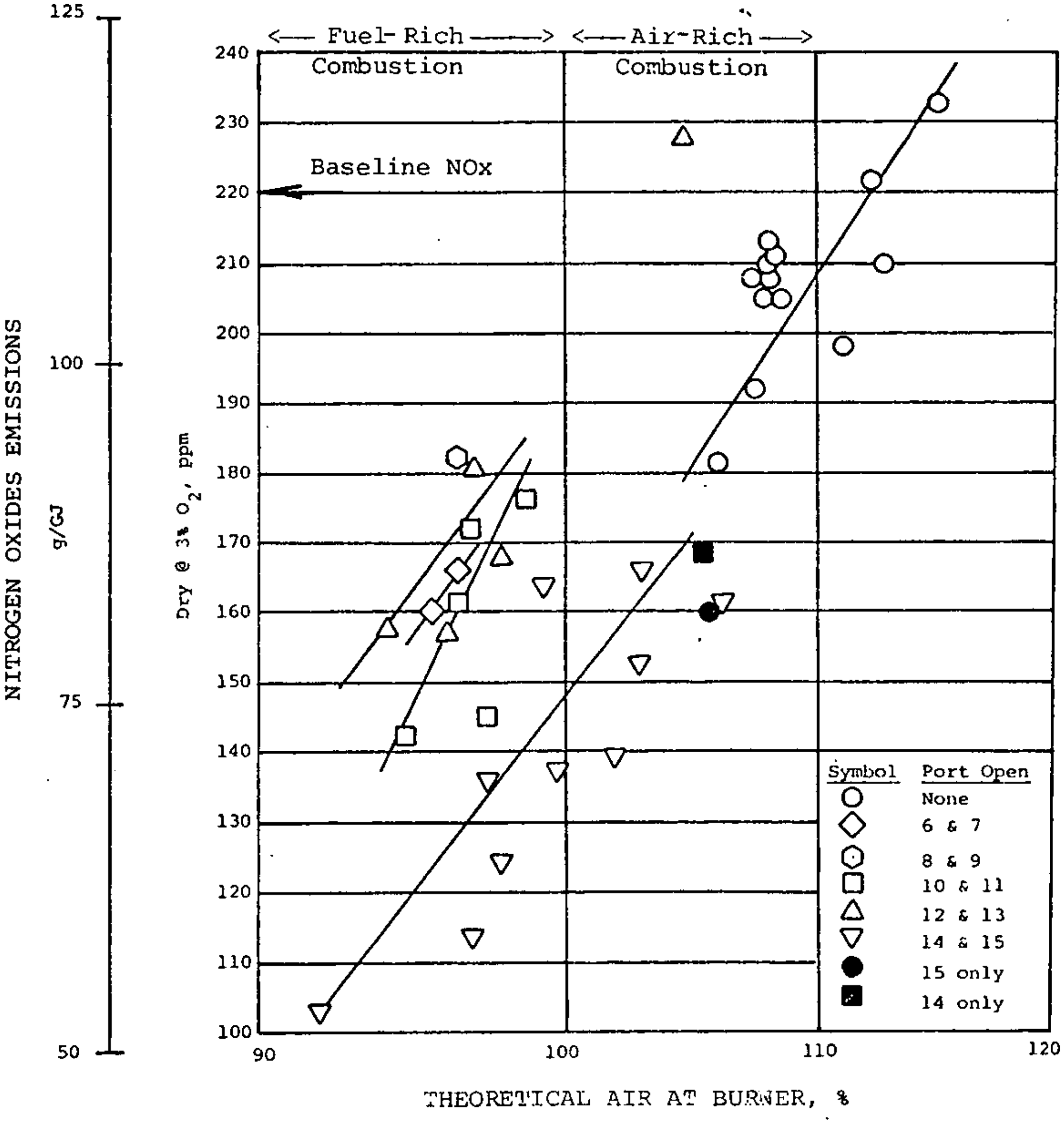


Figure 11. Effect of staged air on total nitrogen oxides emissions, natural gas fuel.

Note: The excess oxygen level in the stock gas was held constant during all staged air tests.

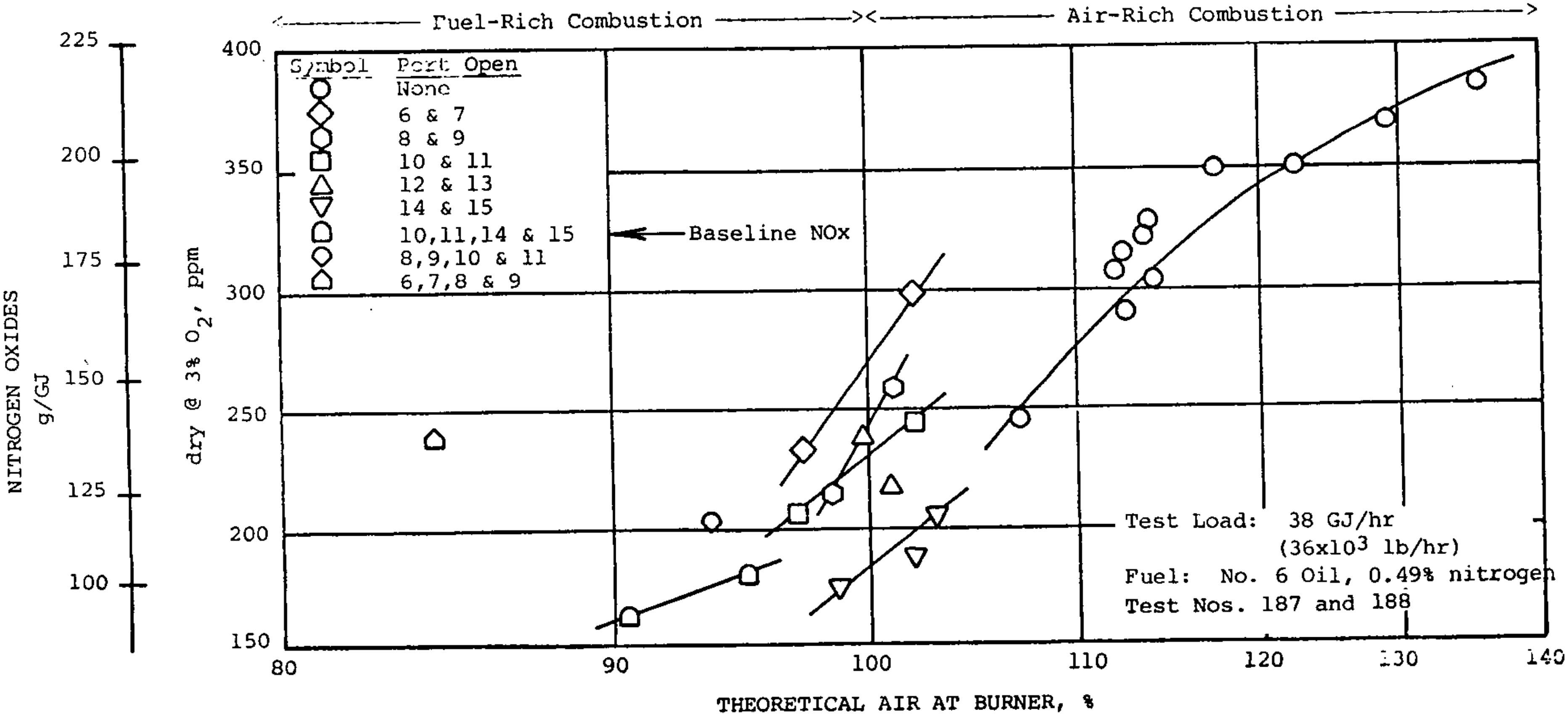


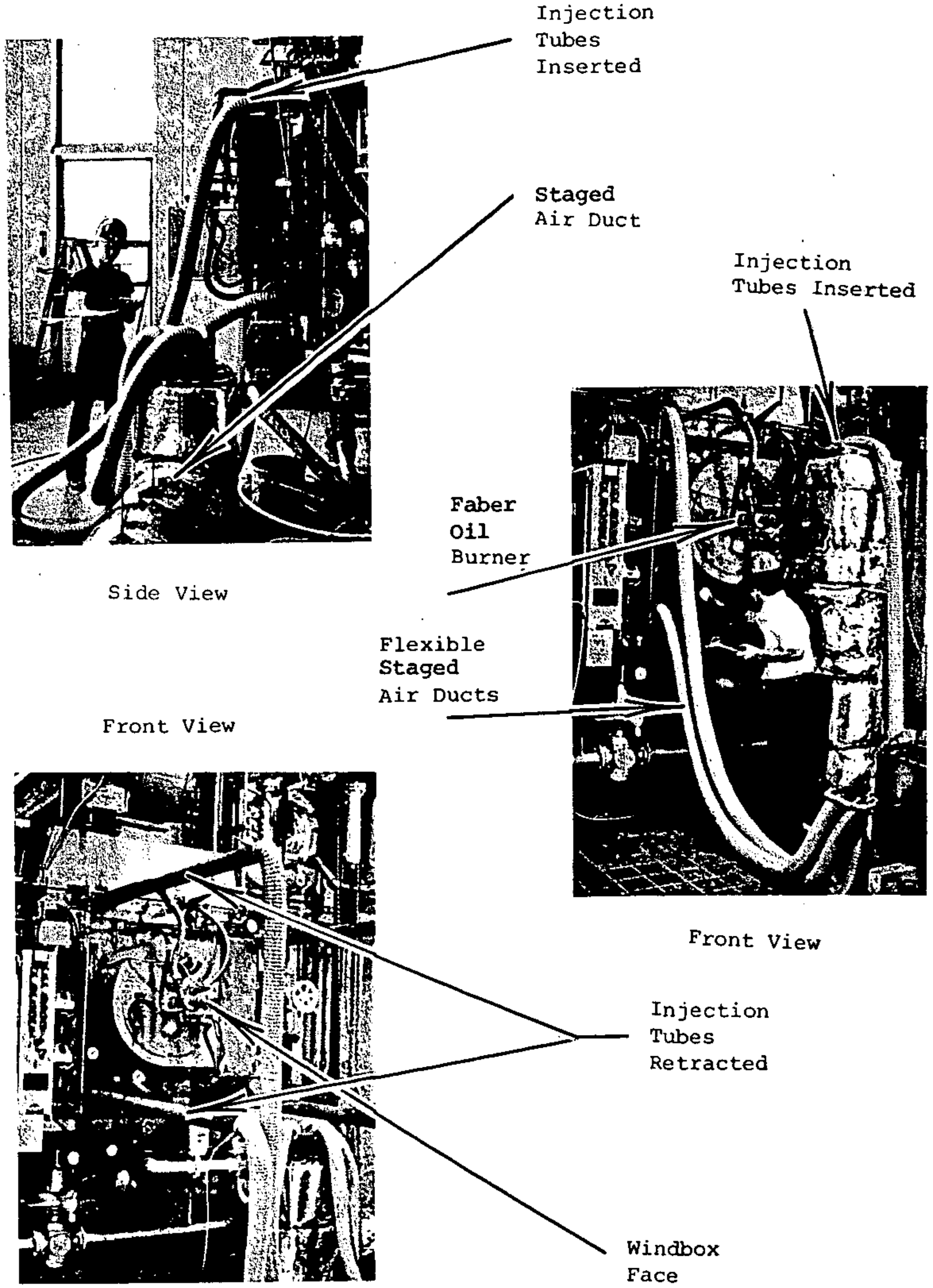
Figure 12. Effect of staged air on total nitrogen oxides emissions, No. 6 oil fuel.

to below the stoichiometric level of 100%. In fact the curve of nitrogen oxides versus the theoretical air at the burner with staged air through ports 10, 11, 14, and 15 was essentially an extension of that obtained merely by reducing the overall excess air with no staged air.

There was a stronger effect of the location of adding the air in stages on the nitrogen oxides emissions from oil fuel than from natural gas fuel. The test results showed that the nitrogen oxides were further reduced as the point at which the staged air was added was moved farther away from the burner. This was caused by the moving of the injection location away from the burner, providing a lower heat release rate and a longer residence time of the combustion products in a fuel-rich region. The decreased heat release rate resulted in overall lower flame zone temperature levels and a reduction in the production of thermal nitrogen oxides.

In addition, the longer residence time under fuel-rich conditions also allowed a greater fraction of the fuel nitrogen compounds to be reduced to molecular nitrogen rather than oxidized to nitric oxide and, thus, reduced the conversion of fuel-bound nitrogen to nitrogen oxides. The insensitivity of the nitrogen oxides reductions to locations of staged air addition with natural gas firing supports the contention that the major effect of staged firing with oil in this unit was a suppression of the conversion of fuel-bound nitrogen.

The second boiler modified for staged air was a Keeler Co. Type DS-17.5 watertube unit rated at 18.5 GJ/hr (17,500 lb/hr steam flow) with a Faber Type D burner and is pictured in Figure 13. The staged air was introduced into the furnace by four steel tubes that were inserted through holes cut into each of the four corners of the windbox. Flexible ducts were attached to the end of each overfire air tube to supply air from the staged air duct to each tube. The tubes could be inserted up to 122 cm into the furnace.



Side View

Front View

Front View

Figure 13. Staged combustion air installation at location No. 19 for Test Nos. 193, 198, and 203.

Tests were conducted for No. 6 oil, both air atomized and steam atomized, and natural gas. A representative effect of staged air on nitrogen oxides emissions for steam-atomized No. 6 fuel oil firing is shown in Figure 14. The data grouping at the upper right is from baseline and excess air reduction tests. The lowest nitrogen oxides emission level that could be obtained by reducing the excess air was 69.6 g/GJ (124 ppm) with 103% theoretical air.

When part of the air was introduced into the combustion zone only 30.5 cm downflame of the burner, there was no reduction in nitrogen oxides emissions relative to the baseline. When the injection point was moved 122 cm into the furnace and the theoretical air at the burner was reduced to 80%, the emissions dropped to 61 g/GJ (108 ppm). This was a 36% drop from the baseline emissions and a 13% drop from the lowest emissions obtainable by reducing the excess air.

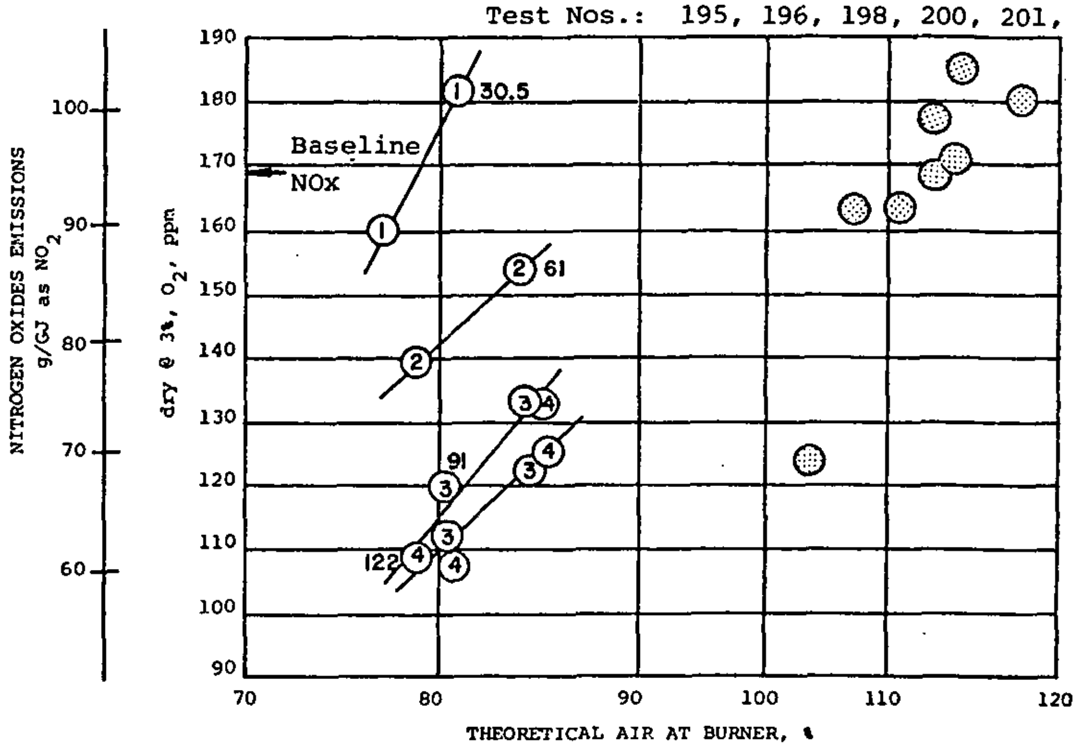
Staged air was more effective with No. 6 oil than with natural gas (for natural gas the nitrogen oxides emissions were essentially the same or increased above the baseline values). This indicated that (1) the fuel/air mixing characteristics for this burner may have been different for natural gas and No. 6 oil, with effective staging being obtained 122 cm (4 ft) from the burner with oil firing; and/or (2) the differences in fuel-air mixing were such that the fuel-bound nitrogen conversion to nitrogen oxides was suppressed with little effect on the thermal-NOx formation.

The nitrogen oxides reductions with the oil- and the gas-fueled boilers where the ports were built in and not adjustable were 10% and 40%, respectively.

On stoker-fired coal units, the staged air ports conventionally are located above the stokers to promote turbulence in the vicinity of the flame zone and obtain complete carbon burnout within

Note: The excess oxygen level in the stock gas was held constant during all staged air tests.

Rated Capacity: 18 GJ/hr
(17,000 lb/hr)
Test Load: 15 GJ/hr (14,000 lb/hr)
Fuel: No. 6 oil, steam atomized
Test Nos.: 195, 196, 198, 200, 201, 2



Shaded symbols are emissions with no staged air. Open symbols indicate staged air. Number inside symbol denotes distance in feet from the burner face of the air addition. Number beside symbol is distance in centimeters.

Figure 14. Effect of staged air on total nitrogen oxides emissions, No. 6 oil fuel.

the furnace. During the program, varying the amount of staged air was investigated as a nitrogen oxide control technique on three boilers. In two tests the nitrogen oxides were reduced by 8% to 25%. In the third with a chain grate, they increased by 10%, because the additional staged air produced a more vigorous flame (but higher grate temperature was measured).

Burner Out of Service

The combustion modification method that has been very effective with utility boilers is operation with some of the burners out of service. In this mode, the fuel supply to selected burners was discontinued while the air flow to the burner was maintained. The total amount of fuel being burned was held constant by increasing the fuel, but again not the air, to the remaining burners. As a result, these burners were operating fuel rich and complete combustion was delayed by the surplus of fuel and the scarcity of air.

With a burner out of service, the total nitrogen oxides emissions from the industrial boilers were reduced by a minimum of 9% and a maximum of 54%. An advantage of this type of combustion modification was that the boiler efficiency was relatively unaffected and varied by only ± 0.5 percentage points over nine runs. A disadvantage was that the combustion process was disturbed such that the particulate emissions always increased. In one case the increase was about 54% and in another the increase was 95% for a comparable drop in nitrogen oxides concentration.

The data shown in Figure 15 are typical of the results that were obtained when burners were taken out of service. For example, Test Nos. 123 and 124 were run on a 74 GJ/hr (70,000 lb/hr) natural gas-fired boiler that had three burners in a horizontal row. By simply reducing the amount of excess air with no burners out of service, it was possible to lower the nitrogen oxides emissions from the baseline level of 108 g/GJ (211 ppm) to 85 g/GJ (166 ppm). Then

Note: The excess oxygen level on the stock gas was held constant during all staged air tests.

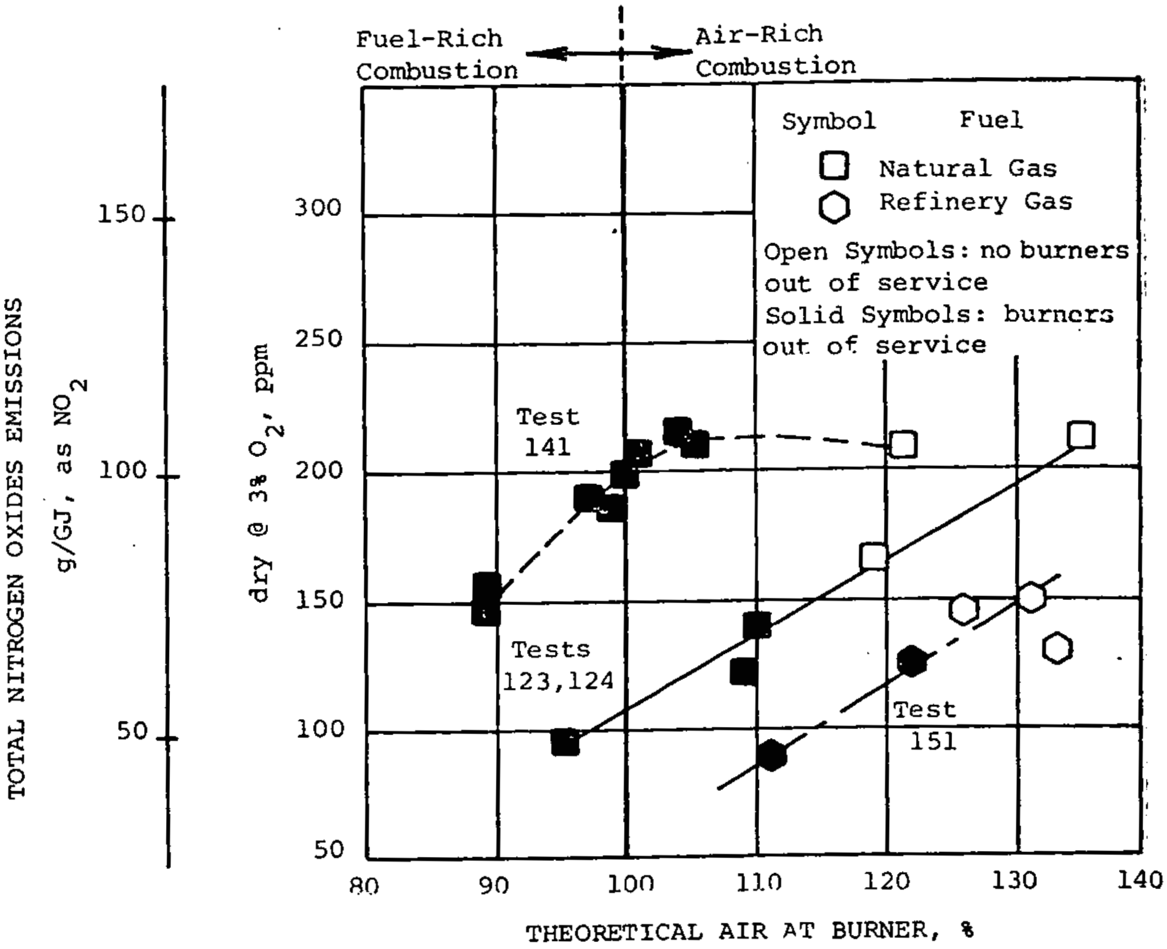


Figure 15. Effect of burners out of service on total nitrogen oxides emissions, natural gas and refinery gas fuel.

the center burner was taken out of service, and it became possible to enter the fuel-rich burning region and to reduce the nitrogen oxides emissions to 49 g/GJ (96 ppm). This was a 55% reduction in nitrogen oxides emissions. The boiler efficiency was unaffected.

Similar results were obtained with oil and coal fuels, the reduction in nitrogen oxides ranging from 20% to 40%.

Burner Register Adjustment

Readjusting the burner air registers succeeded in reducing the nitrogen oxides by 6% to 22%. The efficiency was unchanged to as much as one percentage point lower, and the particulate emissions were unchanged. These results were from a series of tests where the local air/fuel mixture ratio was controlled by varying the burner air register setting and, thus, the amount and the swirl of the air that entered the burner.

The typical effect of secondary air register position on the nitrogen oxides emissions and smoke levels is shown by the results of the testing of a single burner boiler presented in Figure 16. A setting of zero % open corresponded to fully closed, while 100% open was fully open with the register vanes radial to the burner center. (At the fully closed position there was still a small amount of air leakage into the burner.) In addition to the secondary damper percentage open, an approximate ratio of secondary to primary air flow is noted on the ordinate. Opening the secondary damper from 10% open to its 100% open position decreased the amount of primary air resulting in decreased fuel-air mixing near the burner and a 22% reduction in nitrogen oxides emissions. However, the reduction in nitrogen oxides was obtained at a cost of an increase of about three Bacharach smoke numbers.

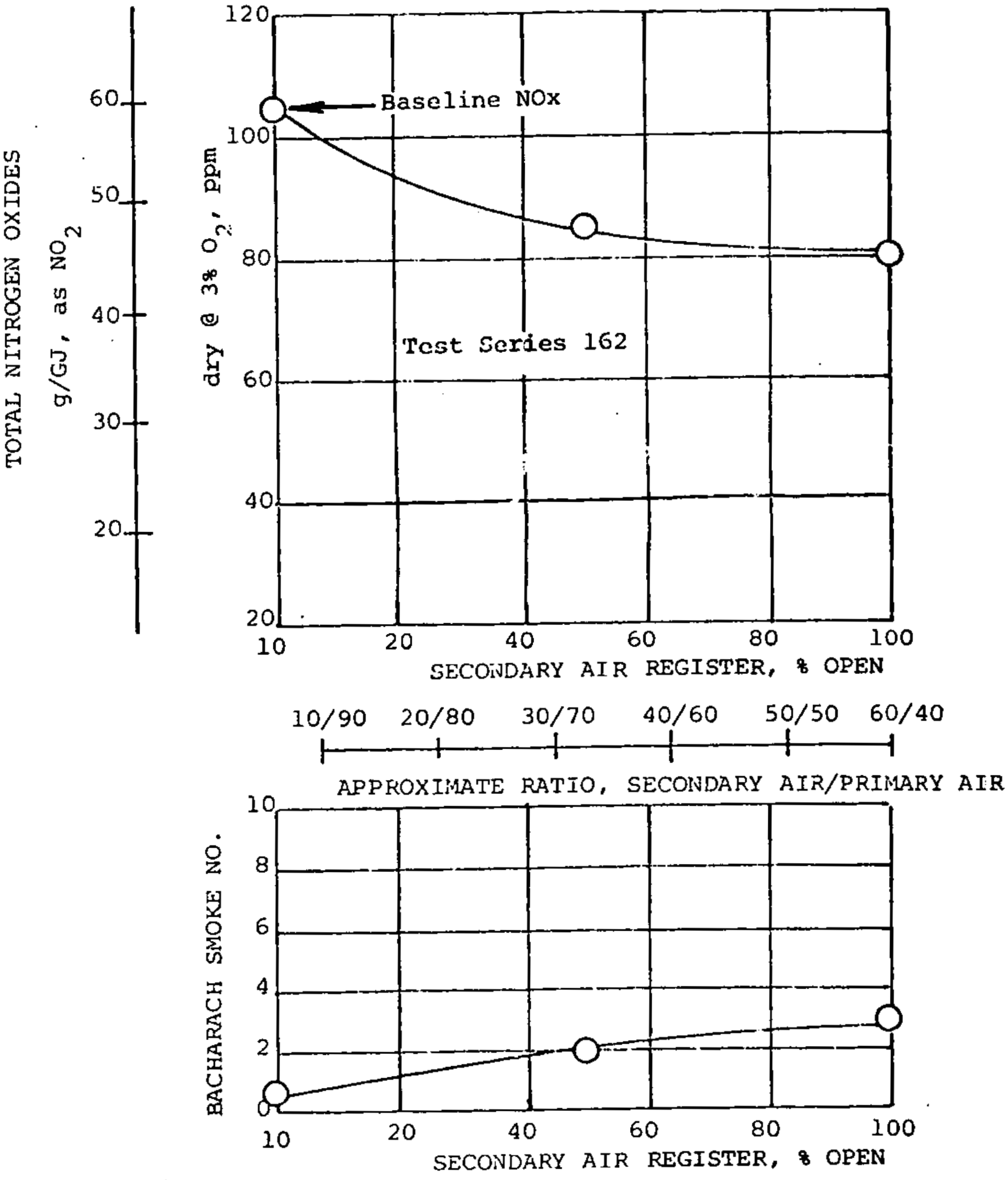


Figure 16. Effect of secondary air register position on total nitrogen oxides emissions and smoke level, No. 2 oil fuel.

In general, the tests involving burner air register adjustments have found the following:

- The major effect of register adjustments on multiple burner units is an alteration of the air distribution between the individual burners, and not a change in swirl in the burner adjusted.
- On single-register burners, increasing the swirl (closing registers) tends to decrease the nitrogen oxides emissions. The mixing of the cooler external circulation gases with the hot combustion zone gases suppresses the formation of the thermal nitrogen oxides.
- On dual-register burners, the major effect of register adjustment on nitrogen oxides emissions appears to be the redistribution of air between the secondary and tertiary air passages with swirl playing a minor role.

Combustion Air Temperature Reduction

Reducing the preheating of the combustion air reduced the total nitrogen oxides by up to 40%. However, the large decreases in nitrogen oxides were accompanied by a decrease in the boiler heat loss efficiency of about 2.5 percentage points per 50 K (90°F) increase in the flue gas temperature.

The combustion air temperature was systematically varied on three separate units by about 83 K (150°F). The results for the three boilers are depicted in Figure 17 for both natural gas and oil fuels. The solid symbols represent the normal air temperatures. During Test Series 189 for example, the nitrogen oxides emissions decreased by 20% as the combustion air temperature was reduced from about 430 K to 350 K (320°F to 175°F). This corresponded to a change of 23 g/GJ (941 ppm) in nitrogen oxides per 50 K (90°F) change in air preheat temperature. The decrease with natural gas fuel in Test 182 was comparable. A comparable effect was not unexpected, since changes in air preheat effect primarily the thermal nitrogen oxides formation, and this effect should be similar for gas and oil firing in the same boiler.

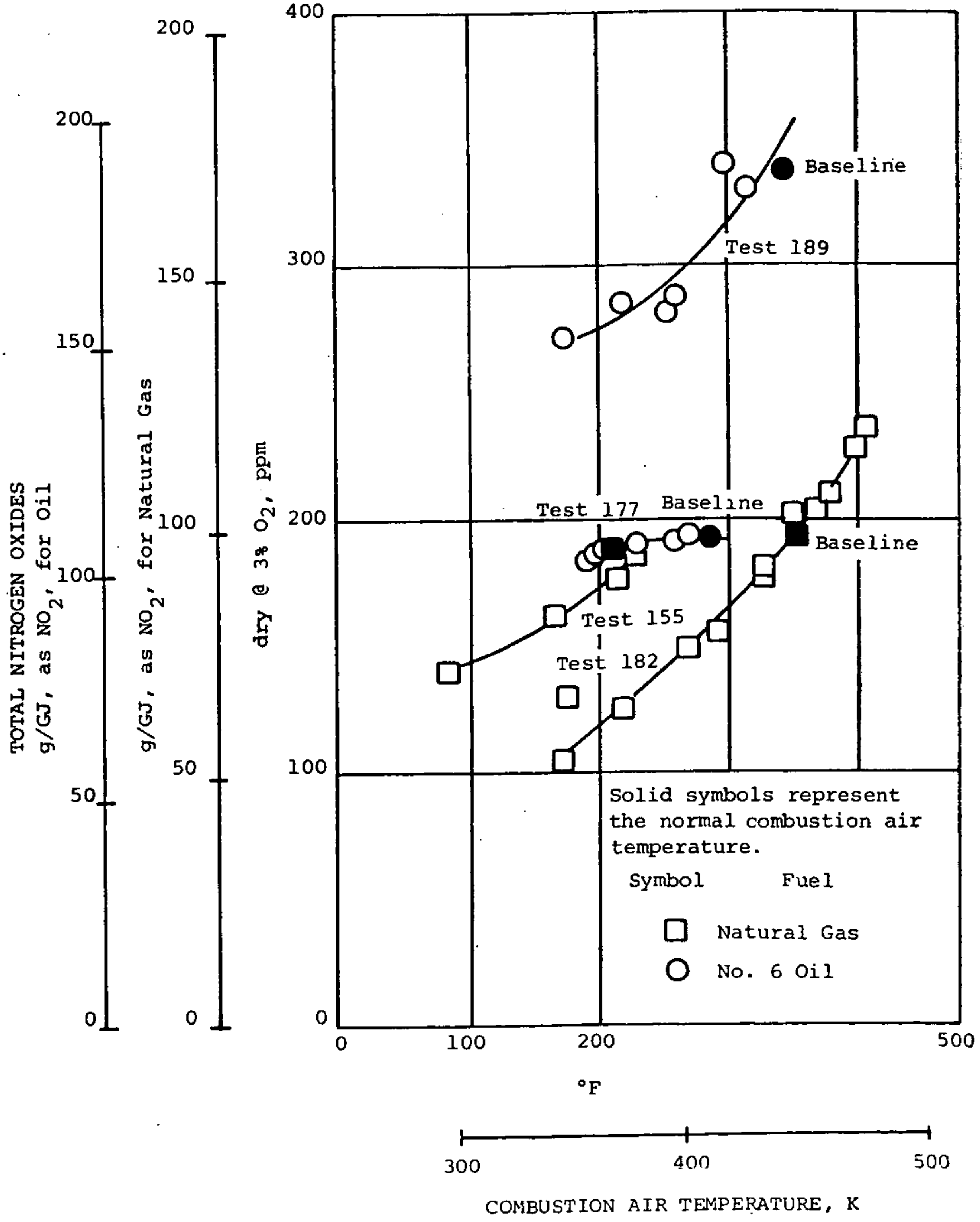


Figure 17. Effect of combustion air temperature on total nitrogen oxides emissions, gas and oil fuels.

Flue Gas Recirculation

Testing of utility-size boilers has established that the recirculation of flue gas into the combustion air reduces flame temperatures in the furnace and limits the formation of thermal nitrogen oxides. Since it also reduces the oxygen concentration in the primary combustion zone there may be a slight reduction in the conversion of fuel-bound nitrogen.

The boiler at Location 19 also was modified by adding a flue gas recirculation capability, and the installation is pictured in Figure 18. The flue gas was drawn from the bottom of the smoke stack by a flue gas recirculation fan and was pumped through the recirculation duct and up into the right side of the windbox through a windbox addition that had been fabricated.

The windbox had been lengthened to accommodate the flue gas inlet and an additional set of registers was installed within the lengthened section to impart swirl to the flue gas and promote mixing with the combustion air. The combustion air came in through the top of the windbox and through the original burner registers. The amount of flue gas being recirculated was controlled by a butterfly valve located in the recirculation duct.

Figure 19 shows that flue gas recirculation was successful in reducing the total nitrogen oxides concentration in the flue gases by ten percent to about 90% of the baseline level with No. 6 oil. With natural gas alone, a seventy percent reduction was achieved to only about 27% of the baseline level. The boiler heat loss efficiency was unaffected. There was an increase in the solid particulate concentration of about 10%, probably due to a slight increase in the unburned carbon in the less stable flame that resulted when flue gas was recirculated.

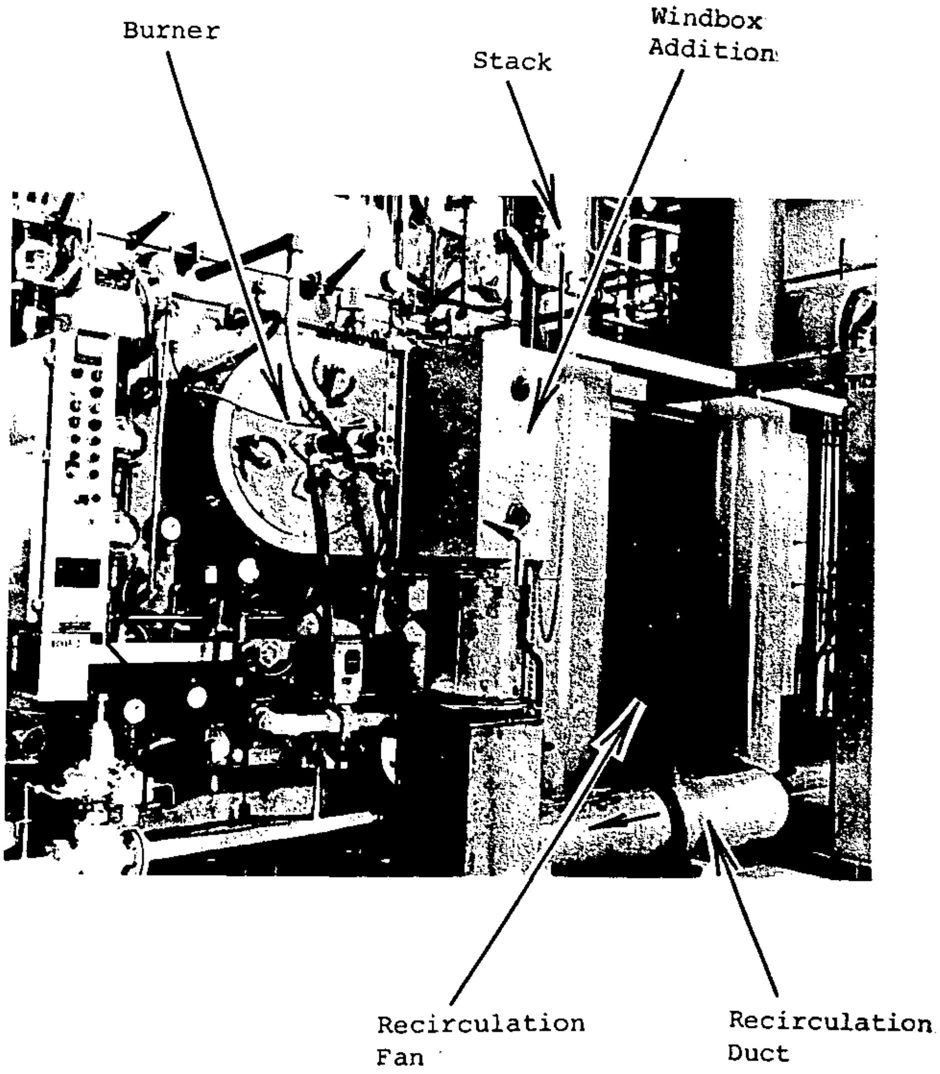


Figure 18. Flue gas recirculation installation at Location No. 19 for Test Nos. 192, 197, and 202.

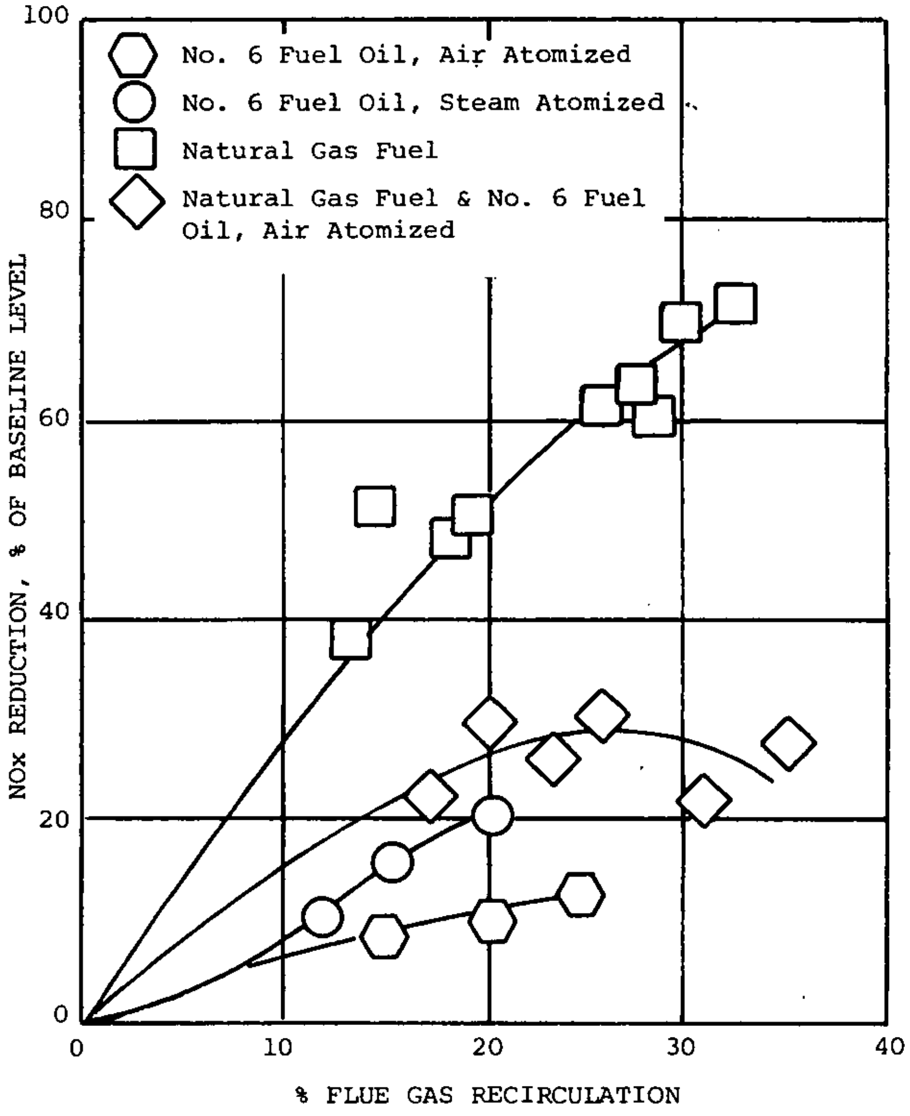


Figure 19. Effect of flue gas recirculation on total nitrogen oxides emission level.

Recirculation was most effective in reducing nitrogen oxides emissions from natural gas firing. This could have been expected because nitrogen oxides emissions from gas occur solely from the thermal fixation of atmospheric nitrogen at elevated temperatures. The flame-temperature-reducing potential of the recirculated combustion products is fully realized in this case.

The effectiveness of flue gas recirculation is less for No. 6 fuel oil firing. The reason is that a significant fraction of the total nitrogen oxides emissions is due to the conversion of fuel nitrogen, which is not highly temperature-dependent. In addition, oil fuel combustion is slower in relation to the intense burning of natural gas from a highly mixed ring-type burner. In the course of combustion, a significant amount of natural recirculation of combustion products within the flame zone occurs and the flame is self-cooled.

Firing Rate Reduction

Industrial boiler owners often have excess boiler capacity, and it might be possible to put some of this excess capacity on line and to reduce the firing rate of the in-service boilers.

When the combustion was modified by lowering the firing rate or steam output of a boiler, the total nitrogen oxides emissions increased in 16 instances and decreased in 19 instances by ± 12% to 25%. The increases and decreases of efficiency also were evenly divided; i.e., ± 3 percentage points. The reason for the increased nitrogen oxides emissions was that the amount of excess air being fired usually was raised at the lower firing rates, and this raise often caused an increase in the total nitrogen oxides emissions.

Gas-fired boilers were relatively insensitive to load changes unless they had air preheaters. Then, reductions in total nitrogen oxides of about 20% were realized as the firing rate was dropped from 100% of name plate capacity to 50% of capacity. Oil-fired boilers showed little or no relationship between nitrogen oxides emissions and firing rate. Generally, coal-fired boilers showed an increase in nitrogen oxides emissions when operating below 60% capacity, caused by the necessary increase in the excess air level.

Fuel Oil Viscosity

Tests were conducted with No. 6 oil over an oil temperature range of 340 K to 395 K (155°F to 250°F). No consistent relationship was observed, although in all cases the change in the total nitrogen oxides emissions was less than ± 10%. The boiler efficiency ranged from unchanged to one percentage point higher.

Burner Tuneup

Tuning the burner to the manufacturer's specifications increased the emissions of total nitrogen oxides from natural gas fuel and did not affect the emissions from oil fuel. In all cases there was an increase of up to one percent in the boiler efficiency calculated by the ASME heat loss method. No consistent trend in the particulate emissions was observed.

The chief effect of burner tuneup with oil fuel was a reduction in carbon monoxide emissions rather than a significant reduction of nitrogen oxides emissions. During Test No. 108 the carbon monoxide from oil fuel was reduced from 139 to 38 g/GJ (407 to 110 ppm) and during Test No. 112, from 40 to zero g/GJ (116 to zero ppm). During Test No. 108, an increase in excess air and stack temperature compensated for the decrease in carbon monoxide in the stack gases and the heat loss efficiency did not change. After the tuneup during Test No. 112, it was possible to operate at a lower level of excess oxygen than originally without any measurable carbon monoxide in the stack gases, and the efficiency increased by one percentage point from 81% to 82%.

With natural gas fuel, if the burner was tuned to reduce the carbon monoxide to near zero and/or to improve the flame appearance or color, the nitrogen oxides emissions were either unchanged or increased. However, tuneup was universally successful in reducing carbon monoxide and increasing the heat input efficiency by as much as one percentage point. Here, the decrease in heat loss due to a lesser amount of combustible carbon monoxide in the stack gas was slightly greater than the corresponding increase in the heat loss due to the higher temperature of the stack gases.

Fuel Atomization Method

To investigate the possibility that one type of atomization produces less nitrogen oxides than others, steam, air, pressure-mechanical, and rotary cup types of oil atomizers were evaluated during the program. The total nitrogen oxides emissions were found to be relatively independent of the fuel oil atomization method and more dependent upon the characteristics of the individual burner.

For a given oil gun, the oil atomization method that produced the lowest nitrogen oxides emissions also usually produced the highest particulate emissions of the test series. The boiler efficiency was unaffected to any significant degree by the type of atomization employed. In general the test results for the atomization methods tested during this program showed that a well-maintained oil gun operated near its design point will produce about the same level of nitrogen oxides and particulate emissions regardless of the atomization method which is used.

Fuel Atomization Pressure

When the fuel oil atomization pressure was increased and the boiler was at 80% capacity, the nitrogen oxides emissions decreased. When the same type of test was done on another boiler at a firing rate of only 25% of capacity, the nitrogen oxides emissions increased by 6%. Concurrently, the Bacharach smoke number decreased by two numbers.

In the first test the increased pressure caused a smaller apex angle of the fuel droplet cone to form. It is postulated that it took longer for the combustion air to penetrate this tighter cone and the combustion, consequently, was delayed. The production of nitrogen oxides was reduced. In the low-firing-rate test, the tightening up of the fuel droplet cone actually enhanced the burning rate of the "lazy" flame, and the total nitrogen oxides production was increased. The ASME heat loss efficiency was not affected significantly by variations in the atomization pressure.

Fuel Switching

The nitrogen oxides emissions from oil could be reduced by switching to an oil that has a lower nitrogen content. There are two important mechanisms for the formation of nitrogen oxides. One is the thermal fixation of atmospheric nitrogen, and the other is the conversion of the nitrogen compounds in the fuel. The magnitude of the potential fuel nitrogen effect is about 730 g/GJ (1300 ppm) of nitrogen oxides for complete conversion of 1% nitrogen (by weight) in a residual oil. For coal, the corresponding figure is about 1200 g/GJ (1900 ppm) of nitrogen oxides per 1% nitrogen in the coal. Actually, only partial conversion of the fuel nitrogen to nitrogen oxides in the products of combustion occurs and the percent conversion depends on the fuel nitrogen content and the availability of oxygen in the combustion zone.

The field test data indicated that the percentage conversion was high for low-nitrogen oil and decreased with increasing nitrogen content. It was found that for normal operating conditions, the thermal nitrogen oxides were in the 34 to 110 g/GJ (60 to 200 ppm) range and that the fuel nitrogen conversion averaged about 46% for all oil fuels tested in Phases I and II.

The particulate emissions could be reduced by switching to a fuel with a lower ash content, for example from No. 6 to No. 5 oil, since a coal and oil fuel property that correlates reasonably well with solid particulate emissions is the ash content.

Burner Type

It was found that the nitrogen oxides emissions were lower from certain burners, however it was difficult to ascertain whether the differences were due primarily to the burner or interrelated burner-boiler characteristics and fuel properties. Pulverized coal burners generally produced slightly more particulate than did stoker-equipped boilers.

Particulate Size

It was found that some types of combustion modifications affected the size of the particulates that were emitted. The distributions shown on Figure 20 are representative of the effects that were observed.

The upper two curves of Figure 20 show the effect on the particulate size distribution of modifying the combustion of oil fuel by reducing the amount of excess air/oxygen. Reducing the excess oxygen from 4.3% to 4.0% reduced the proportion of fine particulates from about 58% to 50%. [The total nitrogen oxides concentration dropped from 109 to 98 g/GJ (195 to 174 ppm).] Apparently the modified combustion resulted in a decrease in the proportion of the smaller and an increase in the proportion of the larger size particulates.

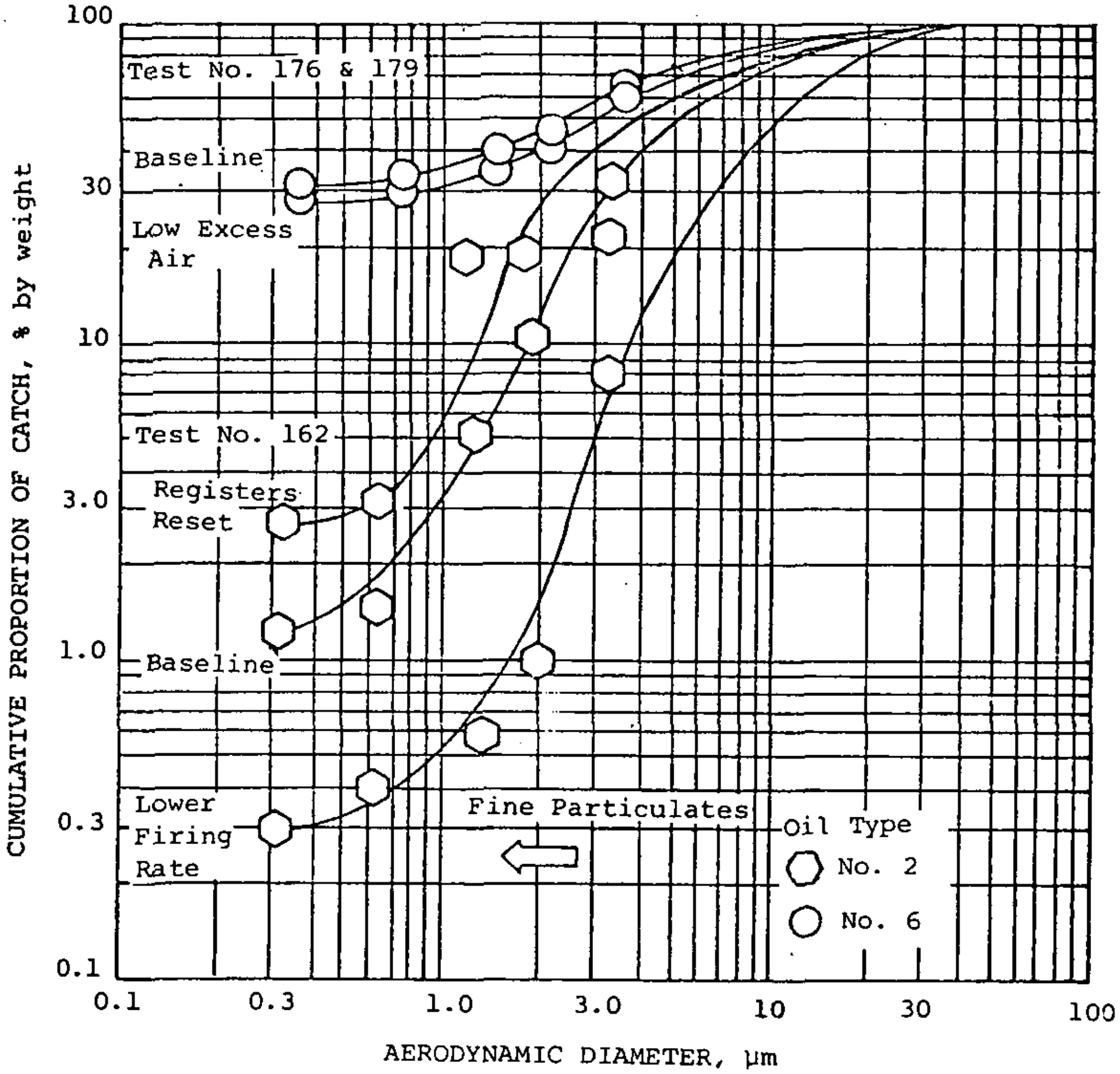


Figure 20. Effect of combustion modification on particulate size. Oil Fuel.

When coal was burned on a chain grate, the effect of reducing the excess air was different. Reducing the excess air increased the proportion of the fine particulates in the catch, rather than reducing them as with oil fuel.

Also shown in Figure 20 is the effect on the particulate size distribution of modifying the fuel and air mixing by resetting the burner registers. The upper curve for Test No. 162 was drawn from data taken after the registers had been reset. The most striking effect was that the proportion of fine particulates rose from a baseline value of about 26% to about 40%.

When the firing rate of a boiler was raised from 33% of capacity to 47% of capacity and the registers reset for the lowest nitrogen oxides emissions, the proportion of fine particulates decreased from about 26% to about 5%. The effect of modifying combusting by tuning the burner resulted in a larger proportion of the fine particulate after tuning.

4.0 CONCLUSIONS

The emissions of industrial boilers as a class are not significantly dependent upon size, but they are very dependent upon the fuel burned. The effect of the type of burner employed is subordinate to the effects of fuel and to the characteristics of the particular burner and boiler combination.

The nitrogen oxides emissions of the boilers tested were at or above the Stationary Source Standard [which actually applies only to new boilers larger than 63 GJ/hr (250,000 lb/hr)] in 30% to 40% of the cases. The particulate emission standard of 0.1 lb/10^6 Btu was exceeded in 16% of the tests of oil fuel and in 100% of the tests of coal fuel.

The combustion modification methods that have been successful in reducing the nitrogen oxides emissions of utility boilers are also effective in reducing the emissions of industrial boilers. Reductions of 30% to 50% have been achieved with the major modification methods. The reduction of nitrogen oxides, however, was accompanied by an increase in particulate emissions of 5% to 50%.

The hydrocarbon, carbon monoxides, and sulfur oxide emissions were relatively unaffected by the combustion modifications. In 60% of the tests, the boiler efficiency either remained unchanged or increased by up to 4 percentage points.

The baseline emissions that are high and the increase in particulate emissions caused by combustion modification can be reduced by sound combustion engineering, such as

- Better boiler operation through improved instrumentation
- Modern low-emission, high efficiency burner and boiler design
- Awareness of the interrelated combustion parameters and working with them as a group.

5.0 REFERENCES

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4. Cato, G.A., et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase II," EPA 650/2-74-078-b, November 1975.

5. Walsh, G., Symposium on Electrostatic Precipators at Southern Research Institute, Birmingham, Alabama, November 1974.

APPENDIX A

GLOSSARY OF SYMBOLS

Burner Type

Air	Air Atomizer
ChGrt	Chain Grate
Pulv.	Pulverizer
Ring	Natural Gas Ring
SpStk	Spreader Stoker
Spud	Natural Gas Gun
Steam	Steam Atomizer

Burner Equivalence Ratio $= \dfrac{(A/F)_{stoic}}{(A/F)_{actual}}$

Burner Theoretical Air $= \dfrac{(A/F)_{actual}}{(A/F)_{stoic}}$

Test Fuel

Coal	Coal
NG	Natural Gas
Ref.Gas	Refinery Gas
NG/#6	Mixture, Natural Gas and No. 6 oil
#2	No. 2 Grade Fuel Oil
#5	No. 5 Grade Fuel Oil
#6	No. 6 Grade Fuel Oil
PS300	Pacific Standard Fuel Oil No. 300 (similar to No. 5 oil)

Test Type

AirReg	Air Register Adjustment
Atom Press.	Burner Atomizing Pressure Adjustment
BOOS	Burners Out of Service
Base	Baseline
BrTune	Boiler Tuneup
CombCyc	Combined Cycle
Damper	Air Damper Adjustment
HiAir	High Excess Air
HiLoad	High Load
LowAir	Low Excess Air
LowLoad	Low Load
NrmlAir	Normal Excess Air
OFA	Overfire Air
SnglCyc	Single Cycle
Steam Injec	Steam Injection
TP	Toxic Particulate
VPH	Variable Combustion Air Preheat Temperature
Viscosity	Fuel Oil Viscosity Variation via Temperature Change

APPENDIX B

CONVERSION TABLE

To Obtain	From	Multiply By
g/GJ	lb/MBtu	430
g/GJ	g/Mcal	239
$\frac{GJ/hr}{m^2}$	$\frac{MGH}{ft^2}$	11.256
$\frac{GJ/hr}{m^3}$	$\frac{MGH}{ft^3}$	37.257
GJ/hr	10^3 lb/hr or MBH	1.055
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Kg	lg	0.4536
Kelvin	Fahrenheit	$T_K = (T_F + 460)/1.8$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895 \times 10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895 \times 10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$

To Obtain g/GJ Of	Multiply Concentration in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NOx (as equivalent NO_2)	0.510
SO_2 or SO_x	0.709

APPENDIX B (Cont)

To Obtain g/GJ Of	Multiply Concentration in ppm at 3% O_2 by
Oil Fuel	
CO	0.341
HC	0.195
NO or NOx (as equivalent NO_2)	0.561
SO_2 or SOx	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NOx (as equivalent NO_2)	0.611
SO_2 or SOx	0.850
Refinery Gas Fuel (Location 33)	
CO	0.306
HC	0.175
NO or NOx (as equivalent NO_2)	0.503
SO_2 or SOx	0.700
Refinery Gas Fuel (Location 39)	
CO	0.308
HC	0.176
NO or NOx (as equivalent NO_2)	0.506
SO_2 or SOx	0.703

10:35 a.m.
Influence of Combustion Modifications
on Pollutant Emissions from Industrial
Boilers
Glenn A. Cato, KVB Engineering

Q: About what percentage of your tests were made on single burner installations?

A: About 2/3.

Q: What percentage was below 50 million Btu input?

A: I would say about one half.

Q: In the statement about the combustion air temperature, you indicated for every 50 degrees Kelvin, you lowered it, losing 2 1/2% boiler efficiency. I am assuming that this is because you were unable to use an air preheater that was in the flue gases. If you were not counting the loss because of the air preheater, would the efficiency remain the same? Was the loss due to the fact that you were unable to utilize a portion of the flue gas temperatures?

A: Yes, the heat that was removed from the combustion air was allowed to go into the atmosphere in the form of a higher temperature stack gas. The higher stack gas temperature resulted in a lower calculated ASME heat loss efficiency.

Q: In other words, if the air was being preheated by some separate source and you cut the separate source out, the boiler efficiency would probably remain the same.

A: Yes, if the stack gas temperature were unchanged, the calculated ASME heat loss efficiency would be unchanged.

Q: There was one thing that I would like to know. You said that generally speaking, when you add over-fire air you compensate by cutting down burner air so that the total excess air remains the same.

A: Right, we maintained the excess oxygen at its original level.

Q: When you added the over-fire air, you said that the further back in the flame pattern you added it, the more effective it was. Where would this be relative to the visual flame pattern, right at the end of the flame or 2/3 of the way down?

A: A little beyond where the visual portion ended. For example, one furnace was about 10 feet long and best air port was about 9 feet out from the burner face.

Q: You said, I believe, the addition of over-fire air caused the particulate emissions to increase. Presumably that was due to the fact that the combustion air at the burner decreased. Do you have any ideas as to why the soot or coal particles did not burn out in the over-fire zone between the end of the flame and the end of the furnace?

A: No, other than it appears that once soot is formed it is pretty hard to burn it. We didn't do any tests that attempted to burn the soot, however, so I almost have to talk from theory.

Q: Did you do any tuning of the boilers before you ran the baseline tests?

A: The ground rules were that we would not. We would just ask the operator to put the boiler at 80% of name plate capacity with all the settings normal for that load. In some cases, however, we found that the excess air was so high compared to other boilers of the same type, that it just wouldn't be logical to call that baseline. In these instances, we asked them to reduce the air to a little closer to a typical level. If the CO was above 100 ppm, we tried to drive it down to below 100 parts per million, and we then would call that baseline, but high CO was rare.

Q: You mentioned something on the multi-burner furnace where you redistributed the air to the air registers. You said that you did not change the swirl to the individual burners. Could you clarify this?

A: That is not what I intended to say. What I intended to say was that on boilers that had multiple burners, when we changed the air register setting, the effect that reduced the NO_x was that we were forcing more or less air through the other burners. This redistribution of the air was the chief effect and not a change in the swirl of the air.

Q: You mentioned that on most boilers that you tested that there was no background CO level. I presume that applies to the gas and the oil. I would like you to comment on what CO levels you found with pulverized coal.

A: Usually it was zero. In four cases out of a total of 19, it was 26 to 126 ppm. Actually, there were more instances of measurable CO with natural gas fuel than with oil or coal.

Q: I would like to make a comment on the utility boiler, then. We always have found a level of CO of around 30 parts per million.

A: I could go along with 30 parts per million on oil or natural gas. However, with coal there was measurable CO in less than 20% of the cases.

A: Do you recall what the range of sulfur content was in the coals that you tested?

Q: The sulfur content of the coal ran from about 1% to 4.5%.

Q: You kept making the point about 100% conversion to SO_x or "sulfur in, sulfur out." I was going to further ask with coals that had high sodium or calcium, if you had done an ash analysis to look at sulfur retention in ash.

A: Two cases were analyzed. One coal had a sulfur content of about 3% and the bottom ash contained about 2% sulfur. In another, the coal sulfur content was about 1%, the bottom ash sulfur content was 0.5%, and the fly ash sulfur content was 0.3%.

* * *

Q: I would like to hypothesize on why the particulates went up when over-fire air was introduced. I do believe that the shorter residence times characteristic of packaged boilers did not allow complete burnout of the coal/ash particle by the second stage air. I also would like to comment on the relatively high levels of excess air with baseline measurements. We believe that it was the lack of maintenance and servicing of the equipment that caused the very high excess air levels that were observed at baseline conditions. We feel that significant reductions can be made by the operators in excess air and CO and increases in the efficiency with lower fuel consumption and lower emissions.

A: I would certainly subscribe to that. In industry, boilers are considered a tool. They want the operator, who is often a foreman, to be able to walk away from the boiler and have it start, stop and run with no problems. So they are very conservative and they run a lot of air through those boilers.

Q: The "sulfur-in, sulfur-out" concept we expect for pulverized coal and oil to hold up very well. I have seen one or two claims that on stoker fed boilers some of the sulfur may stay with the ash. Could you comment on the "sulfur-in, sulfur-out" ratio on stokers?

A: There were five instances that differed significantly from 100% conversion. We tested three spreader stokers and the conversion was 36%, 76% and 137%. The pulverizers converted at a rate of 136% and 205%. In eight other cases it was nearly 100% conversion, or sulfur-in, sulfur-out.

Q: On the units where you did extensive combustion modifications, would you comment on the combustion noise level due to combustion changes, such as over-fire air?

A: In the case of the first boiler I showed you, the one that had the over-fire air ports in the side wall, I don't remember that the noise increased particularly. Of course it is so noisy in those boiler rooms to begin with, it would have to increase a lot before

Q: I would like to make a comment on the utility boiler, then. We always have found a level of CO of around 30 parts per million.

A: I could go along with 30 parts per million on oil or natural gas. However, with coal there was measurable CO in less than 20% of the cases.

A: Do you recall what the range of sulfur content was in the coals that you tested?

Q: The sulfur content of the coal ran from about 1% to 4.5%.

Q: You kept making the point about 100% conversion to SO_x or "sulfur in, sulfur out." I was going to further ask with coals that had high sodium or calcium, if you had done an ash analysis to look at sulfur retention in ash.

A: Two cases were analyzed. One coal had a sulfur content of about 3% and the bottom ash contained about 2% sulfur. In another, the coal sulfur content was about 1%, the bottom ash sulfur content was 0.5%, and the fly ash sulfur content was 0.3%.

Q: I would like to hypothesize on why the particulates went up when over-fire air was introduced. I do believe that the shorter residence times characteristic of packaged boilers did not allow complete burnout of the coal/ash particle by the second stage air. I also would like to comment on the relatively high levels of excess air with baseline measurements. We believe that it was the lack of maintenance and servicing of the equipment that caused the very high excess air levels that were observed at baseline conditions. We feel that significant reductions can be made by the operators in excess air and CO and increases in the efficiency with lower fuel consumption and lower emissions.

A: I would certainly subscribe to that. In industry, boilers are considered a tool. They want the operator, who is often a foreman, to be able to walk away from the boiler and have it start, stop and run with no problems. So they are very conservative and they run a lot of air through those boilers.

Q: The "sulfur-in, sulfur-out" concept we expect for pulverized coal and oil to hold up very well. I have seen one or two claims that on stoker fed boilers some of the sulfur may stay with the ash. Could you comment on the "sulfur-in, sulfur-out" ratio on stokers?

A: There were five instances that differed significantly from 100% conversion. We tested three spreader stokers and the conversion was 36%, 76% and 137%. The pulverizers converted at a rate of 136% and 205%. In eight other cases it was nearly 100% conversion, or sulfur-in, sulfur-out.

Q: On the units where you did extensive combustion modifications, would you comment on the combustion noise level due to combustion changes, such as over-fire air?

A: In the case of the first boiler I showed you, the one that had the over-fire air ports in the side wall, I don't remember that the noise increased particularly. Of course it is so noisy in those boiler rooms to begin with, it would have to increase a lot before you would notice it.

Q: How about where you re-circulated flue products back into the burner?

A: When we first fired oil and recirculated flue gas we had a lot of trouble with flame instability. At first we thought we wouldn't be able to run it at all. The boiler owner worked with us and we spent about 1 1/2 days solving the problem. We finally got rid of the instability which led me to say earlier that, if one considered the interrelated combustion parameters and applied sound combustion engineering, one could get rid of a lot of noise as well as other combustion problems. When we had the unstable flame, of course, we had a lot of noise. But once things were settled down and working well, I would say that there was no noticeable change in noise.

Q: Did you take the trouble to measure the vanadium content in any of the fuel oils, and if you did, could you correlate the measurement with any of the pollutant effects? Did you get the opportunity to substantiate some of the results from the previous paper on the effects of additives in fuel oil in particularly reducing particulates? Secondly, you said that you didn't notice any difference in NO_x formation whether using steam or air for atomization. I thought on one of the graphs you presented there it seemed that steam was giving you a better result on NO_x; maybe you would like to comment on it?

A: What he says is true about atomization. If you go back to our Phase One report, you notice that in a given burner, sometimes steam was better than air. Then with another burner air was better than steam. So I would say that, overall, it didn't seem to matter too much whether you designed a burner for air or steam. Sometimes steam is better and sometimes air is better. It seemed to be a characteristic of the particular boiler-burner combination and of how well that gun was maintained.

As far as the vanadium is concerned, yes, we measured the vanadium content of 18 of the oils that we burned in Phase One. The vanadium content ran from a low of 0.15 ppm to a high of 200 ppm. In Phase Two, the vanadium content of the coal was measured in three instances, running from 42 to 70 ppm, and we are doing a vanadium mass balance. The results of that correlation will be available probably about the end of the year.

[Comment by Session Chairman:]

I might mention that the draft of the final report on combustion modification results has been submitted. The actual final will be available with all the details in about eight weeks. The report that contains the vanadium balance will be published this winter.

Emission Characteristics of Small Gas Turbine Engines

Stationary Source Combustion Symposium

Atlanta, Georgia

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INTRODUCTION

The Combustion Research Branch (CRB) of EPA's Industrial Environmental Research Lab-RTP has initiated both contract and in-house investigations for stationary engine emissions control during the past year. This paper will describe the first phase of the in-house research program in this field.

Two commercially available engines have been installed at the CRB laboratory: a Solar Spartan gas turbine and a Caterpillar D334 precombustion chamber diesel. These engines and a high pressure experimental combustion system currently at the design stage will comprise the facility for engine emission control and other high pressure combustion work.

EXPERIMENTAL APPROACH

Initial experimental work has concentrated efforts on the gas turbine engine. The first phase of investigation has involved a determination of the emission performance of the basic engine and an evaluation of water addition effects on the emission performance at full load. Table 1 outlines the experiments conducted.

Table 1. Experimental Program

Variable	Test Range
Generator Load	Zero to 220 kW
Water Flow Rate	Zero to 11 gal./Hr (Zero to 0.042 m^3/hr)

Water addition was accomplished by mixing water with distillate fuel oil and injecting the resulting emulsion through the engine's normal fuel pumping system.

ENGINE SYSTEM

The gas turbine engine used for this study is the prime element in a standby electrical generator package. This engine is a constant-speed (37,059 RPM), single-shaft, simple cycle, radial flow machine. It is NEMA rated at 308 HP (230 kW) and the maximum rated electrical output from the generator set is 225 kW.

Ambient air is drawn into the machine's air inlet by the compressor section. Air is compressed to 4.2 atmospheres (425 kPa) by the single-stage centrifugal rotor wheel and directed into the combustor assembly. Air is mixed with fuel in the combustor; the mixture is then ignited by a high voltage electric spark and burned. Resulting hot combustion gases next expand through the single stage centrifugal turbine where the gas energy is converted to rotating shaft power. The rotating shaft is connected, through a speed reduction gear box, to the electric generator. Exhaust gases are subsequently passed from the turbine to the atmosphere through a relatively short stack, approximately 9 feet (2.75 meters) above ground level.

The air pollutant emissions from gas turbine engines originate in the combustion process, making this section of the machine the major item of concern. The combustion liner or "can" illustrated in Fig. 1 is a perforated cylinder, domed at the top and open at the bottom. A high pressure, dual orifice fuel nozzle is centered at the top of the dome. An air swirler device is incorporated in the air inlet annulus surrounding the nozzle. This swirler creates a rotating air jet into which the fuel oil is sprayed co-currently to diffuse the oil droplets and stabilize combustion at all firing rates. The remaining compressed air is admitted to the combustion liner through a number of geometrically patterned large and small holes in the sides of the liner. Air entering through the small holes is directed to flow along the inside wall of the liner to prevent overheating the metal. The rest of the air injects radially through the large holes. Air flowing through the large holes in the upper half of the liner mixes with the burning fuel to complete combustion, while air flowing through the lower holes dilutes the hot gases to a satisfactory turbine inlet temperature: about 1600°F (1144K).

Engine load is provided by an AVTRON model K463 load bank. This equipment provides electrical load demands up to 225 kW in 5 kW increments. Basically the unit is a bank of resistance heaters which convert the electric power generated to heat. The heat is transferred to the atmosphere by air cooling the heaters.

The fuel used in the engine is a number 2 distillate oil with an API gravity of 34.0. This oil has a low bound-nitrogen content, thus fuel nitrogen conversion to NO_x was not a major factor in this study. The fuel was obtained from a commercial supplier and had no special properties.

ANALYTICAL SYSTEM

Methods for determining the gaseous and particulate emissions from the gas turbine engine were identical to those currently used in CRB atmospheric pressure combustion or boiler studies. Table 2 contains a listing of the instruments used for each flue gas component measured.

Table 2. Analytical Instruments

Flue Gas Constituent	Analyzer
O_2	Beckman Paramagnetic
CO_2	Beckman NDIR
CO	Beckman NDIR
Gaseous HC	Beckman Flame Ionization
NO/NO_x	TECO Chemiluminescent
Particulate Mass	RAC Staksamplr
Particulate Size	Andersen Cascade Impactor
Smoke	Bacharach RDC Smoke Meter

Velocity profiles were measured near the top of the engine's 16 inch (0.41 meter) diameter exhaust stack. The profiles indicate a wide variation in flue gas velocity throughout the stack cross-section. Measured velocities ranged from 1000 to 6600 ft/min (5.1

to 33.5 meters/sec) with an average of 4230 ft/min (21.5 meters/sec) based on 14 total sample points on two 90 degree traverses. There were no flow reversal zones found during these measurements.

Measurements of gas composition indicated variations with both vertical and horizontal location in the exhaust stack. Because of this spatial variation, a cross-rake type of sampling probe had to be used. Single point gas sampling was not possible in these circumstances.

The stainless steel cross type probe has 20 sampling holes drilled in the four arms at the centers of the standard five equal concentric areas making the sample equivalent to traverse points for a round duct. The probe was positioned about 4 ft (1.22 meters) down into the stack, precluding the possibility of drawing outside air into the probe. Sample gas passes from the probe through stainless steel and Teflon lines between the stack and analyzers. Bulk moisture and condensables are removed from the sample gas steam in Hankinson dryers (refrigerator type) which reduce temperatures to 35°F (275K). For instruments requiring very dry gas (paramagnetic and NDIR), the sample is passed through "Drierite" before reaching the analyzer.

An extension to the engine stack was installed to provide a suitable location for particulate sampling. The extension is 7.5 ft (2.3 meters) high, bringing the total stack height to 16.5 ft (5 meters) above ground level.

OPERATING CHARACTERISTICS

SOUND LEVELS

Noise levels eminating from the gas turbine were measured to obtain an evaluation of the machine's environmental impact at the site just outside the CRB lab. The decibel level as measured at three different locations did not change with electrical load on the machine. Three locations were selected for sound measurement: (1) 2 feet (0.61 meter) from the turbine's weather enclosure, directly opposite the combustion chamber; (2) 4 feet (1.22 meters) from the turbine enclosure, on top of the load bank; and (3) 15 feet (4.57 meters) from the exhaust stack end of the generator set. Table 3 lists the results of the survey made with a standard sound meter using the "A" weighting mode to relate to human sound perception.

Table 3. Noise Levels

Position	Sound Pressure, dbA
1	91
2	94
3	82

These measurements indicate that, in the immediate area of the turbine, the maximum permissible noise exposure per 24 hour day would be 4 hours and 40 minutes. All noise level measurements were made with the acoustic enclosure panels in place. If these panels were removed, noise levels would exceed 100 dbA, limiting exposure to less than 2 hours per day. Since air conditioning units mounted in the vicinity give sound levels between 85 and 90 dbA, the presence of the turbine engine did not seriously deteriorate the environment.

NOZZLE CHARACTERISTICS

The gas turbine engine combustor fuel nozzle, a dual orifice, high pressure type, has unique operating characteristics that could have a significant effect on both the combustion and emission performance of the engine. This nozzle has two concentric outlet orifices with separate flow channels to each orifice. An internal, spring loaded, flow valve divides the total oil flow between the two orifices. Figure 2 illustrates the relative flow rates through each orifice.

Primary fuel is used exclusively for ignition; no fuel flows through the secondary channel until after ignition is established. Flow through the primary (center) orifice forms a low volume, wide angle (90 degrees) spray that gives good light-off performance (fine atomization). As the machine speed increases to 60% of full speed, fuel pressure increases because more fuel is pumped to the nozzle. When the pressure reaches 255 psig (1758 kPa), the divider valve opens and secondary oil flow begins through the annular orifice. The secondary orifice spray angle is narrower (70 degrees) than the primary, thus the two sprays will blend, permitting the primary flow to help atomize the secondary flow at low secondary flow rates. Combined flow increases until a flow rate is reached that will maintain full speed operation of the engine. The atomizing pressure reaches 360 psig (2482 kPa) at zero electrical load. As electrical load is placed on the generator, the oil flow and pressure increase continuously. Atomizing pressure reaches 480 psig (3309 kPa) at rated electrical load. Thus, the droplet size distribution spectrum would be expected to include finer droplets as load on the engine is increased, producing the smallest droplets at full load.

LOAD PERFORMANCE

The gas turbine engine used in this study operates with large quantities of excess air. Excess air changes with load because only the fuel rate changes; no accompanying modulation of air flow is possible. The only changes in air quantity are the result of atmospheric condition changes. Table 4 contains a typical set of excess air values and exhaust temperatures over the load range of the machine.

Table 4. Excess Air Variation With Load

Load, kW	Excess air, %	Stack Temperature, °F(K)	
0	900	595	(586)
50	775	665	(625)
100	650	735	(664)
150	515	815	(708)
200	405	910	(761)
220	375	955	(786)

The relatively low pressure ratio and turbine inlet temperature are indicators of relatively low thermal efficiency operation. At full load operation (220 kW), a typical fuel rate was measured at 245 pounds/hr (111 Kg/hr). Using a net heat value of 18,400 Btu/pound (42.8 MJ/kg), the efficiency was computed to be 16.7%.

EMISSION CHARACTERISTICS

BASELINE

Nitrogen Oxides

The initial investigation for the gas turbine consisted of measuring the emissions produced by the engine over the entire load range of the machine. These measurements were made before any modifications in hardware or operation were attempted to obtain the baseline characteristics. This baseline then served as a comparator for determining the performance of any potential control methods.

Baseline emission characteristics for oxides of nitrogen are presented in Figure 3. Both total oxides of nitrogen (NO_x) and nitric oxide (NO) increase rapidly as load is added to the generator set starting from the no load condition. The difference between total NO_x and NO represents the amount of nitrogen dioxide (NO_2). At the no-load condition, NO_2 represents about 45% of the total NO_x, which contrasts with boiler operations where NO_2 seldom exceeds 5% of the total.

For the zero to 80 kW range the increase in NO_x is actually an increase in NO formation; the NO_2 level remains essentially constant. Since the excess air level of the machine ranges from 700 to 900% in this load bracket, the availability of oxygen and relatively low temperature promotes formation of a considerable amount of NO_2. Increasing quantities of fuel injected into the combustor to meet the increasing load demand create higher combustion intensity and higher temperatures, and result in the formation of more NO.

As load increases from 80 to 130 kW, the rate of formation of NO becomes even greater, but less NO_2 is formed, moderating the rise in total NO_x. The ever increasing quantity of fuel being burned in the fixed volume of the combustion chamber continually increases the combustion intensity and temperatures involved, resulting in the increased NO formation.

As the load is increased from 130 to 220 kW, the formation of NO remains nearly constant and NO_2 virtually disappears. A possible explanation rests with the discrete air injection points in the combustion liner. When the fuel rate cannot be completely oxidized by the air available in the primary combustor zone, combustion will be delayed until additional air is injected. Thus the combustor may well be "self-staging" at this point in the load range. The staging effect would limit the peak temperatures encountered, thereby halting the continual increase in NO.

Carbon Monoxide and Hydrocarbons

Baseline emissions of carbon monoxide (CO) and total gaseous unburned hydrocarbons (UHC) are presented in Figure 4. By definition, gaseous hydrocarbons are those compounds which did not condense at the 35°F (275K) temperature stage in the sampling system. The data pattern is simple, both CO and UHC decrease continuously with increased load on the machine. It is apparent that the UHC levels are an order of magnitude lower than the CO. The CO levels are the major gaseous pollutant problem with this machine since the NO_x levels were relatively low.

As described in the NO_x discussion, the combustor conditions of higher temperatures and combustion intensity with increasing load that contribute to NO formation also contribute to better oxidation of the carbonaceous pollutants. Fuel droplet size distribution changes toward finer drops with increasing load tend to improve the combustion of the carbonaceous pollutants.

The requirement for air film cooling the inside walls of the combustion chamber essentially creates a quench zone along the walls that persists at all load conditions. Inspection of the combustion liner after the test series indicated alternate ring areas of hot and cold (relatively) wall surface. The presence of this quench zone provides a path for CO and UHC to pass through the combustor without oxidizing. Since the CO oxidation reaction rate is relatively slow, the relatively short residence time available in the small combustion chamber contributes to the high concentration in the exhaust gases. The high levels of carbonaceous pollutants were expected from a small gas turbine engine because the ratio of wall area (and quench zone) to total combustor volume is relatively high. The wall effects would be less critical in larger combustors.

Particulates and Smoke

Smoke emissions were not visible during the operation of the engine, except for a 2 to 3 second period at start-up. Visual inspection of smoke spots taken at different load levels indicated a nearly constant smoke number over the load range. All spots were lighter than a No. 6 but darker than a No. 4, thus the smoke level was evaluated as a Bacharach Smoke No. 5 ± ½.

Particulate emissions consist of: (1) solids that can be filtered from the flue gas at high temperature, and (2) solid and liquid material that is collected (condensed) in cold traps after the filter. The results of particulate measurements at zero, half, and full load are presented in Figure 5. The filtered particulate did not vary as significantly with load as did the condensable particulate. This would be expected because of the uniformity of the smoke numbers which are essentially filtered particulates. As with CO and UHC, the particulate matter decreased continuously with load. The same conditions which promote the oxidation of CO and UHC also promote the oxidation of filtered particulate (carbon soot) and condensables (heavy hydrocarbons). The wall quenching and cooling film effects are sources of particulate emissions as they were for CO and UHC. Inspection of the inner surfaces of the combustion liner revealed a thin, uniform carbon deposit on all areas of the dome indicating liquid fuel contact with these cooled surfaces.

The condensable particulates were subdivided into water and benzene soluble fractions. This data is presented in Figure 6. Again, both the benzene soluble and water soluble particulates decreased continuously with load. The benzene fraction is an approximate measure of heavy hydrocarbons, many of which are carcinogenic (benzo-a-pyrenes, for example) or mutagenic.

Filtered particulates were examined further to determine the size distribution at three load levels. The particulate size range currently considered as the most serious because of deep penetration and retention in the human respiratory system falls below 4.0 micrometers. Table 5 presents particle size data in relation to this respirable size range.

Table 5. Particulate Size Distribution

Load, kW	Particle Size Range, μm	Mass Fraction	Relative Fraction[a]
Zero	>4.0	0.40	0.40
"	<4.0	0.60	0.60
110	>4.0	0.42	0.14
"	<4.0	0.58	0.19
220	>4.0	0.71	0.07
"	<4.0	0.29	0.03

---

[a] relative to zero kW load total particulate = 1.0

At no load, the maximum total weight of filtered particulate was obtained. The respirable particles were the largest fraction at this load level. At 110 kW load, the total weight of particulate dropped to 33% of the no load amount. There was a small relative decrease in the mass fraction of respirable particles at this load condition and compared to the no load level, the actual amount decreased. At full load, the total weight of particulate dropped to 10% of the no load amount. Large particles were predominate at the full load condition. The respirable particles were only 29% of the total and were greatly reduced compared to the zero and 110 kW load conditions.

A brief note regarding the cascade impactor used in these tests: fibrous glass mats were used on each collection plate to hold the particles after impaction; otherwise, the carbon soot particles would have re-entrained.

EMULSIFIED FUEL

Oxides of Nitrogen

The simplest method of introducing water into a gas turbine is to mix the water with the fuel and inject the resultant emulsified fuel because only minor hardware changes are required in the engine's fuel system. Since water addition is a known NO_x control technique, it was chosen as the first emission control method to be studied on this small gas turbine engine. Table 6 presents the emulsified fuel compositions used in this study with the engine operating under full load (220 kW) conditions, and at a constant 245 lb/hr oil rate.

Table 6. Emulsified Fuel

Water Rate, gph	Emulsion Composition, wt.% H_2O
0.93	3.1
3.79	8.7
4.65	13.7
6.50	18.1
8.37	22.2
10.23	25.8

As expected, there was a beneficial effect on NO_x using the emulsified fuel. This is illustrated by Figure 7. There is a continuous drop in both NO_x and NO as the amount of water is increased. The amount of NO_2 represented by the difference between the two lines, remained virtually constant. By an addition of 26% water, the NO was reduced about 33% at this operating condition. The limiting factor in this method of water injection will be the condition of the emulsion as water is increased. Batch emulsion studies indicated that water quantities above 35% would have stability problems even with surfactant use and that 50% or more water would invert the emulsion to an oil in water type.

Carbon Monoxide

The fuel emulsion effect on carbonaceous pollutant emissions was less predictable than on NO_x. Hydrocarbon levels at full load were in the 10 to 30 ppm range and no trends were evident with the water addition. The effect on CO was definite and is illustrated in Figure 8. Initial water addition at 1 and 3 gph (0.004 and 0.0114 m^3/hr) reduced the CO levels by up to 4%. Continued water addition, however, increased the CO levels significantly. This obviously is making a bad problem even worse. At the present time lab investigations are concentrating on particulate mass and size distribution effects of emulsified fuel, but results are not yet available.

The fuel emulsion stability was checked by withdrawing samples from the high pressure fuel supply system. This was in the nature of a check to be sure that a lack of emulsion uniformity was not causing effects on the emissions. Uniform emulsions were evident when the samples were drawn. Since a surfactant was not being used, the emulsions were stable for only 15 to 30 seconds after withdrawal, and significant separation of oil and water occurred within a few minutes. However, the emulsion was easily reformed by mild agitation. It was concluded that the fuel supply pumps were maintaining sufficient agitation to prevent oil-water separation in the fuel lines.

ATMOSPHERIC CONDITIONS

One of the major difficulties encountered in conducting experiments on the gas turbine engine is the atmospheric condition effect on emissions. The ambient temperature, pressure, and relative humidity must be monitored and recorded continuously. Because the gas turbine engine inducts such large quantities of air in relation to the fuel (5 times stoichiometry at full load), the water flow through the machine is significant. An example of this is shown in Figure 9. When the NO_x vs. load baseline was first determined, the atmospheric water ingested by the machine was over 24 gallons per hour (0.09/m^3/hr) and the NO_x level exceeded 200 ppm. For the emulsion fuel tests, the baseline NO_x had dropped to 140 ppm and the ingested water was nearly 31 gallons per hour (0.116 m^3/hr). As previously shown in Figure 7, subsequent additions of water with the fuel simply continue the downward trend in NO_x emissions.

Other atmospheric effects noted include the CO variation with ambient temperature. Often, morning data could not be used because the baseline CO levels dropped 200 to 300 ppm as temperatures increased from 78°F (299K) to 95°F (308K). Afternoon data collection was more consistent as temperatures varied only 2 or 3 degrees. Summer weather conditions at RTP, N. C., are simply described as hot and humid. A large variation in emissions would be expected when data runs are made with the cold, dry air in winter.

CONCLUSIONS

Based on these results with the Solar Spartan engine, the major air pollution problems for small gas turbines are the CO, UHC, and fine particulate emissions. NO_x emissions were significant but rather dilute (10-40 ppm, as measured) in the exhaust. Partial load operation of these standby generator sets can create a health hazard in the vicinity of the unit because the stacks are close to the ground. Even though the stack gases are hot, giving a good plume rise, the gases are often released around buildings where they can be drawn into air conditioning systems.

Water addition by emulsifying the fuel oil did not benefit the emissions situation for the small turbine. The CO problems became considerably worse while the NO_x improvement may not be a valuable trade-off for the CO increase. Results of future particulate effects from emulsion firing studies will be needed before a final judgment can be made.

Another potential factor in the fuel emulsion use was the energy efficiency of the machine. However, there was no measurable change in fuel required to produce 220 kW over the range of water content studied. Thus the water addition neither increased nor decreased thermal efficiency.

The high levels of carbonaceous pollutants can be traced to the basic design of the turbine combustion chambers. These chambers require air film cooling of the walls, creating quench zones that prevent complete burn-out of these pollutants. The relatively short residence times inherent in a small volume high intensity combustor also contribute to this problem. The high excess air levels to limit turbine temperature are also part of the problem. There are some potential solutions for solving this problem, and a major thrust for the CRB in-house high pressure combustion program will be to investigate application of potential control methods to the small turbine engine.

Conversion Factors

gallons/hr (0.0037854) = meters^3/hr
HP (0.745) = kW
atmospheres (101.3) = kPa
feet (0.3048) = meters
($^\circ$F + 460)/1.8 = Kelvin
inches (0.0254) = meters
feet/min (0.00508) = meters/second
inches of Hg (3.377) = kPa
pounds-force/inch^2 (6.894) = kPa
pounds-mass/hour (0.4536) = kilograms/hour
Btu/pound (0.002326) = MJ/Kg.

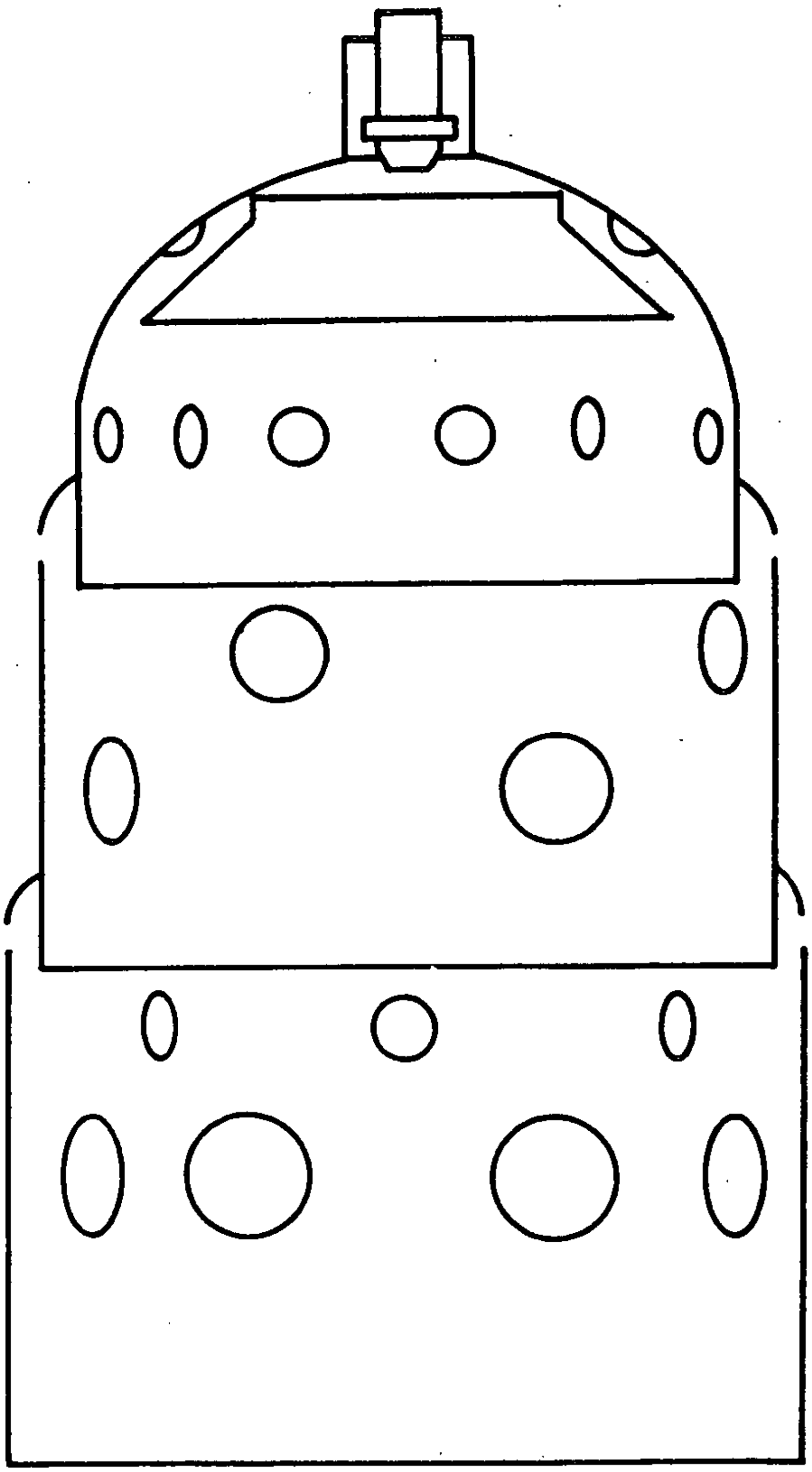

FIGURE 1. GAS TURBINE COMBUSTION LINER

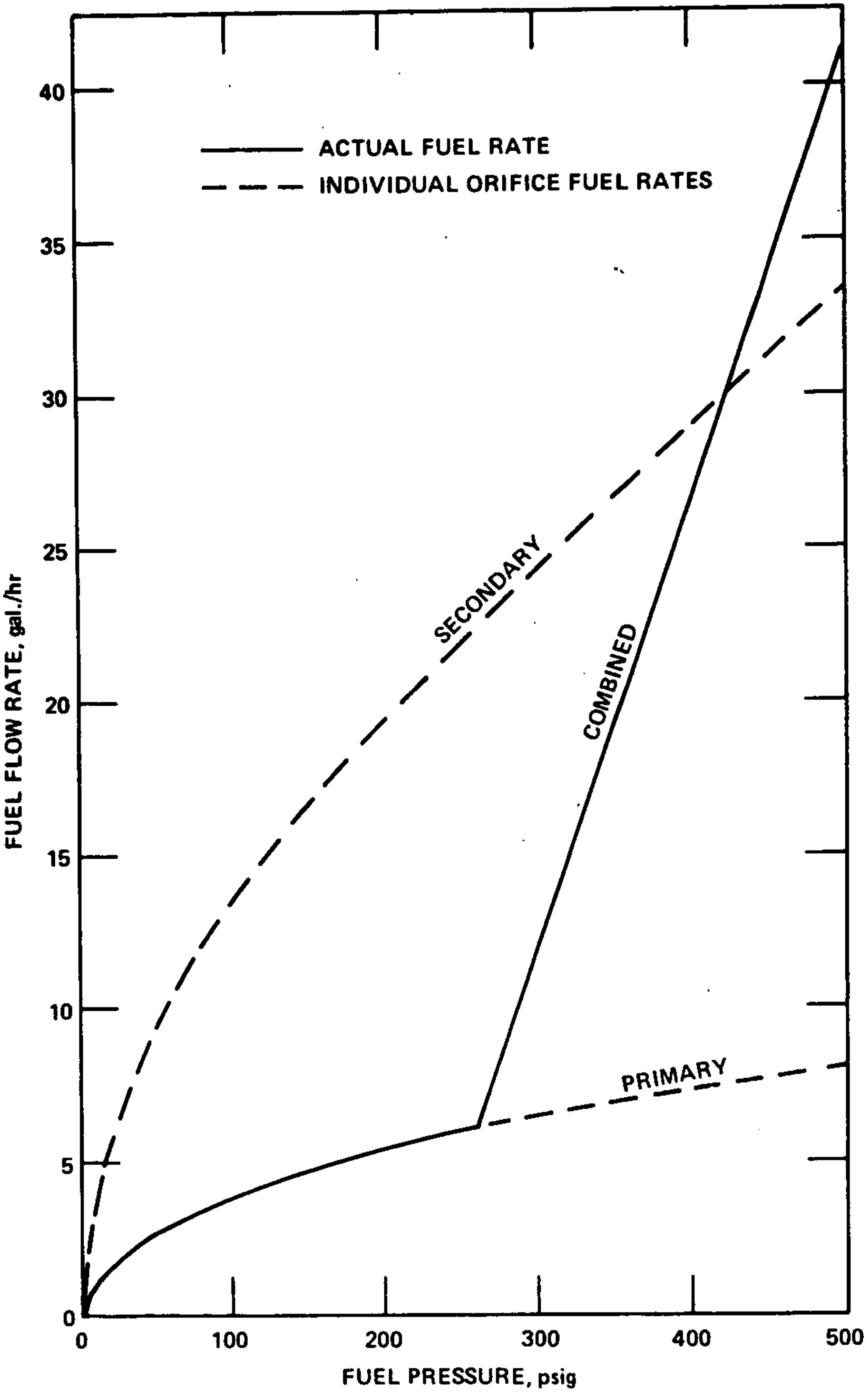

FIGURE 2. FUEL NOZZLE CHARACTERISTICS

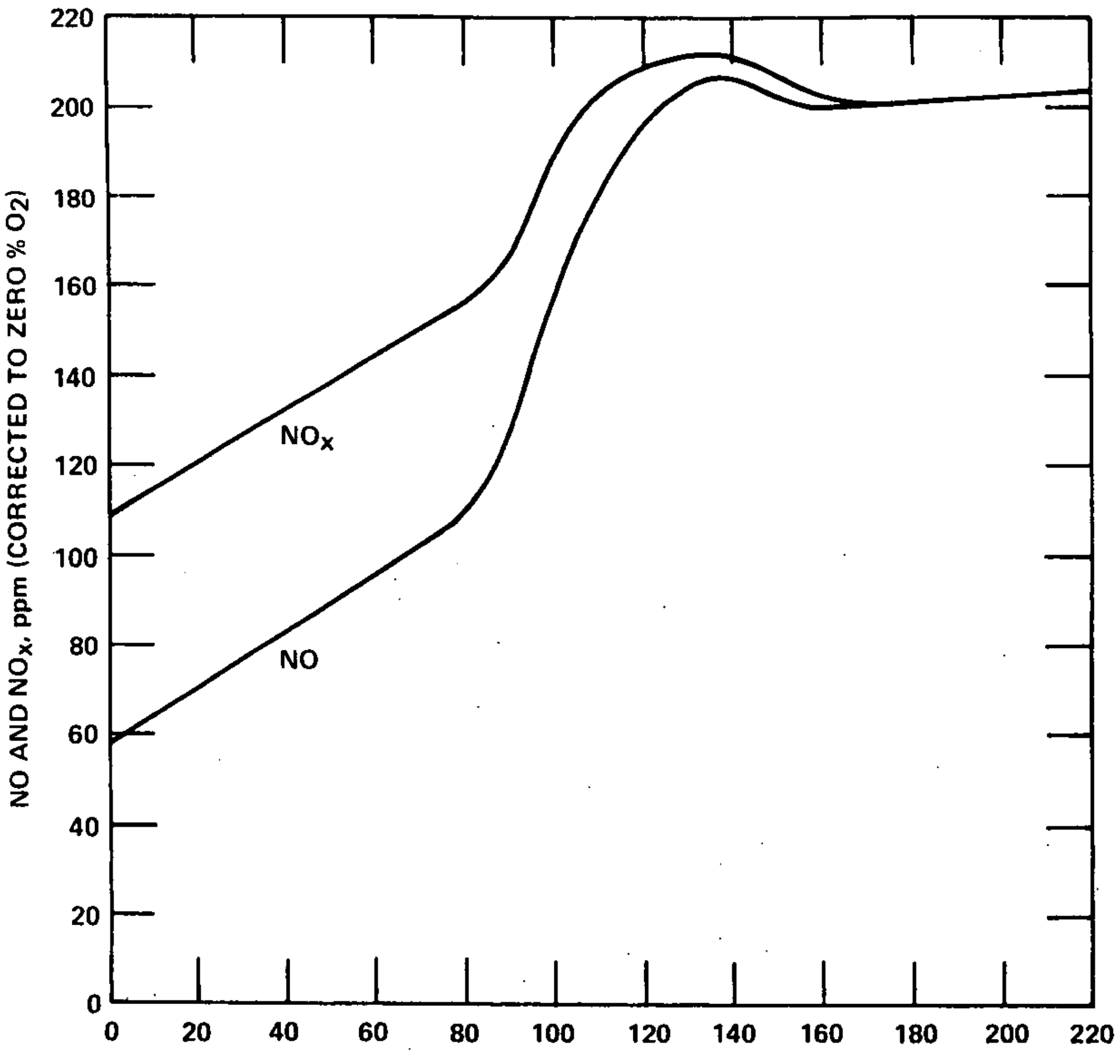

FIGURE 3. NITROGEN OXIDES CHARACTERISTICS

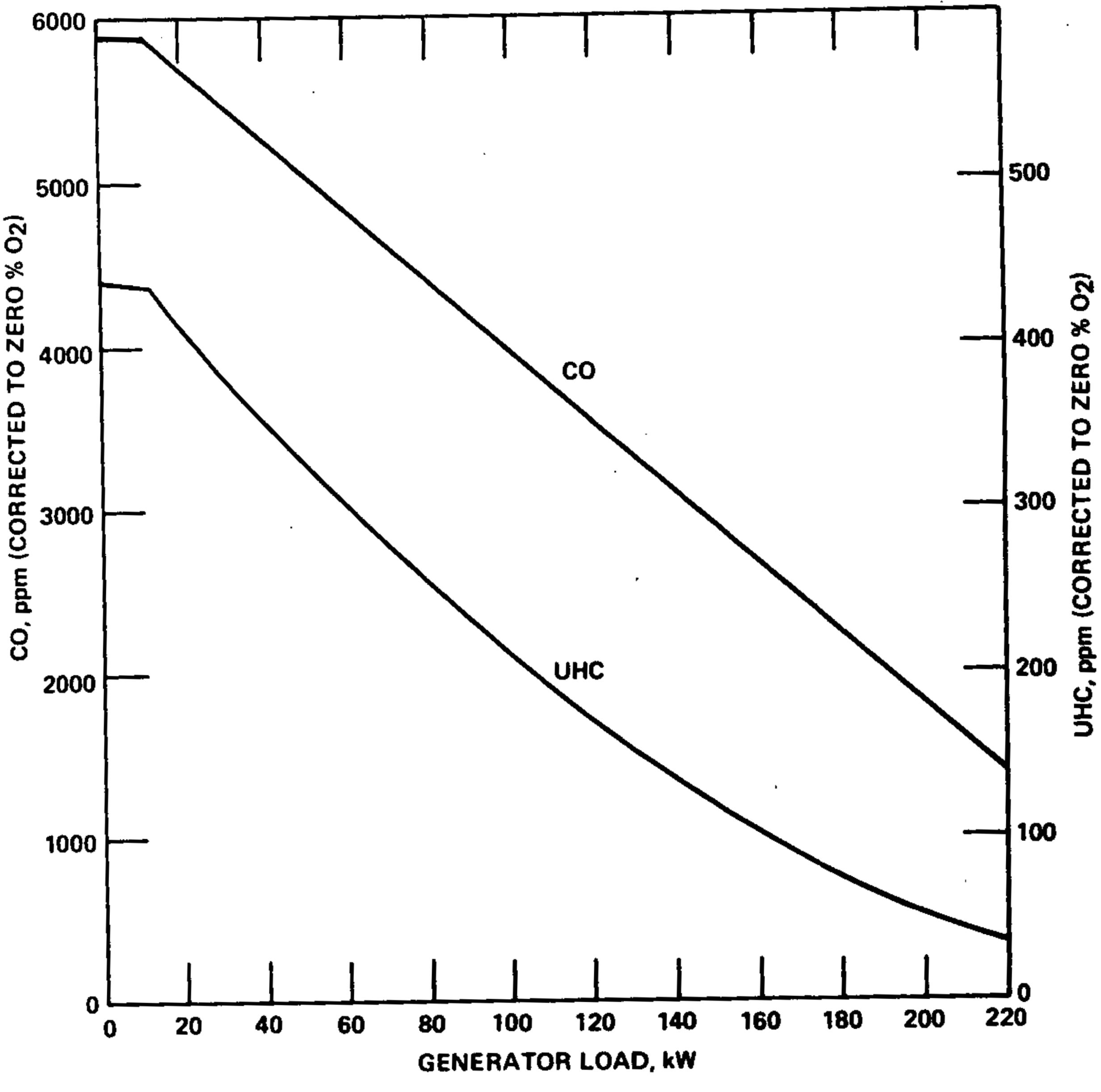

FIGURE 4. CARBON MONOXIDE AND HYDROCARBON CHARACTERISTICS

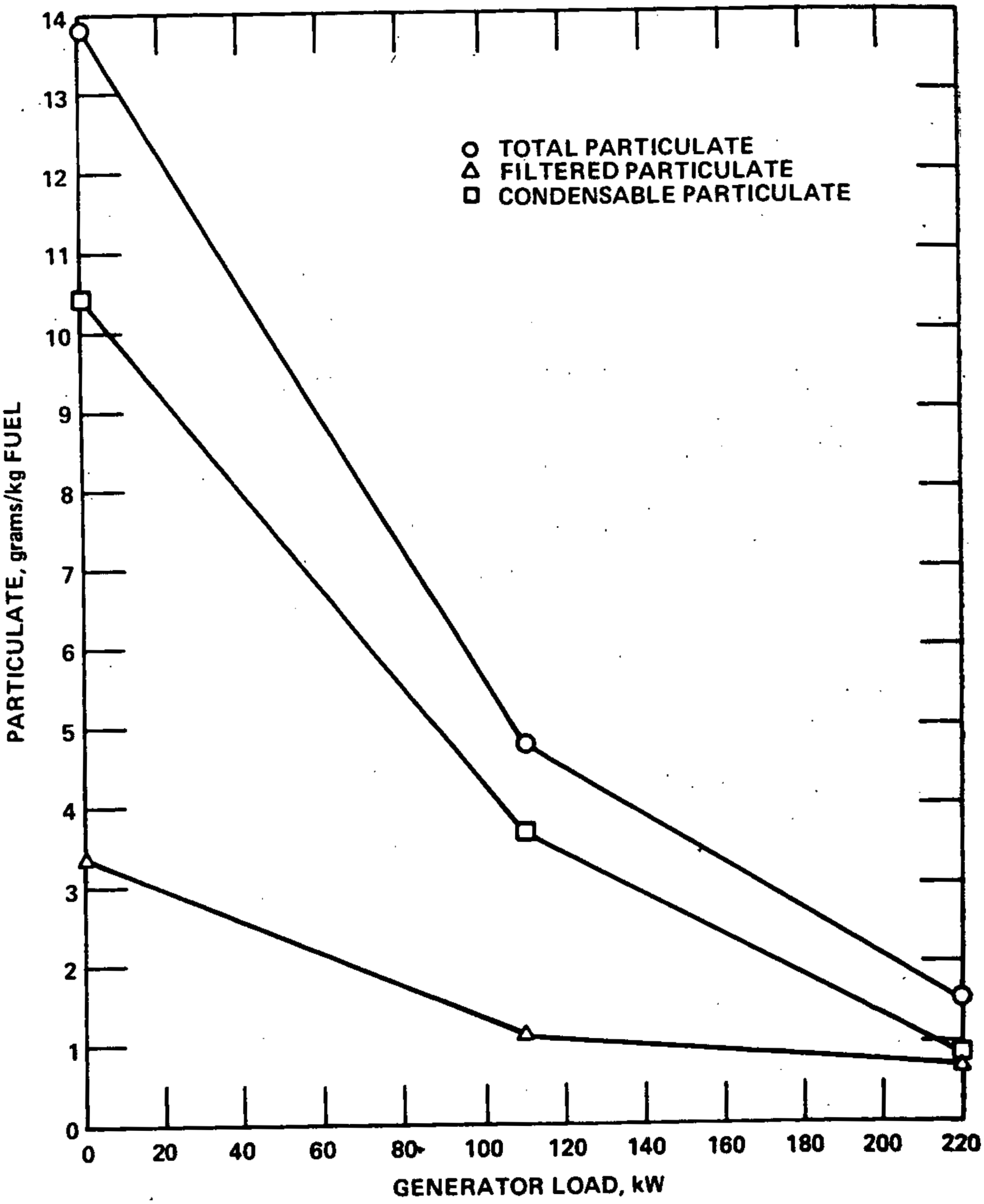

FIGURE 5. PARTICULATE CHARACTERISTICS

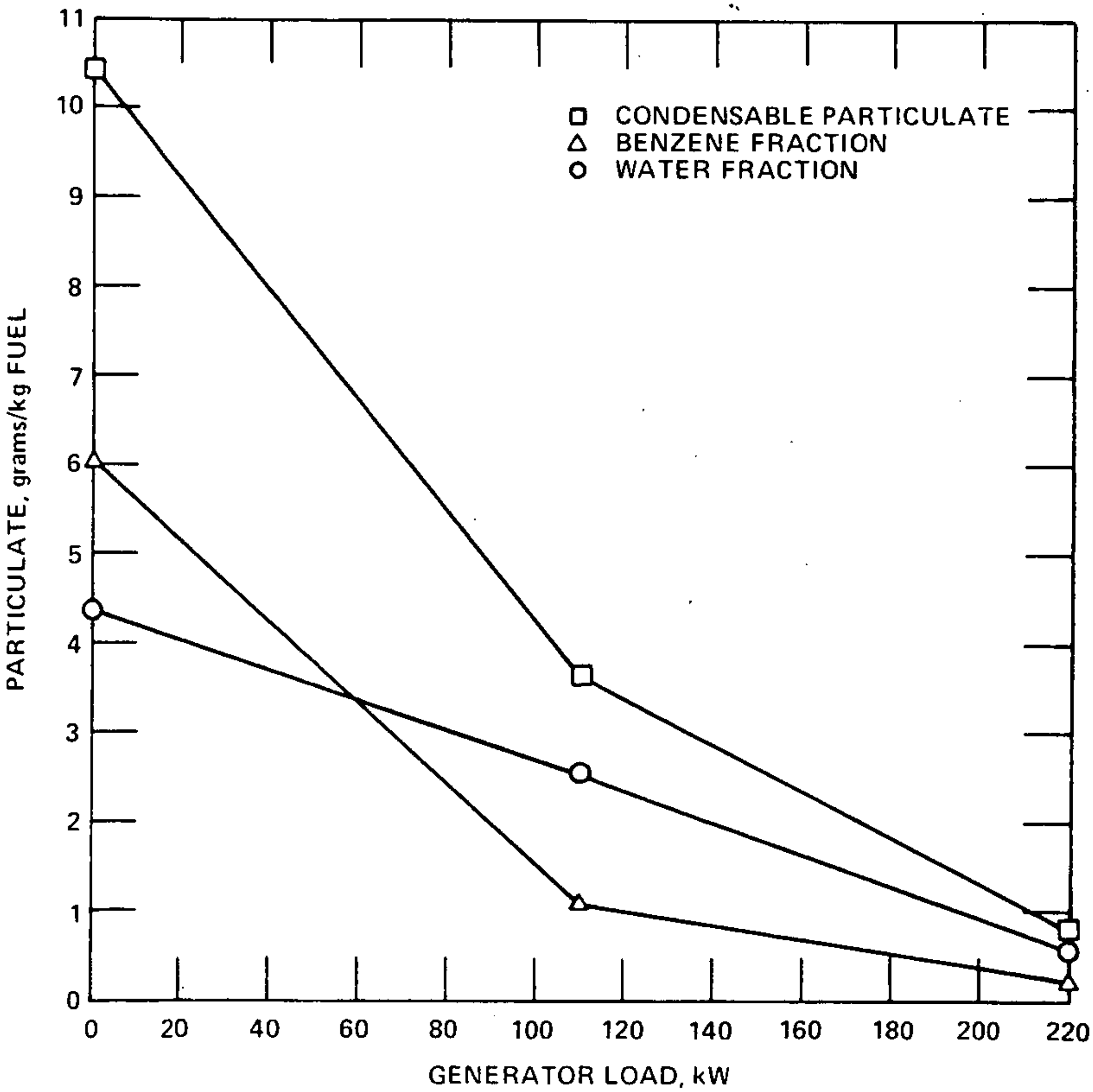

FIGURE 6. CONDENSABLE PARTICULATE CHARACTERISTICS

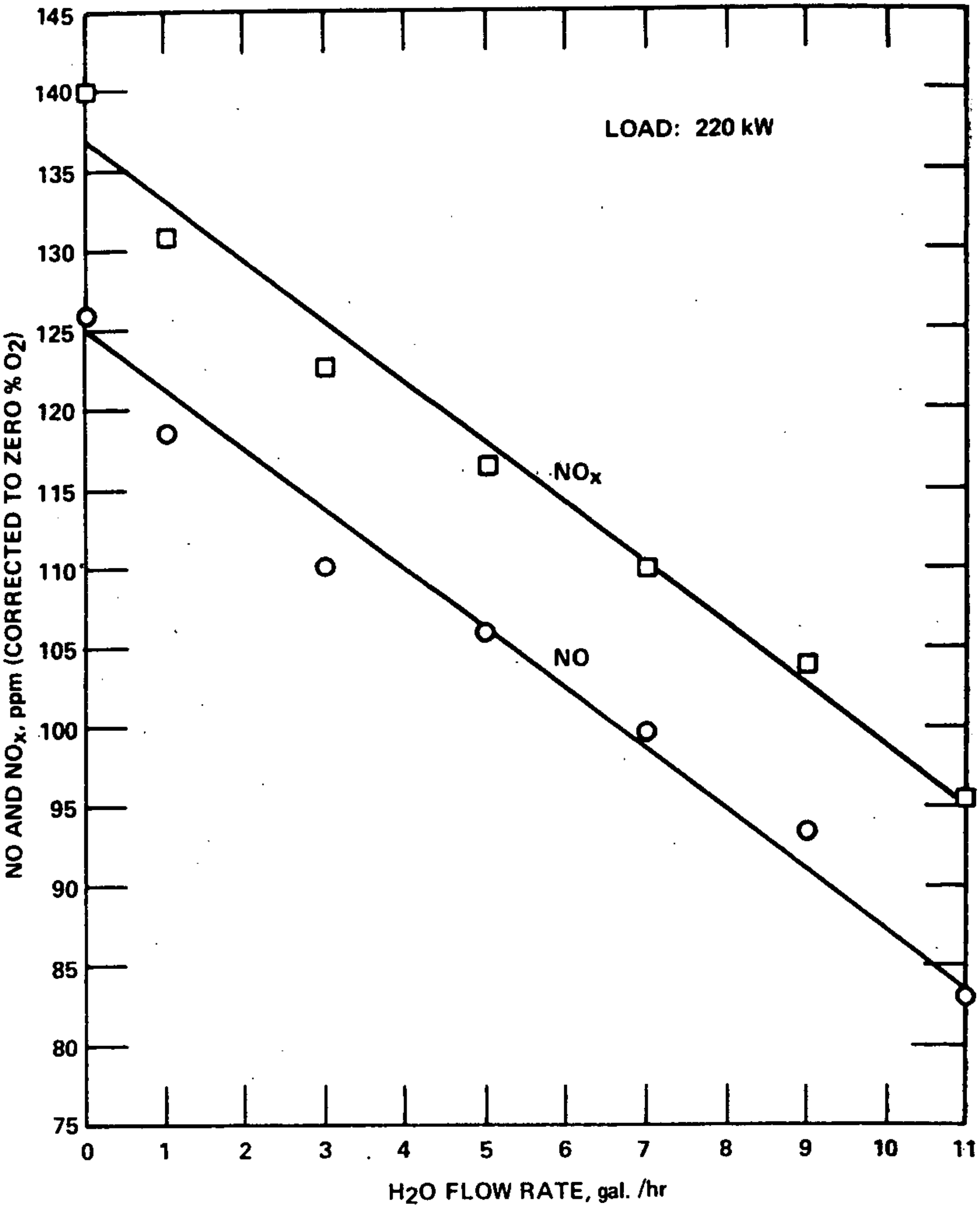

FIGURE 7. NITROGEN OXIDES EMISSIONS -- EMULSION FUEL

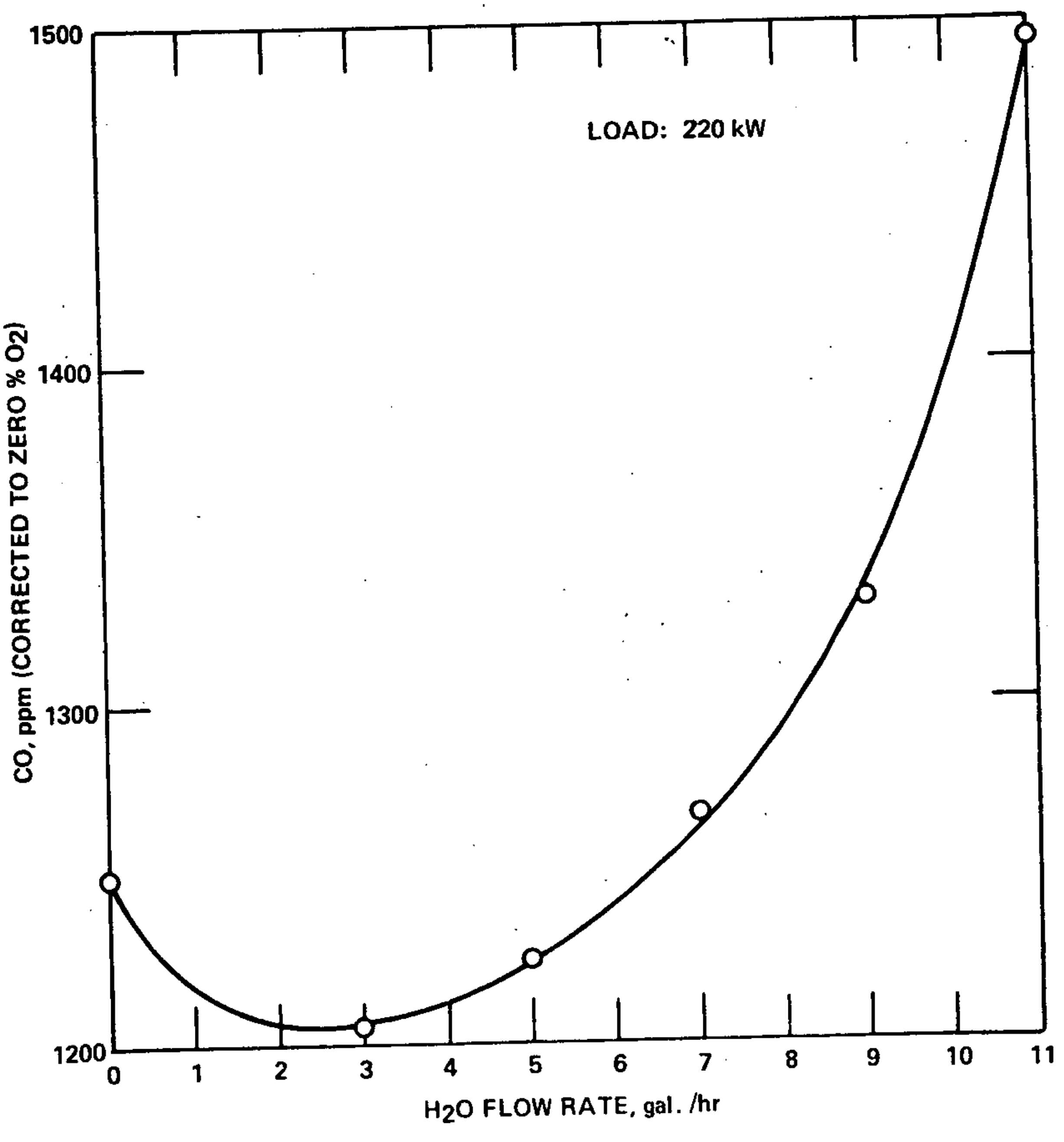

FIGURE 8. CARBON MONOXIDE EMISSIONS -- EMULSION FUEL

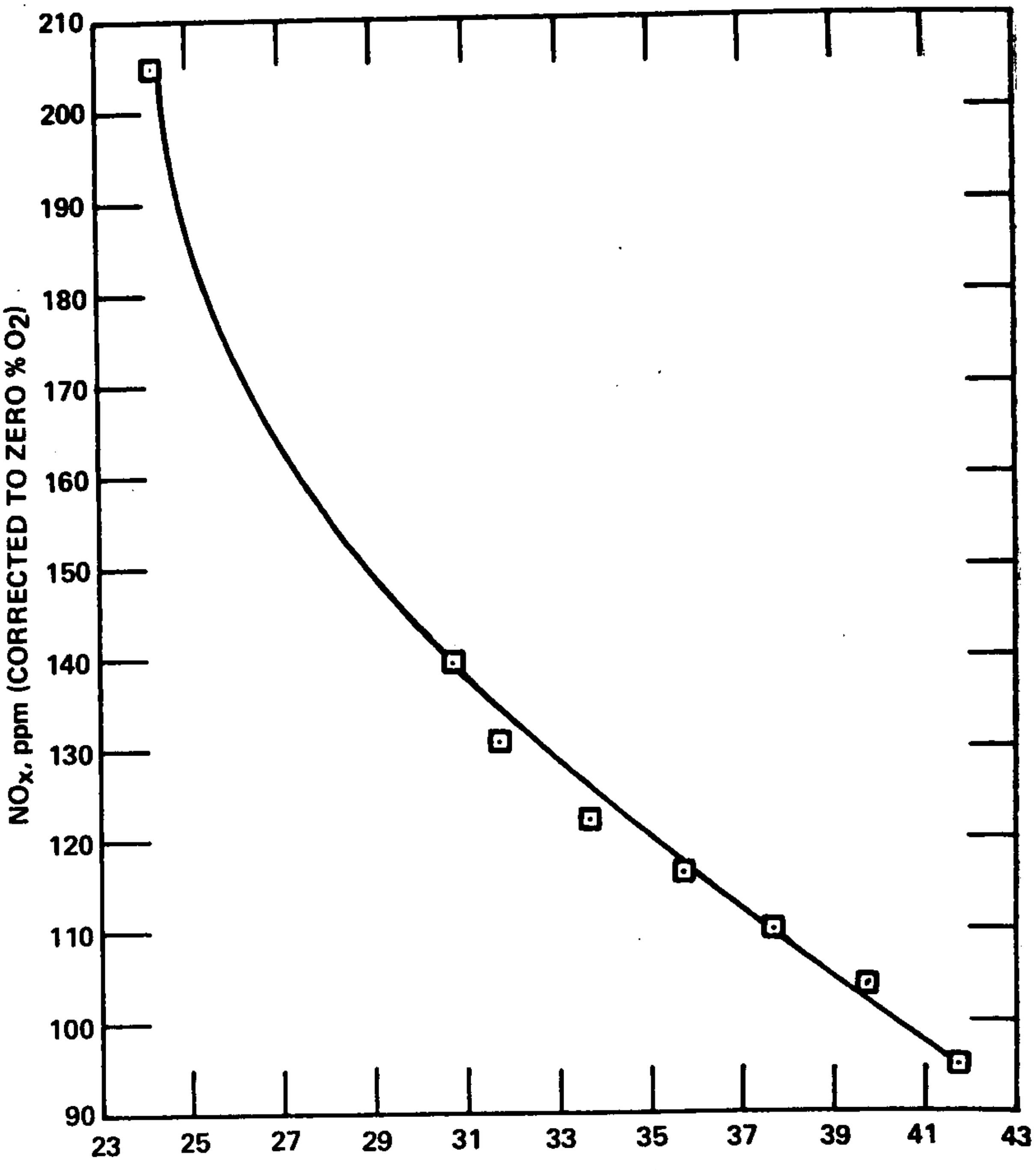

FIGURE 9. ATMOSPHERIC MOISTURE EFFECT

11:30 a.m.
Emission Characteristics of
Small Gas Turbine Engines
John H. Wasser, Research Chemical
Engineer, U.S. E.P.A. Combustion
Research Branch

Q: What quality water did you use in your water injection system; and did you run the tests long enough to notice any effects with regard to turbine fouling and/or corrosion?

A: We used City of Durham water, which according to the health people is fit to drink. We didn't run it long enough to see whether the turbine engine was going to like it or not. We have only done these tests briefly, so I haven't worried about water quality. I don't think it has damaged the machine for the brief tests that we have made. This obviously is a problem and we are going to find out what is in the water to see if there are possible effects on the turbine. We will try to give some thought to that in the future but we just haven't had time to include that in our consideration.

Q: There has been a lot of comment on your paper and the previous one on the CO levels and interactions between the CO and NO. Tom Bowman and John Pohl and I were discussing that the direct reaction of CO plus NO is slow but it is tied in with the oxygen atom and hydroxyl radical kinetics and it makes sense.

Q: Just another comment about the CO. All this kinetics is wonderful, and it governs the system; but don't forget that at 2200 degrees you are kinetically quenching out your CO. If you get a cold wall you are going to get a lot of CO; and, secondly, you have small burners Jack, right?

A: Right, only 8 inches in diameter.

Q: So the surface is creeping in on the reaction, and consequently you are going to get a lot more quenching than you would otherwise.

A: That is right. It is a much more important effect in a small machine than it is in the turbines that you are used to working with, 25 megawatts or larger.

SYSTEMS EVALUATION OF THE USE OF LOW-SULFUR WESTERN COAL IN EXISTING SMALL AND INTERMEDIATE-SIZED BOILERS

BY

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FOR

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INTRODUCTION

The purpose of the first two tasks of the western coal study which this report covers was to survey and screen the small and intermediate sized coal-fired boilers in the United States in order to determine the feasibility of converting a portion of them to a low-sulfur western coal as a means of reducing sulfur oxides emissions. The American Boiler Manufacturers Association (ABMA) sales data which included 362 units for 1965-1974 was used to obtain a more detailed geographical distribution, both by population and capacity, of coal-fired boilers in the range 10,000 to 300,000 lb/hr (pph) steam. The results of this survey show that the heaviest concentration of coal-fired units is centered in the midwest around the Great Lakes. This will then be the area where the maximum potential SOx reduction exists.

In addition to the boiler survey, an analysis was made of the geographical distribution of sulfur in coals used as industrial boiler fuel. This data was then used with the boiler population to arrive at an estimate of the maximum possible SOx reduction achievable by changing fuel to low sulfur western coal. The impact of this reduction was demonstrated for four different areas of the United States and with four coals which are typical of the largest western-coal-producing regions. The results indicate that SOx reductions in emissions from coal-fired industrial boilers of 46% to 78% could theoretically be realized on a nationwide basis, and reductions of 53% to 81% for the midwestern-Great Lakes region by using western coal.

An informal survey was conducted in order to determine current western coal users. One hundred and eleven boiler owners and operators in Minnesota, Wisconsin, Iowa, Nebraska, Michigan, Indiana, Missouri, and Illinois were contacted. Information was gathered on the following:

- Installed boiler population and geographical distribution
- Western coal users and operational experience with particular firing equipment
- Conversion from coal to gas and/or oil
- Potential hosts for boiler testing

A study of the supply variables made it apparent that the two states of Wyoming and Montana are the only western states that are in a position to supply coal to the midwestern and eastern parts of the country during the next ten years. The factors that were taken into consideration were:

- Current production from specific sources
- Production trends and costs
- Shipping costs
- Mine capacities

Analyses of the coal from all of the major producing areas in Wyoming and Montana have been obtained. These typical coal analyses were then compared to the combustion requirements for the individual firing types to arrive at an estimate of the difficulty that would be encountered in switching to the western coal.

The data gathered during the first phase of the program indicate that a conversion to western coal can be a viable SOx emission control technique for most types of coal combustion systems. However, some penalties are involved with unit performance and efficiency. Furthermore, it seems likely that the supply of western coal, especially from Wyoming and Montana, can be made available in midwestern markets at competitive prices.

1.1 BOILER SURVEY

Table 1.1.1 contains ABMA boiler sales data for boilers sold between 1965 and 1974. The data have been sorted according to the following categories:

- Firing Type (pulverized, spreader stoker, overfed stoker, underfed stoker, or other)
- Capacity (10,000 to 300,000 pph steam)
- Year of Sale (1965-1974)
- Geographical Location (1973-1974 have full zip code, 1970-1972 have first three digits of zip code, and 1965-1970 have a one-digit zip code)
- Primary and Alternate Fuel (units that use coal or lignite as a primary fuel or units that can fire coal or lignite as an alternate fuel)
- Domestic Sale
- Stationary Unit
- Standard Industrial Classification Code

These boilers have been located on the map shown in Figure 1.1.1 and compiled in Table 1.1.2 in such a manner that the geographic impact of western coal conversion can be seen. In a similar manner, Table 1.1.3 gives the capacity of the coal-fired units distributed into regions and firing types. This survey presents a more detailed look at this particular class of unit than is available from either Walden (Ref. 1) or the Battelle studies (Ref.2).

Population of Coal-Fired Units Surveyed

Region 3 had 157 boilers installed during the nine year period. This represents 44% of the total population. Within Region 3, the distribution among firing types is as follows: pulverized units account for 8.3%; spreader stokers, 44.5%; overfed stokers, 17.2%; underfed stokers, 2.5%; and other units, 27.4%. Regions 2 and 4 had 20% and 17% of the population respectively. The remaining units were spread over the other regions.

Spreader stokers account for 50% of the units sold during the period followed by 20% for other types of coal firing, 13% for overfed stokers, 9% for pulverized, and 7% for underfed stokers.

TABLE 1.1.1

```
                                                        WESTERN COAL - ABMA DATA                                  PAGE   1
                   DATE: 05/16/75                              TIME: 10:09:25
SELECTION CRITERIA: CAPACITY(10000 TO 300000 PPH)(DOMESTIC(1))(STATIONARY(1))(FUEL(BITUMINUS COAL(1),LIGNITE(10))
SORT ORDER: REGION(A),FIRING METHOD(A),CAPACITY(A)      SORT 80,9,0 WESTNU WESTSR 18,3 72,1 29,8

       REGION  1      FIRING METHOD: SPREADER(2)
 ID    SEQ    DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  OPRS  OPRS  OTHW  SHTP  1-RH  2-RH  P  A  F
                                                                               0   160   130  9999     0     0     0  1  0  2
  1     0   2/28/67   22  1     0     1  1  0  1  1  2  2  1     30000

        1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL               30000 (PPH)

       REGION  1      FIRING METHOD: OVERFEED (4)
 ID    SEQ    DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  OPRS  OPRS  OTHW  SHTP  1-RH  2-RH  P  A  F
                                                                               0     0   125  9999     0     0     0  1  0  4
  1     0   3/12/65    0  1     0     1  1  0  1  1  2  2  1     60000

        1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL               60000 (PPH)
            2 UNITS IN   REGION CAPACITY SUB-TOTAL                90000 (PPH)

       REGION  2      FIRING METHOD: OTHER (A)
 ID    SEQ    DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  OPRS  OPRS  OTHW  SHTP  1-RH  2-RH  P  A  F
                                                                               0     0   125  9999     0     0     0  1  0  0
  1     0   1/18/66    0  1     0     2  1  0  1  1  2  2  1     10000         0   200   100  9999     0     0     0  2  1  0
  2     0  12/ 6/69    0  1     0     2  1  0  1  1  2  1  1     18000         0     0   125  9999     0     0     0  1  4  0
  3     0   4/13/65   24  1     0     2  1  0  1  1  2  2  1     20000         0     0   125  9999     0     0     0  1  0  0
  4     0   1/31/65   20  1     0     2  1  0  1  1  2  2  1     30000         0   250   112  9999     0     0     0  1  0  0
  5     0   8/ 1/67    0  1     0     2  1  0  1  1  2  2  1     35000         0   160   110  9999     0     0     0  1  0  0
  6     0   1/11/67    0  1     0     2  1  0  1  1  2  2  1     40000         0     0   165  9999     0     0     0  1  0  0
  7     0   4/30/66    0  1     0     2  1  0  1  1  2  2  1     50000         0   250   175  9999     0     0     0  1  0  0
  8     0   3/ 8/67   29  1     0     2  1  0  1  1  2  2  1     50000         0   160   125  9999     0     0     0  1  0  0
  9     0   4/ 1/67   39  1     0     2  1  0  1  1  2  2  1     60000         0     0   250  9999     0     0     0  1  7  0
 10     0  10/ 1/66   29  1     0     2  1  0  1  1  2  2  1     70000         0     0   200  9999     0     0     0  1  0  0
 11     0  11/ 1/66   39  1     0     2  1  0  1  1  2  2  1     75000         0     0   200  9999     0     0     0  7  1  0
 12     0   2/28/66   24  1     0     2  1  0  1  1  2  2  1     80000

        12 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL             538000 (PPH)

       REGION  2      FIRING METHOD: PULVERIZED (1)
 ID    SEQ    DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  OPRS  OPRS  OTHW  SHTP  1-RH  2-RH  P  A  F
                                                                               0     0   415   715     0     0     0  1  0  1
  1     0   6/11/65   28  1      0    2  1  0  1  1  2  2  1    120000         0     0   200   500     0     0     0  7  1  1
  2     0   5/28/65   33  1      0    2  1  0  1  1  2  2  1    150000         0   250   225  9999     0     0     0  1  2  1
  3   102  12/ 3/73   39  1  23860    2  1  2  1  1  2  9  1    150000
                                                                               0   250   225  9999     0     0     0  1  2  1
  4   103  12/ 3/73   39  1  23261    2  1  2  1  1  2  9  1    150000         0   250   225  9999     0     0     0  1  2  1
  5   104  12/ 3/73   39  1  23261    2  1  2  1  1  2  9  1    150000         0     0   900   900     0     0     0  1  0  1
  6     0   5/31/65    0  1      0    2  1  0  1  1  1  2  1    230000         0     0   650   750     0     0     0  1  0  1
  7     0   1/31/65   28  1      0    2  1  0  1  1  2  2  1    266000         0   775   600     0   750     0     0  1  2  1
  8   104   1/ 4/74   37  1  25143    2  1  2  1  1  2  9  1    300000

        8 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL             1516000 (PPH)
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TABLE 1.1.1 (Cont)

REGION 2 FIRING METHOD: SPREADER(2)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	7/ 9/65	39	1	0	2	1	0	1	1	2	2	1	19000	0	0	125	9999	0	0	0	1	0	2
2	0	7/16/65	20	1	0	2	1	0	1	1	2	2	1	20000	0	0	125	9999	0	0	0	1	0	2
3	0	8/ 2/65	24	1	0	2	1	0	1	1	2	2	1	25000	0	0	145	9999	0	0	0	4	1	2
4	0	2/28/65	0	1	0	2	1	0	1	1	2	1	1	30000	0	0	125	9999	0	0	0	1	0	2
5	0	3/21/66	24	1	0	2	1	0	1	1	2	2	1	30000	0	0	180	9999	0	0	0	1	4	2
6	0	3/28/69	24	1	0	2	1	0	1	1	2	2	1	30000	0	160	125	9999	0	0	0	1	4	2
7	0	4/15/65	39	1	0	2	1	0	1	1	2	2	1	30000	0	0	120	9999	0	0	0	1	0	2
8	0	4/ 3/67	0	1	0	2	1	0	1	1	2	2	1	35000	0	200	125	9999	0	0	0	1	2	2
9	0	7/26/66	0	1	0	2	1	0	1	1	2	2	1	36000	0	0	125	9999	0	0	0	1	0	2
10	0	8/19/65	0	1	0	2	1	0	1	1	2	2	1	45000	0	0	125	9999	0	0	0	1	0	2
11	0	6/30/67	0	1	0	2	1	0	1	1	2	2	1	45000	0	250	130	9999	0	0	0	1	0	2
12	41	11/14/73	24	1	24522	2	1	2	1	1	2	8	1	50000	0	250	235	9999	0	0	0	4	1	2
13	0	2/ 1/67	0	1	0	2	1	0	1	1	2	2	1	50000	0	250	120	9999	0	0	0	1	0	2
14	0	2/15/68	24	1	0	2	1	0	1	1	2	2	1	60000	0	300	260	9999	0	0	0	1	4	2
15	0	10/ 1/69	28	1	0	2	1	0	1	1	2	2	1	70000	0	200	175	9999	0	0	0	1	0	2
16	12	3/15/74	29	1	26170	2	1	2	1	1	2	9	1	75000	0	250	175	9999	0	0	0	1	2	2
17	63	2/ 5/74	39	1	23803	2	1	2	1	1	2	8	1	75000	0	200	160	9999	0	0	0	1	0	2
18	89	5/28/74	28	1	16050	2	1	2	1	1	2	1	1	78000	0	250	150	9999	0	0	0	1	0	2
19	0	6/ 2/66	24	1	0	2	1	0	1	1	2	2	1	80000	0	0	150	9999	0	0	0	1	4	2
20	0	11/ 1/66	28	1	0	2	1	0	1	1	2	2	1	100000	0	0	175	9999	0	0	0	1	0	2
21	0	3/27/69	37	1	0	2	1	0	1	1	2	2	1	100000	0	250	175	9999	0	0	0	1	0	2
22	0	5/24/65	21	1	0	2	1	0	1	1	2	2	1	100000	0	0	235	9999	0	0	0	1	2	2
23	24	12/13/73	33	1	16050	2	1	2	1	1	2	8	1	100000	0	300	150	9999	0	0	0	1	0	2
24	0	12/27/67	21	1	0	2	1	0	1	1	2	2	1	100000	0	250	225	999	0	0	0	1	2	2
25	0	10/17/69	28	1	0	2	1	0	1	1	2	2	1	125000	0	250	125	0	353	0	0	1	0	2
26	45	10/ 1/74	26	1	16673	2	1	2	1	1	2	9	1	125000	0	715	600	0	725	0	0	4	1	2
27	25	12/14/73	20	1	17810	2	1	2	1	1	2	8	1	150000	0	250	125	9999	0	0	0	1	2	2
28	0	4/19/66	0	1	0	2	1	0	1	1	2	2	1	150000	0	0	175	9999	0	0	0	1	0	2
29	0	8/31/65	28	1	0	2	1	0	1	1	2	2	1	220000	0	0	290	9999	0	0	0	1	0	2
30	0	5/31/65	0	1	0	2	1	0	1	1	2	2	1	220000	0	0	250	9999	0	0	0	1	0	2
31	0	11/30/65	28	1	0	2	1	0	1	1	2	2	1	225000	0	0	415	9999	0	0	0	1	0	2

31 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 2598000 (PPH)

REGION 2 FIRING METHOD: UNDERFEED (3)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	50	1/14/70	80	1	0	2	1	0	1	1	2	9	1	10000	0	160	125	9999	0	0	0	1	0	3
2	0	9/23/65	0	1	0	2	1	0	1	1	2	2	1	15000	0	0	150	387	0	0	0	1	0	3
3	0	5/23/66	0	1	0	2	1	0	1	1	2	2	1	20000	0	0	125	9999	0	0	0	1	0	3
4	0	12/13/66	0	1	0	2	1	0	1	1	2	2	1	21000	0	0	125	9999	0	0	0	1	0	3
5	0	12/13/66	0	1	0	2	1	0	1	1	2	2	1	21000	0	0	125	9999	0	0	0	1	0	3
6	0	7/19/65	0	1	0	2	1	0	1	1	2	2	1	23000	0	0	125	9999	0	0	0	1	0	3
7	0	7/27/65	22	1	0	2	1	0	1	1	2	2	1	25000	0	0	125	9999	0	0	0	1	0	3
8	85	6/21/71	82	1	0	2	1	0	1	1	2	9	1	25000	0	250	125	9999	0	0	0	1	2	3
9	73	10/12/73	82	1	21727	2	1	2	1	1	2	9	1	31000	0	160	125	9999	0	0	0	1	0	3
10	0	1/19/68	0	1	0	2	1	0	1	1	2	2	1	50000	0	250	150	9999	0	0	0	1	0	3

10 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 241000 (PPH)

REGION 2 FIRING METHOD: OVERFEED (4)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	7/14/66	0	1	0	2	1	0	1	1	2	2	1	27000	0	0	175	9999	0	0	0	1	0	4
2	0	7/14/66	0	1	0	2	1	0	1	1	2	2	1	27000	0	0	175	9999	0	0	0	1	0	4
3	0	4/ 6/65	0	1	0	2	1	0	1	1	2	2	1	35000	0	0	125	9999	0	0	0	1	0	4
4	0	2/31/66	0	1	0	2	1	0	1	1	2	2	1	35000	0	0	125	9999	0	0	0	1	0	4
5	0	2/17/65	0	1	0	2	1	0	1	1	2	2	1	40000	0	0	125	9999	0	0	0	1	0	4
6	0	7/30/65	0	1	0	2	1	0	1	1	2	2	1	55000	0	0	170	9999	0	0	0	1	0	4
7	40	9/ 4/74	28	1	16050	2	1	2	1	1	2	8	1	80000	0	250	150	9999	0	0	0	1	0	4
8	23	5/ 7/70	28	1	0	2	1	0	1	1	2	9	1	130000	0	500	475	9999	0	0	0	1	3	4

8 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 429000 (PPH)

TABLE 1.1.1 (Cont)

REGION 2 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	6/30/66	0	1	0	2	1	0	1	1	2	2	1	62000	0	0	125	9999	0	0	0	1	0	5
2	0	8/10/66	0	1	0	2	1	0	1	1	2	2	1	70000	0	0	200	488	0	0	0	1	0	5
3	0	9/ 1/66	0	1	0	2	1	0	1	1	2	2	1	110000	0	0	250	530	0	0	0	1	0	5
4	0	9/ 1/66	33	1	0	2	1	0	1	1	2	2	1	150000	0	0	200	550	0	0	0	1	7	5
5	0	12/26/68	37	1	0	2	1	0	1	1	2	2	1	300000	0	775	635	0	840	0	0	1	0	5

5 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 692000 (PPH)
74 UNITS IN REGION CAPACITY SUB-TOTAL 6014000 (PPH)

REGION 3 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	OF	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	4/30/65	0	1	0	3	1	0	1	1	2	2	1	10000	0	0	100	9999	0	0	0	1	0	0
2	0	5/ 1/67	0	1	0	3	1	0	1	1	2	2	1	15000	0	160	125	9999	0	0	0	1	0	0
3	0	2/28/65	20	1	0	3	1	0	1	1	2	2	1	18000	0	0	140	9999	0	0	0	1	0	0
4	0	2/28/65	30	1	0	3	1	0	1	1	2	1	1	23000	0	0	180	9999	0	0	0	1	2	0
5	0	6/17/65	0	1	0	3	1	0	1	1	2	2	1	30000	0	0	125	9999	0	0	0	1	0	0
6	0	8/ 1/67	0	1	0	3	1	0	1	1	2	1	1	30000	0	250	125	9999	0	0	0	2	1	0
7	0	12/ 1/66	29	1	0	3	1	0	1	1	2	2	1	55000	0	0	850	750	0	0	0	1	0	0
8	0	1/31/65	33	1	0	3	1	0	1	1	2	2	1	60000	0	0	210	475	0	0	0	1	3	0
9	0	2/28/65	20	1	0	3	1	0	1	1	2	1	1	70000	0	0	150	9999	0	0	0	1	2	0
10	0	5/27/68	0	1	0	3	1	0	1	1	2	2	1	75000	0	160	137	9999	0	0	0	1	3	0
11	0	5/27/68	0	1	0	3	1	0	1	1	2	2	1	75000	0	160	137	9999	0	0	0	1	3	0
12	0	6/30/65	0	1	0	3	1	0	1	1	2	2	1	80000	0	0	135	9999	0	0	0	1	0	0
13	0	4/30/65	39	1	0	3	1	0	1	1	2	2	1	80000	0	0	175	9999	0	0	0	1	0	0
14	0	7/ 1/67	0	1	0	3	1	0	1	1	2	2	1	80000	0	200	135	9999	0	0	0	1	0	0
15	0	3/ 2/66	0	1	0	3	1	0	1	1	2	2	1	90000	0	0	160	9999	0	0	0	1	0	0
16	0	11/ 1/66	28	1	0	3	1	0	1	1	2	2	1	100000	0	0	600	750	0	0	0	1	0	0
17	0	2/28/65	39	1	0	3	1	0	1	1	2	2	1	100000	0	0	150	9999	0	0	0	1	0	0
18	0	1/ 1/67	37	1	0	3	1	0	1	1	2	2	1	100000	0	250	175	9999	0	0	0	1	0	0
19	0	7/ 1/67	0	1	0	3	1	0	1	1	2	2	1	110000	0	160	125	9999	0	0	0	1	0	0
20	0	8/ 1/67	0	1	0	3	1	0	1	1	2	2	1	140000	0	1450	1300	0	930	0	0	1	0	0
21	0	10/31/65	26	1	0	3	1	0	1	1	2	1	1	150000	0	0	700	750	0	0	0	1	0	0
22	0	10/ 7/66	0	1	0	3	1	0	1	1	1	1	1	167000	0	0	625	730	0	0	0	1	0	0
23	0	10/ 7/66	0	1	0	3	1	0	1	1	1	1	1	167000	0	0	625	730	0	0	0	1	0	0
24	0	10/ 7/66	0	1	0	3	1	0	1	1	1	1	1	167000	0	0	625	730	0	0	0	1	0	0
25	0	1/ 1/67	28	1	0	3	1	0	1	1	2	2	1	200000	0	250	190	0	425	0	0	1	0	0
26	0	10/ 3/66	33	1	0	3	1	0	1	1	2	2	1	275000	0	0	250	525	0	0	0	7	1	0

26 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 2467000 (PPH)

REGION 3 FIRING METHOD: PULVERIZED (1)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	5/13/66	0	1	0	3	1	0	1	1	2	2	1	19000	0	0	80	9999	0	0	0	1	0	1
2	0	1/29/65	0	1	0	3	1	0	1	1	1	2	1	125000	13000	0	875	900	0	0	0	1	2	1
3	4	7/ 1/71	49	1	0	3	1	0	1	1	1	9	1	125000	18	1100	875	0	900	0	0	1	2	1
4	0	5/31/66	20	1	0	3	1	0	1	1	2	2	1	150000	0	0	220	500	0	0	0	1	0	1
5	0	3/23/67	26	1	0	3	1	0	1	1	2	2	1	150000	0	725	615	0	725	0	0	1	0	1
6	0	6/30/66	0	1	0	3	1	0	1	1	1	2	1	155000	20000	0	900	900	0	0	0	1	2	1
7	59	7/11/72	49	1	0	3	1	0	1	1	1	9	1	215000	25	1450	1275	0	925	0	0	1	2	1
8	0	11/12/65	0	1	0	3	1	0	1	1	1	2	1	250000	22000	0	880	905	0	0	0	1	0	1
9	0	3/25/65	26	1	0	3	1	0	1	1	2	2	1	250000	0	0	1500	900	0	0	0	1	4	1
10	0	7/31/68	0	1	0	3	1	0	1	1	1	2	1	260000	26000	1525	1330	0	925	0	0	1	2	1
11	0	2/17/65	26	1	0	3	1	0	1	1	2	2	1	275000	0	0	475	750	0	0	0	1	0	1
12	0	5/20/66	0	1	0	3	1	0	1	1	1	2	1	275000	29000	0	885	900	0	0	0	1	2	1
13	0	6/30/65	0	1	0	3	1	0	1	1	1	2	1	275000	0	0	925	875	0	0	0	1	0	1

13 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 2524000 (PPH)

TABLE 1.1.1 (Cont)

REGION 3 FIRING METHOD: SPREADER(2) PAGE 4

ID	SEQ	DATE	SIC	DF	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	4/ 6/66	24	1	0	3	1	0	1	1	2	2	1	15000	0	0	100	9999	0	0	0	1	0	2
2	0	8/27/65	24	1	0	3	1	0	1	1	2	2	1	22000	0	0	410	9999	0	0	0	1	0	2
3	0	12/ 7/65	0	1	0	3	1	0	2	1	2	1	1	26000	0	0	170	375	0	0	0	1	0	2
4	0	5/24/65	26	1	0	3	1	0	1	1	2	1	1	29000	0	0	228	9999	0	0	0	4	1	2
5	0	1/31/66	0	1	0	3	1	0	1	1	2	2	1	30000	0	0	125	9999	0	0	0	1	0	2
6	0	1/17/66	20	1	0	3	1	0	1	1	2	2	1	30000	0	0	175	9999	0	0	0	1	0	2
7	0	3/14/66	30	1	0	3	1	0	1	1	2	2	1	30000	0	0	250	9999	0	0	0	1	0	2
8	0	6/29/65	0	1	0	3	1	0	1	1	2	2	1	30000	0	0	135	9999	0	0	0	1	0	2
9	0	2/16/67	0	1	0	3	1	0	1	1	2	2	1	30000	0	180	135	9999	0	0	0	1	0	2
10	0	7/30/65	0	1	0	3	1	0	1	1	2	2	1	32000	0	0	150	9999	0	0	0	1	0	2
11	0	5/16/66	0	1	0	3	1	0	1	1	2	2	1	35000	0	0	175	9999	0	0	0	1	0	2
12	19	8/23/74	37	1	43537	3	1	2	1	1	2	8	1	40000	0	250	140	9999	0	0	0	1	0	2
13	21	8/23/74	37	1	43537	3	1	2	1	1	2	8	1	40000	0	250	140	9999	0	0	0	1	0	2
14	0	6/ 2/66	0	1	0	3	1	0	1	1	2	2	1	40000	0	0	160	470	0	0	0	1	0	2
15	0	4/11/66	0	1	0	3	1	0	1	1	2	2	1	40000	0	0	150	9999	0	0	0	1	0	2
16	0	8/31/65	0	1	0	3	1	0	1	1	2	1	1	40000	0	0	125	9999	0	0	0	1	0	2
17	0	8/31/65	0	1	0	3	1	0	1	1	2	1	1	40000	0	0	125	9999	0	0	0	1	0	2
18	0	6/30/65	0	1	0	3	1	0	1	1	2	2	1	40000	0	0	100	9999	0	0	0	1	0	2
19	89	4/27/70	28	1	0	3	1	0	1	1	2	9	1	40000	0	160	120	0	390	0	0	1	0	2
20	0	5/31/65	28	1	0	3	1	0	1	1	2	1	1	50000	0	0	150	9999	0	0	0	1	0	2
21	0	4/ 0/65	28	1	0	3	1	0	1	1	2	1	1	50000	0	0	230	500	0	0	0	1	0	2
22	0	5/ 1/68	20	1	0	3	1	0	1	1	2	2	1	50000	0	200	150	9999	0	0	0	1	0	2
23	0	1/ 3/67	20	1	0	3	1	0	1	1	2	2	1	55000	0	300	250	9999	0	0	0	1	0	2
24	0	2/18/66	37	1	0	3	1	0	1	1	2	2	1	60000	0	0	150	9999	0	0	0	1	0	2
25	0	4/ 6/66	0	1	0	3	1	0	1	1	2	2	1	60000	0	0	200	9999	0	0	0	1	0	2
26	0	1/17/69	0	1	0	3	1	0	1	1	2	1	1	60000	0	250	200	9999	0	0	0	1	0	2
27	0	5/ 5/66	20	1	0	3	1	0	1	1	2	2	1	60000	0	0	160	406	0	0	0	1	0	2
28	0	5/31/65	37	1	0	3	1	0	1	1	2	2	1	60000	0	0	175	9999	0	0	0	1	0	2
29	0	10/11/67	0	1	0	3	1	0	1	1	2	2	1	60000	0	600	100	9999	0	0	0	1	0	2
30	0	9/ 3/65	20	1	0	3	1	0	1	1	2	2	1	70000	0	0	160	9999	0	0	0	1	0	2
31	0	10/18/65	20	1	0	3	1	0	1	1	2	1	1	72000	0	0	150	9999	0	0	0	1	0	2
32	0	8/31/65	0	1	0	3	1	0	1	1	2	2	1	75000	0	0	150	9999	0	0	0	1	0	2
33	0	4/30/65	20	1	0	3	1	0	1	1	2	2	1	80000	0	0	175	9999	0	0	0	1	0	2
34	25	4/17/74	28	1	49001	3	1	2	1	1	2	8	1	90000	0	225	175	9999	0	0	0	1	0	2
35	25	4/17/74	28	1	49001	3	1	2	1	1	2	8	1	90000	0	225	175	9999	0	0	0	1	0	2
36	0	3/31/66	37	1	0	3	1	0	1	1	2	2	1	100000	0	0	175	9999	0	0	0	1	0	2
37	0	5/25/66	28	1	0	3	1	0	1	1	2	2	1	100000	0	0	150	9999	0	0	0	1	0	2
38	0	3/12/65	28	1	0	3	1	0	1	1	2	2	1	100000	0	0	850	750	0	0	0	1	3	2
39	0	10/ 1/67	37	1	0	3	1	0	1	1	2	2	1	100000	0	250	155	9999	0	0	0	1	0	2
40	0	5/ 4/65	31	1	0	3	1	0	1	1	2	2	1	120000	0	0	150	9999	0	0	0	1	0	2
41	0	1/31/65	39	1	0	3	1	0	1	1	2	2	1	120000	0	0	150	9999	0	0	0	1	3	2
42	31	6/ 1/74	26	1	54467	3	1	2	1	1	2	9	1	120000	0	1500	640	0	750	0	0	1	4	2
43	0	4/30/65	0	1	0	3	1	0	1	1	2	2	1	125000	0	0	200	480	0	0	0	1	0	2
44	0	4/19/68	26	1	0	3	1	0	1	1	2	2	1	130000	0	750	600	0	750	0	0	1	0	2
45	0	2/ 9/66	0	1	0	3	1	0	1	1	1	2	1	140000	13000	0	625	825	0	0	0	1	0	2
46	0	8/26/65	0	1	0	3	1	0	1	1	1	2	1	140000	0	0	625	825	0	0	0	1	0	2
47	0	2/ 4/66	20	1	0	3	1	0	1	1	2	2	1	140000	0	0	440	725	0	0	0	1	0	2
48	0	8/28/69	0	1	0	3	1	0	1	1	2	1	1	150000	0	475	160	9999	0	0	0	1	0	2
49	48	7/16/73	39	1	61552	3	1	2	1	1	2	8	1	150000	0	300	250	9999	0	0	0	1	0	2
50	35	12/16/74	37	1	61552	3	1	2	1	1	2	8	1	150000	0	300	250	9999	0	0	0	1	0	2
51	0	7/17/67	26	1	0	3	1	0	1	1	2	2	1	150000	0	475	400	0	625	0	0	1	0	2
52	25	10/26/72	37	1	0	3	1	0	1	1	2	9	1	150000	0	200	150	9999	0	0	0	1	0	2
53	64	12/17/70	37	1	0	3	1	0	1	1	2	9	1	150000	0	200	150	9999	0	0	0	1	0	2
54	0	10/ 3/66	30	1	0	3	1	0	1	1	2	2	1	150000	0	0	250	525	0	0	0	1	0	2
55	0	4/ 1/67	37	1	0	3	1	0	1	1	2	2	1	160000	0	200	150	9999	0	0	0	1	0	2
56	0	3/28/66	26	1	0	3	1	0	1	1	2	2	1	160000	0	0	450	510	0	0	0	1	0	2
57	0	3/ 1/67	28	1	0	3	1	0	1	1	2	2	1	165000	0	725	650	0	750	0	0	1	3	2
58	0	1/31/66	0	1	0	3	1	0	1	1	1	2	1	170000	0	0	925	905	0	0	0	1	3	2
59	0	8/26/65	0	1	0	3	1	0	1	1	1	2	1	175000	17000	0	900	905	0	0	0	1	0	2
60	71	9/28/71	37	1	0	3	1	0	1	1	2	9	1	180000	0	250	175	0	427	0	0	1	0	2

TABLE 1.1.1 (Cont)

61	0	1/20/66	0	1	0	3	1	0	1	1	1	2	1	180000	17000	0	875	905	0	0	0	1	0	2
62	68	6/20/73	37	1	46011	3	1	2	1	1	2	9	1	200000	0	200	150	9999	0	0	0	1	3	2
63	0	11/30/65	39	1	0	3	1	0	1	1	2	2	1	200000	0	0	450	750	0	0	0	1	0	2
64	66	6/18/73	37	1	48209	3	1	2	1	1	2	9	1	200000	0	250	175	0	427	0	0	1	0	2
65	81	6/17/71	37	1	0	3	1	0	1	1	2	9	1	200000	0	200	150	9999	0	0	0	1	0	2
66	16	5/ 5/70	49	1	0	3	1	0	1	1	1	9	1	200000	0	1000	875	0	900	0	0	1	2	2
67	0	7/31/65	0	1	0	3	1	0	1	1	2	2	1	215000	0	0	650	825	0	0	0	1	0	2
68	0	4/30/66	0	1	0	3	1	0	1	1	1	2	1	220000	0	0	280	600	0	0	0	1	0	2
69	83	8/ 9/73	39	1	47620	3	1	2	1	1	2	9	1	250000	0	250	180	9999	0	0	0	1	0	2
70	0	1/26/66	26	1	0	3	1	0	1	1	2	2	1	250000	0	0	1275	900	0	0	0	1	7	2

70 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 7281000 (PPH)

REGION 3 FIRING METHOD: UNDERFEED (3)

ID	SEQ	DATE	SIC	OE	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	OPRS	OPRS	OTHV	SHTP	1-RH	2-RH	P	A	F
1	0	2/20/69	39	1	0	3	1	0	1	1	2	2	1	18000	0	160	20	9999	0	0	0	1	0	3
2	0	5/31/65	0	1	0	3	1	0	1	1	1	2	1	20000	0	0	100	9999	0	0	0	1	0	3
3	0	2/11/66	0	1	0	3	1	0	1	1	2	2	1	30000	0	0	135	9999	0	0	0	1	0	3
4	0	6/17/66	28	1	0	3	1	0	1	1	2	2	1	40000	0	0	120	9999	0	0	0	1	0	3

4 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 108000 (PPH)

REGION 3 FIRING METHOD: OVERFEED (4)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	OPRS	OPRS	OTHV	SHTP	1-RH	2-RH	P	A	F
1	0	9/12/69	0	1	0	3	1	0	1	1	2	2	1	25000	0	160	150	9999	0	0	0	1	0	4
2	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
3	83	7/31/74	39	1	46201	3	1	2	1	1	2	1	1	30000	0	160	125	9999	0	0	0	1	0	4
4	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
5	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
6	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
7	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
8	0	8/12/68	0	1	0	3	1	0	1	1	1	2	1	30000	0	200	160	9999	0	0	0	1	0	4
9	2	3/12/70	80	1	0	3	1	0	1	1	2	1	1	30000	0	350	275	9999	0	0	0	1	0	4
10	3	3/12/70	80	1	0	3	1	0	1	1	2	1	1	30000	0	350	275	9999	0	0	0	1	0	4
11	4	3/12/70	80	1	0	3	1	0	1	1	2	1	1	30000	0	350	275	9999	0	0	0	1	0	4
12	20	9/30/74	80	1	43725	3	1	2	1	1	2	8	1	40000	0	250	110	9999	0	0	0	1	0	4
13	0	1/31/66	20	1	0	3	1	0	1	1	2	2	1	45000	0	0	150	370	0	0	0	1	0	4
14	0	12/31/69	0	1	0	3	1	0	1	1	2	2	1	50000	0	250	125	9999	0	0	0	1	0	4
15	21	9/30/74	80	1	45631	3	1	2	1	1	2	8	1	50000	0	250	150	9999	0	0	0	1	0	4
16	0	1/13/67	0	1	0	3	1	0	1	1	2	2	1	50000	0	160	110	9999	0	0	0	1	0	4
17	0	4/14/69	0	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	4
18	14	10/31/74	80	1	45201	3	1	2	1	1	2	8	1	60000	0	250	200	9999	0	0	0	1	0	4
19	0	11/19/65	0	1	0	3	1	0	1	1	2	2	1	60000	0	0	125	9999	0	0	0	1	3	4
20	0	11/19/65	0	1	0	3	1	0	1	1	2	2	1	60000	0	0	125	9999	0	0	0	1	3	4
21	0	2/14/66	33	1	0	3	1	0	1	1	2	2	1	65000	0	0	180	9999	0	0	0	1	2	4
22	0	4/29/65	0	1	0	3	1	0	1	1	2	2	1	70000	0	0	145	9999	0	0	0	1	0	4
23	0	4/29/65	0	1	0	3	1	0	1	1	2	2	1	70000	0	0	145	9999	0	0	0	1	0	4
24	31	12/14/73	39	1	40210	3	1	2	1	1	2	8	1	75000	0	200	150	9999	0	0	0	1	2	4
25	30	12/14/73	39	1	40210	3	1	2	1	1	2	8	1	75000	0	200	150	9999	0	0	0	1	2	4
26	0	8/ 5/65	28	1	0	3	1	0	1	1	2	2	1	75000	0	0	150	9999	0	0	0	1	0	4
27	0	12/31/69	0	1	0	3	1	0	1	1	2	2	1	75000	0	250	125	9999	0	0	0	1	0	4

27 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 1295000 (PPH)

REGION 3 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	OE	ZIP	REG	T	FO	SW	SM	EO	PA	NU	CAP(PPH)	CAP (KW)	OPRS	OPRS	OTHV	SHTP	1-RH	2-RH	P	A	F
1	0	6/21/56	0	1	0	3	1	0	1	1	2	2	1	25000	0	0	120	9999	0	0	0	1	0	5
2	0	12/13/67	0	1	0	3	1	0	1	1	2	2	1	30000	0	200	160	999	0	0	0	1	0	5
3	0	5/ 2/59	0	1	0	3	1	0	1	1	2	2	1	30000	0	200	160	9999	0	0	0	1	0	5
4	0	12/13/57	0	1	0	3	1	0	1	1	2	2	1	30000	0	200	160	999	0	0	0	1	0	5
5	0	3/21/66	0	1	0	3	1	0	1	1	2	2	1	40000	0	0	125	9999	0	0	0	1	0	5
6	0	8/31/57	0	1	0	3	1	0	1	1	2	2	1	45000	0	300	250	0	430	0	0	1	0	5
7	0	3/ 1/58	37	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	5
8	0	6/26/58	0	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	5
9	0	3/ 1/59	37	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	5
10	0	4/20/67	0	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	5
11	0	6/26/69	0	1	0	3	1	0	1	1	2	2	1	50000	0	200	125	9999	0	0	0	1	0	5
12	0	3/28/58	0	1	0	3	1	0	1	1	2	2	1	60000	0	160	120	9999	0	0	0	1	0	5
13	0	11/ 1/67	0	1	0	3	1	0	1	1	2	2	1	60000	0	200	150	9999	0	0	0	1	0	5
14	0	5/13/68	0	1	0	3	1	0	1	1	2	2	1	75000	0	250	150	9999	0	0	0	1	0	5
15	0	3/ 4/65	0	1	0	3	1	0	1	1	2	2	1	80000	0	0	135	9999	0	0	0	1	0	5
16	0	2/28/66	0	1	0	3	1	0	1	1	2	2	1	170000	0	0	425	740	0	0	0	1	0	5
17	0	2/20/67	0	1	0	3	1	0	1	1	2	2	1	200000	0	475	300	0	525	0	0	1	0	5

17 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 1095000 (PPH)
157 UNITS IN REGION CAPACITY SUB-TOTAL 14770000 (PPH)

TABLE 1.1.1 (Cont)

```
       REGION  4      FIRING METHOD: OTHER (X)
 ID    SEQ    DATE    SIC DE    ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F   PAGE  6

  1     0   4/30/65   22  1       0    4   1  0  1  1  2  2  1     20000         0     0   150  9999     0     0     0   1  0  0
  2     0   5/11/65   28  1       0    4   1  0  1  1  2  1  1     25000         0     0   200   388     0     0     0   1  7  0
  3     0   1/27/66    0  1       0    4   1  0  1  1  2  2  1     34000         0     0   160   406     0     0     0   1  0  0
  4     0  12/20/65    0  1       0    4   1  0  1  1  2  2  1     75000         0     0   175  9999     0     0     0   1  0  0
  5    33   3/17/72   28  1       0    4   1  0  1  1  2  9  1    130000         0   500   475  9999     0     0     0   1  0  0

       5 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL                284000 (PPH)

       REGION  4      FIRING METHOD: PULVERIZED (1)
 ID    SEQ    DATE    SIC DE    ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

  1     0   9/15/65   22  1       0    4   1  0  1  1  2  2  1    154000         0     0   160  9999     0     0     0   1  3  1
  2    22  12/ 1/73   28  1   28729    4   1  2  1  1  2  9  1    175000         0  1025   900     0   835     0     0   1  2  1
  3     0   2/ 1/66   22  1       0    4   1  0  1  1  2  2  1    200000         0     0   410   725     0     0     0   1  0  1
  4    72   1/ 7/74   28  1   29202    4   1  2  1  1  2  9  1    250000         0   700   610     0   740     0     0   1  2  1
  5    71   1/ 7/74   28  1   29202    4   1  2  1  1  2  9  1    250000         0   700   610     0   740     0     0   1  2  1
  6     0  12/31/68   22  1       0    4   1  0  1  1  2  2  1    300000         0  1475  1300     0   900     0     0   1  3  1

       6 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL               1329000 (PPH)

       REGION  4      FIRING METHOD: SPREADER(2)
 ID    SEQ    DATE    SIC DE    ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

  1     0   5/ 9/65    0  1       0    4   1  0  1  1  2  2  1     12000         0     0   140   353     0     0     0   1  0  2
  2     0   8/ 1/66   22  1       0    4   1  0  1  1  2  2  1     20000         0     0   120  9999     0     0     0   1  0  2
  3    59   7/20/74    0  1   30905    4   1  2  1  1  2  8  1     25000         0   250   233  9999     0     0     0   1  2  2
  4    81   7/20/74    0  1   30905    4   1  2  1  1  2  8  1     25000         0   250   233  9979     0     0     0   1  2  2
  5     0   9/30/65    0  1       0    4   1  0  1  1  2  2  1     25000         0     0   110  9999     0     0     0   1  0  2
  6     0   8/25/66   26  1       0    4   1  0  1  1  2  2  1     28000         0     0   175  9999     0     0     0   1  0  2
  7     0   7/ 8/66   24  1       0    4   1  0  1  1  2  2  1     30000         0     0   125  9979     0     0     0   1  0  2
  8     0  12/29/66   26  1       0    4   1  0  1  1  2  2  1     30000         0     0   200  9999     0     0     0   1  0  2
  9     0   5/ 8/67    0  1       0    4   1  0  1  1  2  2  1     30000         0   160   100  9999     0     0     0   1  0  2
 10     0   8/14/68   22  1       0    4   1  0  1  1  2  2  1     34000         0   250   160  9999     0     0     0   1  0  2
 11     0   8/14/68   22  1       0    4   1  0  1  1  2  2  1     34000         0   250   160  9997     0     0     0   1  0  2
 12     0  10/29/66    0  1       0    4   1  0  1  1  2  2  1     35000         0     0   150  9999     0     0     0   1  0  2
 13     0   4/30/66   22  1       0    4   1  0  1  1  2  2  1     50000         0     0   150  9997     0     0     0   1  0  2
 14    81   7/ 2/73   22  1   30730    4   1  2  1  1  2  7  1     55000         0   250   150  9999     0     0     0   1  0  2
 15    82   5/30/74   39  1   31201    4   1  2  1  1  2  8  1     60000         0   200   150  9999     0     0     0   1  3  2
 16    80   5/30/74   39  1   31201    4   1  2  1  1  2  8  1     60000         0   200   150  9999     0     0     0   1  3  2
 17    81   5/30/74   39  1   31201    4   1  2  1  1  2  8  1     60000         0   200   150  9999     0     0     0   1  3  2
 18     0   5/31/65    0  1       0    4   1  0  1  1  2  2  1     68000         0     0   125  9997     0     0     0   1  0  2
 19    16   3/29/74   39  1   27893    4   1  2  1  1  2  9  1     75000         0   250   125  9999     0     0     0   1  2  2
 20     0   7/ 6/65   22  1       0    4   1  0  1  1  2  2  1     75000         0     0   230  9999     0     0     0   1  0  2
 21     0  11/14/65   22  1       0    4   1  0  1  1  2  2  1     75000         0     0   130   406     0     0     0   1  0  2
 22    15   3/29/74   39  1   27893    4   1  2  1  1  2  9  1     75000         0   250   125  9999     0     0     0   1  2  2
 23    21   4/ 6/72   22  1       0    4   1  0  1  1  2  9  1    100000         0   200   150  9999     0     0     0   1  0  2
 24     2  12/18/73   39  1   27107    4   1  2  1  1  2  8  1    110000         0   250   170  9999     0     0     0   1  0  2
 25     0   3/ 1/67   22  1       0    4   1  0  1  1  2  2  1    130000         0   400   340  9999     0     0     0   1  0  2
 26     9  11/12/73   22  1   28306    4   1  2  1  1  2  8  1    150000         0   200   150  9999     0     0     0   1  0  2
 27    11  11/12/73   22  1   28306    4   1  2  1  1  2  8  1    150000         0   200   150  9999     0     0     0   1  0  2
 28    12  11/12/73   22  1   28306    4   1  2  1  1  2  8  1    150000         0   200   150  9999     0     0     0   1  0  2
 29     9  11/12/73   22  1   28306    4   1  2  1  1  2  8  1    150000         0   200   150  9999     0     0     0   1  0  2
 30    92   6/24/74   28  1   29403    4   1  2  1  1  2  8  1    150000         0   705   600     0   800     0     0   1  2  2
 31    10  11/12/73   22  1   28306    4   1  2  1  1  2  8  1    150000         0   200   150  9999     0     0     0   1  0  2
 32     0   4/30/68   39  1       0    4   1  0  1  1  2  2  1    200000         0  1000   870     0   810     0     0   1  0  2
 33     0   4/30/68   39  1       0    4   1  0  1  1  2  2  1    200000         0  1000   870     0   810     0     0   1  0  2
 34     0   7/ 1/65   28  1       0    4   1  0  1  1  2  2  1    200000         0     0   850   800     0     0     0   1  0  2

      34 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL               2821000 (PPH)

       REGION  4      FIRING METHOD: UNDERFEED (3)
 ID    SEQ    DATE    SIC DE    ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

  1     0   3/22/67    0  1       0    4   1  0  1  1  2  2  1     15000         0   165   110  9999     0     0     0   1  0  3
  2     0   6/21/65    0  1       0    4   1  0  1  1  2  1  1     17000         0     0   100  9999     0     0     0   2  1  3
  3     0   5/10/66   25  1       0    4   1  0  1  1  2  2  1     20000         0     0   145   371     0     0     0   1  7  3
  4     0   9/13/65    0  1       0    4   1  0  1  1  2  2  1     20000         0     0   100   338     0     0     0   1  0  3
  5    10   6/26/74   80  1   37601    4   1  2  1  1  2  1  1     20000         0   160   125  9999     0     0     0   1  0  3
  6     0   5/ 9/65    0  1       0    4   1  0  1  1  2  1  1     21000         0     0   100  9999     0     0     0   1  0  3
  7     0   8/ 4/65    0  1       0    4   1  0  1  1  2  2  1     24000         0     0   100  9999     0     0     0   1  0  3
  8    50   3/30/73   82  1   38237    4   1  2  1  1  2  9  1     30000         0   160   100  9999     0     0     0   1  0  3
  9     0   2/22/66   22  1       0    4   1  0  1  1  2  2  1     30000         0     0   150  9999     0     0     0   1  0  3

       9 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL                197000 (PPH)
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TABLE 1.1.1 (Cont)

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     REGION  4     FIRING METHOD: OVERFEED (4)                                                                                   PAGE   7
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1    34  6/25/74  37  1  35804    4   1  2  1  1  2  6  1     50000         0   200   125  9999     0     0     0   1  0  4
 2    33  6/25/74  37  1  35804    4   1  2  1  1  2  8  1     50000         0   200   125  9999     0     0     0   1  0  4
 3    70  5/23/74  24  1  27030    4   1  2  1  1  2  8  1     70000         0   250   150  9999     0     0     0   4  1  4
 4    74 12/ 2/70  82  1      0    4   1  0  1  1  2  9  1    100000         0   250   125  9999     0     0     0   1  0  4
 5    88 12/ 2/70  82  1      0    4   1  0  1  1  2  9  1    100000         0   250   125  9999     0     0     0   1  0  4

       5 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL          370000 (PPH)

     REGION  4     FIRING METHOD: OTHER (X)
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  6/26/68   0  1      0    4   1  0  1  1  2  2  1     62000         0   275   125  9999     0     0     0   1  0  5
 2     0  2/ 1/68   0  1      0    4   1  0  1  1  2  2  1     75000         0   250   125  9999     0     0     0   1  0  5

       2 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL          137000 (PPH)

     REGION  4     FIRING METHOD: OTHER (X)
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1    94  9/21/73  28  1  28501    4   1  2  1  1  2  8  1    150000         0   675   600  9999     0     0     0   3  1  9
 2    31 12/16/74  28  1  39571    4   1  2  1  1  2  9  1    180000         0   575   500     0   550     0     0   2  1  9
 3    30 12/16/74  28  1  39571    4   1  2  1  1  2  9  1    180000         0   575   500     0   550     0     0   2  1  9

       3 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL          510000 (PPH)
           64 UNITS IN   REGION CAPACITY SUB-TOTAL         5640000 (PPH)

     REGION  5     FIRING METHOD: OTHER (X)
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  4/ 3/69  20  1      0    5   1  0  1  1  2  1  1     35000         0   200   125  9999     0     0     0   2  1  0
 2     0  8/31/65  20  1      0    5   1  0  1  1  2  2  1    150000         0     0   160  9999     0     0     0   1  0  0

       2 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL          185000 (PPH)

     REGION  5     FIRING METHOD: PULVERIZED (1)
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  5/31/65   0  1      0    5   1  0  1  1  1  2  1    180000         0     0   876   900     0     0     0   1  3  1
 2     0  4/ 9/68   0  1      0    5   1  0  1  1  1  2  1    270000     27000  1150   879     0   900   398     0   1  3  1

       2 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL          450000 (PPH)

     REGION  5     FIRING METHOD: SPREADER(2)
ID   SEQ    DATE   SIC DE   ZIP   REG  T FD SW SH EO PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1    56  3/26/74  20  1  58102    5   1  2  1  1  2  1  1     15000         0   200   100  9999     0     0     0  10  0  2
 2    31  9/ 1/74  90  1  63001    5   1  2  1  1  2  8  1     50000         0   250   150  9999     0     0     0   1  3  2
 3    20  7/25/74  92  1  55455    5   1  2  1  1  2  9  1     70000         0   350   150  9999     0     0     0   1  2  2
 4     0 12/21/67   0  1      0    5   1  0  1  1  2  2  1     70000         0   350   150   999     0     0     0   1  3  2
 5     0  4/ 1/68  20  1      0    5   1  0  1  1  2  2  1     90000         0   675   600     0   750     0     0   1  3  2
 6     0 11/30/65  26  1      0    5   1  0  1  1  2  2  1    100000         0     0   160   440     0     0     0   1  4  2
 7     0  3/28/69   0  1      0    5   1  0  1  1  2  2  1    125000         0   475   415     0   750     0     0   1  3  2
 8     0  7/16/68  20  1      0    5   1  0  1  1  2  2  1    130000         0   500   400     0   555     0     0   1  0  2
 9    47  3/27/74  20  1  56716    5   1  2  1  1  2  9  1    130000         0   475   400     0   555     0     0  10  0  2
10     0  7/16/59  20  1      0    5   1  0  1  1  2  2  1    130000         0   500   400     0   555     0     0   1  0  2
11    63  3/24/72  82  1      0    5   1  0  1  1  1  9  1    140000        20   500   415     0   750     0     0   1  3  2
12    63  6/29/73  49  1  55745    5   1  2  1  1  1  9  1    150000         0   775   625     0   760     0     0   1  0  2
13    61  7/ 1/70  49  1      0    5   1  0  1  1  1  9  1    150000        25  1000   650     0   950     0     0   1  3  2
14    40  7/15/74  82  1  52240    5   1  2  2  1  2  9  1    170000         0   600   475   760     0     0     0   1  0  2
15   122 10/25/73  82  1  50010    5   1  2  1  1  2  9  1    170000         0   525   415     0   750     0     0   1  3  2
16     0  4/30/65  20  1      0    5   1  0  1  1  2  2  1    170000         0     0   165  9999     0     0     0   1  3  2
17    44  5/10/74  47  1  55792    5   1  2  1  1  1  9  1    177000        25   750   625     0   830     0     0   1  0  2
18     0  6/30/65  39  1      0    5   1  0  1  1  2  2  1    200000         0     0   825   850     0     0     0   1  3  2
19    72  4/24/70  87  1      0    5   1  0  1  1  2  1  1    200000         0   475   420     0   750     0     0   1  3  2
20     0  4/20/65  26  1      0    5   1  0  1  1  2  2  1    200000         0     0   615   755     0     0     0   1  0  2
21     0  6/15/66   0  1      0    5   1  0  1  1  1  2  1    250000     22000     0   875   905     0     0     0   1  0  2
22    46  3/27/74  20  1  56721    5   1  2  1  1  2  9  1    250000         0   475   410     0   555     0     0  10  0  2

      22 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL         3137000 (PPH)
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TABLE 1.1.1 (Cont)

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      REGION  5      FIRING METHOD: OVERFEED (4)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  3/16/65  20  1      0     5  1  0  1  1  2  2  1     30000         0     0   125  9999     0     0     0   1  0  4
 2     0  5/31/64   0  1      0     5  1  0  1  1  2  2  1     75000         0   250   225  9999     0     0     0   1  3  4
 3     0  7/20/66   0  1      0     5  1  0  1  1  2  2  1    150000         0     0   390  9999     0     0     0   1  3  4
 4     0  8/ 4/66   0  1      0     5  1  0  1  1  2  2  1    150000         0     0   255   507     0     0     0   1  3  4

        4 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL        405000 (PPH)

      REGION  5      FIRING METHOD: OTHER (X)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  3/11/69   0  1      0     5  1  0  1  1  2  2  1     55000         0   180   150  9999     0     0     0   1  3  5

        1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL         55000 (PPH)
           31 UNITS IN   REGION CAPACITY SUB-TOTAL        4232000 (PPH)

      REGION  6      FIRING METHOD: OTHER (X)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0 11/ 2/66  28  1      0     6  1  0  1  1  2  2  1     75000         0     0   200   485     0     0     0   1  7  0
 2     0  1/27/66  26  1      0     6  1  0  1  1  2  2  1    225000         0     0   875   825     0     0     0   3  1  0

        2 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL        300000 (PPH)

      REGION  6      FIRING METHOD: SPREADER(2)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  4/ 1/68  26  1      0     6  1  0  1  1  2  2  1    200000         0   925   215     0   550     0     0   1  0  2
 2     0  4/12/69  26  1      0     6  1  0  1  1  2  2  1    200000         0   925   215     0   550     0     0   1  0  2
 3     0  4/ 1/68  26  1      0     6  1  0  1  1  2  2  1    200000         0   925   215     0   550     0     0   1  0  2
 4     0  8/19/65  26  1      0     6  1  0  1  1  2  2  1    270000         0     0   875   835     0     0     0   1  3  2

        4 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL        870000 (PPH)

      REGION  6      FIRING METHOD: OTHER (X)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  1/23/68   0  1      0     6  1  0  1  1  1  1  1    167000         0   350   225  9999     0     0     0   1  0  5
 2     0  1/23/68   0  1      0     6  1  0  1  1  1  1  1    167000         0   350   225  9999     0     0     0   1  0  5
 3     0  1/23/68   0  1      0     6  1  0  1  1  1  1  1    167000         0   350   225  9999     0     0     0   1  0  5

        3 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL        501000 (PPH)
            9 UNITS IN   REGION CAPACITY SUB-TOTAL        1671000 (PPH)

      REGION  7      FIRING METHOD: OTHER (X)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1    45  3/14/72  20  1      0     7  1  0  1  1  2  9  1    200000         0   500   420     0   600     0     0   1  0  0

        1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL        200000 (PPH)

      REGION  7      FIRING METHOD: SPREADER(2)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     5 10/24/74  33  1  80468     7  1  2  1  1  2  1  1     40000         0   160   140  9999     0     0     0   1  0  2
 2     6 10/24/74  33  1  80469     7  1  2  1  1  2  1  1     40000         0   160   140  9999     0     0     0   1  0  2
 3    19 10/29/70  82  1      0     7  1  0  1  1  2  9  1     65000         0   250   100  9999     0     0     0   1  3  2
 4     0  2/10/65   0  1      0     7  1  0  1  1  2  2  1     65000         0     0   100  9999     0     0     0   1  3  2
 5    39  1/31/70  82  1      0     7  1  0  2  1  2  9  1    100000         0   500   300   445     0     0     0   1  3  2
 6     0  8/12/67   0  1      0     7  1  0  2  1  2  1  1    100000         0   500   380   445     0     0     0   1  3  2
 7    71  4/ 8/70  82  1      0     7  1  0  2  1  2  9  1    100000         0   400   300   400     0     0     0   1  0  2
 8    59 10/ 1/74  28  1  82935     7  1  2  1  1  2  8  1    300000         0   350   300  9999     0     0     0   1  2  2
 9    58 10/ 1/74  28  1  82935     7  1  2  1  1  2  8  1    300000         0   350   300  9999     0     0     0   1  2  2

        9 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL       1110000 (PPH)

      REGION  7      FIRING METHOD: UNDERFEED (3)
ID    SEQ   DATE    SIC DE   ZIP   REG  T FD SW SM EQ PA NU  CAP(PPH)  CAP (KW)  DPRS  OPRS  OTHW  SHTP  1-RH  2-RH   P  A  F

 1     0  7/31/65   0  1      0     7  1  0  1  1  2  2  1     14000         0     0    80  9999     0     0     0   1  0  3
 2     0  9/26/56   0  1      0     7  1  0  1  1  2  2  1     17000         0     0   125  9999     0     0     0   1  0  3

        2 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL         31000 (PPH)
           12 UNITS IN   REGION CAPACITY SUB-TOTAL        1341000 (PPH)
```

TABLE 1.1.1 (Cont)

REGION 8 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	44	7/14/72	20	1	0	8	1	0	1	1	2	9	1	200000	0	500	420	0	600	0	0	1	0	0

1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 200000 (PPH)

REGION 8 FIRING METHOD: PULVERIZED (1)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	4/15/69	20	1	0	8	1	0	1	1	2	2	1	250000	0	500	400	0	575	0	0	1	2	1

1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 250000 (PPH)

REGION 8 FIRING METHOD: SPREADER(2)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	12/ 2/68	0	1	0	8	1	0	1	1	1	2	1	200000	20000	1050	890	0	905	0	0	1	0	2
2	95	5/24/74	20	1	98948	8	1	1	1	1	2	9	1	200000	0	425	250	9999	0	0	0	1	2	2
3	0	12/ 2/68	0	1	0	8	1	0	1	1	1	2	1	200000	20000	1050	890	0	905	0	0	1	0	2
4	94	5/24/74	20	1	98837	8	1	1	1	1	2	9	1	200000	0	425	400	9999	0	0	0	1	2	2
5	30	12/18/72	26	1	0	8	1	0	1	1	2	9	1	220000	0	250	185	0	500	0	0	1	0	2

5 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 1020000 (PPH)

REGION 8 FIRING METHOD: OVERFEED (4)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	2/ 9/66	0	1	0	8	1	0	1	1	2	2	1	30000	0	0	105	9999	0	0	0	1	0	4
2	29	2/19/73	82	1	83440	8	1	2	1	1	2	8	1	35000	0	250	105	9999	0	0	0	1	0	4
3	72	9/28/71	20	1	0	8	1	0	1	1	2	9	1	180000	0	250	225	9999	0	0	0	1	3	4

3 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 245000 (PPH)

REGION 8 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	43	8/30/74	26	1	98401	8	1	1	1	1	2	1	1	75000	0	250	150	9999	0	0	0	2	1	9

1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 75000 (PPH)
11 UNITS IN REGION CAPACITY SUB-TOTAL 1790000 (PPH)

REGION 9 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	12/20/66	28	1	0	9	1	0	1	1	2	1	1	160000	0	0	860	830	0	0	0	1	7	0

1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 160000 (PPH)
1 UNITS IN REGION CAPACITY SUB-TOTAL 160000 (PPH)

REGION ~~10~~ 9 FIRING METHOD: OTHER (X)

ID	SEQ	DATE	SIC	DE	ZIP	REG	T	FD	SW	SM	EQ	PA	NU	CAP(PPH)	CAP (KW)	DPRS	OPRS	OTHW	SHTP	1-RH	2-RH	P	A	F
1	0	12/ 6/69	0	1	0	10	1	0	1	1	2	1	1	18000	0	200	100	9999	0	0	0	2	1	0

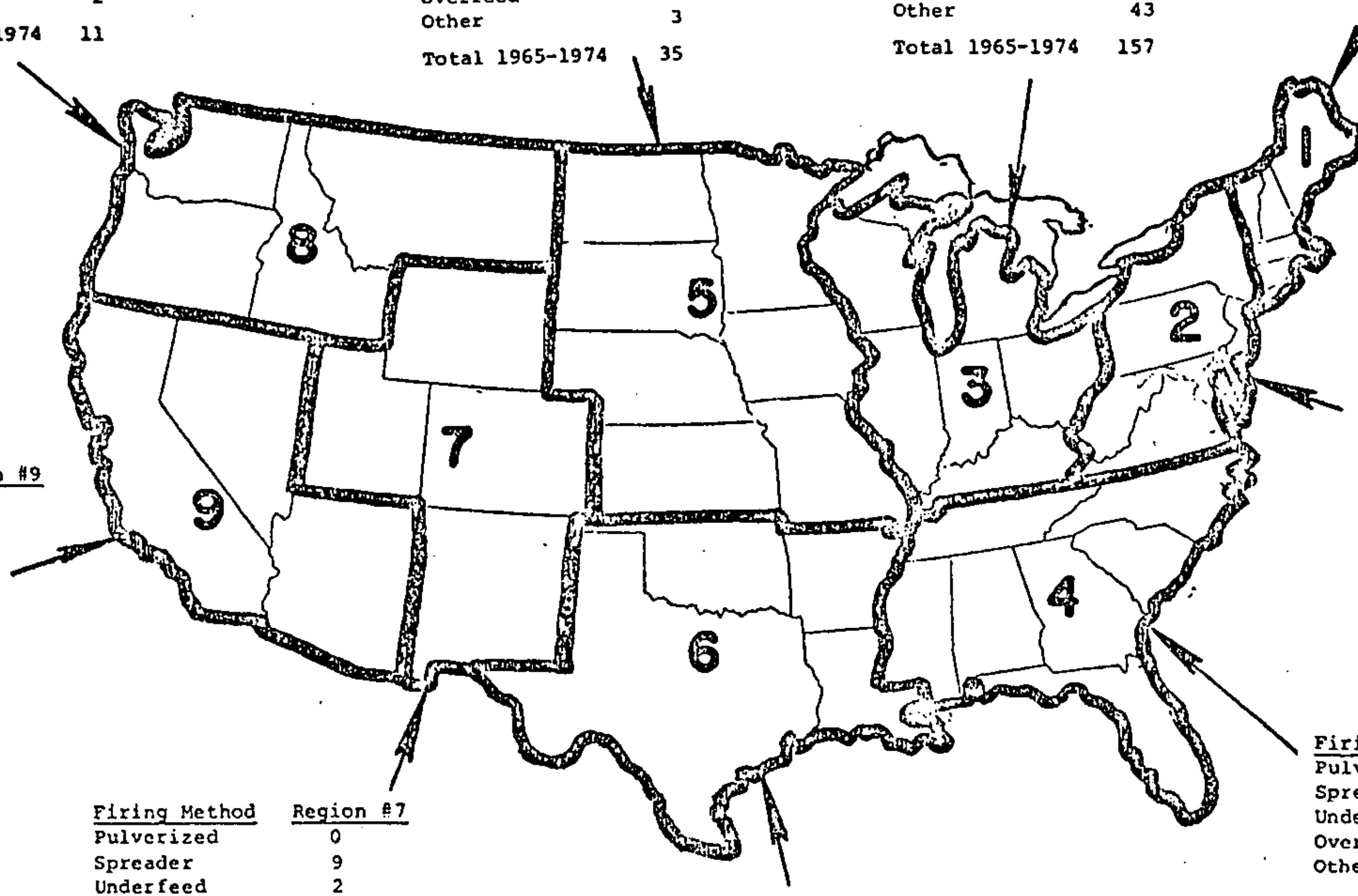
1 UNITS IN FIRING METHOD CAPACITY SUB-TOTAL 18000 (PPH)
1 UNITS IN REGION CAPACITY SUB-TOTAL 18000 (PPH)

Firing Method	Region #8
Pulverized	1
Spreader	5
Underfeed	1
Overfeed	2
Other	2
Total 1965-1974	11

Firing Method	Region #5
Pulverized	2
Spreader	22
Underfeed	0
Overfeed	4
Other	3
Total 1965-1974	35

Firing Method	Region #3
Pulverized	13
Spreader	70
Underfeed	4
Overfeed	27
Other	43
Total 1965-1974	157

Firing Method	Region #1
Pulverized	0
Spreader	1
Underfeed	0
Overfeed	1
Other	0
Total 1965-1974	2



Firing Method	Region #2
Pulverized	8
Spreader	31
Underfeed	10
Overfeed	8
Other	17
Total 1965-1974	74

Firing Method	Region #9
Pulverized	0
Spreader	0
Underfeed	0
Overfeed	0
Other	2
Total 1965-1974	2

Firing Method	Region #4
Pulverized	6
Spreader	34
Underfeed	9
Overfeed	5
Other	10
Total 1965-1974	64

Firing Method	Region #7
Pulverized	0
Spreader	9
Underfeed	2
Overfeed	0
Other	1
Total 1965-1974	12

Firing Method	Region #6
Pulverized	0
Spreader	4
Underfeed	0
Overfeed	0
Other	5
Total 1965-1974	9

Figure 1.1.1 Regional Boundaries used in Table 1.1.2.

NEW ABMA CARD LAYOUT

1 KVB Sequence Number

2 ABMA Sequence Number

3 Date - Day, Month, Year

4 SIC Number (see below)

5 Domestic or Export

6 Zip Code (see below)

7 Region Code (see Figure 1.1.1)

8 Type Code: (1) Watertube

9 Draft Conditions: (1) pressurized furnace; (2) balanced draft

10 Steam (1), or Hot Water (2)

11 Stationary (1) or Marine (2)

12 Utility or Other

13 Packaged or Field Assembled

14 Number of Units

15 Capacity pph

16 Capacity kilowatts

17 Design Pressure psig

18 Operating Pressure psig

19 Hot Water Outlet Temperature or Saturated Steam

20 Superheat Temperature

21 First Reheat Temperature

22 Second Reheat Temperature

23 Primary Fuel: (1) Bit. Coal; (2) Oil; (3) Nat. Gas; (4) Wood Bark, or solid wood products; (5) Bagasse; (6) Blk. Liquor; (7) Other Fuels; (8) Waste heat; (9) Waste heat with aux. firing; (10) Lignite; (11) Raw municipal, unsorted; (12) Raw municipal, non-combustible removed; (13) Raw municipal, sorted and sized; (14) Other industrial waste

24 Alternate Fuel: Use code as in 23 (1-9); if no alt. fuel, insert "X"

25 Firing Method

RANGE OF ZIP CODES BY STATES

Alabama	AL	35001-36999	Nebraska	NE	68001-69399
Alaska	AK	99501-99999	Nevada	NV	89001-89899
Arizona	AZ	85001-86599	New Hampshire	NH	03001-03899
Arkansas	AR	71601-72999	New Jersey	NJ	07001-08999
California	CA	90001-96199	New Mexico	NM	87001-88499
Colorado	CO	80001-81699	New York	NY	10001-14999
Connecticut	CT	06001-06999	North Carolina	NC	27001-28999
Delaware	DE	19701-19999	North Dakota	ND	58001-58899
Dist. of Columbia	DC	20001-20099	Oklahoma	OK	73001-74999
Florida	FL	32001-33999	Oregon	OR	97001-97999
Georgia	GA	30001-31999	Pennsylvania	PA	15001-19699
Hawaii	HI	96701-96899	Rhode Island	RI	02801-02999
Idaho	ID	83201-83899	South Carolina	SC	29001-29999
Illinois	IL	60001-62999	South Dakota	SD	57001-57799
Indiana	IN	46001-47999	Tennessee	TN	37001-38599
Iowa	IA	50001-52899	Texas	TX	75001-79999
Kansas	KS	66001-67999	Utah	UT	84001-84799
Kentucky	KY	40001-42799	Vermont	VT	05001-05999
Louisiana	LA	70001-71499	Virginia	VA	22001-24699
Maine	ME	03901-04992	Washington	WA	98001-99499
Maryland	MD	20601-21999	West Virginia	WV	24701-26899
Massachusetts	MA	01001-02799	Wisconsin	WI	53001-54999
Michigan	MI	48001-49999	Wyoming	WY	82001-83199
Minnesota	MN	55001-56799	Puerto Rico	PR	00600-00799 &
Mississippi	MS	63001-65899			00900-00999
Missouri	MO	63001-65899	Virgin Islands	VI	00800-00899
Montana	MT	59001-59999	Pacific Islands	PI	96900-96999

SIC CODES

15	Offices, shopping centers, and malls
20	Food and kindred products
22	Textile mill products
24	Lumber and wood products
26	Paper and allied products
28	Chemical and allied products
29	Petroleum refining and related
30	Rubber products
33	Primary metal industries
37	Transportation
39	Miscellaneous manufacturing
49	Electric utilities
65	Apartments, housing projects
73	Equipment rental and leasing companies (boiler rental co)
80	Hospitals, medical centers, nursing homes, and related facilities
82	Schools and colleges
00	Non-manufacturing

TABLE 1.1.2

NUMBER OF UNITS SOLD
FROM 1965 TO 1974 BY REGION

	Geographic Regions*									
Categories	1	2	3	4	5	6	7	8	9	Totals
Other		17	43	10	3	5	1	2	2	83
Pulverized		8	13	6	2			1		30
Spreader Stoker	1	31	70	34	22	4	9	5		176
Underfed		10	4	9			2			25
Overfed	1	8	27	5	4			3		48
Total	2	74	157	64	31	9	12	11	2	362
Percent of Total	0.6	20.4	43.4	17.7	8.5	2.5	3.3	3.0	0.6	

*Geographic Region (by number code)

1. New England States
   Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont
2. Mid-Atlantic States
   Delaware, Maryland, New Jersey, New York, Pennsylvania, Virginia, West Virginia
3. East-North-Central States
   Illinois, Indiana, Kentucky, Michigan, Ohio, Wisconsin
4. South-Atlantic States
   Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, Tennessee
5. West-North-Central States
   Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
6. West-South-Central States
   Arkansas, Louisiana, Oklahoma, Texas
7. Rocky Mountain States
   Colorado, New Mexico, Utah, Wyoming
8. Northwestern States
   Idaho, Montana, Oregon, Washington
9. Southwestern States
   Arizona, California, Nevada

The total number of coal-fired boilers that have been sold in the last nine years in this size category is small (362) compared to the total number existing in the United States which are still firing coal. Ehrenfeld (Ref. 1) estimated that there were 5,239 boilers installed in the country in the size range 10,000 to 250,000 pph steam that could burn coal. The number of units that actually fire bituminous coal or lignite is considerably smaller. For example, in 1973 36 overfed units were sold; however, 33 of these units were specifically designed to burn wood. Overfed and spreader stoker units are two categories of firing types where there appears to be a significant wood-burning contribution. Typically, these units are installed in the wood and paper processing industries where the waste wood and paper products are burned as boiler fuel. However, such units will fire bituminous coal when there is insufficient waste wood to meet load demands.

The pulverized coal firing type and the underfed stoker firing type are limited to bituminous coal and lignite firing.

The "other" category includes cyclone units at the larger end of the size range, above 200,000 pph steam. The smaller units in the "other" category include vibrating grate, reciprocating, and oscillating grate stokers. Some of these units may be equipped with a system whereby the ash is blown off the water-cooled grate with either steam or air.

More detailed information about grate design is not available from the ABMA records. For example, spreader stokers may be equipped with traveling grates or dumping grates. Some smaller overfed units are equipped with water-cooled grates; however, this is not common.

Capacity of Coal-Fired Units Surveyed

Table 1.1.3 gives the steam capacity in thousands of pounds per hour for all of the coal-fired boilers in the size category 10,000 to 300,000 pph steam. The data is presented in the same format as Table 1.1.2 to facilitate comparison. Inspection of the data indicates that the capacities of the units sold closely follows the population distribution for both firing categories and geographic regions. In Region 3, spreader stokers account for 49.4%; other units, 24%; pulverized, 17.1%; overfed, 8.8%; and underfed, 0.73% of the total capacity of the region. Again the overall capacity distribution for the nine regions follows population distribution. Region 3 has 41.3% of the total followed by Region 2 at 16.8%, Region 6 at 4.7%, and Regions 9 and 1 at 0.5% and 0.25% respectively.

TABLE 1.1.3

CAPACITY (kpph steam) OF COAL-FIRED UNITS SOLD FROM 1965 TO 1974 BY GEOGRAPHIC REGION

Firing Category	Geographic Regions									
	1	2	3	4	5	6	7	8	9	Total
Other		1,230	3,562	931	240	801	200	275	178	7,417
Pulverized		1,516	2,524	1,329	450			250		6,069
Spreader Stoker	30	2,598	7,281	2,821	3,137	870	1,110	1,020		18,867
Underfed		241	108	197	405		31			577
Overfed	60	429	1,295	370				245		2,804
Total	90	6,014	14,770	5,648	4,232	1,671	1,341	1,790	178	35,734
Percent of Total	0.25	16.8	41.3	15.8	11.8	4.7	3.8	5.0	0.5	

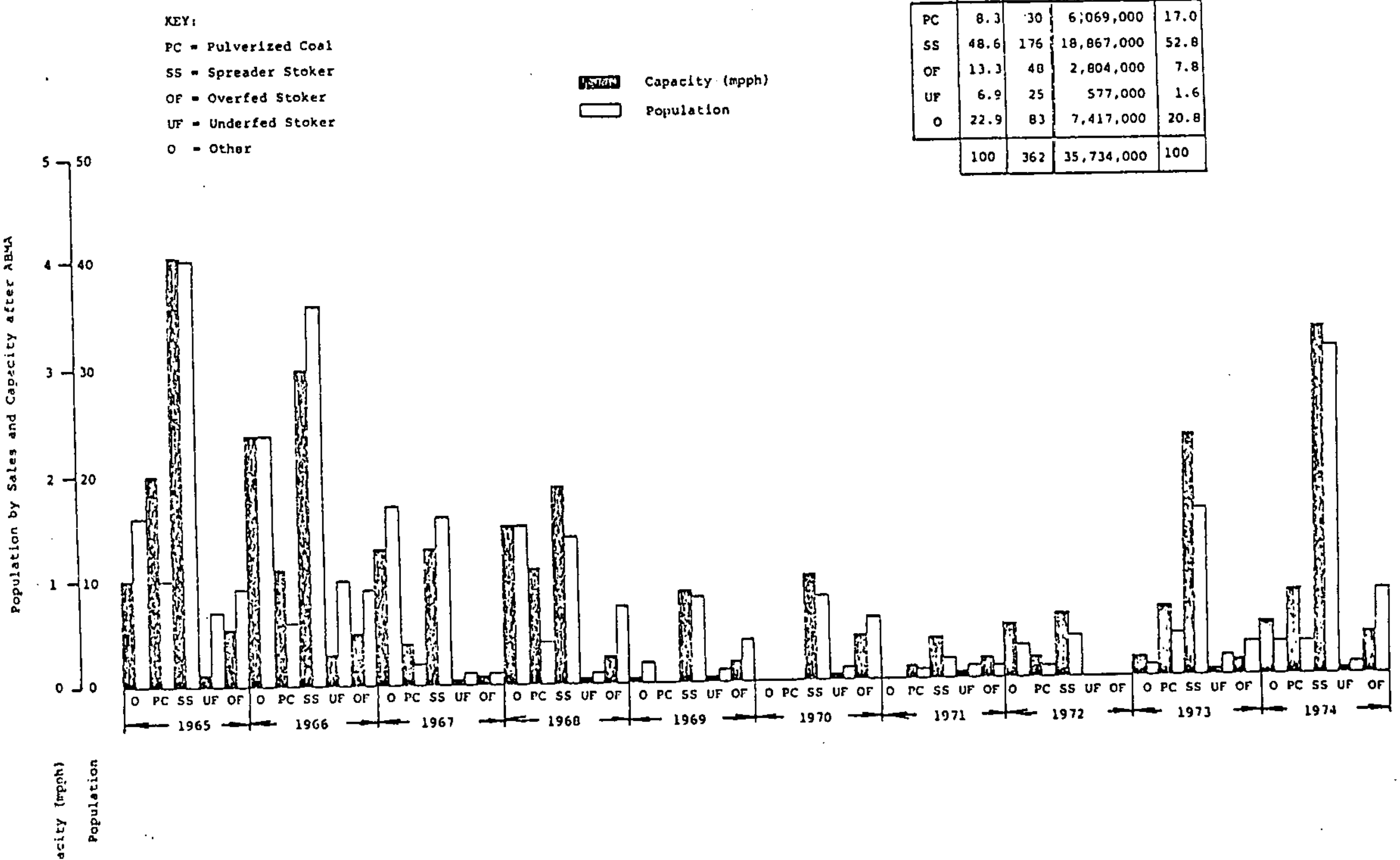
Sales Trends

Figure 1.1.2 contains the 1965-1974 ABMA sales data for coal-fired units in the size range 10,000 to 300,000 pph steam. The data are plotted by year as population and total steam capacity for the five firing types. It can be seen that boiler sales have declined steadily from 1965 to a low point in 1971. Beginning in 1973, however, there was a general increase in sales with spreader stokers sales approaching 1966 sales numbers. Spreader stokers represent the largest single firing type, both by number and total capacity. Pulverized-coal-fired units are predominantly the larger units above 200,000 pph steam. This becomes obvious when population data and capacity data for pulverized coal units are compared. Spreader stoker units cover the entire size range of interest for this study with units as small as 10,000 pph steam and as large as 300,000 pph. The spreader stoker appears to be the unit of choice for most industrial coal-fired installations. Spreader stokers are also found in small utilities where they are used as peaking units.

For the nine-year period, the sales of each firing type relative to each other has remained roughly constant. During years of heavy sales, the spreader stoker has outsold all others. Over this period, spreader stoker sales accounted for 49% of all units by population and 53% by capacity. The next largest category is the other firing types which account for 23% of the units by population and 21% by capacity. Overfed and underfed units combined represent 20% of the population, but only 9% of the capacity. Finally, the pulverized-coal-firing category contains 8% of the population and 17% of the capacity.

Design Trends

The versatility of the spreader stoker has made it the favorite firing method over the years and this trend appears to be continuing with even greater strength. The recent sales increase in coal-fired equipment has been dominated by the spreader stoker. The data also show a trend toward larger spreader stokers. One reason for the popularity of the spreader stoker is that they are capable of burning a wide range of coals,



TOTALS

	%	No. of Units	Capacity of Units (pph)	%
PC	8.3	30	6,069,000	17.0
SS	48.6	176	18,867,000	52.8
OF	13.3	48	2,804,000	7.8
UF	6.9	25	577,000	1.6
O	22.9	83	7,417,000	20.8
	100	362	35,734,000	100

Figure 1.1.2. Coal-Fired Units Sold from 1965-1974 in the Size Range 10,000 to 300,000 pph Steam.

from high ranked eastern bituminous to lignite, as well as many byproduct waste fuels. Spreader-stoker firing has a very quick response to load changes and the turndown range extends from 20% of full load to maximum capacity. Traveling grates remain the most popular grate configuration for spreader-stoker-fired boilers rated higher than 75,000 pph. They are designed to handle a wide range of coals as well as process wastes and municipal refuse. In view of this flexibility and the fluctuating coal economy, the traveling grate is expected to be the system of choice for at least the next five years.

New Developments

It is difficult to estimate the environmental and economic impact of potential developments on this boiler size category. Some examples of these new developments whose effect may be to increase the total capacity of this size range or to decrease it are given below:

- Greatly expanded in-plant electrical generation would increase the size range capacity
- Deregulation of natural gas prices would serve to increase the size range capacity by a reconversion to coal-firing
- Further oil price increases would increase the size range capacity in the same way gas deregulation would
- Legislation restricting the use of natural gas for process units would increase the number of units and the capacity in the size range
- Large-scale coal gasification and/or liquifaction would tend to decrease the coal-fired capacity of the size range; however, this development is at least ten years in the future
- Increased commercial electrical generation with resultant lower energy rates would not measurably affect this size category of boiler
- Environmental legislation aimed at sulfur particulates and NOx would probably not measurably affect this size category due to the severity of the energy constraints

1.2 GEOGRAPHICAL SULFUR DISTRIBUTION

Boiler Capacity

The total output capacity of boilers in the size range of 10 to 250 MMB/h was estimated by Locklin (Ref. 1) to be 1.09×10^6 MMB/h for the 10 to 100 kph range (10 to 100 MMB/h) and 0.80×10^6 MMB/h for the 100 to 250 kph range. These figures were based on the 1971 estimate of Ehrenfeld (Ref. 2), updated for sales during the period of 1967 to 1974.

The percent capacity as coal-fired units was given in the same reference (1) as 10% for the 10 to 100 kph range and 19% for the 100 to 250 kph range. Thus the total heat capacity installed for coal is estimated to be:

$$Q_{10-100} = 0.955 \times 10^9 \text{ MMB/y}$$

$$Q_{100-250} = 1.332 \times 10^9 \text{ MMB/y}$$

For a heating value of 10,000 B/lb, the coal consumption in these boilers is:

$$M_{10-100} = 47.7 \text{ MMT/y}$$

$$M_{100-250} = 66.6 \text{ MMT/y}$$

Current Coal Sulfur Distribution

The current distribution of sulfur in coal was estimated from seam analyses given in the Keystone Coal Manual (Ref. 3), from mine analyses in the same source, and from mine analyses summarized by Reference 4. For western coals only the mine analyses were used, since they were felt to be a more reliable indication of what is available. For midwestern and eastern coal, the seam analyses were used since the area is heavily mined and better characterized. Where seam reserve estimates were available, the sulfur percentage was weighted by these estimates. For the western coal, the sulfur percentage was weighted by mine capacity.

Table 1.2.1 summarizes the results obtained by this method for the western coal states. Table 1.2.2 summarizes the values for midwestern and eastern states obtained from the seam analyses and reserve estimates. Table 1.2.3 (which was not used) summarizes the values for midwestern and eastern states obtained from mine analyses and capacity.

As can be seen, the number of mine analyses available is very low for some states, making a uniform basis for averaging by this method impossible. Furthermore the averages for states with few mines reporting (such as Illinois or Missouri) are quite different from the seam analyses. For these reasons Tables 1.2.1 and 1.2.2 were used in subsequent calculations.

Coal Usage by Region and Origin

In order to determine the sulfur emissions in coal-burning boilers, it is necessary to first estimate the consumption of coal by its origin in order to relate the average sulfur values determined above to the total coal consumed. A study by the Bureau of Mines has categorized coal consumption by regions of consumption and origin (Ref.5). This study considered utility consumption, coking operations, barge and train propulsion, and "other categories". Since most of the boilers considered in this study are smaller than utility size, the assumption was made that the coal-burning boiler distribution was in accordance with the use distribution of coal in "other categories". In order to check this assumption, the percentage of the total coal burned by boilers of less than 500 kph [given by Ehrenfeld (Ref. 1)]for the Great Lakes and Central Regions was compared to the value resulting from the method described above. A value of 51.3% was obtained from Reference 1 versus 54.5% calculated from the Bureau of Mines report. The slight disagreement could be due to the somewhat heavier concentration of industrial boilers in this region which would bias the sample more in the < 250 kph range than if the 250 to 500 kph units are included.

Table 1.2.4 summarizes the data for coal consumption according to the region of origin and the state of use. These data were converted to percentages to estimate the regional distribution of the total boiler heat (coal) consumption. The regions of origin and average sulfur content (derived by averaging state averages of Tables 1.2.1 and 1.2.2) are delineated in Table 1.2.5.

TABLE 1.2.1

WESTERN COAL SULFUR CONTENT, HEATING VALUE, AND ASH FUSION TEMPERATURE (AVERAGED BY PRODUCTION)

State	Capacity[(a)]	1973 Production[(a)]	Sulfur[(b)]	AFT[(c)]	HV[(d)]
Arizona	13.50	2.97	0.37	2180	10,900
Colorado	9.45	6.23	0.79	2292	13,400
Montana	25.88	9.95	0.92	2223	8,700
New Mexico	15.77	9.95	0.61	2400[(e)]	9,800
North Dakota	12.27	9.34	1.50	2163	7,010
Utah	10.00	5.40	0.56	2195	13,110
Washington	12.33	3.21	0.80	2300	8,100
Wyoming	36.74	13.60	0.59	2209	10,100

[(a)] MMT/y

[(b)] lb/MMB

[(c)] °F

[(d)] B/lb, as received

[(e)] Doesn't include Navajo Mine

TABLE 1.2.2

MIDWESTERN AND EASTERN COAL CHARACTERISTICS
(AVERAGED BY SEAM RESERVES WHERE GIVEN)

State	Sulfur[(a)]	No. of Seam Analyses
Alabama	1.01	67
Illinois	2.97	61
Indiana	2.19	8
Kansas	4.40	10
Kentucky (East)	0.79	17
Kentucky (West)	2.41	4
Maryland	1.53	11
Missouri	3.14	6
Ohio	2.62	16
Oklahoma	1.36	20
Pennsylvania	1.47	43
Tennessee	1.50	44
Virginia	0.68	45
West Virginia	0.88	27

(a) lb/MMB

TABLE 1.2.3

MIDWESTERN AND EASTERN COAL CHARACTERISTICS FROM MINE DATA (WEIGHTED BY PRODUCTION)

State	Sulfur[a]	No. of Mines Reporting
Alabama	0.49	5
Illinois	1.81	4
Indiana	2.72	1
Kentucky	1.02	40
Maryland	1.44	3
Missouri	5.56	1
Ohio	4.02	14
Oklahoma	0.43	1
Pennsylvania	1.69	39
Virginia	0.81	4
West Virginia	1.08	39

[a] lb/MMB

TABLE 1.2.4
COAL USAGE FOR OTHER DEVICES BY REGION OF ORIGIN AND STATE OF USE (1973)
(Thousands of Tons/Year)

Region of Origin	1	2	3 & 6	4	5	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	
STATE OF USE																							
Massachusetts	5		47				9																61
Connecticut	42						7																49
Maine, N.H., Vt, R.I.	9	1	10				11																31
New York	1010	304	798	92			144																2318
New Jersey				3		1	74																78
Pennsylvania	1542	2295	802	101		95	837																5672
Ohio	52	305	144	4912			3770															2	9346
Indiana	3			3		16	286	175	639	4129													5253
Illinois			9			9	629	111	3419	-100													4261
Michigan			132	1085		291	3672	-400	397	73												-30	5954
Minnesota			22	3		2	254	11	106	263							2				345	940	1948
Wisconsin	-100		-60	56		37	1393	253	645	9							-120					-7	2680
Iowa						53	12	192	1151	---	37			13				1					1459
Missouri							5	12	1367					27		13							1424
N.Dak, S.Dak.																		7		314			321
Neb., Kansas													6	133		-50		-264					453
Del., Maryland	770		13			62	80																925
Wash. DC	23		46				190																259
Virginia	7					172	2337																2516
W. Virginia	12	449	1098	478		193	2134																4364
N. Carolina			17			5	1418																1440
S. Carolina							1106																1106
Georgia, Florida							-200		-100	-100	-100												500
Kentucky			31			25	742	1070															1868
Tennessee						-30	1458	461		-100		166											2215
Ala., Miss.						42	5	-1820	-318			1668											3853
Ark, La, Ok, Texas							75					54		2123									2252
Colorado						10							104		-100	313		-350					877
Utah																		32	722				754
Mont. Idaho																		144	134			17	295
Wyoming																		246					246
New Mexico													13				5						18
Ariz., Nevada																	23		114				137
Wash., Oregon																		83	119			30	232
																							65,165

TABLE 1.2.5

AVERAGE SULFUR CONTENT BY COAL-PRODUCING REGIONS (1973)

Region	States	Sulfur (lb/MBtu)	% of Total Coal (lb/MBtu)
1	E. Penn., Md.	1.47	5.49
2	W. Penn.	1.47	5.15
3 & 6	W. Virginia	0.88	4.96
4	Ohio	2.62	10.33
5	Michigan	--	--
7	W. Virginia	0.88	1.60
8	W. Va., E. Ky., Tenn.	1.06	31.99
9	W. Ky.	2.41	6.91
10	Illinois	2.97	12.49
11	Indiana	2.19	7.33
12	Iowa	--	--
13	Ala., Ga., Tenn.	1.26	2.90
14	Ark., Okla.	1.36	0.19
15	Ky., Tenn., Mo., Okla.	2.10	3.52
16	Colorado	0.79	0.15
17	Col., N. Mex.	0.70	0.58
18	N. Mex., Ariz.	0.49	0.23
19	Wyoming	0.59	1.73
20	Utah	0.56	1.67
21	N. Dak., S. Dak.	1.50	0.48
22	Montana	0.92	0.57
23	Wash., Oregon	0.80	1.54

1.3 ESTIMATE MAXIMUM POSSIBLE SULFUR REDUCTION

Present Sulfur Emissions

The data of Tables 1.2.2 through 1.2.5 were applied to calculate the sulfur emissions from coal-burning boilers in the 10,000 to 250,000 pph steam range. The sulfur emitted was simply:

$$M_{s_{10-100}} = \sum_{1}^{23} f_i \, s_i \, Q_{10-100}$$

$$M_{s_{100-250}} = \sum_{1}^{23} f_i \, s_i \, Q_{100-250}$$

where

$M_{s_{10-100}}$ = mass of sulfur (as sulfur) emitted from boilers in the 10 to 100 MMB/h range

f_i = fraction of the coal originating in region i

s_i = average sulfur content of coal in region i

$M_{s_{100-250}}$ = mass of sulfur (as sulfur) emitted from boilers in the 100 to 250 MMB/h range.

Substitution of the appropriate values gives:

$$M_{s_{10-100}} = 0.805 \text{ MMT/y (as sulfur)}$$

$$M_{s_{100-250}} = 1.123 \text{ MMT/y (as sulfur)}$$

When the same data was used to estimate the sulfur emissions only in the midwestern and Great Lakes states, the following values were obtained:

$$M_{s_{10-100}}(\text{CU,GL}) = 0.462 \text{ MMT/y}$$

$$M_{s_{100-250}}(\text{CU,GL}) = 0.645 \text{ MMT/y}$$

It is significant that the total emissions from this district (which is most accessible to western coal sources) are 57% of the national total. This is because of the high concentration of boilers in this region and the high sulfur content of the coal in these regions.

Reduction in Sulfur by Using Western Coal

The sulfur emissions using western coal were estimated both nationwide and for the midwestern-Great Lakes region for two different cases:

1. Western coal characteristics were weighted according to present mine capacity. That is, increases in production would be met by increases in all mines proportional to their present capacity.
2. Western coal characteristics of individual states were used.

Table 1.3.1 summarizes the nationwide sulfur emissions and net savings realized by using western coal for the boilers in the 10 to 250 MMB/h range.

TABLE 1.3.1

NATIONWIDE SULFUR EMISSIONS USING WESTERN COAL

Coal Source	Total Sulfur Emitted[a]	Net Decrease[a]	% Decrease
Composite western	0.85	1.08	56
Arizona	0.42	1.51	78
Wyoming	0.67	1.25	65
Montana	1.05	0.88	46

[a] MMT/y as sulfur

Table 1.3.2 summarizes the sulfur emissions and reduction possible for the midwestern-Great Lakes region for the same conditions.

TABLE 1.3.2

MIDWESTERN-GREAT LAKES SULFUR EMISSIONS USING WESTERN COAL

Coal Source	Total Sulfur Emitted[a]	Net Decrease[a]	% Decrease
Composite western	0.42	0.69	62
Arizona	0.21	0.90	81
Wyoming	0.33	0.77	70
Montana	0.52	0.59	53

[a] MMT/y as sulfur

In both cases, sizable reductions are seen to be possible. The Midwestern-Great Lakes region has the potential for even larger reductions than the nationwide average because of the higher sulfur fuels currently being burned in this region.

These reductions are theoretical reductions and do not reflect any problems that may occur while firing western coal. Potential problems such as equipment derating or an increase in other emissions would adversely impact these projections. On the positive side, an additional reduction may be realized in SOx stack emissions due to differing sulfur forms (organic, pyritic, or sulfates) in western coals as compared to midwestern or eastern coals. Also, the different nature of the western coal ash (high NaO and MgO) may act to effectively reduce SOx emissions.

2.1 DEFINE CANDIDATE WESTERN COALS

Wyoming and Montana are the two largest western coal producing states. The geography of the western coal deposits dictate that these two states will be the most successful in supplying midwestern and eastern coal consumers at competitive prices to eastern coal. Therefore, the coal resources of these two states will be the focus of this task.

Wyoming

Wyoming has 545 billion tons of coal between 0 and 6,000 ft of cover. This is 17% of the national total and ranks Wyoming first among the states in total coal resources. Of this resource, only 25%, or 136 billion tons, is in a mapped and explored category within 3,000 ft of the land surface. Of that amount, approximately 2% is lignitic, 10% is bituminous, and 88% is subbituminous. One-half, or 68 billion tons, of the mapped resources are considered recoverable. Seventeen percent, or 23.7 billion tons, of the explored resources are classified as strippable. This strippable resource is greater than that of any other state and represents nearly 20% of the nation's known strippable coals. Of those 23.7 billion tons, 19 billion are termed recoverable and 14 billion of that are classed as reserves by today's standards. While almost 90% of Wyoming's strippable coals underlie the Powder River basin, the Hams Fork and Green River regions each contain over 4%. The remaining 1% to 2% of the resources lie in the Hanna field and Bighorn basin areas. A map showing active Wyoming coal mines is shown in Figure 2.1.1.

The rank of Wyoming coal ranges from lignitic to high-volatile "A" bituminous. Lignite occupies a very small region in the northeastern part of the Powder River basin. Bituminous coal is restricted to the Black Hills region and portions of the Hanna field, Green River region, and Bighorn basin. High-volatile "B" and "A" bituminous coal is reported only in the Hams Fork region. Subbituminous coals are found in all major coal regions except the Black Hills region, and account for most of the state's resources and current production.

Typical Wyoming coal analyses exhibit the following ranges and averages:

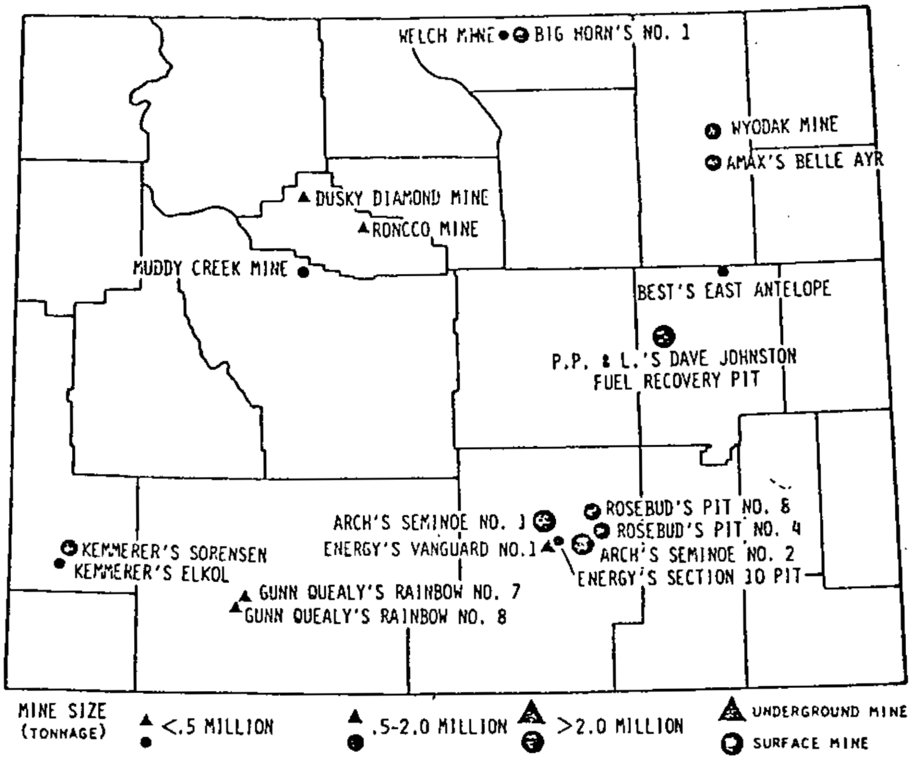


Figure 2.1.1. Active Wyoming Coal Mines.

As Received	Range	Seam Reserve Average
Moisture, %	1.7 - 32.8	14.2
Volatile Matter, %	32.0 - 46.0	39.0
Fixed Carbon, %	-- --	41.0
Ash, %	1.4 - 17.5	5.2
Sulfur, %	0.2 - 5.0	0.7
Heating Value, Btu/lb	7,500 - 13,500	10,850

In terms of quality, coals with the lowest heat values, as well as the highest moisture and volatile contents, are found in the Powder River basin. The higher heat values are more prevalent in the western and southern portions of the state. Ash varies widely, with small isolated pockets of high-ash content (15% to 18%, dry basis) in the Powder Riber basin, Bighorn basin, and Hams Fork region. Sulfur contents are realtively low and variable. The southern and eastern parts of the Green River region contain some of the highest sulfur values. Overall, more than 99% of Wyoming's coal contains less than 1% sulfur and about one-half of that is less than 0.7% (as-received basis). Ninety-six percent of the strippable coals contain less than 1% sulfur, 3.5% is between 1% and 2%, and 0.5% is greater than 2% sulfur (as received).

There are 25 coal seams currently being mined in Wyoming. Surface-mined seams are between 6 and 118 ft thick, but average 32 ft. Seams mined underground range from 3.7 to 20 ft, averaging 8.5 ft. The thickest surface mined seams occur in the Hams Fork region and Powder River basin. The latter basin also contains the nation's, and perhaps the world's, thickest seam of 220 ft.

Table 2.1.1 contains a listing of the active mines in Wyoming and Montana. Also shown are the estimated reserves, estimated useful life, and current 1973 and 1974 production of the mines.

The coal analyses of the 14 largest mines in Wyoming and Montana are presented in Table 2.1.2.

TABLE 2.1.1

COAL CANDIDATES FOR TESTING (ACTIVE MINES)

Company	Mine	Reserves	Life (yrs)	Current Production (Million tons/yr)	
MONTANA:				1973	1974
Westmoreland	Sarpy Creek	1500 MT	100	4.00	--
Decker	Decker No. 1	2240 MT	30	4.15	6.79
Peabody	Big Sky	---	---	1.97	2.23
Western Energy	Colstrip	1440 MT	50	4.25	3.21
WYOMING:					
Amax	Belle Ayr	18,500MT	50	0.89	3.30
Wyodak	Wyodak			0.75	--
Arch Mineral	Seminoe 1	305 MT	15	2.87	3.14
	Seminoe 2			1.50	2.59
Rosebud	Rosebud			1.51	1.96
Kemmerer	Ekol	1679.9MT	100	0.40	--
	Sorenson		60	2.55	2.44
Bighorn	Bighorn		15	0.45	--
Energy Development					
Pacific Pwr & Light	Dave Johnston		35	2.90	2.7
	Jim Bridger		35	--	--

TABLE 2.1.2

COAL ANALYSES OF THE FOURTEEN LARGEST MINES IN WYOMING AND MONTANA

MINE	SEAM	Moisture (%)	Volatiles (%)	Fixed Carbon (%)	Ash (%)	Sulfur (%)	Btu (As-Received)	Btu (Dry)	Ash Softening Temperature (°F)	Free Swelling	Hardgrove Grindability Index	COMMENTS
WYOMING												
Belle Ayr	Smith-Roland	28.86	29.86	30.47	5.18	0.29	7,821	11,237	2,078	N.A.	53.28	See Appendix A for Ultimate Analysis
Wyodak	Smith-Roland	28.13	31.63	34.32	5.90	0.52	8,332	11,470	2,280	N.A.	54.0	See Appendix A for Ultimate Analysis
Seminoe 1	Bed No. 25	13.96	---	---	6.98	0.37	10,000	---	---	--	--	
Seminoe 2	Hanna No. 2	11.5	42.6	39.3	6.6	0.4	10,890	---	---	N.A.	--	
Rosebud	No. 80 & 82 Bed	14.20	35.03	42.56	8.21	1.0	10,300	12,200	2,210	N.A.	58.0	
Sorenson & Ekol	Adaville	20.2	42.3	53.4	4.3	0.9	10,080	12,620	2,410	N.A.	58.0	
Bighorn	Armstrong & Monarch	23.85	32.35	38.49	5.30	0.61	9,300	---	2,140	N.A.	45.6	See Appendix A for Ultimate Analysis
Energy Development	Bed 65	11.6	---	---	7.1	0.7	11,020	---	---	--	--	
	Brooks	13.66	---	---	6.5	0.45	10,806	---	---	--	--	
Dave Johnston	School	24.12	39.89	17.75	18.24	0.33	7,070	9,317	---	0.5	48.3	Captive Mine
Jim Bridger	Deadman	20.52	29.09	40.71	9.68	0.47	9,150	---	---	--	--	Captive Mine
MONTANA												
Sarpy Creek	Rosebud-McKay Robinson	25.	29.	37.	9.	0.73	8,450	---	2,161	N.A.	56.	See Appendix A for Ultimate Analysis
Big Sky	Rosebud-McKay	26.5	29.11	34.5	9.89	1.31	8,360	MAF 13,134	2,222	N.A.	51.6	See Appendix A for Ultimate Analysis
Decker No. 1	Dietz	23.	34.	39.3	3.7	0.4	9,600	12,320	2,250	N.A.	52.	See Appendix A for Ultimate Analysis
Colstrip	Rosebud	25.5	27.72	38.33	8.45	0.8	8,750	---	2,250	N.A.	--	See Appendix A for Ultimate Analysis

MAF = Mineral Matter and Ash Free

N.A. = Non-agglomerating Coals

Sulfur content of the Wyoming coal produced by these mines is all well below 1% and the heating value is generally around 10,000 Btu/lb. The ash softening temperature (reducing atmosphere) of these coals varies somewhat from seam to seam but is generally around 2150°F. Grindability of the coals as measured by the Hardgrove Index indicates that they are slightly harder to grind than comparable eastern coals. The Hardgrove Index ranges from 0 to 100 with 100 representing good grindability. Therefore the lower the Hardgrove Index number, the more difficult the coal is to grind. This poorer grindability will have an effect on the performance of coal pulverizing mills in pulverized-coal-fired units. The Hardgrove Index, however, does not give a true representative indication of the western coals grindability as received since the coal must be air dried prior to performing the test. The higher moisture content of western coals requires higher air temperature in the pulverizer to improve grinding performance.

Montana

Figure 2.1.2 depicts the geographical areas of Montana coal fields. The Fort Union region of eastern Montana is presently the focus of major development. The interest in this area is expected to continue for the foreseeable future. Estimates place the strippable coal in this region at more than 38 billion tons. Figure 2.1.3 shows the locations of strippable subbituminous coal and lignite fields in eastern Montana. Table 2.1.3 gives the name of the field, the coal bed, thickness, estimated reserves, average tons/acre, ash, sulfur, and Btu. Although coal is present in other parts of the state, it is of less significance because recovery would require deep mine methods.

Characteristics of the topography and the thickness of the Fort Union coal beds make possible the mining of large quantities of coal from relatively small, compact areas, which facilitate reclamation. Coal beds 25 to 60 ft thick are not uncommon, and in the Decker area, the coal in a single bed reaches a thickness of 80 ft. Matson and Blumer (Ref. 6) have surveyed southeastern Montana and analyzed 32 coal deposits; proximate analyses, forms of sulfur, calorific values, and major ash constituents of the coal samples are included.

Currently, only five companies are producing coal from the Fort Union beds of eastern Montana. They are:

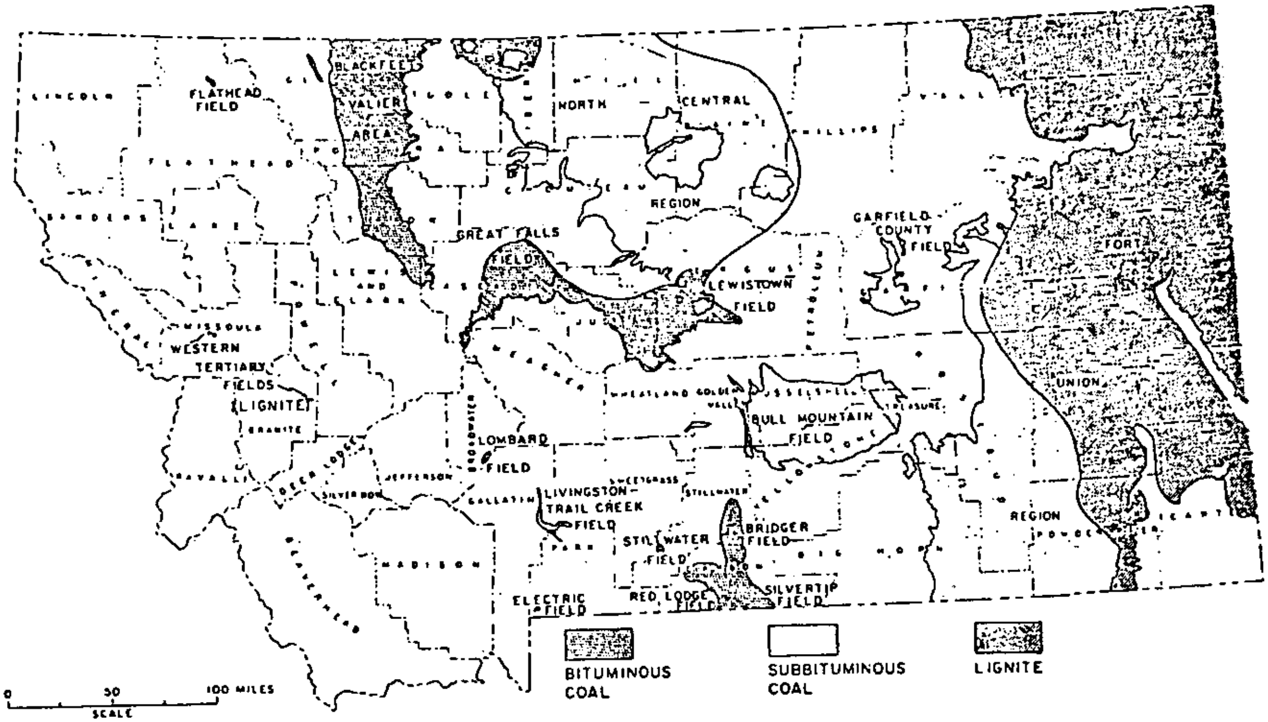


Figure 2.1.2. Map of Montana Coal Fields.

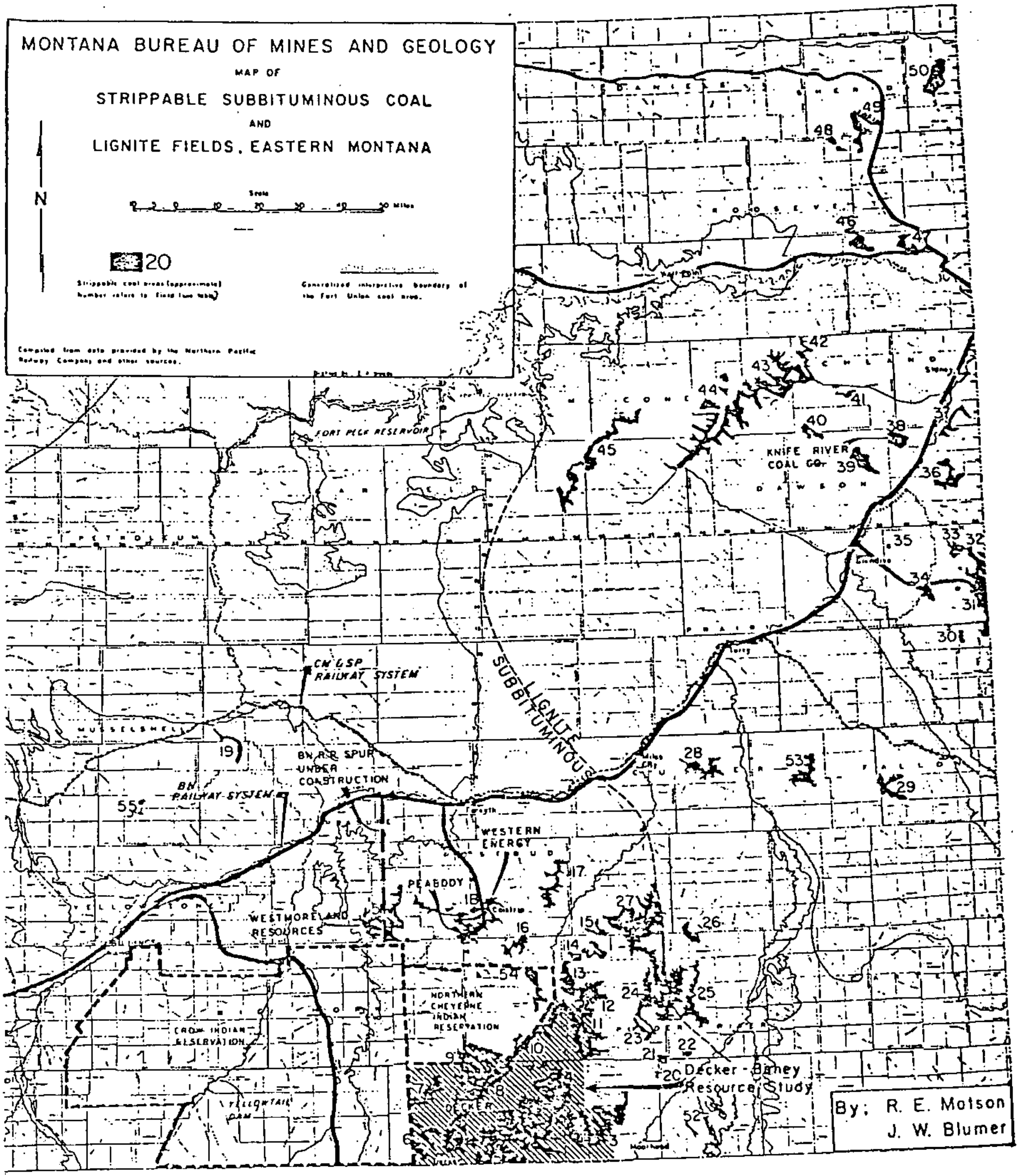


Figure 2.1.3. Location of Strippable Subbituminous and Lignite Coal Fields in Eastern Montana.

TABLE 2.1.3

STRIPPABLE SUBBITUMINOUS AND LIGNITE COAL FIELDS, EASTERN MONTANA

No. on map	Name of field	Coal bed	Thickness in feet	Estimated reserves in millions of tons (G, good; F, fair; R, rough)	Average tons/acre	Ash[1]	Sulfur[1]	BTU[1]
1	Decker	Anderson-Deitz	20-89	1,947 F	76,435	4.0	0.4	9,652
2	Hanging Woman Creek	Anderson-Deitz	12-35	3,099 G	38,625	6.4	0.3	8,446
3	Moorhead	Anderson-Canyon	6-30	1,979 G	40,005	5.3	0.3	8,296
4	Poker Jim Lookout	Anderson-Deitz	15-58	573 G	67,825	5.7	0.4	7,804
5	Roland	Roland	10	315 F	17,700	5.6	0.3	7,637
6	Squirrel Creek	Roland	10	130 F	17,700	5.6	0.3	7,637
7	Upper Rosebud	Anderson	20	220 F	35,400	4.4	0.4	8,391
8	Birney	Brewster-Arnold	18	321 G	26,470	5.9	0.4	8,872
9	Canyon Creek	Wall	30-60	200 F	70,800	4.6	0.3	9,090
10	Poker Jim-O'Dell Creek	Knoblock	10-40	770 G	47,825	4.9	0.3	8,850
11	Otter Creek	Knoblock	20-60	1,041 G	51,290	4.7	0.4	8,466
12	Ashland	Knoblock	25-70	2,595 G	95,000	4.8	0.2	8,371
13	Cook Creek	Sawyer	8-12	53 F	17,700	5.1	0.7	7,917
14	Beaver Creek	Knoblock	12-22	160 F	30,090	7.0	0.5	8,146
15	Liscom Creek	Knoblock	8	75 F	14,160	8.7	0.6	7,900
16	Greenleaf-Miller Creek	Knoblock	12-22	260 F	32,655	7.8	0.8	8,395
17	Sweeny-Snyder	Terrel	18	312 G	29,650	5.8	0.7	8,170
18	Colstrip	Rosebud	25	1,440 G	43,835	8.4	0.7	8,700
19	Carpenter Creek	Carpenter	5-8	50 F	14,015			
20	Fire Creek	Pawnee	16-20	40 G	31,870	6.0	0.4	7,650
21	Upper Cache Creek	Pawnee	20	40 G	35,400	6.0	0.4	7,650
22	Lower Cache Creek	Broadus	12	10 G	21,275	7.2	0.3	7,438
23	Sonnette	Pawnee	20	206 G	35,400	6.6	0.7	7,334
24	Pumpkin Creek	Sawyer	30	1,900 G	45,315	7.9	0.5	7,457
25	Broadus	Broadus	5-26	737 G	38,985	7.2	0.3	7,438
26	Sand Creek	Knoblock	15-32	278 G	46,660	6.7	0.3	7,340
27	Foster Creek	Knoblock	8-16	1,200 G	20,690	7.7	0.5	7,605
28	Pine Hills	Dominy	17	280 G	30,950	7.2	0.5	7,293
29	Lame Jones	Dominy	6-10	150 R	14,160			6,020
30	Lamesteer	Harmon (?)	6-10	35 R	17,700			6,332
31	Wibaux	C	5-40	643 G	34,720	7.9	0.9	6,050
32	Little Beaver	C	8-15	134 R	15,865			
33	Four Buttes	C	5-20	91 G	17,570			6,140
34	Hodges		6-8	10 R	12,390			
35	Griffith Creek		8-12	10 R	17,700			
36	Smith-Dry Creek	G	8-12	150 R	17,700			
37	O'Brian-Alkali Creek		8-12	150 R	17,700			
38	Breezy Flat	Pust		200 F	30,090	6.7	0.5	6,520
39	Burns Creek	Pust	12-20	200 R	30,090			
40	N.F. Thirteen Mile Creek	Pust	10-43	225 F	44,250			6,880
41	Fox Lake	Pust	7-17	46 F	21,240			6,880
42	Lane	Lane	7	561 R	12,390			7,150
43	Carroll	Carroll	6	345 R	11,584	5.5	0.3	7,400
44	Redwater River	S	9-21	642 G	26,550	6.1	0.4	7,400
45	Weldon-Timber Creek	S	8-20	724 G	28,320			7,660
46	Fort Kipp	Ft. Kipp-Ft. Peck	5-8	331 G	22,830	4.6	0.2	6,110
47	Lanark	Lanark	7	100 G	12,390	6.3	0.4	6,853
48	Medicine Lake		9	58 F	15,510	7.2	1.0	6,870
49	Reserve		7	246 F	13,495	7.6	0.4	6,599
50	Coal Ridge	Coal Ridge	10	150 F	17,700	7.5	0.4	5,830
51	Sarpy Creek	Rosebud-McKay	10-35	1,500 F	35,400	6.5	0.5	8,600
52	East Moorhead	Cache	9-26	541 G	33,850	7.2	0.5	7,148
53	Knowlton	Dominy	8-31	798 G	52,030	4.1	0.4	6,689
54	Cheyenne Meadows	Knoblock	30-65	1,200 G	88,500	4.1	0.4	8,400
55	Charter	Mammoth	5-14	60 G	17,700			
				29,531				

---

1. "As-received" basis (where more than one sample available. Figures given are averages)

Source Montana Bureau of Mines and Geology

Knife River Coal Co. has an average annual production of slightly over 300,000 tons of lignite coal with a Btu rating of 6520 and a sulfur content of 0.5%. This mine is dedicated to the Montana-Dakota Utilities Co. power plant at Sidney, MT.

Western Energy Co. is a wholly-owned subsidiary of Montana Power Co. with operations at Colstrip. Coal analyses are given in Table 2.1.2.

Decker Coal Co. is a joint venture between Pacific Power and Light and Peter Kiewit Sons' Co; the latter being the operating partner. Table 2.1.2 gives coal analyses for this company.

Peabody Coal Co. is currently mining over 1.5 million tons annually from the Rosebud and McKay beds near Colstrip, MT. Unit trains haul coal 800 miles to Cohassett, MN for Minnesota Power and Light.

Westmoreland Resources is a Montana-based partnership owned by Kewanee Oil Co, Penn Virginia Corp., Morrison-Knudsen Co., Inc., and Westmoreland Coal Co. Westmoreland's operations are located at Sarpy Creek, MT. Westmoreland ships coal to five midwest utilities:

- Northern States Power Co., Minneapolis, MN
- Wisconsin Power and Light, Madison, WI
- Dairyland Power Cooperative, LaCrosse, WI
- Interstate Power Company, Dubuque, IA
- Central Illinois Light Company, Peoria, IL

The coal analyses of the four producing mines in Montana from Table 2.1.2 show somewhat higher sulfur content (0.8% average), and lower Btu (8500 average) than Wyoming coals. It is this combination that could make Montana coals of marginal value for reducing sulfur below the 1.2 lb SO_2/MBtu regulation. Ash softening temperatures and Hardgrove grindability are comparable to Wyoming coals.

Coal analyses for the 14 largest mines in Montana and Wyoming are presented in Table 2.1.2. They are representative of approximately 95% of the projected coal production capacity from these two western states through 1983. The use of any one of these coals in the test program would be valid based on the ability of that mine to produce coal at better than present production levels through 1983. However, all mines listed in the table have expansion plans. Most mines project a doubling of present production by 1980 and some, such as Westmoreland Resources, expect to increase production by a factor of five by 1982.

2.2 EXAMINATION OF SUPPLY VARIABLES OF SPECIFIC WESTERN COALS

Introduction

Availability, mining and transportation costs determine the price that must be ultimately paid by a user of western coal. Coals with desirable properties such as relative high heating value and low sulfur content demand a higher price as do coals in limited supply. Prices at the mine are also subject to several factors including type of mining operation, storage and handling facilities and the extent to which the coal is processed. Variables affecting transportation cost are size and frequency of shipment and location of user with respect to existing transport facilities.

The data presenting the current production from the mines in Montana and Wyoming are presented in Table 2.1.1 (Section 2.1), along with projections of future expansion.

Table 2.2.1 gives the average value per ton of bituminous and lignite coals at the mine for 1971 and 1972. Note that strip mining costs per ton had risen from $1.79 to $2.01 in Montana and from $3.35 to $3.69 in Wyoming or approximately 10%. Projected cost to maintain and expand future production are considered confidential by the mine operators and therefore were not made available for this study. Additional increases beyond the 10% annual rate were expected for 1973, 1974 and beyond due to inflationary pressures.

Transportation costs have the greatest influence on western coal prices to potential users in the midwest due to the long distances involved. The only feasible means of transporting western coal to users and to distribution centers in the midwest is by rail. No other alternative exists. Once the coal reaches the Great Lakes or Mississippi River, water transportation systems become available. Early transfer to waterway shipment is preferred over all-rail transport since the cost is lower.

Rail Transportation

Existing rail lines of three major carriers service the Montana-Wyoming coal fields. These lines are illustrated in Figures 2.2.1 and 2.2.2. The Burlington Northern has extensive rail connections in both states that transport coal from the Powder River basin along main line connections

TABLE 2.2.1

AVERAGE VALUE PER TON, F.O.B., OF BITUMINOUS AND LIGNITE PRODUCED, BY DISTRICT

District	1971				1972			
	Underground	Strip	Auger	Total	Underground	Strip	Auger	Total
1. Eastern Pennsylvania	$10.08	$6.49	$6.26	$8.12	$9.60	$6.92	$6.66	$8.25
2. Western Pennsylvania	9.53	6.09	5.61	8.78	10.79	6.38	5.34	9.93
3. Northern West Virginia	7.73	6.12	5.53	7.36	8.55	6.84	6.36	8.16
4. Ohio	6.75	4.76	4.35	5.24	7.41	5.29	4.69	5.96
5. Michigan	--	--	--	--	--	--	--	--
6. Panhandle	6.60	4.56	--	6.55	7.51	6.50	6.50	7.49
7. Southern Numbered 1	13.82	10.22	10.02	13.21	14.87	11.40	11.88	14.45
8. Southern Numbered 2	9.32	6.31	6.67	8.18	10.19	6.41	6.47	8.86
9. West Kentucky	5.46	4.50	5.25	4.83	5.97	4.81	5.64	5.23
10. Illinois	5.96	4.95	--	5.46	6.83	5.49	--	6.14
11. Indiana	6.61	5.05	--	5.18	6.62	5.51	--	5.58
12. Iowa	4.82	4.54	--	4.66	4.80	4.91	--	4.86
13. Southeastern	11.30	5.83	5.05	7.97	13.40	6.93	6.18	9.43
14. Arkansas-Oklahoma	13.99	9.13	8.50	10.53	14.79	8.37	--	9.04
15. Southwestern	--	5.16	--	5.16	--	4.86	--	4.86
16. Northern Colorado	5.25	--	--	5.25	5.17	--	--	5.17
17. Southern Colorado	8.18	3.91	--	6.71	9.46	4.11	--	7.25
18. New Mexico	--	2.62	--	2.62	--	2.68	--	2.68
19. Wyoming	6.25	3.35	2.20	3.39	4.89	3.69	--	3.74
20. Utah	7.37	8.00	--	7.37	8.93	8.00	--	8.93
21. North-South Dakota	--	1.91	--	1.91	--	2.02	--	2.02
22. Montana	9.33	1.79	--	1.82	9.74	2.01	--	2.03
23. Washington	13.55	7.16	--	7.27	16.40	6.99	--	7.07
Total	8.87	5.19	6.57	7.07	9.70	5.48	6.54	7.66

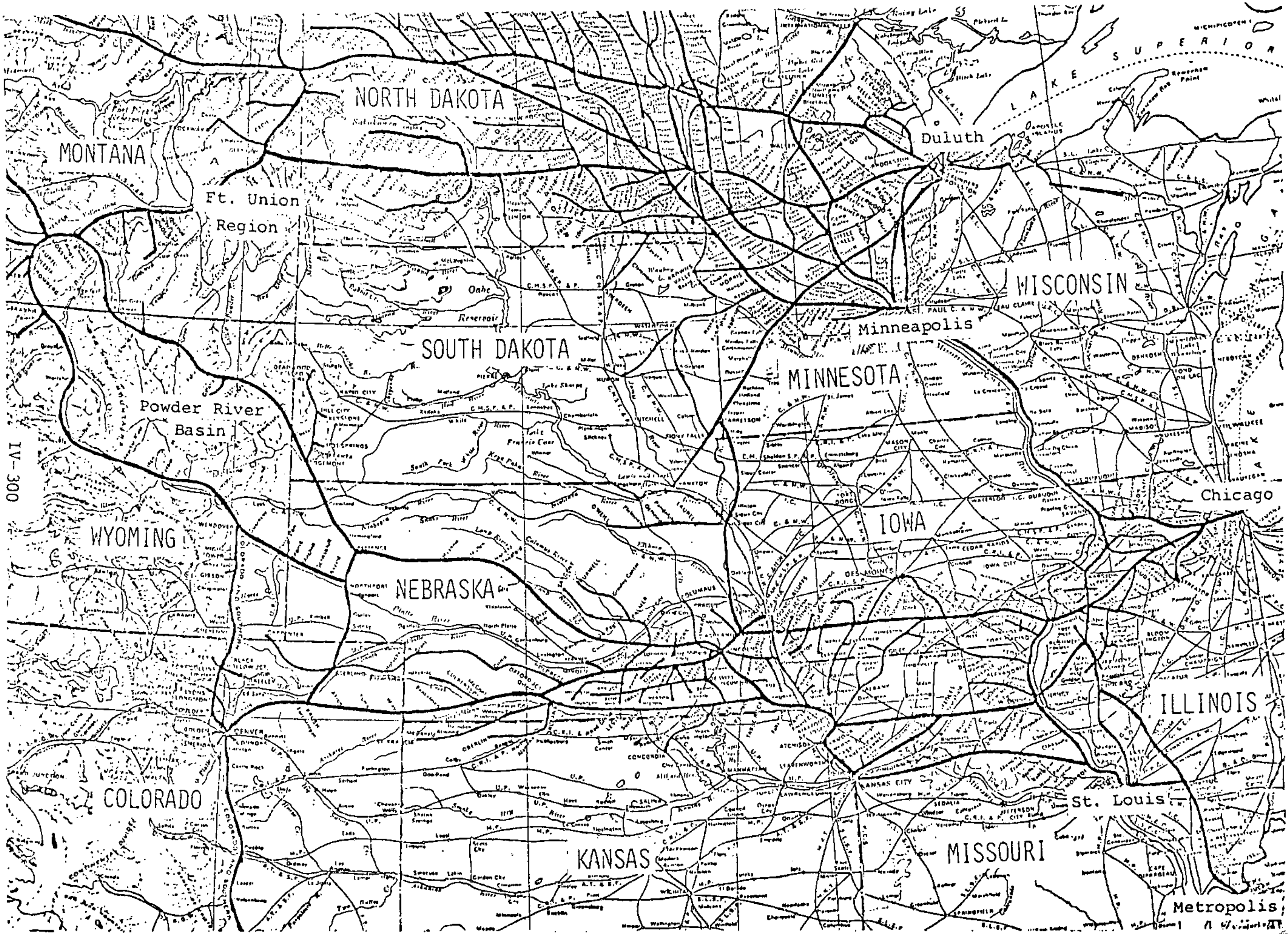


Figure 2.2.1. Main Lines of the Burlington Northern Railroad.

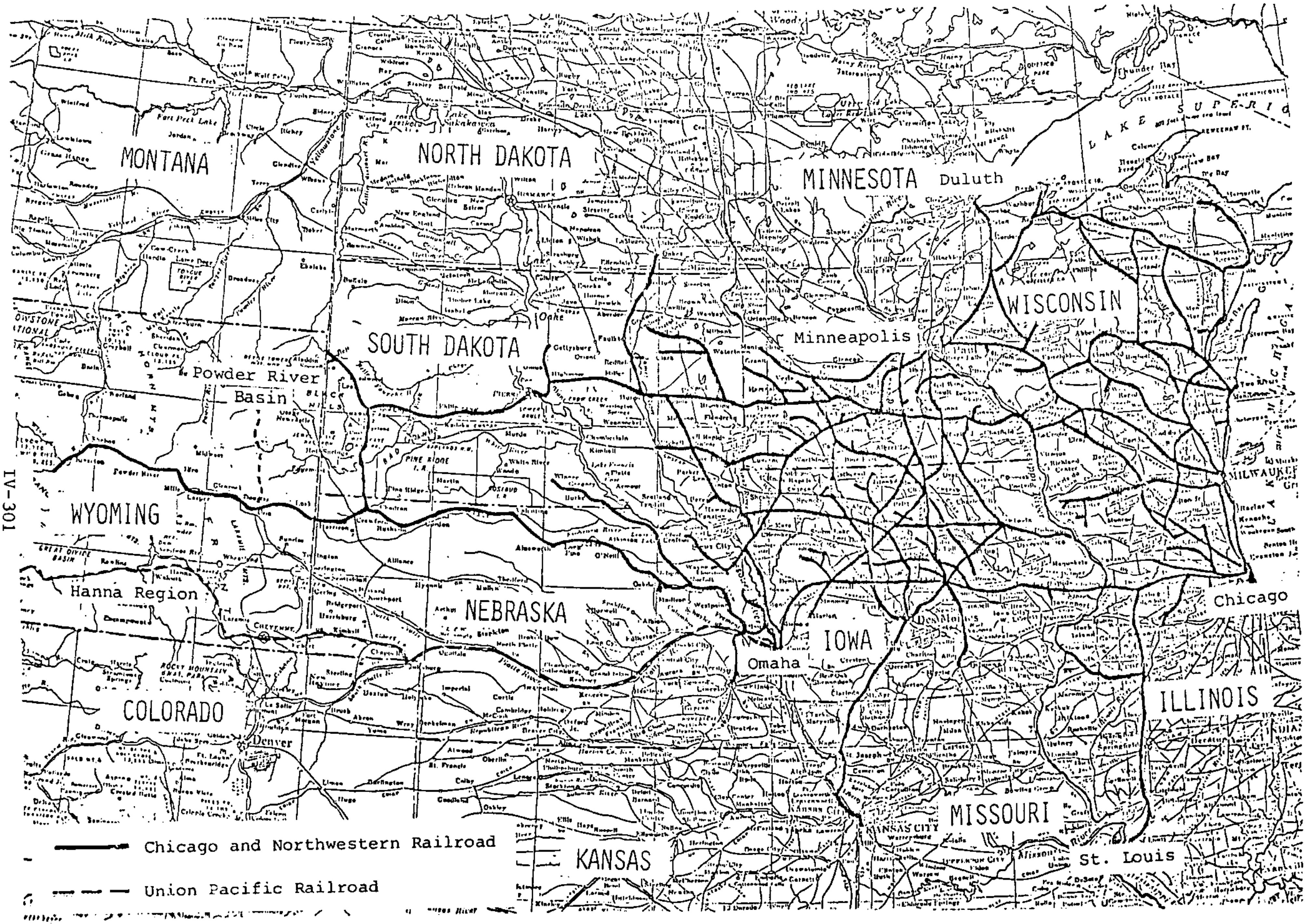


Figure 2.2.2. Main Lines of the Chicago and Northwestern and Union Pacific Railroads.

to several key distribution points. Existing mining operations along the main line of the Union Pacific through southern Wyoming ship coal to Omaha and Kansas City. Tracks of the Chicago and Northwestern Railroad extend into the Powder River basin in eastern Wyoming with existing facilities that generally split the BN and UP systems to the Great Lakes. Several joint ventures between the UP and C&NW are under way to deliver southern Wyoming coal to the Minnesota, Wisconsin, and Chicago areas.

Figure 2.2.3 presents a geographical distribution of the various types of coals employed in the operations of the firms questioned during the survey of current users of western coal (Section 1.1). Western coal is available at reasonable shipping costs to users along major rail connections to the west. The coal is also transferred from existing rail to river barges for distribution along the Mississippi River and from rail to lake barge in Duluth to allow transport to other Great Lakes ports. A complete breakdown of the firms contacted and the types of coals used are included in Appendix A and Section 1.1.

No additional main line connections are planned for western coal shipments; however, some track extensions and improvements have been deemed necessary. As shown in Figure 2.2.4, a 116-mile track connecting the main lines of the BN and the C&NW has been proposed jointly by the two railroads to open up the central Powder River basin. Also planned for the C&NW is a complete upgrading of the main lines from Shawnee, Wyoming, to Freemont, Nebraska. Extensive additions and improvements to the coal-handling equipment have also been undertaken.

Unit Train Operation

Currently the most economical means of transporting western coal to midwestern markets is by unit train. A unit train is a set of locomotives and cars that operate in a continuous cycle from one origin to one destination and return. Techniques and equipment are now in use that have made the widespread use of western coal possible. The continued application of the unit train is a key factor in future western coal shipments.

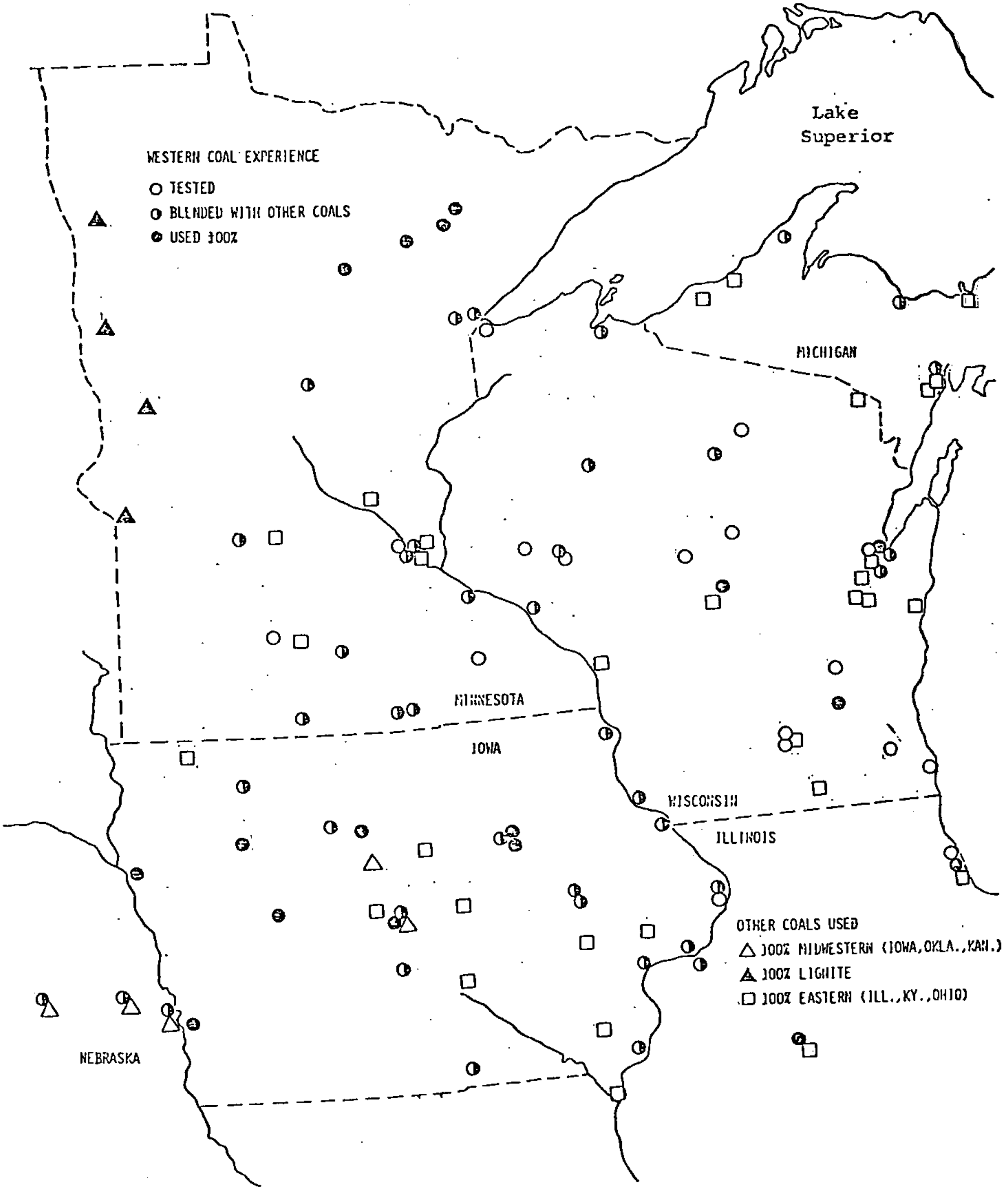


Figure 2.2.3. Coal Users Contacted During Survey.

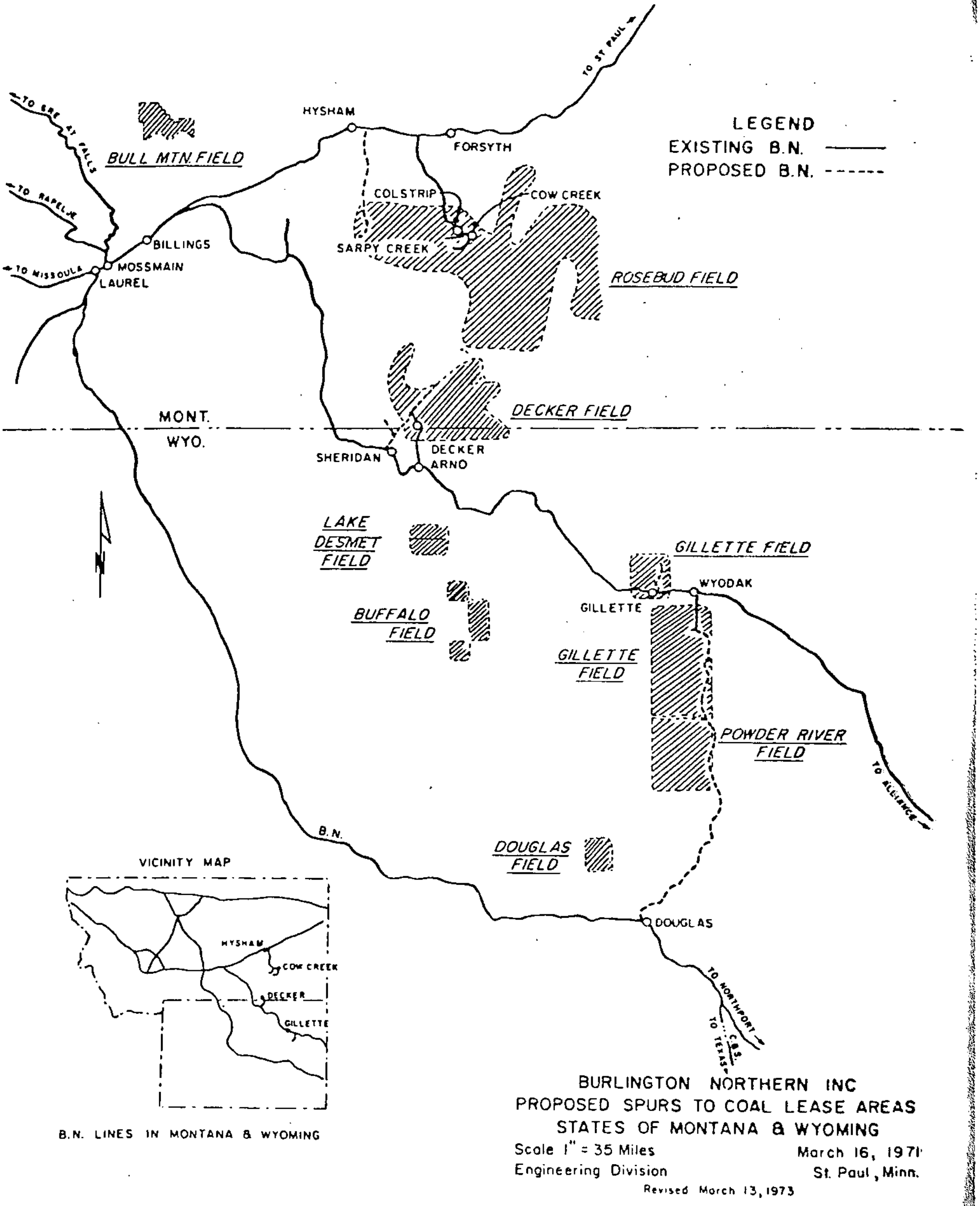


Figure 2.2.4. Western Coal Fields showing Rail Lines in Area.

Loading is generally accomplished by a high-speed conveyor system. The coal is carried to a storage bin located at the top of a tipple and loaded into the train as it moves continuously underneath. A typical loading operation of 100 cars can be completed in approximately four hours.

The trains are multiple engine powered with the diesels generally separated into two groups. The lead diesel, located in a group in the front of the train, is manually operated and transmits commands to the other group of engines located near the middle. The purpose of this group is to spread the tractive efforts through the train so that the draw bar pull on the front car is not excessive. Problems of stack due to the extremely heavy trailing weights are also significantly diminished. The locomotive arrangement also helps in overcoming potential brakeline air pressure losses which is a serious problem in the operation of long trains. Stops during long hauls are limited to routine maintenance and inspection.

The unloading process is accomplished by the use of either rotary or bottom dumping cars. Rotary dumpers are equipped with swivel couplings so that each car can be rotated about the coupling without being detached from the train. Significant improvements to coupling designs and positioners have greatly reduced unloading times. Bottom dump cars with specially designed hoppers for fast unloading are employed with shakers or vibrators for complete discharge. Unloading of an entire train to storage facilities or water transportation can usually be accomplished in under four hours.

The unloaded coal is stored in conical piles or in bins and silos. Covered storage is usually preferred due to the protection from the weather and reduced handling costs; however, the increased initial capital investment is higher than with open storage. The key factor in ground storage is to make it possible to recover as much of the coal as possible with the minimum amount of handling. Problems are also encountered with unsightly and dusty open storage conditions in metropolitan areas.

Improvements in unit train performance are being made by the use of advanced car designs and materials, along with better scheduling of equipment employment and maintenance. The regions of long-distance hauling have required modifications to the dynamic braking system and coupling devices. Coal hopper cars are larger, 100 ton vs. 70 ton, and equipped with automatic door opening and closing devices or swivel couples for rapid unloading. It is estimated that an additional 2800 new large coal hopper cars will be needed to haul western coal once full production is met. Periodic inspections and maintenance are conducted at regular intervals (usually 500 miles) for safety and improved mechanical reliability.

While the continued improvement of unit train operation has allowed railroads to hold shipping rates down, current inflationary pressures are requiring adjustments to shipping costs. The primary factors affecting these costs are labor and materials. Rates over a particular route are determined through negotiations between the railroad and the receiver. These rates are periodically adjusted based on a mechanism established during negotiations. These rate adjustments are usually based on the Index of Railroad, Material Prices and Wage Rates of the Association of American Railroads.

Current unit train shipments involving the BN, UP and C & NW are outlined in Table 2.2.2. Listed are the location (mine) of origin, destination (user), 1974 shipment volume and the rates as of March 1, 1975. In all cases, shipments are made directly to utilities and are primarily used in boilers of greater than 300,000 lbs steam/hr. As illustrated in Table 2.2.2, shipping rates range from $3.43 per net ton (17¢/MBtu) for delivery in Sergeant's Bluff, Iowa, to almost $9.00 per net ton (45¢/MBtu) for receipt in Hammond, Indiana.

In addition to unit train deliveries, several hundred cars per month are moved from the western coal fields to the midwest in single and multiple car shipments, and in entire train loads on a non-unit train operation. These shipments generally go to paper companies, industrial concerns and small utilities in Iowa, Wisconsin and Minnesota.

Shipping rates for non-unit train deliveries as supplied by Burlington Northern demonstrate the dramatic cost increases that must be absorbed by the small users. The tariff from Colstrip, MT, to Minneapolis, MN on shipments of train load lots on a single line haul not under unit train operation is $5.55 p.n.t., while a single car shipment is $9.03 p.n.t. Similarly in the UP system, unit train deliveries from Hanna, WY to Kansas City, MO are shipped for $3.74 p.n.t., while lot deliveries of 1,500 tons cost $7.99 p.n.t. A typical western coal tariff is presented in Table 2.2.3.

TABLE 2.2.2

UNIT TRAIN SHIPMENTS OF WESTERN COAL

From	To	Approximate 1974 Volume in Tons	Rate as of March 1, 1975 cents/net ton	cents/MBtu	Carrier
Hanna, Wyoming (Arch Minerals)	Oak Creek, Wisconsin (Wisconsin Electric Power)	750,000	690	35	UP-CNW
Hanna, Wyoming	Omaha, Nebraska (Omaha Public Power)	500,000	594	30	UP
Hanna, Wyoming (Energy Dev. Corp)	Sergeant Bluff, Iowa (Iowa Public Service)	1,100,000	343	17	UP-CNW
Hanna, Wyoming	Council Bluffs, Iowa (Iowa Power & Light)	220,000	650	33	UP
Hanna, Wyoming (Arch Minerals)	Waukegan, Illinois (Commonwealth Edison)	2,800,000	774	39	UP-CNW
Hanna, Wyoming (Arch Minerals)	Hammond, Indiana (No. Indiana Pub Serv)	1,550,000	887	45	UP-CNW
Hanna, Wyoming (Arch Minerals)	Kansas City, Missouri (Kansas City P & L)	800,000	374	19	UP
Colstrip, Montana (Western Energy Co)	Chicago, Illinois (Commonwealth Edison)				BN
Colstrip, Montana (Western Energy Co)	Becker, Minnesota (Northern States Power)		Proposed for 1976		BN
Decker, Montana (Decker Coal Co)	Superior, Wisconsin (Distribution in the Detroit Edison system)	1,000,000			BN
Colstrip, Montana (Western Energy Co)	Portage, Wisconsin (Wisconsin P & L)	2,000,000	530	30	BN
Decker, Montana (Decker Coal Co)	Havana, Illinois (Commonwealth Edison)	4,500,000			BN-C&IM
Sarpy Creek, Montana (Westmoreland)	St. Paul, Minnesota (NSP and others)		Proposed for 1976		BN

TABLE 2.2.2 (Cont)

From	To	Approximate 1974 Volume in Tons	Rate as of March 1, 1975 cents/net ton	cents/MBtu	Carrier
Sarpy Creek, Montana (Westmoreland)	Madison, Wisconsin (Wisconsin Power & Light)	Current total shipments of 4,000,000 TPY			BN
Sarpy Creek, Montana (Westmoreland)	Alma, Wisconsin (Dairyland Power Coop)				BN
Sarpy Creek, Montana (Westmoreland)	Dubuque, Iowa (Interstate Power Co)				BN
Sarpy Creek, Montana (Westmoreland)	Peoria, Illinois (Central Illinois Light)				BN
Sarpy Creek, Montana (Westmoreland)	Minneapolis, Minnesota (Northern States Power)				BN
Colstrip, Montana (Peabody Coal Co)	Cohassett, Minnesota (Minnesota Power & Light)	1,500,000			BN
Belle Ayr, Wyoming (Amax Coal Co)	Cason, Texas (Southwestern Elec Pwr)	1,750,000			BN-KCS
Belle Ayr, Wyoming (Amax Coal Co)	St. Louis, Missouri (Distribution in the American Electric Power System)	2,000,000			BN

TABLE 2.2.3

WESTERN COAL TARIFF FOR LOCAL, JOINT, AND PROPORTIONAL RATES
BURLINGTON NORTHERN, INC.
Effective April 8, 1975

SECTION 1
SPECIFIC RATES IN CENTS PER 2,000 LBS
(For application, see page 22 of tariff)

ITEM	COMMODITY, CARLOADS	APPLICATION		RATES
		FROM	TO	
Ⓔ 200-F	BITUMINOUS COAL. In open top cars. Minimum weight marked capacity of car, except when loaded to full visible capacity, actual weight will apply. Route via: ① BN-direct. ② BN-Minneapolis, MN-CNW. ③ BN-Minneapolis, MN-SOO. ④ BN-St Paul, MN-MILW. ⑤ BN-St Paul, MN-RI. ⑥ BN-Miles City, MT-MILW. Ⓔ Expires as indicated in Item 150. (ML A-8696)	Colstrip . . . . MT	Ames . . . . . IA	② 1044
			↓Austin . . . . MN	②④⑥ 1000
			Burlington . . IA	① 1049
			Cedar Falls . IA	②⑤ 1029
			Cedar Rapids . IA	②④⑤⑥ 1044
			Clinton . . . IA	① 1029
			Corn Belt . . IA	④⑥ 1044
			Davenport . . IA	① 1029
			Dubuque. . . IA	①④⑥ 1029
			Eau Claire . . WI	②③④⑥ 1000
			Humbolt. . . IA	② 1044
			Iowana . . . IA	① 1029
			Menasha . . . WI	③④ 1312
			Milwaukee . . WI	②③④⑥ 1312
			Muscatine . . IA	④⑤⑥ 1029
			Neenah . . . WI	③④⑥ 1312
			Neenah-Menasha WI	② 1312
			Rochester . . MN	② 1000
			Spencer . . . IA	②④⑥ 1044
			Waterloo . . IA	②⑤ 1044
			Waupun . . . WI	④⑥ 1312

EXPLANATION OF REFERENCE MARKS

REFERENCE MARK		EXPLANATION
↓	B	Denotes Reduction.

B-Brought forward without change.

Multiple line haul deliveries are even more expensive. For example, the proposed unit train tariff from Colstrip to Columbia, WI, via the BN and C&NW is $5.30, while a single car delivery to the same area is $13.12, or 148% higher..

The above shipping costs point out the problem facing small users of western coal. Unit train operation for large users (primarily utilities), has allowed shipping costs, and therefore total cost, of western coal to become competitive with the traditional bituminous coal suppliers in the east and midwest. In order to make western coal more attractive to non-utility users, a method must be found to incorporate the unit train concept into the small user's supply system.

Rail-to-Water Transfer Facilities and Distribution Centers

The concept of a central distribution center supplied by unit trains and feeding several users has been proposed. All of these facilities will be used initially to supply a large utility and will be in conjunction with a rail-to-water transfer system. Since many present coal users are supplied from traditional sources in Illinois and Kentucky by water, the importance of this transfer is obvious. Currently, western coal supply/distribution centers are planned or under construction in the Duluth, Minneapolis, and St. Louis areas.

A rail-to-ship coal handling facility is currently under construction in Superior, Wisconsin, to handle western coal shipments to Detroit Edison that will result in a 40-50% reduction in all rail shipping costs through Chicago. Initially, this facility will handle 8,000,000 tons per year of Decker coal to Detroit Edison delivered by unit trains on the Burlington Northern and Chicago and Northwestern systems. An additional 6,000,000 tons per year capacity that is as yet uncommitted will be available for other users.

The C. Reise Coal Company, who will have joint ownership of this facility, is planning an additional facility to handle primarily smaller customers in train load lots of 50 cars on a non-unit train operation from the Peter Kewitt operations at the Big Horn and Rosebud Mines. Significant shipping cost reductions will be realized from single car deliveries. The coal will be loaded on to lake barges to distribution to customers along the Great Lakes. It may prove feasible to subsequently transfer the coal from lake barge to other surface transportation for delivery to user.

A plan for a coal wharf to store and transfer coal from trains to river barges has been proposed for the Minneapolis - St. Paul area. The facility, commonly called "Pig's Eye", will be supplied by unit trains along the Burlington Northern and Chicago and Northwestern Railroads from the Sarpy Creek Mine in Montana. The facility is primarily designed for use by Northern States Power, Dairyland Cooperative, Interstate Power Company, and Wisconsin Power and Light. However, storage and transfer facilities for smaller users have been planned. The facility will handle approximately 5,000,000 tons of coal per year.

Currently the coal wharf project has not been approved by the State of Minnesota due to environmental concerns. Arguments against the facility include unsightly conditions, dust and noise. Several proposals to improve the situation including a possible dome to cover the facility, have been made. None has yet been approved. Without this facility, future expansion of western coal to small users in the Minnesota - Wisconsin area is in serious jeopardy.

Four other rail-to-river facilities are currently proposed or under construction in the St. Louis area. A 10,000,000-ton facility in Metropolis, Illinois, is scheduled for completion in 1976 that will be for the sole use of the American Electric Power Company, a holding company that consists of several utilities in Ohio, Michigan, West Virginia, and Tennessee. Coal will be delivered by unit trains from Wyoming and Utah by the Burlington Northern and Missouri Pacific Railroads. This facility may eventually expand to 20 million tons per year.

A facility initially designed for industrial users has been proposed for the Tri Cities Regional Port District. Again, deliveries will be made by unit train, stockpiled, and supplied to users either by river barge using existing port facilities or by truck. The initial capacity for the facility is 2-3 million tons per year but may go as high as 15 million tons.

An existing rail-to-water facility in St. Louis operated by the Peabody Coal Company has been employed to transfer coal to the American Electric Power Company for test purposes. Once the Metropolis, Illinois, facility is completed, this may be available for unit train delivery and storage for non-utility users.

Another planned operation to be developed by the American Commercial Barge Company similar to the Pig's Eye coal wharf has been proposed for the St.Louis area. Initially, this would be employed for shipments to utilities in the lower Mississippi River. Like the St. Paul facility, this project is meeting resistance from environmental groups and has been forced to alter locations. This operation, once approved, will have a capacity of between 10 and 20 million tons per year, the portion of which will be available for small users is as yet undetermined.

Lake and River Transportation

The lower transportation costs and existing coal-handling facilities make an early transfer to waterway shipment preferred over an all-rail shipment. As illustrated in Figure 2.2.5, the existing inland waterway system composed of the Mississippi and Ohio Rivers and the Great Lakes provides an excellent means of transporting western coal to potential domestic markets.

Substantial savings in transportation costs can be realized using water shipment. Freight rates on inland waterways range from three to five mills per ton mile compared to rates of five to eight mills per ton mile for unit train shipments. It has been estimated that a net savings of $6 to $8 per ton can be realized on western coal shipments from Montana to Detroit Edison using a combined rail and lake ship transfer over an all rail shipment to Chicago.

Jumbo barges that are 195' x 35' and carry 1500 tons are used to transport coal on river waterways. Barges are generally grouped into tows that can range from 15 jumbos on the upper Mississippi to 30 on the lower Mississippi. These tows can be used in areas of limited draft and allow

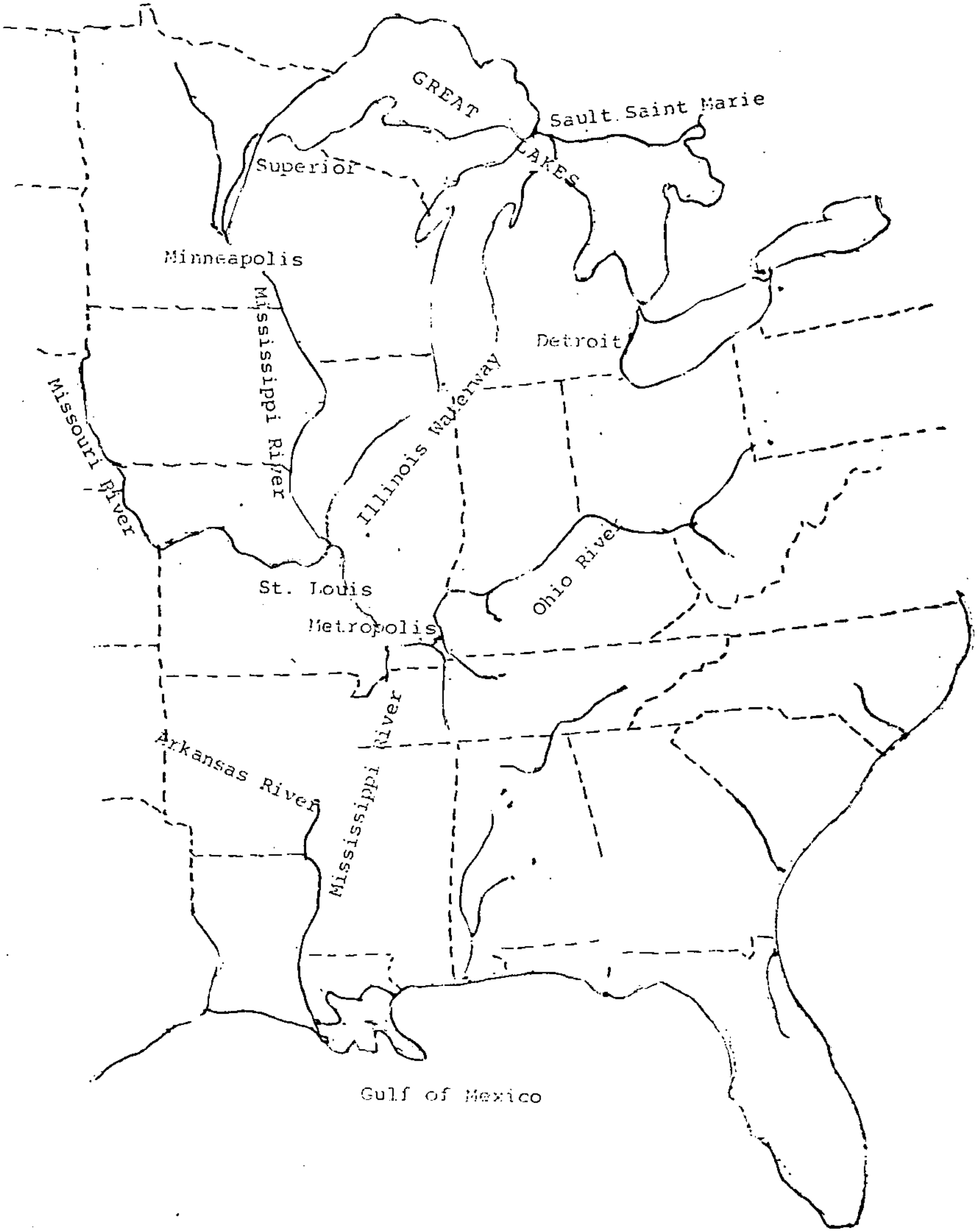


Figure 2.2.5. Mississippi River and Great Lakes Inland Waterway Network.

coal shipments on all inland waterways except the upper Ohio River. It is estimated that an additional 260 new jumbo barges will be required to haul western coal once full production is met.

Expansion of the Soo Locks at Sault Saint Marie on the Great Lakes has allowed the use of giant lake vessels that can transport up to 60,000 tons of coal. These ships are self-unloading and are generally replacing the jumbo barges in areas where draft is not a problem. A recent Maritime Administration study indicates that such ships will operate for approximately one-half the ton-mile cost of the jumbo barges and one-third that of unit trains.

An added incentive to a rail-to-water transfer is the fact that many coal users are presently supplied by water. Industrial plants have been located on waterways to take advantage of the low cost water transportation and the availability of water for cooling and processing. In certain instances, especially with electric utility generating stations, coal is delivered directly to the dock of the plant that will use it.

Conclusion

Estimates are that the present 50 million tons annual output of western coal will increase to 250 million tons annually. The coal reserves and technology required to mine it are presently available. Adequate rail and water transportation facilities exist to transport the western coal to potential domestic users. The development of rail-to-water transfer facilities, distribution centers, and additional transportation equipment are the key elements in future expansion of western coal use. In order for this expansion to occur, a favorable economic climate must exist that will encourage the development of this coal on a long-term basis.

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1:20 p.m.
Systems Evaluation of the Use Of Low-Sulfur Western Coal in Existing Small and Intermediate-Sized Boilers
Dr. Kenneth L. Maloney, KVB Engineering

Q: I missed the point on the 2000 ppm CO level on the Kentucky coal. What is the host boiler owners' approach to the high CO emissions? How are they coping with the problem?

A: That wasn't the Kentucky coal; that was on the Montana coal.

Q: I'm sorry; so that is not their base coal, then.

A: They will fire anything they get that comes down the river.

Q: But is there no way to get around that problem?

A: They don't worry about CO since they don't measure it. One can increase the excess O_2 to offset the CO emissions, but then one pays a NO penalty. We changed the flame patterns in this unit and we, as Mike Heap talked about the other day, can get a long skinny (low NO) flame, but it hits the back wall and of course you don't want that. Then, of course, we can get a nice short, compact flame, with very high NO. So we did do some tuning. When we go into a unit, we test it as we found it, if it is not too radically off base. Then we try to do some modifications. In a pulverized unit, this consists of burner/air register modifications, where one tries to get the O_2 distribution smoothed out in the duct and the flame shaped up nicely. We search for a NO vs. CO tradeoff point where the combustible losses do not impact unit efficiency.

Basically, this involves lowering the excess O_2 through the unit. We then do another series of emission tests and then we switch coals.

Q: On the sulfur analysis, you gave 4% for Kentucky and 1.8 for Montana, which is roughly a 2-1 ratio; but on SO_2 it was 3800 for Kentucky and only 1000 for Montana, which is about 4 to 1, which means either some of your sulfur is unaccounted for or maybe that Montana number should be 18. The Montana coals are supposed to be low sulfur and 1.8 seems kind of high for Western. Have you looked at sulfur in the ash?

A: We are analyzing the fly ash and the bottom ash for sulfur on this unit. The completed data are not available yet but preliminary inspection indicates that there is some sulfur retention by the ash. They will be happy to hear about this in Montana.

Q: Probably this question should be to Mr. Cuffe, but during the discussions the last couple of days, CO popped up again and again and again whenever we were talking about NO_x and people are talking about the possibility of the CO and the NO_x having interaction. Yesterday, it was mentioned that some trade-offs are acceptable. Some of these CO limits we are now talking about are starting to creep up there pretty high. Most people have mentioned that there is no standard for that.

Well, there is no standard. I was wondering, now that we are all here, what are the future thoughts about a potential standard for CO? You kind of figure since they are setting standards for everything else, it is just a matter of time till they get around to it. I think that is a very important question, especially in lieu of what the discussions in the last couple of days have led to.

A: [By Stan Cuffe of EPA:]

I guess I can't say just what a standard would be for CO. I can say, however, that in setting a new source performance standard the Clean Air Act does not require that you look at ground level concentrations to see what the impact is. It does require that you base the standard on the best systems of emission reduction, taking cost into account. However, we also have to prepare environmental impact statements. So, for any source, large or small, for which we would set a pollutant standard, we will do diffusion modeling to see what effect the standard would have for a specific pollutant on ground level concentrations. In a number of cases, because the ambient air quality standard for CO is quite high, we have not been that concerned.
I think that in EPA in the last several years since the act was passed, we have looked through now and set standards, gathered data, etc., on 30,40,45 different sources. These have been primarily particulates and SO_2. I think in the next several years, although we will still do some particulate and SO_2, the emphasis will be more on controlling sources of oxides of nitrogen and hydrocarbons.
Today, you can probably get more information down at RTP from Dr. Knelson, who is the Director of the

Health Effects Laboratory. Still, if there is a tradeoff, we are much more interested in controlling nitrogen oxide and hydrocarbons than CO. Obviously, if the CO got to an extremely high concentration, and the types of sources were small stacks instead of real high stacks and you could have high ground level concentrations, then naturally we would be concerned with it. On proposed standards that we will have...well, they have already been proposed for electric arc furnaces in steel mills; we did not cover carbon monoxide I don't believe. It was just particulates there that we were concerned with. I can't tell you right off hand just what the level would be, and so forth. Again, as I am sure most of you realize, it is not just the concentration coming out of the stack but it is the mass rate of emissions and then what that would be on short and long term ground level concentrations. I am sorry I can't be more precise on that. I do know that it has a lower priority than either of the other pollutants that I mentioned.

Q: I think that is a help to us, Stan, because this tradeoff between NO and CO has been a very important aspect of combustion research for a long time. So this is going to be something that will have involvement.

A: There was one interesting point that one of the turbine representatives who just left said: that even if there were not standards set for carbon monoxide, they would not allow it to get too high. Because of the large amount of excess air if you get up over 1000 ppm of CO their turbine efficiency drops off several percent. So, in terms of economics, they just couldn't allow that. [Comment by Stan Cuffe.]

Q: I think indeed the data has shown that there is a NO/CO tradeoff. I think the important thing to bear in mind is that is for a fixed system design, for any given piece of hardware, as you decrease excess air you would normally decrease NO; you will then reach a point at which the CO breaks and increases. For specifics let's go back to Paul Combs' comments on the residential furnace, which is not a general case, but it is a case in point. I think some of the data has shown, that in fact, by a different design, by changing air fuel mixing design, you can move the point of this tradeoff much closer to stoichiometric. In the case of the residential system you can go from, say, a 60% break tradeoff point, 60% excess air to 15% excess air as the point of that tradeoff, and simultaneously lower the NO_x emissions. So, this has different impacts in terms of simple changes in the operating conditions for a fixed configuration, modification of a design of a fixed configuration retrofit of a hardware change, and, finally, new unit design. The point that should be made is where we are looking toward a new unit design and lower excess air operation for efficiency we are also looking to push the tradeoff point through the design for CO, smoke, and unburned hydrocarbon much closer to stoichiometric.

A SURVEY OF EMISSIONS CONTROL AND COMBUSTION EQUIPMENT DATA IN INDUSTRIAL PROCESS HEATING

by

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The blast furnace is a cylindrical, tapered, refractory-lined vertical furnace. It is charged with iron ore, pellets, sinter, coke, and limestone and discharges hot metal and slag containing mineral gangue and other impurities. It is a counterflow process wherein the raw materials are charged at the top and travel down through the furnace reacting with an ascending stream of reducing gases, primarily carbon monoxide and hydrogen. The trend in blast furnaces has been toward larger furnace design, higher blast temperature, improved burden, auxiliary fuel injection, and improved scheduling and firing practice.

In steelmaking, iron from the blast furnace, commonly called hot metal, and scrap are charged along with fluxes into the process melting equipment. This equipment consists of open hearths, basic oxygen furnaces, and electric furnaces, which remove impurities such as carbon, manganese, silicon, and phosphorous to specified levels by oxidation.

Fuels used in open hearths consist of residual oil, natural gas, coke-oven gas, tar and pitch. The amount of fuel required per ton of steel produced is in the range of 1.5 to 4 million Btu per ton. Increased productivity has been achieved by oxygen enrichment of combustion air, roof-mounted oxygen lances, and utilization of roof-mounted oxygen-fuel lances to accelerate scrap melting rates and decrease fuel consumption. However, the use of oxygen lancing has resulted in increased dust loading of the waste gases and has required installation of more costly air pollution control equipment.

Much of the open-hearth steelmaking capacity has been replaced by the basic oxygen furnace (BOF). Auxiliary fuel is not required in the BOF because the heat generated during oxidation of the carbon, silicon, manganese, and phosphorous is sufficient to bring the metal to pouring temperature. In the process, oxygen is blown downward through a water-cooled lance into a bath containing hot metal and scrap. Furnace capacities range up to 300 tons and the time required per cycle is very short, from 45 to 60 minutes. The BOF has an inherent limitation in that the amount of scrap in the charge is limited to 25% to 30%. Some additional flexibility can be obtained by preheating the scrap prior to charge.

Excluding fuel use for scrap preheating, other uses are for refractory dryout and keeping the BOF vessel hot between heats. These uses amount to about 200,000 Btu per ton of steel produced.

Two technological advances which will affect energy requirements are direct reduction and continuous casting. Direct reduction consists of beneficiating iron ore to a higher degree of metallization (up to 95%), which can then be charged into an electric melter without the addition of scrap, or it can be used directly in the BOF. This process allows the bypass of sintering and blast-furnace operations.

In the continuous-casting process, the ingot stage is bypassed, and the molten steel is transformed directly in slabs, blooms or billets. The energy required to reheat the ingot prior to rolling into slabs, blooms and billets is also eliminated. The quantity of steel produced by continuous casting is increasing.

In most cases, field interviews did not elicit much relevant information regarding emission problems and control, except that every effort is being made, at great expense, to comply with local standards. Attention was drawn to the large energy requirements needed to achieve compliance with future standards, particularly those for fugitive and NO_x emissions.

It was generally agreed that not much is known about NO_x emissions and that further research is required.

Cement

The cement industry consumes natural gas, oil, and coal in the direct-firing of rotary kilns to produce the final cement product. The amount of energy required ranges from 4.3×10^6 to 7.0×10^6 Btu per ton of final product. The amount of energy consumed is dependent upon the process employed (wet or dry), age of equipment, and the application of waste-heat recovery systems. Users of natural gas reported curtailments ranging from 10% to 100% during the coming winter season.

Coal, on the other hand, was reported to be readily available at dramatically increased prices, ranging from 55% to 80% between 1972 and early 1975.

The industry is very much aware of the increasing non-availability of natural gas and oil and increasing energy costs; it is expected that coal will become the dominant fuel in the near term. In addition to the conversion from other fuels to coal, the industry can reduce the quantity of energy required per ton of cement by installation of heat recuperative devices such as suspension preheaters, chains systems kiln feed-end enlargement, and improved process control. Reduction in the amount of energy consumed per ton of product can be as high as 50%, depending upon the type of installation.

Adoption of a vertical kiln operation in place of the rotary kiln can potentially reduce energy requirements by as much as 50%. The vertical kiln has been used successfully in Europe and Japan. It does not appear that vertical kilns will be favorably accepted by U.S. industry because of capacity limitations and some problems with product quality.

The cement industry has been able to comply with local, state and Federal emission requirements by the use of baghouses to trap particulate matter. However, disposal of the collected particulates is becoming a major problem since it cannot be recycled to a great extent into the raw material stream. A revision of the ASTM standard for cement alkali content would help alleviate this problem.

Areas of further research directed to reduced energy consumption and more efficient pollution control include investigation into the substitutability of Type 2 cement for Type 1 cement, investigation of alkali reaction problems, improved process control, and development of combustion technology to reduce NO_x emissions.

Glass Industry

The major uses of energy in the glass industry are glass melting (80%) and annealing (15%). Energy for the melting process consists of natural gas, oil, and electricity. Melting is carried out in continuous melters (containers, flat glass) and batch melters (specialty glass, etc.). Continuous melters are reverberatory furnaces equipped with checkerbrick regenerators for preheating combustion air and range in capacity from 50 to 1400 tons, depending upon the type of glass produced. Batch melters consist of pot or crucible furnaces fired directly or indirectly with capacities of 1 to 50 tons.

A fuel-fired continuous glass melter consumes about 6.0 x 10^6 Btu per ton of glass melted, excluding hold-over time. However, this estimate varies considerably and is dependent upon furnace insulation, combustion control equipment, molten glass depth, and the type of glass being produced. According to the industry, there are several process modifications that can be implemented to reduce the amount of energy required per ton of product. Those which have potential for near-term implementation are improved process monitoring and control capability, electric melting, and electric boosting. Estimates of energy savings range up to 18% reduction per ton of product by electric melting (excluding the energy required to generate the electricity).

Methods of air pollution control currently in use in the glass industry are primarily electrostatic precipitators (ESP) and baghouses for particulates, and the use of low-sulfur fuels for SO_x emissions. The quantity of NO_x emitted is dependent upon several factors, some not clearly understood and currently undergoing study. Other emissions, such as carbon monoxide and hydrocarbons, are controlled by closely monitoring the combustion process.

Aluminum

The primary aluminum industry is heavily dependent upon electricity as an energy source (almost 52%), followed by natural gas (30%), and oil (18%). Approximately 160 x 10^6 Btu of energy is consumed in a primary aluminum plant for heat and power in the production of 1 ton of aluminum ingot. Additional fabrication consumes about 36 x 10^6 Btu in transforming the ingot into finished product. Secondary recovery of aluminum from scrap requires about 20 x 10^6 Btu to produce 1 ton of ingot. Since this program is primarily concerned with the processes involving combustion of fuels, emphasis was placed on remelting operations wherein ingot is melted prior to fabrication.

Reverberatory furnaces are used for melting aluminum ingot prior to fabrication. Natural gas is the principal fuel used in furnace operation and oil is used when gas becomes unavailable. The efficiency of the burner decreases when oil is used because a minimum distance is required to achieve atomization and complete combustion of the oil. The thermal efficiency of a reverberatory furnace under optimum operating conditions is 25% to 35%.

In its efforts to conserve energy, the industry is continuing research and development programs to improve existing manufacturing processes, streamline production processes by modifying equipment, and install energy management programs at all organizational levels. These programs are the direct result of the current decline in availability of natural gas to industrial users. The increased use of coal for steam generation is regarded as a near-term solution to the energy problem; in the long-term, greater dependence will be placed on nuclear power.

Some of the most recent developments directed toward reducing energy consumption include flash calcining, electrolytic smelting, use of pulverized coal, and preheating of metal charge. The use of flash calcining reduces the amount of energy required to produce alumina by 30%, from about 2000 Btu to 1400 Btu per pound of product. The process combines the benefits of the fluidized bed and dispersed-phase technology to improve heat transfer and reduce heat losses.

Electrolytic smelting reacts chlorine and alumina to produce aluminum chloride, which is then electrolytically decomposed in a separate cell producing chlorine and aluminum. Power requirements for this process are 30% less than customary production processes.

An experimental program is being undertaken to determine the feasibility of using a pulverized-coal combustion system in a melting furnace. This is being initiated because of natural gas shortages and uncertainties in the availability of alternate fuels. Success of the program is dependent upon successful development of a process for SO_x removal from the stack gases.

Baghouses are used along with stack after-burners to control particulate and gaseous emissions. The amount of energy expended to operate emission control devices is in the range of 3000 to 6000 Btu per pound of product. The amount of energy required to operate a baghouse is approximately 1000 Btu per pound of product, requires extensive maintenance, and is not effective for the control of gaseous emissions.

Petroleum Refining

Energy consumption in a petroleum refinery amounts to around 10% of the crude throughput. Most of this energy is consumed as fuel in fired heaters. The fuel is derived from the product output of the refinery Unlike the other industries included in this program, the refiner is not dependent upon outside sources of fuel; however, the fuel consumed reduces the amount of product available for resale. A reduction in energy consumption of about 8% has been achieved by the industry since 1972.

This reduction has been attributed to alterations in operating practice and closer monitoring of process stages. Fuel consumption has been reduced by checking heater performance on a full-time basis. Improved oxygen analyzer installations are employed as well as preheat of the heater feed.

In most existing refineries the different units are operated as separate entities, each having intermediate tankage for feed and products. The trend is toward the elimination of intermediate tankage and reducing fuel consumption by running hot feed between process units.

New refineries are being designed in this manner, along with changes in design conditions such as a reduction from 400°F to 250°F in the lowest temperature at which heat will be recovered by exchange.

Refinery operators have been able to comply with emission standards that have been established in the past, however, some instances of conflict were cited between fuel conservation and anticipated stricter emission standards. There is concern that NO_x standards, yet to be established, will put the refineries above the standard as a result of air preheat. In another instance, it was calculated that when lower stack temperatures are achieved to improve fuel efficiency, ground level emissions increase.

Recommendations made by refiners were directed primarily at the establishment of emission standards. In the interest of fuel conservation it was recommended that standards provide the flexibility of waivers to refineries located in areas remote from cities. It was also recommended that guidelines be set by environmental tolerances, rather than a specification based on the process capability. In terms of hardware development, it was suggested that fuel-oil burner design be improved to allow combustion with lower excess air requirements.

INTRODUCTION

The purpose of this study is to identify the significant emission sources within the industrial process-combustion field, to investigate the potential for effective emissions control for industrial process combustion, and to compile information on combustion equipment in use and future trends in process and equipment design. This program investigated the interactions between current and potential energy conservation measures and emission control programs, assessed the potential for R&D work to advance emissions control, and recommended R&D programs to solve the problems involved.

The program was divided into 3 distinct phases for the purpose of industry selection, data collection, and data analysis.

The first phase of this program (Phase I) was to determine those industries and industrial processes which have a high potential for conserving energy and reducing emissions. Their selection was based on the relative amounts of energy consumed and the relative emissions of pollutants. The selection process included consideration of the potential for simultaneous energy conservation and air pollutant emission controls.

The second phase of this program (Phase II) consisted of an intensive series of visits to industrial plants, corporate headquarters, trade associations, and builders of process heating equipment. The purposes of these visits were to validate and fill the voids in the information collected in Phase I and to assess a number of elements relating to existing and future trends in process technology and equipment design affecting energy consumption and air pollutant emissions.

The information obtained from the trade associations, equipment builders, and industrial plants was correlated and analyzed in Phase III to provide an assessment of process and equipment design and operating factors which are major influences on both fuel efficiency and air pollutant emission rates. This data analysis resulted in estimates of the potential for improvement in fuel-use efficiency and reduction of emissions for existing equipment designs and for new processes and equipment designs which may be instituted in the future. Upon completion of the data analysis, recommendations for specific programs aimed at reducing energy consumption and air pollution emissions were made, including the identification of potential sponsors for these programs.

PHASE I. INDUSTRY SELECTION

In a program of this type, it is generally not feasible to consider all industries. Consequently, a system was developed for selecting pertinent industries. The system relates energy consumption, pollution emissions, and the potential for reducing both for each industry, and then determines the relative merits of studying each industry in terms of achieving the program objectives. Toward this end, the following system of restraints and weighting factors has been developed for selecting the industries to be studied in this program.

Restraints

The first step in the development of this system was to define the restraints as determined by the problems to be solved. The following restraints were selected:

1. Total energy use in process heating. This program is primarily concerned with those industries which consume large amounts of energy because it is in these industries that the most significant results of implementation of energy conservation technology will be realized. Some industries, however, consume large amounts of fossil fuels for feedstock and steam generation — ostensibly, the paper industry, the chemical industry, the petroleum refining industry, and the food processing industry. In the areas of feedstock and steam generation, little can be done to alter the energy utilization patterns. Consequently, only those industries that consume large amounts of energy for process heat are being considered in this program.

2. Combustion-related uses of energy. A further refinement of the first restraint is to limit the investigation to combustion-related aspects of energy consumption. In so doing, industries which consume large amounts of purchased electricity for process heating will be eliminated from consideration. Electricity consumption is not within the scope of this program, although in-plant generation is considered if the relative load is large enough.

3. Relative number of processes within an industry. In some industries, energy is consumed by a large number of relatively small-scale processes which, when added together, show a very large total energy consumption figure for the industry as a whole. Typical of such an industry is the industrial chemical industry. The total amount of energy consumed for process heating in the chemical industry in 1972 was about 2800 trillion Btu. However, most of this energy was consumed in the manufacture of thousands of chemicals which incorporate myriads of individual processes with varying energy requirements. To study an industry such as this would give minimal return toward the project objectives in that reductions in energy consumption of a process in this industry would have a minimal effect on the national energy picture. On the other hand, in an industry with a limited number of processes, such as the cement industry, in which more than 90% of the 581 trillion Btu of energy consumed in 1972 was consumed in kilns, even a small (5-10%) increase in fuel utilization efficiency of the kiln would have a significant, widespread impact on the entire industry as well as the national energy picture.

4. Known and/or estimated total emissions. Two of the stated purposes of this program are to identify the significant sources of emissions within the industrial process combustion field and to determine the potential for effective emissions control for industrial process combustion. Therefore, the emissions of an industry must be a restraint in the industry-selection process. Emissions from industrial process combustion can be broken down into three categories:

   a. Emissions directly related to combustion — typically NO_x, SO_x, CO, and particulates.

   b. Emissions indirectly related and therefore somewhat controllable by combustion techniques — typically such emissions as particulates from a glass melter or cement kiln where the combustion gases "pick up" the dust of the raw material and carry it out the stack.

   c. Emissions independent of the combustion process — typically emissions from chemical reactors or electrolytic processes.

5. Types of emissions — NO_x, SO_x, CO, and particulates. These are the emissions of primary concern in this program as they are the emissions most closely related to the combustion process. Secondary emissions of concern are

fluorides, chlorides, and other halides, although these are only indirectly related to the combustion process.

6. Potential for energy conservation. Energy conservation is one of the primary purposes of this program. Consequently, only those industries which have a high potential for reducing energy consumption should be considered. The paper and paperboard industries, although consumers of large amounts of energy (more than 1300 trillion Btu in 1972), will be eliminated from consideration because 95% of this energy is consumed as boiler fuel, an application which already has a direct fuel utilization efficiency greater than 80%. The potential for increasing the efficiency of direct utilization of fuel is low.

7. Potential for reducing emissions. Reducing combustion-related air pollutant emissions is the other primary objective of this program. Consequently, as in the case of energy consumption, those industries with a low potential for reducing emissions will not be considered in this program.

Upon applying the restraints and a weighting system (see Appendix A), the following industries were selected for study in this program:

- Iron and steel (all energy-using processes)
- Cement (primarily kiln operation)
- Glass (melting, forehearth operation, annealing)
- Aluminum (primary melting, reheating, secondary production)
- Petroleum refining.

These industries ranked highest in terms of the evaluation characteristics used in this program. That is, all of these industries use large amounts of process heat directly from the combustion of fossil fuels; all of these industries are relatively large emitters of combustion-related air pollutants; and all of these industries have a high potential for reducing energy consumption and air pollutant emissions. Note that these industries have been selected based on the combination of all of the above factors. Consequently, there are industries, such as the paper and paperboard manufacturing industry, that consume twice as much energy as the cement industry and 4 times as much as the glass industry, but, because 95% of that energy is consumed in boilers to generate steam (a process efficiency in excess of 80%), the potential for reducing energy consumed directly by the boilers is very low. Thus, this industry received a low priority rating and is not being considered in this program. Information related to the industries considered for this study is shown in Table 1.

Table 1. PROFILE AND WEIGHTING FACTORS FOR INDUSTRIES CONSIDERED FOR STUDY IN THIS PROGRAM

Industry	Total Energy Consumed, 10^{12} Btu/yr	% Consumed for Process Heat	Weighting Factors*			
			Base Energy Number	Emission Index No.	Potential Energy Consumed	Potential Emissions Recorded
Iron and Steel	3100	80	22	10	10	10
Petroleum Refining	2861	60	12	5	3	3
Cement	581	90	24	8	10	7
Glass	250	90	22	7	8	7
Aluminum	352	80	15	7	5	5

*See Appendix A-1.

B-94-1766

PHASE II. DATA COLLECTION

Iron and Steel Industry — Processes and Equipment

The major operations in an integrated steel plant are the coke oven, blast furnace, basic steelmaking, rolling mill, and finishing.

Coke Ovens

Coke is the product of destructive distillation of some types of bituminous coal, commonly referred to as metallurgical coal. It is produced in by-product coke ovens, sometimes called slot ovens, because of their shape. Each oven is a narrow, rectangular retort closed at the top except for charging ports, with gas off-take ports in the sides and bottom. Each end of the oven is fitted with a tightly sealed removable door. One end is the "pusher end" from which a ram is inserted to push out the coke; the other end is called the "coking end" from which the hot coke is pushed into a quenching car. Adjacent retorts are separated from each other by heating flues and are called underfired ovens because the air and fuel ports are located at the bottom of the heating flues. A large number of the retorts and associated flues are stacked together and the entire series is called a battery.

High, medium, and low-volatile coals are crushed, ground, and blended to obtain the desired coking characteristics. About 65% to 80% of the charge is high-volatile coal containing 30% to 40% volatile matter, the remainder of the charge consists of medium and low-volatile coal. After charging the retort, the coal is converted into coke in approximately 16 to 18 hours in older ovens and in about 12 hours in modern, taller ovens equipped with improved combustion and control systems.

By-products of the coking operation include coke-oven gas, tar, ammonium sulphate and light oil products (BTX). About 60% of the sulfur content of the coal is carried over into the coke. The balance goes to the coke-oven gas as hydrogen sulfide. A representative material balance for a coke-oven plant is shown in Table 2.

Table 2. COKE-PLANT MATERIAL BALANCE

	Quantity	lb Per Ton of Dry Coal
Coke	78.5%	1574.0
Coke-Oven Gas	10,600 cu ft (540 Btu)	312.3
Tar	7.55 gal	74.8
Ammonium Sulfate	21.0 lb	21.0
Light Oil Derivatives	2.85 gal	20.9
Total		2000.0

The fuels used for heating the coke ovens are selected on the basis of cost, availability, and combustion characteristics. Top to bottom temperature gradients must be minimized. Coke-oven gas and natural gas-air mixtures provide the desired high flame temperatures, while blast-furnace gas has a much lower heating value and lower flame temperature, but does have a high concentration of inerts which act as diluents to retard combustion and lengthen the flame. The primary fuel for underfiring coke ovens has been coke-oven gas. About 1/3 of the coke-oven gas produced is used for this purpose. Blast furnace gas and natural gas together account for 15% to 20% of the total input for underfiring coke-ovens. Total fuel input for underfiring has been about 3.0 million Btu per ton of coke produced.

The major technological trends affecting coke-oven energy requirements are —

- Higher and wider ovens using high conductivity refractories. Coking rates and productivity have increased; however, increases anticipated in efficiency have been offset by higher coking temperatures and greater heat losses. Thermal efficiencies of coke ovens are reported in the range of 60% to 70%.
- Predrying of Coal Charge. Predrying of coal increases coke-oven productivity and reduces heat losses resulting in a saving of about 100,000 Btu per ton of coke. Emissions during charging of predried coal are also reduced.
- Use of Formcoke. Formcoke is a calcined agglomerate of bituminous coals (non-caking). Pollution in formcoke processes is also reduced.
- Improved Blast Furnace Operations. The quantity of coke required per ton of pig iron produced is reduced by using a higher top pressure, hotter blast air temperature, oxygen enrichment of blast air, and increased use of fuel injection.
- Direct Reduction of Agglomerated Iron Ore. Direct reduction and electric furnace melting produce steel with no pig-iron requirement and pre-reduction of part of the blast furnace burden will reduce the coke requirements and increase blast furnace output.

Blast Furnace Plant

The blast furnace and its associated stoves for preheating blast air, the sinter plant, and storage, sizing and handling facilities for raw materials are the major components of the blast furnace area in an integrated steel plant.

Sinter Plant

Some of the iron ore and flue dusts are available in particle sizes less than 1/4 inch and cannot be charged directly to the blast furnace. These products are mixed with flux and coke breeze and loaded onto a traveling grate-sintering machine. An auxiliary fuel such as natural gas, coke-oven gas, or oil is used to initiate combustion on the surface of the mixture and is referred to as ignition fuel. Combustion is continued over the length of travel by forcing air through the mixture on the grates. The mixture is heated to a fusion temperature which causes agglomeration of the iron-bearing particles. The sinter discharged is cooled, crushed, and screened prior to transfer to the blast furnace charging oven.

The major source of energy used in the production of sinter is the carbon content of coke breeze and flue dust. The amount of ignition fuel required is about 0.12 million Btu per ton of sinter. The total fuel requirement, including coke breeze, is about 2.0 million Btu per ton of sinter.

Blast Stoves

Blast stoves are checker-brick-lined chambers used to supply heated air to the blast furnace. The stoves are regenerative heat exchangers; during part of the cycle being heated by combustion of blast furnace top gas and during another part of the cycle heating the blast air. Three or four stoves are required for each blast furnace. In operation, a stove heats air until the air preheat temperature drops to a preset value. The stove is then isolated from the hot blast main and reheated by combustion of blast furnace gas to the temperature required to heat blast air. Regenerative air preheating results in a cyclic variation in blast-air temperature and the stoves may be used as staged temperature preheaters in various combinations with the objective of reducing the cyclic variations in blast temperature.

Thermal efficiency of the blast stove is quite high, about 72%, as would be expected of a regenerative heat exchanger. However, efficiency has decreased from about 87% in 1960 because of a continuous increase in blast temperature. Average blast temperature in 1969 was in the 1500°-1600°F range and in 1960 was below 1300°F. Some installations are now approaching a 2000°F blast temperature.

The major reasons for increasing blast-air temperature are to reduce coke consumption in the blast furnace and to increase the output of pig iron. Auxiliary fuel injection in the blast furnace also requires higher blast-air temperature to maintain temperature in the melting zone. Other factors also affect coke rate and production. These will be discussed in the blast-furnace section of this report.

About 25% of the blast furnace top-gas is used for stove heating. In 1969, this amounted to 165 trillion Btu. Increases in blast-air temperature and a reduction in blast furnace gas heating value have required the use of coke-oven gas and natural gas for higher heat release in blast stove heating.

Current technology trends in blast stove design and operation include —

- Improved designs for burners and combustion chambers
- Improved hot valve designs
- Better refractories and checker-brick design
- Automatic stove charging equipment
- Improved modes of stove operation.

Blast Furnace

The blast furnace is a cylindrical, tapered, refractory-lined, vertical furnace. It is charged with the basic iron-making raw materials, iron ore, pellets, sinter, coke and limestone, and discharges hot metal or pig iron and a slag which contains the mineral gangue and other impurities. It is a counterflow process in that the iron-making materials are charged at the top through a double-bell seal and travel down through the furnace reacting with an ascending stream of reducing gases, primarily carbon monoxide and hydrogen. The reducing gases are produced by blowing preheated air through ports called tuyeres into the bottom of the furnace, where reaction with the incandescent coke takes place. Auxiliary fuels such as fuel oil, natural gas, tar, or powdered coal are frequently injected at the tuyeres to increase iron output and decrease the coke rate. With auxiliary fuel injection, higher blast-air temperature or oxygen enrichment is usually required to maintain the iron melting temperature. Exceptionally good results have been achieved on a pilot-plant basis by injection of reformed natural gas at the tuyeres. Theoretical calculations have shown that even better results could have been obtained by injection of hot reformed gas above the tuyeres in the gaseous reduction zone. Although these programs have been curtailed by reduced availability of natural gas, the results indicate that blast-furnace injection may become a potential application for use of low-Btu gas produced by gasification of coal, assuming a favorable economic justification. A suitable reducing gas can also be produced by partial oxidation of residual oil, but the present cost and availability of low-sulfur oil make this approach uneconomical.

Pollutants From Iron Making

The coke-oven plant has been identified as one of the major sources of air and water pollution from integrated steel plants. Some of the sources of emissions are —

- Coal handling, processing, and storage
- Charging the coal into the ovens
- Leakage during coking, particularly from the doors
- Discharge of incandescent coke
- Water quenching of coke
- Contaminated water discharged.

A variety of methods has been incorporated in recent coke-oven plant designs to effectively control emission of pollutants.

Sinter plants are inefficient as users of energy and are major contributors to steel mill particulate and gaseous emissions. Emission control is technically difficult and expensive. Some steel plants have phased out sinter lines and pelletized iron ore has now assumed a dominant position as a major blast furnace charge. Pelletizing plants are located near the iron ore sources and the emissions from the pelletizing process do not contribute to the steel mill emission control problems.

The major pollutants from sinter plants are particulates, sulfur oxides, and carbon monoxide. Leakage from the seals between the exhaust ducts and the sintering furnace structure accounts for most of the emissions.

Disposal of in-plant fines and flue dusts as process feedstocks will be required by means other than landfill. Both pelletizing and hot-briquetting will probably be used.

Emission of pollutants from blast furnace stoves consists of dust carried over from the blast furnace. With properly designed combustion systems and air-gas ratio controls, carbon monoxide should not be considered a significant emission. Particulate emission from blast-furnace stoves is not treated separately in the literature, but is considered part of blast furnace particulate emissions.

Steelmaking

In steelmaking, iron from the blast furnace, commonly called hot metal, and scrap are charged along with fluxes to melting process equipment. Impurities such as carbon, manganese, silicon and phosphorus are oxidized to or below specified levels during the melting process. These oxidation reactions are exothermic and contribute part of the total process energy requirement. The fluxes and some of the oxidized impurities form a slag layer and the rest of the oxidized components leave as gases. The major types of melting process equipment are the open-hearth, the basic oxygen furnace (BOF) and the electric furnace.

Open-Hearth Steelmaking

The open-hearth furnace is a large reverberatory vessel heated from the top by burners located at each end of a long, narrow chamber. A long, luminous flame is produced so that a high percentage of heat transfer to the bath is by radiation. The heating process is regenerative in that refractory checker-brick are located downstream of each firing port so that combustion air is being preheated at one end, while exhaust gases are reheating the checker-brick at the other end. After a timed interval the flow is reversed. Scrap metal, fluxing agents, iron ore and hot metal are charged through doors located above the bath level along the length of the furnace. Open-hearth furnace capacities range from 100 to about 600 tons per heat.

The high productivity of competitive steelmaking processes has brought about major improvements in open-hearth furnace productivity. Some of these improvements are oxygen-enrichment of combustion air, roof-mounted oxygen lances, roof-mounted oxygen-fuel lances to accelerate scrap melting an higher combustion-air preheat temperature. However, the use of oxygen lancing has resulted in increased dust loading of the waste gases and this has required installation of more costly air pollution control equipment.

Fuels used in open-hearth furnaces include residual oil, natural gas, coke-oven gas, tar and pitch. Part of the thermal requirement is provided by exothermic oxidation of impurities contained in the hot metal portion of the charge. Fuel required per ton of steel produced is in the 1.5 to 4 million Btu range.

depending on the hot metal/scrap ratio and the amount of oxygen lancing used.

Basic Oxygen Furnace (BOF) Steelmaking

In the BOF process, oxygen is blown downward through a water-cooled lance into a bath containing scrap and hot metal. Heat produced by oxidation of carbon, silicon, manganese and phosphorus is sufficient to bring the metal to pouring temperature and auxiliary fuel is not required. The furnace is an open top, tiltable, refractory-lined vessel shaped somewhat like the old fashioned glass milk bottle. Furnace capacities range up to 300 tons and time required per cycle is very short, from 45 to 60 minutes.

The BOF has displaced the open-hearth as the major steel production process but is much less flexible because of the inherent limitation of 25% to 30% scrap in the charge. The amount of BOF capacity in an integrated steel plant is, therefore, closely associated with hot metal availability. Additional flexibility in scrap use can be obtained by preheating the scrap with an oxygen-fuel burner. In many steel plants an open-hearth shop is modernized and equipped with appropriate pollution control equipment so that it can be used in conjunction with BOF shops to provide the required flexibility to accommodate variations in hot metal/scrap ratio. A combination of BOF shops and electric furnace shops provides the maximum in flexibility and may represent the makeup of future steelmaking facilities.

Excluding fuel use for scrap preheating, other uses are for refractory dryout and to keep the BOF vessel from cooling between heats. These uses amount to about 200,000 Btu per ton of steel produced.

Decarburization of the iron charged to the BOF produces about 400,000 Btu of carbon monoxide per ton of steel. The off-gases also contain large amounts of particulates, which must be removed before discharge into the atmosphere. Typical American practice is to burn the combustible gases in water-cooled hoods mounted above the BOF vessel, cool with excess air or water sprays, and pass the cooled gases through high-energy scrubbers or electrostatic precipitators. In most cases, the BOF vessels are equipped with open hoods which admit air for combustion of carbon monoxide on a relatively uncontrolled basis. If additional steam can be used in the plant, the combustion hood can be used as a steam generation device, although the steam production will only be cyclic.

In Japan, a closed-hood gas collection system known as the OG system is used, wherein the waste gases containing CO are scrubbed, collected, and used as fuel gas. The basic OG system is used at a few steel plants in the United States, but the CO-rich off-gas is burned in a flame stack rather than stored and used for fuel. A major advantage of the OG system, other than recovering a fuel gas, is the large reduction in the volume of waste-gas required to be handled by the scrubbing system.

Electric Furnace Steelmaking

Production of steel in electric-arc furnaces has grown rapidly since World War II and is currently estimated to be more than 15% of total steel production. Because of the phase-out of open-hearth steelmaking, the increase in BOF steel production, and the associated scrap-use limitation, the amount of steel produced in electric-arc furnaces is expected to increase even more.

Combustion of fossil fuels currently plays a very small role in electric steelmaking. This may change in the future as advances in technology permit the increased use of scrap preheating. Most authorities agree that scrap preheating will be accomplished outside the electric-arc furnace in a specially designed charging bucket probably equipped for bottom discharge. Many of the designs use excess air burners to limit flame temperature and minimize oxidation of the scrap. Associated air-pollution problems include particulates from dirty scrap, iron oxide, and oil vapors. The requirement for both incineration at or above 1400°F and particulate removal has caused shutdown of several scrap preheating installations because of economic considerations.

Direct Reduction

A number of direct reduction processes are currently in use to provide an alternative to the blast furnace in the production of feed material for steelmaking furnaces. Both batch and continuous processes are in use involving such equipment as rotary kiln, counterflow vertical shaft, traveling grate-kiln and multistage fluid bed. Various types of raw materials are processed, such as lump ore, oxide pellets, and beneficiated concentrate. The degree of metallization ranges up to 95% and a highly metallized product can be charged to an electric melter without scrap addition. Pre-reduced charge can be used in the blast furnace and steelmaking equipment such as the BOF. Some advantages of direct reduction are –

- Lower capital requirements than for coke-oven blast furnace ironmaking.
- Reduced dependence on hot metal for steelmaking.
- Consistent chemical analysis of the feed material to the steelmaking process.
- Reduced dependence on scrap.

In the past, direct reduction plants in the United States have been associated with mini-steel plants which are not fully integrated. These plants are dependent upon a reliable supply of natural gas at a low price. Currently, both availability and price are adverse to the process and it seems doubtful that additional plants will be constructed. Natural gas consumption in the most efficient plant is in the range of 13 to 14 million Btu per ton of product; less efficient plants may require as much as 20 million Btu per ton.

Hot metal from the blast furnace is transferred to the steelmaking furnace in large, refractory-lined vessels or ladles. These are also used for transferring molten steel to the various casting operations. The refractory linings of the vessels must be cured after replacement and preheated before each use. Typically, open-flame burners are used for this at a very low thermal efficiency. Fuel requirements for ladle drying and heating range from 200, 000 to 400, 000 Btu per ton of metal.

Ingot and Continuous Casting

After removal from the furnace, the steel is poured into ingot molds or transferred to the continuous caster. Forming steel into ingots is an intermediate step prior to further processing. The steel is cooled to a solid, whereupon the ingot mold is removed. The finished ingot can be sent directly onto additional processing or stored indefinitely to meet scheduling needs.

In the continuous-casting process, the ingot stage is bypassed, and the molten steel is placed into one or more streams or strands which are fed from a holding chamber called a tundish. The molten steel is transformed directly into slabs, blooms, or billets and cut to the desired length by a traveling torch. The continuous casting process eliminates intermediate ingot formation, along with the energy required to reheat the ingot prior to the formation of slabs, blooms, or billets. The amount of steel output produced by continuous casting is increasing.

Soaking pits are used to reheat ingots to rolling temperature (about 2340^0 to 2400^0F for carbon steel). Ingots are charged at a variable temperature because of varying time intervals between ingot pouring and charging into the soaking pits, brought about by conflicts in rolling schedules or other delays. The amount of energy required for reheating ingots varies a great deal because of the temperature variation in heating a cold ingot and one at intermediate temperature levels.

Soaking pits are simple round, square, or rectangular-shaped refractory-lined chambers having a retractable cover. Several pits grouped together are referred to as batteries, having common flue ducts and a single recuperator and stack. Fuels used in soaking pits include mixed blast furnace gas and coke-oven gas, mixed blast furnace gas and natural gas-air, straight coke-oven gas, straight natural gas and residual oil. Single, nozzle or port-mixing burners are used and the burners are used and designed to minimize the temperature gradient between the burner wall and the back wall of the pit. Problems in fuel utilization occur when changing from one fuel to another, particularly from gaseous to liquid fuels, because of major variations inflame length and heat-release profiles.

Mill operating practices have a major effect on soaking pit fuel economy. Among them are –

- Ingot charging temperature
- Percentage of cold ingots charged
- Pit loading
- Holding time at temperature.

Fuel requirements vary from 545, 000 to 2 million Btu per ton. The national average fuel consumption in soaking pit operations is estimated at 1 million Btu per ton.

Good combustion control is essential for maintaining fuel efficiency in soaking pits. These include temperature control-fuel input, pit pressure and air/fuel ratio. Substantial fuel reductions can be obtained by installing recuperators on soaking pits now operating on cold combustion air. Improved recuperator design can deliver combustion air preheated to higher levels than the current range of 700° to 800°F. The potential for fuel reduction is about 15%, taking into account the large number of soaking pits operating with cold combustion air or inefficient recuperators.

Most of the fuel used by the steel industry in reheat furnaces is for slab, bloom, and billet heating. The evolution of the modern, continuous, reheat furnace has been forced by rolling-mill improvements, steel quality requirement, floor space limitations, and low-cost energy, toward the direction of increased heating rates and higher mean effective thermal head temperatures. Most of these furnaces are a continuous-pusher type with the load supported on water-cooled skids over most of the furnace length, and on a refractory hearth in a final soak zone which is over fired. Both three-zone and five-zone furnaces are in use. More of the fuel input is progressively burned near the charge end to increase furnace capacity. As a result, flue-gas temperatures have increased and this factor, as well as the heat lost to water-cooled surfaces, has resulted in increased fuel requirements per ton of steel heated. In recent furnace designs the soak zone has been eliminated by using a walking beam design wherein the load is alternately supported on stationary and moving water-cooled supports. This furnace produces a uniformly heated product without the cooler regions associated with the water-cooled support skids and has the highest output per unit of floor space, but accomplishes this at the expense of fuel economy.

Average fuel consumption for reheat furnaces with preheated combustion air is in the range of 2.0 to 2.2 million Btu per ton for 3-zone furnaces and 2.7 to 2.8 million Btu per ton for 5-zone furnaces.

Fuel economy for steel mill reheat furnaces is effected by furnace design, firing arrangement, heat losses, heat recovery, combustion and process controls, and operating practices. Although the furnaces are continuous, frequent delays at the rolling mill have an adverse effect on fuel efficiency and on the temperature uniformity of the product. Another important factor is the number of operating turns per week.

Estimates of total fuel requirements of steel mill reheat furnaces are frequently based on an average consumption value of 2.5 million Btu per ton of steel heated. Some of the rolled products may be reheated more than once and consequently estimates of total fuel consumption for reheating range up to 300 trillion Btu per year.

Fuel conservation measures for reheat furnaces include those previously mentioned for soaking pits:

- Retrofitting recuperators to furnaces using cold combustion air or presently using inefficient recuperators
- Improved combustion control
- Improved operating practice
- Programmed input control.

Additional measures specifically for reheat furnaces include the following:

- Improved maintenance of skid rail insulation
- Control of air infiltration
- Increased temperature of preheated combustion air.

Emissions from soaking pits and reheat furnaces may include carbon monoxide and unburned hydrocarbons produced by inadequate or poorly maintained ratio controls. These can be eliminated by the installation of better equipment or improving maintenance practices. The most significant emission will be NO_x, produced by the high flame temperatures required and combustion-air preheat.

Annealing, heat treating, and finishing operations follow in sequence the reheating and rolling mill operations. The major portion of the fuel used in the steel industry for annealing is for cold rolled products in strip form. Approximately 35% of total United States steel production is in the form of strip and other cold rolled products. Estimates of the amount of energy consumed for annealing, heat treating and finishing operations range from 50 to 60 trillion Btu per year, including electricity. About half of this quantity is for annealing.

Fuels used for these processes are mainly natural gas and coke-oven-gas. Natural gas is preferred because the sulfur content of a fuel has an adverse effect on product quality and maintenance of furnace alloy components.

Temperatures employed in heat treating and finishing operations are much lower than those required in other types of process equipment and, consequently, NO_x levels should be correspondingly lower. Other emissions, such as carbon monoxide and hydrocarbons, are associated with the quality and maintenance of air-fuel ratio control equipment. Many of the heat treating and annealing operations require the use of a protective atmosphere, primarily reformed natural gas. Disposal or leakage of protective atmospheres can result in locally high concentrations of carbon monoxide.

Equipment used in annealing, heat treating and finishing operations include the following:

- Batch and continuous coil and strip annealers
- Car bottom, roller hearth pusher tray, and other types of heat treat furnaces
- Tin-plating lines
- Galvanizing lines.

Some of the energy conservation measures being used on annealing equipment are:

- Conversion from radiant tube to direct firing
- Recuperation
- Improved combustion controls
- Use of ceramic fiber furnace linings replacing brick refractories
- Substitution of nitrogen from oxygen plants for natural gas based atmospheres.

Because of the relatively small percentage of total fuel use in this area and the low level of NO_x produced, any conservation measures adopted will not have a material effect on overall steel plant emission levels.

Steel Industry Field Survey

Trends in Process and Equipment Modifications

1. Iron Making

Coke Ovens — Current and Near-Term

- Pipeline charging of predried and preheated coal
- Coke-side hood ducted to emissions control equipment
- Wider and higher coking chambers
- Improved H_2S removal from coke-oven gas using molten carbonate treatment (500 lb steam/ton coke)
- Multistage combustion system
- Sealed container case to receive coke
- Continuous wet and dry coke quenching for emission control and waste heat recovery.

Coke Ovens — Long-Term

- Dry coke quenching using inert gas and waste heat recovery
- Replacement by formcoke or other compacted forms of calcined coal.

Sinter Plant — Current and Near-Term

- Improved seals to minimize infiltration and leakage.
- Waste-gas temperature control to prevent condensation in emission control equipment.
- Gas recirculating siphon designed to minimize volume handled by emission control equipment.

Sinter Plant — Long-Term

- Replacement by hot briquetting process.

Blast Furnace — Current and Near-Term

- Larger furnaces.

- Higher blast temperature
- Improved burden (oxide pellets, sinter)
- Higher top pressure
- Auxiliary fuel injection
- Improved stove design, scheduling and firing practice.

Blast Furnace — Long-Term

- Pre-reduced iron as part of charge.

2. Steelmaking

Open Hearth — Current and Near-Term

- Use declining because of basic oxygen furnace and emission-control cost
- Use required by mills having inadequate supply of hot metal. Emission control equipment is required.
- Increased use of oxygen roof-lancing to increase output. NO_x level probably increases.

Open Hearth — Long-Term

- Use will continue to decline, probably to about 10% of total steel production by 1985.

Basic Oxygen Furnace (BOF) — Current and Near-Term

- Collection and control of emission by the OG IRSID-CAFL processes (non-combustion). The OG system uses 2-stage venturi scrubbing for particulate removal and a flame stack for carbon monoxide combustion
- Submerged injection of oxygen (QBOP).

Basic Oxygen Furnace (BOF) — Long-Term

- Recovery of carbon monoxide from BOF off-gases (about 400, 000 Btu per ton melted)

- Improved scrap preheating system with emission controls and fueled by recovering carbon monoxide from BOF off-gases
- Reduction in hot metal requirement.

Electric Furnace — Current and Near-Term

- Primarily improvements in emission control equipment
- Larger furnaces
- Development of practical scrap preheating systems.

Electric Furnace — Long-Term

- Electric furnace melting of pre-reduced charge, pellets or lump ore.

Trends in Utilization of Fuels

The American Iron and Steel Institute has reported to the FEA on the overall energy consumption by the steel industry by source for the base year 1972 and a projection for the year 1980 as follows:

Source	Year 1972	Year 1980
Coal, %	67.3	68.5
Purchased Gas and Oil, %	28.8	26.9
Purchased Electricity, %	3.9	4.6
Btu X 10^6 per Net Ton Shipped	32.6	30.1

During the field interviews, various integrated steel plants reported the following energy consumptions by source for 1974:

Plant	A	B	C
Coal, %	75	60	70
Oil, %	10	22	5
Natural Gas, %	15	18	20
Purchased Electricity, %			4.7
Other, %			0.3

General fuel-use trends in the industry will be to increase the relative amount of coal consumed per ton of steel shipped and to decrease dependence on purchased oil and gas. The amount of oil used compared to natural gas will increase because of the decreased availability of natural gas. Major shifts toward increased use of coal will require very large amounts of capital, both for new production facilities and for the associated emission control equipment.

Ironmaking — Current and Near-Term

- Increased use of coal as a primary fuel, both in increased coke-oven output for blast furnace injection and for boiler firing.

- Increased availability of coke-oven gas.
- Decreased use of coke-oven gas for under-firing coke ovens, partial replacement by increased use of blast-furnace gas.
- Coal and high-sulfur oil will be used as blast-furnace injectants.
- Use of natural gas as a blast furnace injectant, for blast stove heating and other auxiliaries will decline sharply.
- Direct combustion of coal in pelletizing facilities, both travelling grate and shaft type will decrease use of natural gas and oil.

Ironmaking — Long-Term

- Coke ovens will be replaced, possibly to a major extent, by form coke or some other pyrolyzed coal product. Heating value of the gas output may be much less than that of coke-oven gas, possibly less than 200 Btu/CF.
- Coal gasification plants producing low-Btu gas may be installed in steel mills or the product gas made available from a nearby source.
- Heating value of the low-Btu gas will be in the 175 to 300 Btu range, depending on the process used. This gas may be a good blast furnace injectant if the economics are favorable.
- Direct reduction to a highly metalized iron product using solid reductants may replace part of the coke oven-blast furnace ironmaking capacity.* The availability of low-sulfur fuels at a competitive price will be essential and appears to be doubtful at the present time.

Steelmaking — Current and Near-Term

- Use of oil, natural gas or in-plant gases for steelmaking furnaces will continue to decline as additional open-hearth furnaces are replaced by BOF and electric furnace steelmaking.
- Use of natural gas as an open-hearth fuel will decline sharply, replaced by oil or coke-oven byproducts.

Steelmaking — Long-Term

- Recovery of carbon monoxide waste gas from BOF steel-making and possibly using it to preheat the scrap charge will enable the industry to increase the scrap/hot metal ratio in the BOF charge.

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*The fuel sulfur content must be at a low level to produce a metallized product satisfactory for electric melting.

- Development of direct reductive processes using solid reductant.
- Application of nuclear energy to steelmaking with availability of reducing gases for direct reduction or blast furnace injection.
- Development of continuous steelmaking.

Soaking Pits and Reheat Furnaces — Current and Near-Term

- Shift from natural gas and coke-oven gas to oil firing or blast-furnace gas and other coke-oven byproducts.
- Fuel conservation by use of techniques previously discussed.
- Increased use of induction heating for slabs and billets.
- Increased use of continuous casting.

Soaking Pits and Reheat Furnaces — Long-Term

- Use of coal, solvent refined coal or a slurry or emulsion of oil and solid fuel.
- Major reduction in fuel requirements by development of a process for production of steel strip directly from molten steel.

Heat-Treating and Finishing Operations — Current and Near-Term

- Available natural gas and coke-oven gas conserved in other mill areas will be used.
- Some installations will be converted to oil firing. In most cases, distillate oil will be required because of sulfur limits.
- Gas atmospheres produced from natural gas will be replaced to a large extent by byproduct nitrogen from captive oxygen plants.
- Electric heating will replace natural gas in cases where alternatives are not feasible.

Emission Problems

In most cases, those interviewed were not disposed to discuss specifics of emission control problems, except to state that every effort is being made at very heavy costs to comply with local standards. In many cases, attention was drawn to the large energy requirements for compliance with future standards, particularly those for fugitive emissions and building air evacuation.

It was generally agreed that not much is known about NO_x emissions from steel-mill equipment.

In one case, concern was expressed that flare-stack combustion of carbon monoxide might not be effective.*

Another concern was that baghouses and precipitators or scrubbers are not effective in the elimination of oil vapor from oily scrap. Combustion of such vapors or carbon monoxide adds greatly to the volume of gases handled in pollution control equipment.

Major combustion-related emission problem areas were given as:

- Coke ovens
- Sinter lines
- Open-hearth furnaces
- BOF and electric furnaces
- Acid recovery from waste pickle liquor.

Research Programs Recommended

Ironmaking

- Design, construction and operation of a form-coke demonstration plant (3000 ton/day).
- Completion of the development of direct coal injection into the blast furnace.
- Development of an improved process for desulfurization of coke-oven gas.

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*Because of the inherent difficulty of burning CO in a cold environment.

- Development of a process for hot briquetting of in-plant fines to replace sinter lines.
- Development of a process for agglomeration of mill scale.
- Design, construction and operation of a 3000 ton/day coke dry-quenching demonstration plant.
- Development of an improved process for treatment of coke-oven water discharge, particularly for cyanide removal.
- Development of an air recirculation process for sinter lines to reduce the volume of stack gases and to control carbon monoxide emissions.

Steelmaking

- Development of a process for control of NO_x from steelmaking processes.
- Development of processes to control emissions of oil vapors from charging oily scrap to BOF or electric furnaces.

Cement Industry

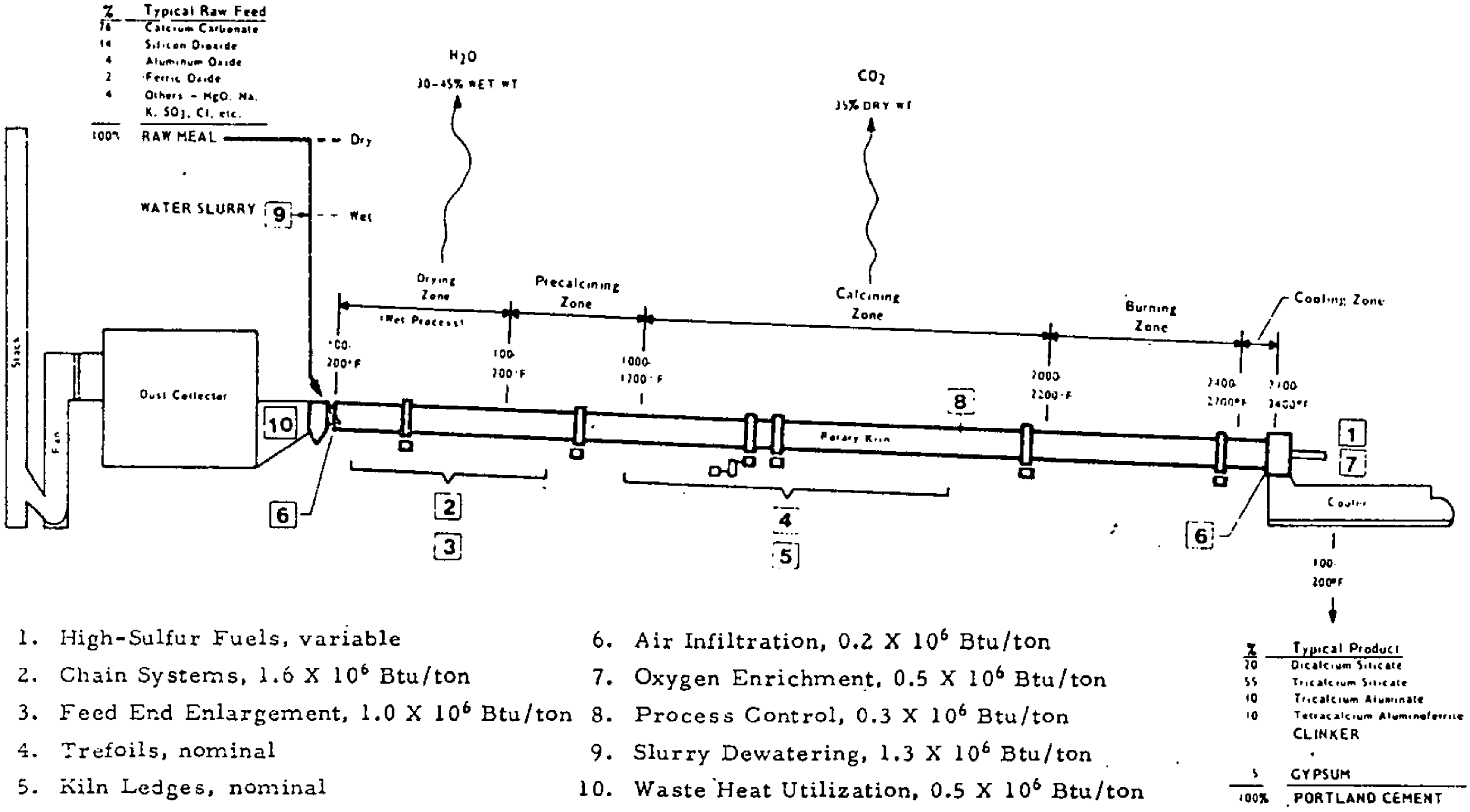
The manufacture of portland cement is accomplished in three operations: raw material preparation, including crushing and grinding; "burning" of the raw material to produce the clinker; and clinker processing, including cooling and grinding, as required. The primary energy-consuming process is the drying and calcining of the raw material, which consumes about 90% of the total amount of energy used in the entire manufacturing process.

Kilns

Two basic types of equipment are used in the burning (calcining) process — the rotary kiln and the vertical-shaft kiln. Most of the cement in this country is produced in rotary kilns — large refractory-lined steel cylinders that revolve at about 1 rpm. These kilns, as shown in Figure 1, vary in diameter from 12 to 25 feet and are up to several hundred feet in length. They are mounted at an angle slightly off horizontal, so that as they rotate, the charge moves by gravity from the high charging end to the low discharging end. The discharge end of the kiln is also the firing end. The burners used are similar to those used in the glass industry — high-velocity, non-premix burners. The primary fuels used are natural gas and coal; fuel oil accounts for only 15% of the total industry's fuel consumption.

The thermal efficiency of the rotary-kiln process varies considerably in practice, depending on the use of preheaters for raising the temperature of the raw material prior to charging into the kiln. The use of such preheaters not only reduces the energy consumption of the burning process, but also reduces the physical length of the kiln. Table 3 shows the effects of preheaters on energy consumption by the rotary kiln.

The primary difference between the wet and dry processes is the moisture content of the raw material charge. In spite of its



1. High-Sulfur Fuels, variable
2. Chain Systems, 1.6 X 10^6 Btu/ton
3. Feed End Enlargement, 1.0 X 10^6 Btu/ton
4. Trefoils, nominal
5. Kiln Ledges, nominal
6. Air Infiltration, 0.2 X 10^6 Btu/ton
7. Oxygen Enrichment, 0.5 X 10^6 Btu/ton
8. Process Control, 0.3 X 10^6 Btu/ton
9. Slurry Dewatering, 1.3 X 10^6 Btu/ton
10. Waste Heat Utilization, 0.5 X 10^6 Btu/ton

Figure 1. SHORT-TERM ENERGY-SAVING CONCEPTS IN THE U.S. CEMENT INDUSTRY

higher energy consumption, the wet process is used because of the raw material preparation, grinding and so on, in this form.

Table 3. ENERGY CONSUMPTION OF VARIOUS CEMENT-MANUFACTURING PROCESSES

Process	Energy Consumption, 10^6 Btu/ton of Cement	Production Over Average Current Practice, %†
Wet		
Long Kiln	5.94	--
Calcinator and Short Kiln	4.68	26.9
Semiwet		
Preheater and Short Kiln	3.60	43.8
Dry		
Long Kiln	4.68	--
Suspension Preheater and Short Kiln	3.15	50.8
Semidry		
Grate Preheater and Short Kiln	3.42*	46.6

*Includes 0.54 X 10^6 Btu/ton for drying.

†Average current consumption is that of long kiln.

The other major type of kiln is the vertical kiln. The concept of a vertical kiln is not new. Satisfactory performance of the vertical kiln requires that the raw material be dampened and nodulized prior to charging. In contrast to the rotary kiln, low-volatile fuels, such as coal, are required. In the vertical kiln, the nodules and fuel are fed continuously into the top of the kiln, and the clinker is extracted, cold, from the bottom by a rotating grate. Fuel consumption in a vertical kiln is about 3.6 million Btu/ton of clinker produced.

Other methods of reducing energy consumption in the cement industry include the installation of chain systems, kiln feed end enlargement, use of trefoils and kiln ledges, oxygen enrichment, increased process control, slurry dewatering, and waste-heat utilization.

Air Pollution Emissions

The major air pollutant emissions problem in the manufacture of portland cement is particulates, which occur in all phases of cement manufacturing from crushing and raw material storage, to clinker production, clinker grinding, storage, and packaging. Emissions also include the products of combustion of the fuel used in the rotary kilns; these are typically NO_x and small amounts of SO_x. However, many cement plants are switching fuel, from oil and gas to coal and petroleum coke. These alternative fuels may produce increased amounts of both NO_x and SO_x. However, no data are currently available. Table 4 presents a summary of emissions from cement-manufacturing processes currently in use.[1]

Most efforts to control air pollutant emissions focus on particulates because they are not only the greatest problem, but also the easiest to control. The most desirable method of control is to collect the dust and recycle it by injecting it into the burning zone of the kiln, thus converting it to clinker.

Combustion-related emissions are more difficult to control. Nitrogen oxide emissions may be controlled by such techniques as flue-gas recirculation, controlled mixing of the fuel and air, and changes in burner block designs. The controlling factor to implementing these techniques is economics. The emissions of SO_x, and

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[1] U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Publication No. AP-42, 2nd Ed. Research Triangle Park, N.C., April 1973.

Table 4. EMISSION FACTORS FOR CEMENT MANUFACTURING WITHOUT CONTROLS[a,b]

Pollutant	Dry Process Kilns	Dry Process Dryers, grinders, etc.	Wet Process Kilns	Wet Process Dryers, grinders, etc.
Particulate[c]				
lb/ton	245.0	96.0	228.0	32.0
kg/MT	122.0	48.0	114.0	16.0
Sulfur dioxide[d]				
Mineral source[e]				
lb/ton	10.2	--	10.2	--
kg/MT	5.1	--	5.1	--
Gas combustion				
lb/ton	Neg[f]	--	Neg	--
kg/MT	Neg	--	Neg	--
Oil combustion				
lb/ton	4.2S[g]	--	4.2S	--
kg/MT	2.1S	--	2.1S	--
Coal combustion				
lb/ton	6.8S	--	2.6	--
kg/MT	3.4S	--	1.3	--
Nitrogen oxides				
lb/ton	2.6	--		
kg/MT	1.3	--		

[a] One barrel of cement weighs 376 pounds (171 kg).

[b] These emission factors include emissions from fuel combustion, which should not be calculated separately.

[c] Typical collection efficiencies for kilns, dryers, grinders, etc., are: multicyclones, 80 percent; electrostatic precipitators, 95 percent; electrostatic precipitators with multicyclones, 97.5 percent; and fabric filter units, 99.8 percent.

[d] The sulfur dioxide factors presented take into account the reactions with the alkaline dusts when no baghouses are used. With baghouses, approximately 50 percent more SO_2 is removed because of reactions with the alkaline particulate filter cake. Also note that the total SO_2 from the kiln is determined by summing emission contributions from the mineral source and the appropriate fuel.

[e] These emissions are the result of sulfur being present in the raw materials and are thus dependent upon source of the raw materials used. The 10.2 lb/ton (5.1 kg/MT) factors account for part of the available sulfur remaining behind in the product because of its alkaline nature and affinity for SO_2.

[f] Negligible.

[g] S is the precent sulfur in fuel.

the other major combustion-related emissions, are inherently controlled in the burning process because most of the raw-material feed is converted to calcium oxide, which reacts with the sulfur dioxide. In addition, the presence of sodium and potassium compounds in the raw material aids in the direct absorption of sulfur dioxide into the product. Sulfur dioxide is also removed by this same mechanism in baghouse filters, in which the sulfur-dioxide-laden gases contact the collected cement dust. However, the degree of control by sulfur dioxide absorption depends upon the alkali and sulfur content of the raw material and fuel.

Cement Industry — Field Survey

A series of interviews were made with cement manufacturers to obtain information related to current operating practice, including fuel availability, potential for process modification, and pollution control problems. The companies interviewed employ both the wet and dry cement manufacturing processes and range from limited to widespread operations on a geographical basis, and from single to multi-plant operations.

The amount of energy required to produce one ton of cement ranged from a high of 7 X 10^6 Btu to a low of 4.3 X 10^6 Btu in a plant equipped with preheaters. Fuels consumed in kiln operation consist of natural gas, oil and coal. Users of natural gas reported curtailments ranging from 10% of base year (1972) use to complete curtailment during the winter season. The range of gas curtailment is subject to geographical location, and where intrastate supplies are available, the curtailment is less than from interstate sources. The price of natural gas has increased markedly from 1972 levels of $0.32/1000 CF to $0.50/1000 CF in early 1975. Further curtailments and increased prices are expected by the firms contacted.

Coal has been available in adequate amounts although the price has increased dramatically, in one case doubling over the period of one year. One firm reported a price increase of $\$0.35/10^6$ Btu, from $\$0.42/10^6$ Btu in 1972 to $\$0.77/10^6$ Btu in 1974. In another instance, a firm stated the contract price of coal had gone from $17.50/ton in 1974 to $27.50/ton in 1975. In contrast to this, the spot price of coal declined from $40/ton in 1974 to $31.00/ton in early 1975. As a result, this firm is seeking coal purchases amounting to 50% of its needs on the basis of a 5 year contract. In the past, spot prices had been lower than contract prices and it was possible to purchase coal cheaper on the open market. It is expected that this price relationship will not occur again and greater reliance will be placed upon contractual purchases. The sulfur content of the coal used is 2-1/2% or less. Some of the plants not currently using coal cannot do so because of physical limitations. Much space is required for coal-handling equipment and storage. Some older plant sites do not have access to additional space. Other plants do not have ready access to coal due to transportation problems, such as distance and cost.

One of the firms contacted had some kilns equipped with air preheaters and some without. A reduction in energy consumption of about 20% was reported for the kilns equipped with the preheaters. The amount of energy consumed in kilns with preheaters was about 4.3×10^6/ton, in kilns not equipped with preheaters the energy requirement is about 5.3×10^6 Btu/ton. Another company had installed preheaters on a trial basis and found them to be unsuccessful. It was found that the raw material clay contained an excessive amount of oil which caused fires. As a result, the company recovers waste heat for use in the steam generation of electricity.

Suspension preheaters require additional horsepower for controlling air movement within the plant. The following power requirements were given as examples:

Process	kWhr/bbl*
Wet processing plant w/o preheater	25-28
Dry processing plant w/o preheater	29-34
Wet or Dry w/preheater	38-43

*5.3 bbl/ton of cement.

In addition to the increased power requirements of air suspension preheaters, it was stated that the raw materials must be properly sized to achieve optimum utilization. The material must be in the range of 1/2-inch to 2 inches in diameter to assure circulation of the preheated air. Material smaller in diameter tends to cake and restrict air flow. If the raw materials used have a high level of alkali salts, the cement produced will have a high alkali content. The raw materials can pick up the sulfur emitted in the waste-heat stream and add to the problems of sulfur control brought about by the sulfur content of the fuel used in firing the kiln.

As in the case of coal, some older plants can be restricted in the application of preheaters by the amount of space available within the plant for the installation. Such an installation could be readily incorporated into the design of a new plant.

None of the firms interviewed had experience with the operation of a vertical kiln. One firm had no knowledge of any experimental testing. The other firms followed the work going on in Europe and Japan with vertical kiln operation. From the impression given in the course of the interviews, it does not appear that vertical kilns will be accepted favorably by U.S. industry. Each of the firms stressed the capacity limitations of the vertical kilns, many such kilns would be required to equal present installed capacity. A second disadvantage of the vertical kiln is poor product quality. The kiln is stationery and the raw material falls by gravity through the kiln. The raw material has a tendency to cake and block passage because of the lack of agitation.

Two of the firms contacted expressed an awareness of oxygen enrichment as a means of reducing fuel consumption. Tests results were unsatisfactory; in one instance the amount of fuel required was only reduced by 5%. Oxygen enrichment is not economical in terms of oxygen cost and does not conserve fuel when the amount of energy required to produce the oxygen is taken into consideration.

Of the firms contacted only one had chain systems installed in their kilns. One firm utilized waste heat for electricity generation and the other used waste heat in the operation of preheaters. The firm using chains reported satisfactory results and stated that the temperature of waste gases was reduced to the lowest practical limit.

All of the firms were able to comply with local, state, and Federal emission requirements by the use of baghouses. These systems trap particulate matter which evolve primarily from the kiln and the clinker cooler. Electrostatic precipitators have been installed on a limited basis, but were found less satisfactory than baghouses. Corrosion of the unit and water disposal were two of the main problems encountered.

Disposal of the particulate matter is a major problem in the industry. One firm is faced with the problem of disposing of 650 tons of waste per day and this is expected to double in the next ten years. The material must be hauled by truck to suitable landfill sites. In some states the landfill site must be specially prepared to prevent seepage of salts into sub-strata water. In many instances the expense of equipping an older kiln with the proper dust-handling equipment cannot be economically justified and have been phased out of service.

The solid particulate matter cannot be recycled into the raw material stream because of its alkaline content. The alkali content of low-alkali cement cannot exceed 0.6% per ASTM standard. If this standard were revised upward to 1.5%, it was stated that all of the collected particulate matter could be recycled and the land disposal problem would be solved. The alkali salts react with the aggregate used in the final concrete product, and the cement manufacturer has no control over the type of aggregate used. The opinion was given that increased alkalinity would not affect the quality of the cement.

Emissions of SO_x and NO_x are not as large a problem to the industry. SO_x emissions are controlled primarily by use of low-sulfur fuels and controlled burning practice. The sulfur in the waste-heat stream reacts with the particulates collected and the raw materials as they are fed into the kiln. NO_x is not a major problem because of the absence of legislation.

Suggested areas of further research included —

- Investigation into the substitutability of Type 2 cement for Type 1 cement.
- Investigation of alkali reaction problems that are of a local geographical nature.
- Improved process control to monitor combustion practice to conserve fuel.
- The development of combustion technology to reduce NO_x.

Glass Industry

The manufacture of glass involves three major energy-consuming processes: melting the raw materials, refining the molten glass, and finishing the formed products (as shown in Fig. 2). Typically, about 80% of the energy consumed by the glass industry is for melting and refining, and 15% is for annealing. The remaining 5% is for "others" such as mechanical drives and conveyors (shown in Table 5).

Table 5. BREAKDOWN OF ENERGY CONSUMPTION BY THE GLASS INDUSTRY IN 1971*

	Flat Glass (SIC Code 3211)	Containers (SIC Code 3221)	Pressed and Blown Glass (SIC Code 3229)	Total
Glass Produced, 10^6 tons	2.56	10.90	3.50	16.96
Energy Consumption, 10^{12} Btu				
Melting	44.7	104.3	50.5	199.5
Annealing	8.4	19.6	9.5	37.5
Other	2.8	6.5	3.2	12.5
Total Energy Consumption, 10^{12} Btu	55.9	130.4	63.1	249.4
Average Energy Consumption for Melting, 10^6 Btu/ton of glass	17.5	9.6	14.4	11.8
Average Energy Consumption for Entire Production, 10^6 Btu/ton	21.8	12.0	18.0	14.7

* Excludes energy consumed for electricity generation.

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Glass Melting and Refining

Both continuous melters and batch melters are used in the glass industry, depending upon the output. Continuous melters are used in the production of large-demand container glass (bottles, jars), flat glass, and plate glass. Batch melters are used for specialty glasses, high quality optical glass, and hand-blown glass products. Continuous melters are normally maintained at temperature throughout a compaign, which might extend from 4 to 6 years. Batch melters are shut down frequently and allowed to cool off. Table 6 is a summary of the melting and refining equipment used in the glass industry.

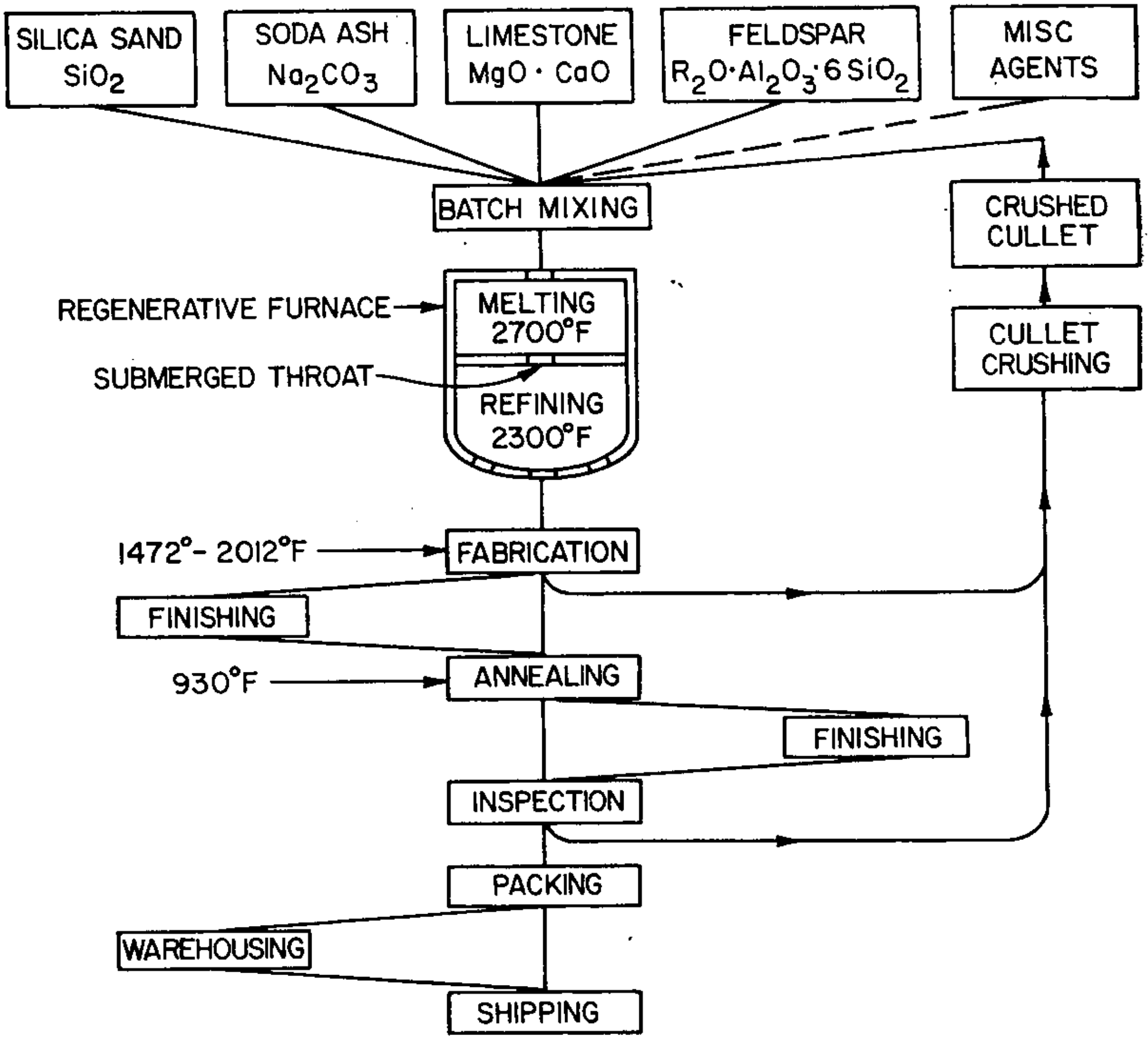

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Figure 2. FLOW DIAGRAM FOR SODA-LIME GLASS MANUFACTURE

Table 6. GLASS-MELTING AND REFINING EQUIPMENT

Continuous Melters
- Melting Tank
- Refining Section With Premix Burners

Batch Melters
- Unit Melters or Day Tanks
- Batch Melters for Optical and Special Glass
- Crucible or Pot Melters

Continuous Melters

Continuous melters in the glass industry are reverberatory furnaces equipped with checker-brick regenerators for preheating combustion air. Depending upon the firing arrangement used, the melters are classified as end-port or side-port fired (shown schematically in Figures 3 and 4). However, further breakdowns are made, based on the location of the burners relative to the air inlet ports. The burners can be placed over the air ports, through or at the air port sidewalls, or underneath the air ports. Each firing configuration produces a different flame geometry with different heat-release characteristics, yet the overall thermal efficiency of furnaces with any of these configurations is typically about 30%.

The fuels consumed in the melting process are primarily natural gas and fuel oil. However, the use of submerged electrode electric melting is increasing due to the air pollutant emissions and low thermal efficiency of fuel-fired melters. Typically, a fuel-fired melter consumes about 6.0 million Btu/ton of glass melted, compared to about 3.0 million Btu/ton of glass melted in electric melters (excluding energy consumed for electricity generation). However, this figure is known to vary considerably, depending upon such factors as furnace insulation, combustion control equipment, molten glass depth, and type of glass being produced.

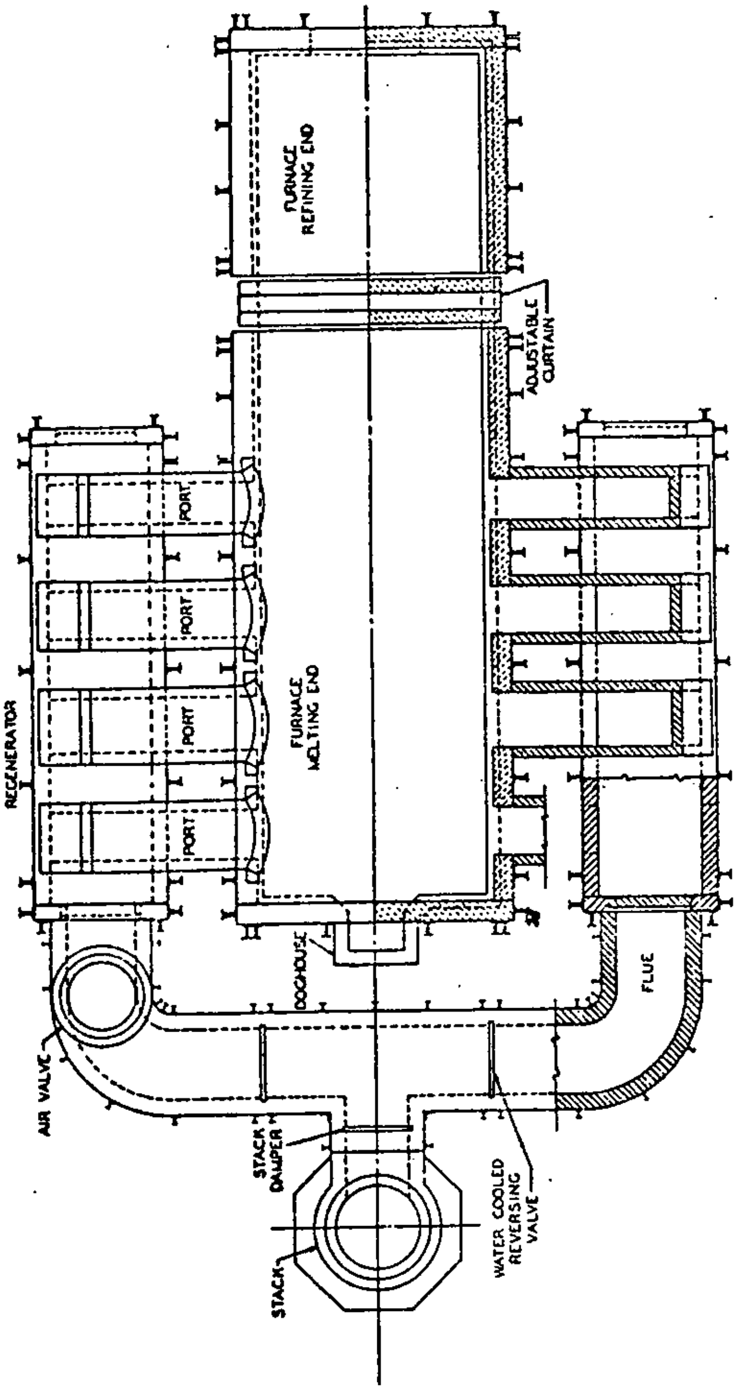

Figure 3. PLAN VIEW OF SIDE PORT FLAT GLASS FURNACE

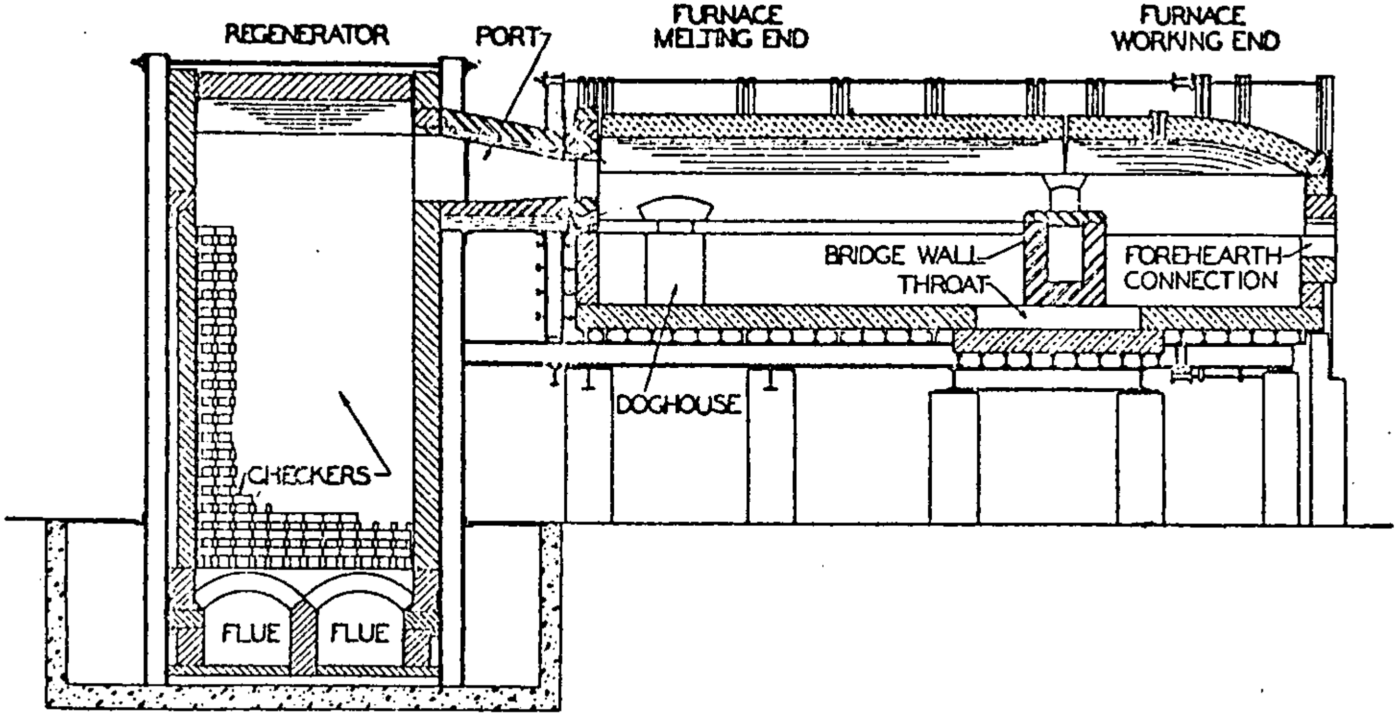

Figure 4. LONGITUDINAL SECTION OF TYPICAL END PORT TANK

Note that these fuel consumption figures apply to furnaces during melting operations. However, data on energy utilization (Table 5) indicate that energy consumption is actually higher because operation is suspended many times during the year for breakdowns and holidays. During these periods, the furnaces are idled to maintain furnace temperature while production stops. Thus, energy is consumed but no glass is produced, thereby increasing the overall average energy consumption per ton of glass produced. An even greater source of discrepancy is the variation in the amount of cullet, i.e., recycled glass, used from one glass plant to the next. The amount of cullet charged varies from 10% to 30% of the total raw material charged to the melter. Lower percentages of cullet charged result in higher fuel consumption. In general, economic considerations prevent higher percentages of cullet from being charged.

Continuous Refineries

After completion of the melting phase, the molten glass flows into the refining section where the glass temperature is reduced and the glass is degassed. Refiners vary from plant to plant. In some cases, it is an integral part of the furnace, separated from the molten area by a wall, but taking its heat from the combustion in the melter. In other cases, the refiner is separate from the furnace and is heated with burners of its own, separate from the melter. Premix burners are used in this application, and due to strict quality control of characteristics such as color, natural gas is the preferred fuel. The total energy consumed for melting and refining glass represents about 80% of the total energy consumed by a typical glass manufacturing plant.

Batch Melters

A very large amount of glass, particularly for pressed or blown products, is produced in batch melters. These are classed as day tanks or unit melters, and crucible or pot melters. Crucible or pot melters are small rectangular or circular structures. Open pots — round crucibles with capacities of 1 to 2 tons of glass — are used in rectangular furnaces in which thick plate glass is cast or special glass compositions are made. In circular pot furnaces, covered pots are used for melting relatively small amounts of special compositions, thus protecting the glass from the flames. One advantage of pot furnaces is that different glass compositions can be handled simultaneously, and the temperature of each pot is controlled individually, within a limited range. Pot furnaces are typically, although not always, provided with regenerators for fuel economy.

Day tanks, or unit melters, are built up with refractory blocks, thus differing from the pot, which is a single piece of refractory. Day tanks are usually fired separately, rather than in groups, and they have greater capacities than pots. In addition, they can be heated to higher temperatures than pots, thus permitting the melting of compositions not particularly adaptable to pot-melting. Refining of the glass in both pot melters and day tanks is carried out as part of the melting operation in the same physical unit. The fuels used in batch melters are natural gas and oil, although some melters which produce optical-quality glass or colored glass may be restricted to using natural gas because of the potential adverse effect of liquid fuels on the quality of these glasses.

Glass Annealing

Annealing is the other major energy-consuming operation in the glass industry, accounting for approximately 15% of the total energy consumed. While annealing of large handmade ware may be carried out in batch ovens, most ware from either batch or continuous-melting operations is annealed in large tunnel-type ovens provided with moving mesh-belt conveyors. These ovens, known as lehrs, are temperature zoned, starting at about 1200°F, at the glass input and decreasing in such a way that the cooling curve of the ware precisely matches that required to obtain a strain-free product. The size and arrangement of the lehrs depends on the characteristics of the ware being annealed. Large ware with thick walls requires slower annealing rates than small ware with thin walls.

Lehrs are heated by convection, radiation, or a combination of the two. The most effective means, which provides the greatest control and temperature uniformity critical to the production of strain-free glass, is by zoned, convection lehrs with internal distributors to obtain lateral temperature uniformity. External fans and heater boxes are used in these lehrs, which makes it possible to use either natural gas or oil as fuel. However, some lehrs are direct-fired by atmospheric or premix burners or by excess air burners. In this case, natural gas is the only fuel used so that the glass is not likely to be contaminated by the "clean" combustion products.

Annealing lehrs generally operate at a thermal efficiency of only 20%. Much of the inefficiency is due to poor maintenance and operating practices. Most lehrs leak a considerable amount of unwanted cold air into their chambers or lose heated air through unwanted openings.

Air Pollution Emissions

In addition to being the primary consumer of energy in the glass industry, the glass-melting furnace is also the primary source of air pollutant emissions. The primary emissions are particulates, sulfur oxides (SO_x — sulfur dioxide and sulfur trioxide), nitrogen oxides (NO_x — nitric oxide and nitrogen dioxide), and carbon monoxide. Hydrocarbons are not a problem if proper combustion conditions are maintained. Table 6 summarizes emissions from various glass-melting tanks as measured by a number of investigators.

Air pollution emissions from annealing lehrs are not considered to be a big problem. These emissions (CO and unburned hydrocarbons) occur almost entirely as the result of incomplete combustion

Table 6. AIR POLLUTANT EMISSIONS FROM VARIOUS PRODUCTION GLASS MELTERS

Investigators	CO	NO_x	Particulates, lb/hr	Halogens	SO_x
	ppm			ppm	
IGT[2]	35-50[a]	490-700	6-8	1.0	28[e]
Ryder and McMackin[4]	0-5[b]	450-600	--	--	--
Stockham[5]	375[c]	340	--	7.1	267
Arrandale[1]	--	--	2-10[d]	--	--
Netzley[3]	--	--	2-10[d]	--	--

[a] 8% excess air.

[b] 25-45% excess air.

[c] Excess air unknown.

[d] Variable with production rate.

[e] Natural gas fired.

resulting from improper use of the combustion equipment. The one exception is SO_x, which is emitted because of the sulfur in the fuel. However, since oil is the only fuel containing sulfur used in lehrs and its use is very limited, the amount of SO_x emission is insignificant.

Factors Affecting Air Pollutant Emissions

Several factors influence the emission rate of particulates from a glass-melting furnace, including batch composition, batch preparation, and type of fuel. The production rate of the furnace also is a factor.

Measurements of stack emissions from a glass melter have shown that the particulates emitted are primarily sodium sulfate, which is a minor ingredient of most glass batch. In the furnace, it vaporizes and decomposes to form elemental sodium and sulfate. When these gases pass through the checker-brick and are cooled, sodium sulfate is re-formed. Only about 40% of the sodium sulfate charged into the furnace is vaporized; the remainder goes into the glass. In addition to the sodium sulfate, a small amount of raw batch that is carried out of the furnace by the flue gases is emitted. This emission can be minimized by proper batch preparation, consisting primarily of wetting the material before charging it into the furnace.

The amount of SO_x emitted from a furnace depends on 1) the sulfur content of the fuel and 2) the amount of sulfur-bearing compounds in the raw materials. Consequently, natural-gas-fired furnaces generally exhibit lower SO_x emissions than oil-fired furnaces unless the sulfur has been removed from the oil. Measurements of SO_x emissions from a batch melter charged with batches of various sulfur content showed a direct correlation between sulfur in the batch and SO_x emitted. The greater the sulfur content of the raw batch, the higher the SO_x emissions.

The amount of NO_x emitted from a glass-melting furnace depends upon several factors, some of which are not understood. One important factor is flame temperature: NO_x formations in the furnace increase as flame temperature increases. For example, during a recently completed experimental program, NO_x emissions were measured during a complete firing cycle of a glass melter. NO_x emissions were highest at the beginning of the firing cycle and then, as the cycle continued, decreased by about 30%. At the beginning of the firing cycle the combustion air is preheated to a higher temperature, which results in a hotter flame than at the end of the cycle, when the checker-brick and hence the air have cooled considerably. Other major factors in NO_x formation in a glass melter, such as flame velocity and recirculation patterns of flue gases, are being studied.

Methods of air pollution control currently in use in the glass industry are primarily electrostatic precipitators (ESP) and baghouses for particulates, and the use of low sulfur oil for SO_x emissions. In terms of equipment costs, ESP and baghouses are about the same upon installation. However, less energy is consumed by ESP. To be effective, baghouses require a substantial pressure differential which creates a need for a substantial amount of horsepower to move the particulate-laden air through the house. In addition, baghouses require more maintenance than ESP to be totally effective.

One of the problem areas faced by the glass industry in its attempts to clean up their emissions is the variances in regulations that exist from one state to the next. More than one company interviewed indicated that because of these variances, different solutions must be implemented to bring two plants, located in different states but otherwise identical, into compliance. Thus in one state, baghouse systems may adequately control a company's particulate emissions, while in a neighboring state a process modification, the use of electric melters instead of fossil-fuel-fired melters is necessary. Such variances are not only costly to a company, but also may dramatically effect energy utilization as in the above example.

Other emissions, such as carbon monoxide and hydrocarbons, can be controlled easily with proper combustion conditions. If opal or green glass is being produced, halogens such as chlorine and fluorine also are emitted in very large quantities from a fossil-fuel melter. However, the industry has converted completely to electric melting, and this switch has eliminated these emissions.

Glass Industry-Field Survey

According to the glass industry, there exist several process modifications for potential implementation by the industry sometime in the future which would affect energy utilization and/or air pollution emissions. These are —

- Expansion of process monitoring and control capacity
- Electric melting
- Electric boosting
- Oxygen enrichment
- Raw batch preheating
- Raw batch agglomeration
- Use of low-temperature heat to drive compressors
- Augmentation of heat transfer from flames
- Submerged combustion.

Of these modifications, only the first three are considered by the industry to have potential for implementation in the near future. This is due primarily to the fact that such techniques are economically feasible and technical feasibility has been demonstrated to the satisfaction of the industry, so that implementation is already occurring. According to industry, the latter modifications listed are generally considered to be economically unattractive or technically unfeasible in spite of the published data to the contrary. The following discussion presents a brief description of the modifications involved and the industry's viewpoint concerning implementation with respect to each.

Expansion of Process Monitoring and Control Capacity

There are several modifications which can be made in the area of process monitoring and control which will favorably influence the utilization of energy in a downward direction, according to persons interviewed within the industry. One such modification is the use of improved temperature-sensing devices for continuous-process monitoring. For example, infrared sensors focused on critical areas of the melter, such as the optical block on the bridgewall, which are used to gauge melter performance, can be used not only to continuously monitor melter temperature, but also the signal from such a unit can be used to control fuel input based on melter temperature. Another such modification is the use of flue-gas analyses to monitor excess air and maintain it at a minimum level. None of these monitoring techniques are expensive and all of them would contribute to improving the efficiency of operation.

Electric Melting (and Boosting)

Primarily for purposes of reducing air pollutant emissions, the glass industry strongly supports the implementation of electric melting and boosting. Electric melting, as a method of producing glass, has been proven technically and, in most cases, economically feasible by virtue of its relatively widespread usage within the industry. (Actually, electric boosting, wherein a fuel-fired melter is supplemented by electric melting, is very popular and more prevalent within the industry than pure electric melting.)

Oxygen Enrichment

Oxygen enrichment is a technique whereby pure oxygen is added to the combustion air of a fuel-fired melter, resulting in an increase in flame temperature, which in turn results in a reduction in fuel required to melt a ton of glass, or alternatively allows a melter operating at design capacity to boost its production above design capacity. Based on the results of the interviews with glass manufacturers, oxygen enrichment is a long term goal, primarily because acceptance by the industry requires substantial changes in fuel and oxygen costs to economically justify implementation.

Raw Batch Pretreatment

The area of raw batch pretreatment includes batch agglomeration, or compaction, and preheating of the batch prior to charging into the furnace. Most companies interviewed feel that batch agglomeration is not economically justified within the near term for reasons of reduced energy utilization or reduced particulate emissions. However, at least one major glass manufacturer has recently put into operation several pelletizing lines to supply pelletized batch to the melters. At the present time, there are no data available regarding the specifics of this operation.

Coupled with the compaction of glass batch is the idea of preheating it prior to charging into the melter. It is clear that such a process must be coupled with a batch-compaction process in order to minimize batch losses during preheating and to minimize particulate emissions from the batching operation. The industry contends that preheating of the batch will cause it to become sticky, making the charging operation next to impossible.

Submerged Combustion

Submerged combustion is a melting process whereby the fossil-fuel burner is located beneath the molten glass surface and the hot combustion products pass through the glass resulting in a very high rate of heat transfer from the gases to the glass. Because the product from this type of melter is foam glass, that is, it contains millions of air bubbles, it is unacceptable to the industry as such for use without substantial refining. The only possible use for submerged combustion would be in a premelter, which at least one company has implemented. Because the refining step requires a substantial amount of energy (more than usual), it is not clear that there is a reduction in the overall amount of energy consumed to melt the glass. Consequently, substantial development is still required before it will become acceptable to the industry, making implementation long-term at best.

Augmentation of Heat Transfer From Flames

This is a rather nebulous area for consideration in that there are potentially numerous things which can be done to improve heat transfer from the flame to the molten glass. One such example is the use of devices which allow an operator to accurately and precisely position the burners. A second example is the injection of water vapor into the flame which theoretically increases the radiative properties of the flame, resulting in an increase in heat-transfer rate. The entire area of augmenting heat transfer has great potential, according to the industry, but implementation of most of the developments is deemed to be long term.

Use of Low Grade Thermal Energy

At least one company interviewed expressed the opinion that waste heat from the melting process, most of which is below 1000°F and consists of 20% of the energy that goes into melting the glass, could be used to directly drive turbines for air compressors which would then be used in the blowing operations. Alternatively, but not as efficient, was the suggestion that this heat be used to drive turbines in the generation of electricity. While such practices are not currently used, with some development, usage might increase in the long term.

Improvements in Equipment Design

Because of the rate at which equipment is replaced within the glass industry, implementation of improvements in equipment design are considered long term. Improved energy utilization is expected from the application of better insulating techniques, improved regenerator design, and improved firing patterns by burner placement. Annealing lehr efficiency is effected by numerous design considerations. Among the most prominent considerations are the use of lightweight lehr belts, method of belt return, proper insulation of the heating zone, use of radiant burners in the heating roof section, and design to prevent forward drift. Plant layout to minimize transit time of the glass between the forming machine and lehr is also important. As indicated, most of these design modifications are considered long term in terms of implementation and impact.

Aluminum Industry

Primary aluminum manufacture is divided into four basic operations: mining the bauxite; refining the bauxite into alumina; smelting the alumina into aluminum; and melting and reheating of the aluminum for forming, casting, rolling, and shaping. Since this program is concerned with the combustion processes in aluminum manufacture, this categorization will only deal with the bauxite refining process in primary aluminum manufacturing and all of the heating processes in secondary aluminum manufacturing.

Bauxite Refining

The refining of bauxite to obtain alumina is accomplished in the Bayer Process. The objective of this process is to separate out the impurities, which include iron oxide, silica, and titanium dioxide.

The first step in the Bayer Process is digestion of the bauxite into a solution of hot caustic soda. The product of the digestion process is a liquid containing dissolved alumina. This liquid is cooled and hydrate alumina is allowed to precipitate out of the solution. The precipitate is filtered, washed, and then heated in rotary kilns at 1800^0F, resulting in commercially pure, dry alumina. The rotary kiln equipment and technology are similar to that used in the cement industry.

Smelting

The smelting process, wherein alumina is converted to aluminum, is an electrolytic process, and thus does not concern this program. However, the process depends on the production of carbon anodes for use in the pots and this production requires large amounts of fuel, not only as a source of carbon, but also for drying and baking the anodes once they are formed. The drying is done in rotary kilns or vertical-shaft kilns, similar to those used in the cement industry.

Baking is done in batch-type box furnaces or continuous ring-type furnaces.

Batch-Type Furnaces

Batch-type furnaces are, typically, box furnaces, fired primarily with gas or oil and varying load capacity from 100 lb to over 200, 000 lb. Because they are batch-type furnaces there is a considerable amount of energy wasted during a typical cycle, which includes charging the material, heating up the furnace for baking, and then cooling down the furnace for unpacking and reloading with fresh charge. Fig. 5 shows a typical cycle, relating the time and temperature for baking carbon. The cycle varies according to such parameters as type and size of electrodes processed and the size of the furnace being used. Typically, a box-type furnace consumes about 18 million Btu/ton of carbon baked.

Ring-Type Baking Furnaces

Most of the furnaces used for anode baking are of this type. The operation of a ring furnace is cyclical and can be broken down into five steps: loading, preheating, heating, cooling, and unloading. Most ring furnaces are gas-fired, using either natural gas or producer gas. They are also regenerative furnaces, thus affording economies in fuel consumption. Additionally, the waste heat of the combustion products is used in the preheating step. Such economies result in a typical fuel consumption rate of 9 million Btu/ton of carbon baked — about 50% less than the box-type furnaces.

Primary Aluminum Melting

Aluminum melting is accomplished in furnaces at temperatures of about 2000°F. The types of furnaces used for melting are —

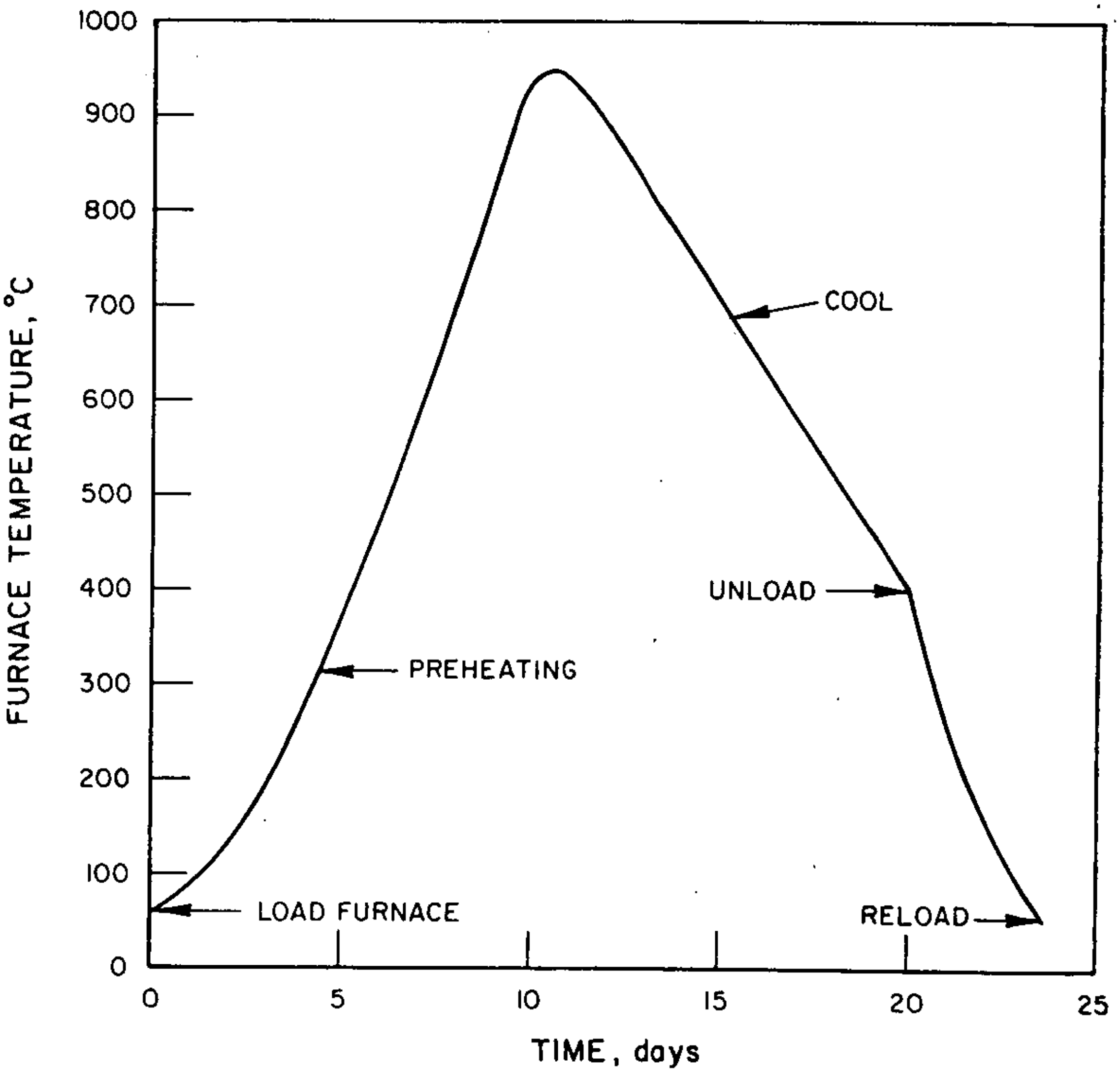

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Figure 5. TYPICAL OPERATION AND THERMAL CYCLE FOR BAKING CARBON

- Large and small stationary tilting reverberatories
- Holding furnaces (reverberatories)
- Tilting, barrel-type furnaces
- Stationary and tilting crucible furnaces
- Dry-hearth melters.

The type of furnace used depends on a number of parameters including —

- Quantity of metal required
- Type and form of charged materials
- Desired melting rate and temperature control
- Type of product.

Of the various possible types of furnaces, batch-type reverberatory furnaces are the most commonly used. They are usually rectangular, refractory-lined boxes with burners at one sidewall and charging doors above the metal line along one side. These melters vary in capacity from less than 5 tons to over 80 tons. Aluminum melters, considering only melting, are designed for melting rates as high as 65 lb/sq ft-hr. If charging, holding, and discharging are also considered, the melting rate decreases to about 35 lb/sq ft-hr. Fuel efficiency for these melters is about 30%. Dry-hearth furnaces, another type of reverberatory furnace, can melt at a rate of 100 lb/sq ft-hr, but are not used for high-quality aluminum-alloy production.

Crucible or Pot Furnaces

Crucible or pot furnaces are used in cases where the required capacity, generally 30 to 1000 lb, is low and the need for flexibility is high. Crucible furnaces are used for melting as well as holding. They may be stationary or tilting, or the crucible may be removed and transferred to the casting area. Heat transfer in a crucible furnace is through the crucible walls. Burners are situated tangentially around the furnace to supply uniform heating to the crucible. The modes of heat transfer to the pot are primarily convection and radiation; however, in the case of convection, direct impingement is avoided as hot spots will reduce crucible life and interfere with the control of the metal temperatures. Use of these modes of heat transfer results in an average fuel efficiency of about 15% to 20%, as opposed to 30% in reverberatory furnaces where heat is transferred directly from the flame and surrounding refractories to the metal surface.

Burner Equipment and Firing Arrangement

Both premix and nozzle-mix burner equipment are used for aluminum melting. Premix burners, both the aspirator and inspirator types, are used primarily on small crucible melters, particularly those that are fired tangentially. Only nozzle-mix burners are used on the large-scale melters because of the longer, more luminous flame and adaptability to dual fuel firing. Normal practice is to use a few large burners (10 to 20 million Btu/hr) rather than several smaller burners. Some burner designs are quite similar to those used on steel-mill soaking pits having the capability of adjusting the flame geometry to suit melting-chamber requirements. Roof-firing with radiant burners, although theoretically ideal for heating aluminum where flame impingement on the bath surface is undesirable because of high oxidation loss, is not used on the large, side-charged melters because of the severe splashing problems encountered. Radiant burners are, however, used on smaller reverbs that are charged through endwall charging wells and on holding furnaces where a relatively quiescent atmosphere is very desirable.

One of the preferred firing arrangements for large reverbs is the W-flame, two-pass geometry. In this arrangement, two burners are located in one endwall, with the flue port located below the burners on the furnace centerline just above the metal line. The high-velocity, hottest flue products are well above the bath and transfer heat directly to the arch, while the cooler, low-velocity combustion products are distributed over the entire bath surface area and transfer heat to the bath with a minimum of flame impingement.

For the holding furnace, which requires a much lower input, single-pass firing is more desirable. The burners are at one end of the furnace and the flue is at the other, avoiding the danger of short-circuiting to the flue that is inherent with the W-flame design at low burner input.

Natural gas, LP gases, distillate and residual fuel oils, and electricity can all be used satisfactorily to heat the large reverberatory melters, although natural gas has been preferred because of low cost, cleanliness, and controllability. Induction melters have reached the 15-ton melter-capacity level. However, the interest in induction melting in the program is low and will not be considered in detail.

Aluminum Reheating for Forging and Extrusion

Almost all of the fuel-fired furnaces used for heating aluminum and aluminum alloys for forging and extrusion are of the convection type and are indirectly heated. Indirect heating with radiant tubes is preferred, particularly for alloys sensitive to surface reactions with combustion products. The heating furnaces are typically continuous, using chain or slot conveyors and distributing the heated air through ported or slotted tubes or through plenum chambers. The wind-flow distribution systems can be transverse, longitudinal, or vertical, depending on the mass, size, shape, and loading of the stock being heated; allowable temperature drop in the circulating wind; required heating rate; and allowable temperature variation in the heated stock. Heating-wind temperatures is normally about 75°F hotter than the final stock temperature.

A flame-impingement furnace is frequently used for heating "soft" aluminum alloys for extrusion but not for heating the "hard" alloys because of adverse effects on surface metallurgy and the inability to control billet temperature within required limits. In this furnace, the billets are conveyed on alloy brackets fastened to a heavy-duty conveyor chain that runs cold below the bottom of the furnace. The alloy brackets extend through a slot in the bottom of the furnace and support the billets on the centerline of the heating chamber. A row of premix "blast" burner tips fire horizontally at the billet centerline. Heating rates of about 2 to 3 minutes per inch of billet thickness are normally maintained. The lower half of the furnace is made up of two separate, sequented, cast-refractory sections individually supported by the furnace structural elements. The top part of the furnace is made up of a number of half-circular cast refractory sections with flue ports at the top. The flow of ambient air up through the conveyor slot, by draft effect, cools the chamber walls to approximately the local billet temperature. This minimizes the risk of billet overheating, or even melting, during production delays. These gas-fired, rapid, billet heaters represent major competition to 60-cycle induction heaters for aluminum extrusion. Input to each furnace zone is controlled by a radiation-type, temperature-measurement instrument sighting at the billets through an open tube between the furnace zones. Unfortunately, if a billet is not loaded onto each conveyor fixture, the instrument sights on an open space and calls for maximum input, incurring the danger of overheating or melting the billets. Typical operating problems with the impingement billet heaters are a) poor billet temperature control after a production delay or a change in production rate, b) overheating or melting of billets if a gap is left on the conveyor, c) conveyor maintenance, and d) refractory failure.

Forging or extrusion temperatures for aluminum and for most aluminum alloys are usually 750^0 to 850^0F. Some of the "hard" alloys are forged at 900^0 to 920^0F. The heat content of aluminum above 700^0F and corresponding fuel-input requirements in millions of Btu/ton for various efficiency levels are shown in Table 7.

Table 7. HEAT CONTENT OF ALUMINUM WITH FUEL-INPUT REQUIREMENTS FOR VARIOUS EFFICIENCY LEVELS

	Heat Contents		Gross Efficiency, %		
Temperature, ^{0}F	Btu/lb	Net, 1000 Btu/ton	10	20	30
			10^6 Btu/ton		
700	146	292	2.92	1.46	0.97
800	172	344	3.44	1.72	1.15
850	185	371	3.71	1.85	1.24
900	199	398	3.98	1.99	1.33
1000	277	454	4.54	2.27	1.51

Almost all convection reheat furnaces use natural gas because of favorable price, controllability, and freedom from carbon deposition or pollution-control problems. Atmosphere control is initially important for direct-fired furnaces, and the atmosphere is most readily controlled with natural gas firing. In indirect heating with radiant tubes, application of residual oil firing is extremely difficult.

From the available data, it appears that the convection heaters for forging and extrusion operate at very low efficiency level, probably averaging 10% to 15% overall. The major reasons for the low efficiency level appear to be conveyor reheating, excessive air infiltration, and high flue-gas temperature from radiant-tube firing. The most important single factor affecting efficiency is air infiltration. Convection-heating furnace designers estimate that 100 % excess air is heated because of leakage losses.

About the only effective means for improving the efficiency of existing convection-furnace designs using radiant-tube heating is to install recuperative radiant-tube burner systems. A fuel saving of 20% to 25% can be attained by preheating combustion air to the 650° to 750°F range.

Air Pollution Emissions From Primary Aluminum Manufacture

Information regarding air pollution emissions is very limited, and then it is restricted primarily to discussions of fluorides and particulates. No data are currently available on combustion-related emissions from primary aluminum manufacturing processes. However, there is no reason to believe that these emissions will be any different than those from similar processes in other industries. Thus, it can be presumed that CO, hydrocarbons, nitrogen oxides, and sulfur oxides are being emitted. The extent to which these emissions are a problem remains to be determined.

The product of the secondary aluminum industry is a metallic aluminum alloy in the form of 15 and 30-lb ingots, 1000-lb sows, or hot molten alloy. Some scrap is melted to produce a deoxidizer for steel mills in the form of a notched bar or shot.

The scrap raw material is purchased on the open market in various forms. The scrap can be divided into two categories: residues and solids. Residues include dross and skimmings from melting operations in the primary aluminum industry, from fabricators, and from foundaries. Dross, the scum that forms on the surface of molten metal, is high in aluminum content. Solids consist of borings, turnings, new clippings and forgings, old castings, sheet, and castings containing iron.

The quantity of energy required to melt 1 pound of secondary aluminum is about 5% of the amount required to produce the same quantity of virgin aluminum from bauxite in the primary industry. Depending upon the size and condition of the melting furnace, approximately 10, 000 Btu of energy is required per pound of product produced, excluding the energy required to operate pollution control devices.

Three basic operations are employed in recovering aluminum from scrap materials: preparation prior to smelting; charging, smelting, and refining; and pouring the product. The operations vary among different smelters and result in a variance in the quantity of energy required.

Presmelting varies according to the type of scrap. Solids are sorted, sweated, dried, and reduced in size, and residues are reduced in size and screened to separate the metal values from the contaminants. High-quality scrap consisting of forgings and new clippings has very little contamination and usually is sorted only to remove foreign metal.

Borings and turnings are heavily contaminated with cutting oils. The material is received in intertwined pieces that are crushed in ring crushers or hammermills. After crushing, the material is fed into gas- or oil-fired rotary dryers to burn off oils, grease, and moisture. The material then is screened to remove fines and passed through a magnetic separator to remove available iron.

After pretreatment, the aluminum scrap is charged into reverberatory furnaces in a series of seven steps: 1) charging the scrap into the furnace, 2) adding fluxing agents, 3) adding the required alloy materials, 4) mixing, 5) removing magnesium, 6) degassing, and 7) skimming. All these steps are not practiced by all smelting operators, and the choice of steps depends upon the desired end product.

The amount of time required to fully charge a furnace depends upon its size, which can range from 10 to 90 tons. It takes from 4 to 75 hours to fully charge a furnace, the average time being 24 hours. The time required to complete a smelting cycle depends upon the size and design of the furnace, fluxing procedures, alloy requirements, and heat input.

A typical secondary aluminum recovery plant consists of two to four — sometimes as many as 10 — reverberatory furnaces which are predominantly natural gas-fired. A furnace with a 40-ton nameplate capacity rating may actually produce 20 tons of product per heating cycle. Approximately one-third of the 10,000 Btu/lb required in the smelting operation, as previously mentioned, powers the auxiliaries, such as pretreatment of the scrap. The thermal efficiency of a reverberatory furnace under optimum operating conditions is 25% to 35%.

Although natural gas is the principal fuel in furnace operation, oil can be an alternative with some modification in operating practices. The efficiency of the burner decreases when oil is used. The reverberatory furnace operates by deflecting the flame onto the charge by a sloping-roof arch. The burner is fired diagonally downward toward the melter bottom against, or just over, the metal bath. Combustion products vent at the opposite end of the furnace through a combination hopper and flue. Much of the heat transfer occurs by radiation from the roof and sidewalls of the furnace. The furnaces can be fixed, tilting, or rotary, and a luminous flame is desirable, although flame length can be a limiting factor, depending on burner placement and furnace geometry. The efficiency decreases when oil is used because a minimum distance is required to achieve atomization and complete combustion.

Aluminum Industry-Field Survey

The companies contacted during the course of this study consisted of two primary producers and one secondary producer. The major energy conservation steps undertaken by these firms can be summarized as follows:

- Continuing research and development programs to improve existing manufacturing processes

- Streamlining production processes by modifying equipment and operating practices
- Installation of energy management programs at all organizational levels.

These programs are the direct result of the current decreasing availability of natural gas supplies to industrial users and increasing oil prices. The increased use of coal, particularly for steam generation, is regarded as a near-term solution to the problem. A prospective development anticipated for the long-term time frame is increased development of nuclear power.

Approximately 52% of the energy requirements within the primary aluminum industry is the form of electric power. This power is generated internally as well as purchased from outside sources. The two primary producers interviewed produced a major portion of their power requirements internally.

The average power consumption of an aluminum smelter is about 8 kWhr per pound of aluminum produced from alumina. The most efficient smelter requires about 6.5 kWhr per pound.

Some of the newest developments within the industry include the following:

- Flash calcining
- Electrolytic smelting
- Pulverized coal
- Preheating metal charge.

A flash calcining unit has been developed on a proprietary basis. This system combines the benefits of the fluidized bed and dispersed-phase technology to improve both heat exchange rates and to reduce heat losses. The amount of energy consumed in a rotary calciner to produce alumina is approximately 2000 Btu per pound of product. Reportedly, the flash calciner requires 1400 Btu per pound of product.

Electrolytic smelting, another process of a proprietary nature, has been developed and reduces power requirements within the smelting step by 30%. The process includes a reactor to react chlorine and alumina to produce aluminum chloride. The aluminum chloride is then electrolytically decomposed in a separate cell producing chlorine and aluminum. The chlorine is then recycled back to the first stage reactor.

Reverberatory melting furnaces are used both in primary and secondary producing industries to remelt mixtures of scrap and primary aluminum. In the past, these furnaces have been fired with natural gas and have been recently converted to residual oil because of the natural gas shortage and uncertainties concerning future propane availability.

One of the firms is about to embark on an experimental program wherein a pulverized coal combustion system will be installed on a melting furnace. Successful development of a compact, efficient process for SO_2 removal from the stack gases would lend itself to the establishment of coal as a primary fuel within the aluminum industry.

The average efficiency of fuel fired melters is in the range of 25% to 35%, dependent upon operating practice, age, and condition. Preheating the metal charge and combustion air can increase fuel efficiency up to as high as 50%. Melters fired with natural gas, propane or oil with an acceptable sulfur level do not require stack-gas cleaning or scrubbing to meet existing pollution legislation. Conversion to coal firing would require the installation of a stack-gas cleaning device for fly-ash removal. Solvent refined coal (SRC) which has a very low ash content, could be used as a fuel in reverberatory furnaces, if its price is competitive with the cost of residual oil or coal, including the expense of stack-gas cleaning devices.

From a practical sense, No. 2 fuel oil is easier for the furnace operator to use than No. 6 oil. However, No. 2 oil is at the mercy of fuel allocation programs, as is natural gas, and is subject to extreme swings in availability.

The composition of No. 6 oil makes it difficult to handle in a reverberatory furnace. The No. 6 oil available today is a blend of tars and fluidizing agents that render it incompatible with good combustion practice. The oil must be preheated to 190° to 200°F to make it flow, and in this temperature range the blending agents flash out. In addition, No. 6 oil must be used under high pressure to achieve atomization; it has a high ash and sulfur content, is high in particulates produced, and is costly in terms of storage requirements. The general availability of No. 6 oil also is of concern to the secondary aluminum industry because it must compete for available supplies with the electric utilities. Moreover, refineries are producing less residual oil because of higher yields of gasoline and other light oils.

The cost of electricity as a fuel is 3 to 8 times greater than the cost of natural gas or fuel oil. The average price paid for natural gas in 1970 was 50¢ to 60¢/1000 CF. Present natural gas prices range from a low of 90¢1000 CF in the Southeast to as much as $2.00/1000 CF in the Pacific region. The opinion was stated that the large-volume industrial user is losing his favored position in the switch from wholesale to retail natural gas pricing. During 1971-72, the price of No. 2 fuel oil was 8¢/gal; currently, it is 32¢/gal, with further increases anticipated.

The primary means of controlling stack emissions within this firm, and for many others in the industry, is stack afterburners. The afterburners, which are fired with natural gas, consume approximately 2000 Btu/lb of product produced, in addition to the 10,000 Btu required to produce 1 pound of aluminum. No. 2 fuel oil can be used in the afterburner if natural gas is not available; however, the Btu requirement of fuel oil is greater: 5000 Btu/lb of product produced.

In applications requiring additional control, venturi scrubbers or baghouses may be installed after the afterburner. The type of unit depends upon the emissions. The scrubbers are used to remove chloride and fluoride contaminants. After the material from the scrubber has been evaporated, the product is a dry salt. The salt presents an additional solid waste problem because many states do not allow disposal in landfills without expensive preparation to prevent leaching into substrata water. Some states do not allow the disposal of salts of any kind in spite of extensive preparation steps.

The recycling of aluminum cans has become a growing source of scrap for aluminum melters, amounting to 68 million pounds in 1973. Associated pollution control problems include the lacquer coatings used on beverage containers and oil or lubricants on rolling mill and die casting scrap. One of the firms interviewed proposes the development of a selective oxygen injection system for melters to provide a low energy system for pollution control.

Baghouses are used along with afterburners to control particulate emissions. The amount of energy required to operate a baghouse is equivalent to approximately one-half of the energy required to operate the afterburner, or about 1000 Btu/lb of product produced. Baghouses require extensive maintenance and are not effective for the control of gaseous emissions. In addition, a potential fire hazard exists in the use of a baghouse because of the high organic content of the material collected. Disposal of the particulate matter collected in a baghouse presents the same problem as the disposal of salts.

Petroleum Refining

Petroleum refining is largely accomplished by distillation separation into intermediate feedstocks and products. The intermediate feedstocks require heating and thermal cracking or catalytic treating before separation of the desired products. This separation usually requires additional heating after the catalytic treatment or thermal cracking.

Total refinery energy consumption amounts to around 10% of the crude throughput. Most of this energy is consumed as fuel in fired heaters. The amount of energy consumption depends largely on the complexity of processing which takes place after the initial crude distillation separation. Generally a gasoline oriented refinery will have fuel consumption considerably greater than a distillate oriented refinery. In the long run, the refinery output is controlled to meet consumers demand. This demand is for high gasoline production in the summer and fall seasons with high distillate fuel production during the winter season.

Petroleum refining involves the use of fired heaters in many operations beginning with initial crude distillation unit. On this unit, separation is made by distillation of the crude oil into the fractions which become the charging stock for the other operating units in the refineries. In a typical fuels refinery these units are as described briefly below:

Reforming Unit: On this unit the fraction of straight run gasoline boiling above 160°-180°F is vaporized in a fired heater, desulfurized over a catalyst, and relieved of the sulfur and light fractions. The straight run gasoline is vaporized in another fired heater and routed over a platinum-containing catalyst which reforms the approximately 45% naphthenes to aromatics, which have a high octane. This gasoline is relieved of the light hydrocarbons, making it a finished gasoline.

Catalytic Cracker: The material boiling above kerosene in the crude unit is routed to a cat cracker where it is cracked at 875°-925°F to make a variety of materials including gasoline, olefins for alkylation, and distillate fuel.

Delayed Coker: This unit is a high fuel consumer employing fired heaters to heat the charge oil for distillation. The distillation bottoms are routed through another heater to coke drums where the heavy fractions remain while coking. The unit produces gas, olefins for alkylation, gasoline, distillate fuel and coke.

Alkylation Unit: The three and four carbon olefins and isobutane are reacted in this unit to make alkylate, a mixture of seven, eight, and nine carbon-atom compounds, which are widely branched to give a very high octane gasoline. Separation of the reaction products is by distillation towers reboiled by a fired heater.

Distillate Hydrotreaters: These units are supplied with hydrogen and the feedstocks heated in fired heaters to 650°-750°F before routing over a fixed bed of catalyst for desulfurizing and upgrading the burning qualities of the distillate fuels.

In most existing refineries the different units are operated as separate entities having intermediate tankage for charge and products. This provides both operating and maintenance flexibility. Trends have been to eliminate the intermediate tankage and reduce fuel consumption by running hot feed from one unit to another. New refineries can be designed in this manner to effect savings in fuel consumption while accepting the risks of intermediate processing bottlenecks or reduced stream factors. The completely integrated refinery can have no greater on-stream factor than the lowest of the stream factors of the individual units.

The approach to developing information on trends in refinery fuels consumption was to interview the fuels and emission coordinators in the central office of the refining companies. Two of the largest refiners were interviewed. These refiners have fourteen refineries running a total of 1.7 million barrels per day of crude oil. Also interviewed was the director of refining of the American Petroleum Institute (API), who is responsible for setting up a fuel-conservation program involving more than 80% of the U.S. refinery capacity.

His program resulted in the naming of a fuel-conservation coordinator for each of the refining companies. A program for fuel conservation was implemented for which results have become available.

These results have been reported as follows:

	Energy Consumption, weighted average for 37 companies, 1000 Btu/bbl input
1972 Base Period Total Energy Consumption	667
1972 Base Period Adjustment to 1974	+9
Adjusted 1972 Base Period Total Energy Consumption	676
Less 1974 Last Half Year Total Measured Energy Consumption	624
Energy Conservation Improvement for last half of 1974	52
% Reduction from 1972 Base	7.8%

It is generally accepted that the greatest single factor affecting the refining industries' improvement in fuel consumption was the response of the industry to the economics of the high price of crude which occurred during the last quarter of 1973 and the resultant higher price of fuel consumed. One of the companies interviewed arbitrarily set a fuel price for conservation economics to reflect its selling price as fuel oil rather than the price of purchased natural gas, which continued to be much below the more realistic price of refinery fuel oil.

Effort to improve fuel consumption involved giving increased attention to the current practices in firing the process heaters and boiler house. In the larger refineries, checking of heating performances and assisting the operators to achieve correction to proper firing conditions is a full time job for one man. Firing to 10% excess air was accepted as a goal for furnaces firing gaseous fuel, with 20% excess air for furnaces firing predominantly oil fuel. Improved oxygen analyzer installations are being employed to monitor this. These goals were not being attained, and it was felt that improved fuel oil burner design would be required to accomplish this. They feel that most existing furnaces lack the combustion space to burn predominantly oil without a reduction of furnace throughput.

Preheat of the heater feeds is being given increased attention in both existing and new installations. Cleaning of heat transfer surfaces in exchangers and heaters both on-stream and off-stream is getting increased attention. Some novel techniques being applied to fired heaters are:

1. Use of water lance for shock cooling and flaking deposits from outside of tubes
2. Use of walnut shells for blasting of powdery deposits from outside of furnace tubes.

Increased maintenance of insulation on hot lines and increased attention to required operating reflux ratios on distillation columns are being employed in existing installations.

Refining organizations hope for continued improvements in fuel conservation by long-range projects, both of a replacement nature for existing equipment and in the installation of new units having the benefit of improved design.

A comparison of past practice with future design practice shows how the furnace design conditions will be tightened up.

	Past Practice	Future Designs
Lowest temperature for heat removal by exchange	400°F	250°F
Furnace stack-temperature	800°F	400°F

They recognize that furnace tube outside skin temperature will be a consideration for the future designs as they will have to keep surfaces above the dewpoint of the furnace gases.

Conservation coordinators feel that retrofit installations of air heaters and steam coils can be justified at current high fuel prices. In completely new installations they will expect to have a greater ratio of convection surface to radiant surface. Increased use of extended surface convection furnace tubes is expected. One group favored a furnace design that will eliminate the damper in the breeching to the stack, using instead an air supply box servicing multiple burners. Such installation would provide dampers on the forced air supply to the windboxes. They do not expect to be going to flue-gas recirculation for emissions control.

The API refinery survey showed that 31% of the refinery fuel consumed was purchased natural gas. Replacement of this gas with liquid fuels will require more furnace volume, as mentioned above.

Some instances of conflicts between lower emissions and fuel conservation were cited. In the interest of improving heater efficiency they are going to air preheat. However, they are concerned that NO_x standards which might be set in the future will put them above the NO_x standard. In another instance, when lower stack temperature is achieved in the interest of improved fuel efficiency, it can be calculated that ground-level emissions will increase. It makes no sense to forego such installations in order to meet ground-level emissions standards. In another instance, installation and operation of Claus tail-age cleanup units unquestionably results in high energy consumption but with no compensating improvement in overall efficiency.

The refineries are removing H_2S from their major fuel-gas streams. In so doing they are eliminating SO_2 emissions from the heater stacks. By installing a Claus unit to convert the H_2S to free sulfur, they undertake a large expenditure for which there is little or no return. This is accepted without question as they recognize that 95% of the sulfur emission is thus eliminated. However, the remaining 5% of the sulfur is now going up a single stack. It requires an expenditure equal to or exceeding the Claus unit expenditure to recover the remaining 5% of the sulfur. Furthermore, the Claus stack-gas recovery unit adds increased investment and labor costs with practically zero return.

Recommendation by Refiners

1. That emission guidelines be sufficiently flexible so as to allow waivers for refineries in areas remote from cities. This practice is in the interest of fuel conservation.
2. That guidelines be set by environment tolerances rather than a specification based on the refiners or a process' capability.
3. That fuel oil burners be improved so as to allow combustion with lower excess air.

APPENDIX A

Weighting Factors

The next step in the selection process is the assigning of weighting factors to each of the restraints in terms of their relative importance. In developing the weighting factors, the following assumptions have been made:

1. All air pollutants are equal in importance.
2. Conservation of energy and reduction of emissions are equal in importance.
3. Industries with no potential for energy conservation or reduction of emissions will be excluded from consideration.

Given these assumptions, the weighting factors are assigned based on a scale of 1 to 10 where 1 is a low-priority and 10 is a high-priority rating. To determing the suitability of a particular industry, the following set of numerical operations would be performed:

1. Base energy consumption X emission index number = emission weighted base number.
2. Estimated potential for energy conservation X emission weighted base number.
3. Estimated potential for reducing emissions X emission weighted base number.
4. Items 2 + 3 = conservation and emission weighted number.

Based on the value obtained in 4 above, the industries for study have been selected with the highest value given the highest priority.

Table A-1 defines the weighting system we used to arrive at the numbers used in the above set of equations.

Table A-1. WEIGHTING SYSTEM FACTORS

1. Base energy number

The base energy number is arrived at by summing the weighting factors for restraints Nos. 1, 2, and 3, where the following values are assigned (scale 1 → 10).

Restraint No. 1. Energy use in process heat
1 = Low usage; 10 = High usage

Restraint No. 2. Combustion-related uses
1 = No combustion-related uses; 10 = All combustion-related uses

Restraint No. 3. Number of processes
1 = Numerous processes; 10 = One process only

2. Emission index number

The emission index number is arrived at by summing the weighting factors for restraints Nos. 4 and 5. However, since the primary emissions of concern as indicated in restraint No. 5 are generally directly combustion-related, the emission index number can be based on restraint No. 4 alone with values assigned as follows:

1 = Mostly independent emissions; 10 = mostly combustion-related emissions

3. Potential for energy conservation

1 = Low potential; 10 = High potential

4. Potential for reducing emissions

1 = Low potential; 10 = High potential

POM AND PARTICULATE EMISSIONS FROM SMALL COMMERCIAL STOKER-FIRED BOILERS

By

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ABSTRACT

This paper describes a program to evaluate emissions, including POM from residential and small commercial stokers. The program consists of: (1) a survey to identify processes for manufacturing smokeless coal and to evaluate the suitability of these fuels for stoker-firing; (2) a survey to identify the manufacturers and designs of small stokers currently being marketed; and (3) an experimental laboratory program to measure emissions while firing a small stoker with several candidate stoker fuels. In the experimental program, a 20-horsepower stoker-fired boiler is fired with anthracite, bituminous, Western and "smokeless" coals over several operating cycles. From the results of these experiments and the survey, a program will be recommended to increase environmental acceptability and to improve the economics of residential and small commercial stoker boilers. The experimental portion of this program is currently being conducted and, as a result, data are not available for discussion.

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INTRODUCTION

Coal was still a major fuel fired in residential and small commercial heating systems as late as the 1950's. Coal usage then rapidly declined as the market area of the less expensive and more conveniently fired fuels, gas and oil, expanded. Even in certain geographical locations where coal was cheaper than oil or gas, the high maintenance costs and labor associated with firing coal coupled with an increased awareness of the environment virtually eliminated the use of coal for residential and small commercial space heating applications by the 1960's.

However, the uncertainty in both the short- and long-term availability of oil and gas has created renewed interest in burning coal to meet our nation's energy needs. In order to technically assess the environmental impact of burning coal, specifically in residential and small commercial applications, the EPA has funded a program to evaluate the emissions from these units under smokeless operation.

This program consists of:

(1) A survey to identify the manufacturers and designs of stokers currently being marketed. Because the design and operation of small

stokers is almost a lost art, a discussion of design and operational aspects are included in this survey.

(2) A survey to identify processes for the manufacturing of smokeless coal and to evaluate the suitability of this fuel for stoker firing.

(3) An experimental laboratory program to measure emissions while firing a small stoker with several candidate fuels.

This program is ongoing as experimental data are currently being obtained. Accordingly, the results of the laboratory work are unavailable for publication at this time, but will be included in the final report on EPA Contract No. 68-02-1848.

OBJECTIVES AND SCOPE

The overall objectives of this program are:

(1) To evaluate emissions from residential and small commercial stoker-fired boilers under typical boiler operation, including smokeless operation.

(2) To assess the advisability of increased utilization of coal for residential and small commercial applications including consideration of operating efficiency, fuel type and availability, economics, and environmental impact.

A 20-hp stoker-fired boiler system is being used to evaluate emissions from the combustion of anthracite, Western, processed "smokeless", and high- and low-volatile coals under several boiler operating cycles. Pollutants of interest include NO, SO_2, smoke, particulate, and the polycyclic compounds.

TECHNICAL BACKGROUND ON STOKERS

To provide a basis for an assessment of the increased utilization of stokers, a description of the design and operation of stokers is given to identify the complexity (in contrast to oil and gas) of burning coal in small units. Also, a summary of the survey of stoker manufacturers is included.

Stoker Design and Operation

Smoke evolved when burning high-volatile coal has always been a problem for residential and small commercial heating units. Development of the residential underfeed stokers, such as the inverted-underfeed stoker designed in the 1940's, made it possible to burn high-volatile coal smokelessly. However, recent attention has focused on all emissions which includes not only smoke, but NO_x, SO_x, CO, particulate, and POM. Levels of these emissions are related to stoker design, stoker operation and firing procedure, and the type of coal burned. These aspects are discussed below.

Stoker Design

The small mechanical stokers in the range of interest are of the underfeed type. The underfeed stoker with a worm-feed mechanism is normally used to feed coal at rates up to 1200 lb/hr. In contrast to handfiring or spreader stokers, underfeed stokers supply fresh coal to the boiler or furnace by feeding it underneath the hot coals. This stoker consists of a retort, fan, motor, transmission, air duct, air duct control, hopper and feed screw. Figure 1 is an illustration of a typical stoker assembly.

Motor and Transmission. The underfeed stoker is driven by an electrical motor, usually mounted on top of the transmission. The motor drives the transmission through V-belts. Various electrical devices control the operation of the motor including room thermostat, boiler limit switch, and the hold-fire timing relay. The transmission rotates the coal-feed screw at a speed determined by the capacity of the heating system. Feed rates can be varied by changing the motor or transmission pulleys.

Feed Screw. The feed screw conveys the coal from the hopper to the retort, or with a bin-fed type, directly from the coal bin to the retort. The feed screw extends from the coal supply (hopper or bin) through the worm-tube into the retort, where it discharges the coal it conveys.

Retort. The retort is a cast-iron chamber in the shape of a cup or trough in which the coal is ignited and the volatile gases are driven off. The retort is surrounded by a windbox and contains slotted holes for admitting air under slight pressure to the fire. These slotted holes, or air admitting ports, are often referred to as the tuyeres.

Because anthracite differs in combustion characteristics from bituminous coals, a different retort design is required to burn this coal successfully. The bituminous retort is built to burn a coal relatively high in volatile matter and to fuse ash into a removable clinker; the anthracite stoker retort, on the other hand, is built to burn coal of low volatile content and to spill ash into a pit or to the receiver for the ash. Also because anthracite burns with a slow uniform flame, it requires less combustion space than bituminous coals.

Fan and Air Control. Fans for supplying combustion air in the underfed stokers are usually squirrel-cage types that provide relatively high pressures and low volumes. The fan is equipped with either a manual or automatic damper to regulate air flow. The fan develops sufficient static pressure to overcome a series of resistance generated by flow through the fuel bed, tuyeres, air ducts and regulating damper.

Stoker Operation

The residential and small commercial stoker-boiler operate basically the same in principle although their operating cycles can be different depending upon application. Characterization of the operation of these units is complicated because they seldom operate with a steady-state heat-release rate.

Off-On Cycle. Figure 2, a plot of CO_2 levels as a function of time, illustrates the nonsteady heat-release rate of stokers. Units of this size operate in an off-on cycle, the time in each mode related to the load. During the on-cycle, fresh coal is fed underneath the hot coals and air is admitted through the tuyeres. The heat-released rate increases substantially as the coal bed temperatures gradually increase, but often not reaching a steady-state temperature before the thermostat stops the stoker screw and fan. The heat-release rate is then reduced drastically, but the bed continues to burn, being supplied by minimal quantities of air by the natural draft. At this time unburned hydrocarbons can be released because of insufficient air. Figure 3 shows a typical plot of retort and stack temperatures during an overnight run of a stoker on a 10-minute on and 50-minute off cycle.

Full-Load and Hold-Fire Operating Cycles. There are two extremes in stoker-boiler operation, namely, full-load and no-load. During full-load operation, the stoker is running continuously; however, the stoker is stopped for at least 5 minutes in every 30-minute cycle so that bed temperatures cool and the ash fuses*. If not given an opportunity to cool, certain coals will remain fluid and sticky with resulting nonuniform feeding and irregular burning of the large caked masses.

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* This off cycle can vary with ash content composition of the fuel. Anthracite with a low ash content and high fusion temperature can be burned continuously with no off period.

During the no-load period, the boiler operates in a hold-fire period of operation. Thus, the stoker is kept alive by short starts to keep the fuel bed sufficiently alive to respond quickly when the boiler load increases. The typical hold-fire period for bituminous coal is approximately a 5-minute operation of the stoker in each 30-minutes;* otherwise the fuel bed temperature will be too low to ignite fuel that enters the retort during the on-period.

Partial load operation falls in between these extremes. The stoker always feeds at a constant rate and adjusts to varying loads by varying the on time in each cycle of operation.

Coal Classifications

Selection of stoker coals is of paramount importance in successful stoker operation. Proper stoker adjustments for smokeless operation are largely dependent on the coal analysis and coal size. For instance, unsatisfactory stoker operations occur if

- a large percentage of fines restricts the amount of air that reaches the fuel bed
- a high percentage of ash results in troublesome clinker formation
- a low ash-fusion point coal creates clinkers that are difficult to remove from the stoker as the ash may melt and fuse or stick to the tuyeres.

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* The hold-fire period for anthracite can be as low as one minute every half hour.

Accordingly, the most desirable coals for small stoker operation are relatively free-burning, low-volatile, and low-sulfur coals that are sized 3/4 x 1/4. The free-burning coals include all coals that neither cake nor coke.* These coals burn to a fine ash and do not restrict air flow through the fuel bed. Low-volatile coals tend to burn slowly with a uniform flame and as a consequence do not generate appreciable levels of smoke over the entire stoker operating cycle. Finally, sulfur oxide levels are related to the sulfur content of the fuel, and thus, the low-sulfur coals are the most desirable.

Among coals that have been commonly marketed in the United States for residential and small commercial stoker applications include anthracite, bituminous and Western or sub-bituminous. In addition, a smokeless coal has been commercially developed and has been used in England, although not for mechanical stoker firing. A brief discussion of these coals as related to stoker firing is given below.

Anthracite. Anthracite is a desirable coal for coal firing because it is a free-burning, low-volatile, and low-sulfur coal. Most anthracites have ash-fusion temperatures above 2700 F which permits the ash to spill over the retort into a pit or into a conveyor trough for ash removal. This property makes anthracite stokers adaptable to a continuous modulation mode of operation rather than an off-on cycle. Being low in volatile content, it burns slowly and uniformly

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* Caking coals emit tars and swell when heated; coking coals do not swell when heated but emit tars.

with a compact flame allowing a smaller combustion chamber than bituminous coal. In addition, because anthracite is a hard coal, it does not degrade (in size) during handling and shipping.

Bituminous. Bituminous has been a widely used coal for stoker firing because it is found near population centers. There is a wide range in the analysis of bituminous coals but it generally contains 25 to 50 percent volatile matter, 7 to 15 percent ash, and 2 to 4 percent sulfur. This coal has been fired successfully in stokers but requires precise air adjustments and routine maintenance.

Western Subbituminous. Western subbituminous coals have not been widely used for stoker application; although in some local regions, like Salt Lake City where it is readily available, significant quantities have been burned for residential heating. In general, these coals have high moisture (frequently as much as 50 percent), high ash (10 percent), and low ash fusion temperatures. Because Western subbituminous coals tend to degrade easily and have low heat content, their market area has been restricted to regional usage. However, they do have low sulfur content which makes them environmentally attractive.

Processed Smokeless Coal. The analysis of processed smokeless coal indicates that its composition is ideally suited to stoker firing. This coal, however, as manufactured would present problems in feeding with conventional stokers; the coal is extremely hard and was produced in sizes typical of the present day charcoal briquet.

Smokeless Combustion

Smoke is a suspension of small solid particles in flue gases discharged during the burning of fuel. The particles are of two types--unburned residues of carbon formed by decomposed volatile material from the fuel, and ash remaining after the fuel is burned.

Any fuel may be burned smokelessly at suitable temperatures with enough oxygen, good mixing, and sufficient time to complete the combustion. It is important to burn the volatile matter completely and rapidly to avoid soot or carbon formation. Carbon smoke particles formed by decomposition without oxygen are difficult to burn, and usually are lost as smoke.

A high volatile coal may give off as much as 35 percent of its weight as combustible vapors and gases when it is heated. Rapid heating causes rapid evolution of volatiles which then requires a high rate of air supply and rapid mixing to permit complete combustion. Even with sufficient air and complete mixing, there are situations in which the temperature is too low to ignite the combustible mixture. In one such instance the coal may be added to a cool fuel bed where there is no hot spot to ignite the tars and gases as they slowly distill. In another, the vapors and air may be adequately mixed at a sufficient temperature, but they may pass out of the combustion zone and be quenched by the cool surfaces in the boiler and flue. Any of these deficiencies result in carbon particles and condensed tar droplets that appear as smoke. In summary, the requirements for smokeless combustion are temperature for ignition, turbulence for mixing, and time for completion of combustion reactions.

Any fuel with a volatile content of up to 25 percent by weight will burn smokelessly when a few precautions are taken to provide the necessary temperature, turbulence, and time in the combustion zone. This tendency for smokeless combustion follows from the lower requirements for combustion air to burn the volatiles. Higher proportions of air are available to burn the solid carbon in the fuel bed (which produces a hotter bed) and less mixing and time are required for complete combustion in the gas phase above the solid fuel bed.

POM Generation

The term POM, polycyclic organic matter, is used variously, depending on the scope of the material compositions being considered. Thus, chemically, the term POM includes all polycyclic compounds; hydrocarbons, heterocyclic compounds, and chemical derivatives such as acids and alcohols that can be derived from them. Among these are several compounds of great concern because of their potential carcinogenicity.

Available data are not suffucient to provide an accurate quantitative statement of POM emissions from residential and small commercial stoker-fired units. However, the potential exists for substantial yields of POM because of the chemical composition of stoker coal and the manner in which these stokers are typically operated, particularly during the first phase of the "off" period.

Chemical Composition of Coal. Coal is composed of high-molecular-weight compounds that are more difficult to burn out than in the lower molecular hydrocarbons found in the fluid fuels. These higher molecular weight compounds if only partially destroyed by the flame provide a "building block" from which the large ring structure hydrocarbon can be formed, some of which are carcinogenic.

Stoker Operation. It has been observed that POM are generated by pyrolysis in the preflame zone of a burner at above 550 C, and the concentration of individual POM rise with increasing pyrolysis temperatures up to a critical value of about 750 to 800 C. With further increases in temperatures, the concentration falls again due to the onset of the decomposition process. The POM formed by pyrolysis in the preflame zone is destroyed as the vapors enter the hottest portion of the flame and then gradually reformed in the falling temperature portion. As described early, the off-on cycle of stoker operation with low fuel-bed temperature gradually building up to a peak and then falling again appears conducive to POM generation.

Stoker Survey

The findings from the survey of over twenty present or past manufacturers (or their representatives) of residential and small commercial stoker-fired space heating equipment include:

- Residential and small commercial stoker-boilers are similar in design as systems components are scaled (up or down) to match the desired range of operation. The stokers are of the underfeed type.
- The conventional underfeed bituminous stokers are capable of firing most coals except anthracite.
- The conventional underfeed anthracite stokers are designed to fire anthracite only. There is a possibility that this stoker could fire "smokeless" or processed coal if properly sized.
- There is only one manufacturer of the conventional bituminous stoker in the size ranges of interest. Domestic sales are about 500 units/year.
- There is only one manufacturer of the conventional anthracite stoker. Sales are less than 20 units/year. One additional manufacturer makes an anthracite stoker that is an integral part of the boiler system.

- There are only three major manufacturers (H. B. Smith, Kewanee, and Weil McLain) of boilers for stoker firing. Of these, only Weil McLain currently manufactures a boiler in the residential size range.
- There are over 200,000 living units heated by anthracite coal. Most of these units are hand-fired.
- There has been renewed interest in stoker firing in the size ranges of interest. The majority of activity has been for small commercial applications rather than residential.
- The majority of the new stoker-boiler systems are designed for hot water, while most replacements are for steam systems. There has been some renewed interest in residential stoker-fired warm air furnaces.

EXPERIMENTAL PROGRAM

A 20-bhp stoker-boiler facility including provision for stack sampling was installed. Initially, emissions will be measured utilizing the bituminous stoker capable of firing high- and low-volatile bituminous coal, a processed smokeless coal,* and a Western subbituminous coal. Later in the program, an anthracite stoker will be installed to fire the anthracite and possibly the processed smokeless coal.

Experimental Facility

Figure 4 is a photograph of the overall system layout that includes:

- Kewanee 3R-5 20-bhp (200 kw), fire-tube, hot-water boiler
- Will-Burt 75 lb/hr (34 kg/hr) bituminous stoker
- 14-inch (0.35 m) diameter stack section
- Sampling platform.

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* The processed smokeless coal is a lignite char briquet with a corn-flour binder.

A Van Wert 60 lb/hr (27 kg/hr) anthracite stoker (not shown) can also be mated to the boiler.

Approximately 10 pipe diameters above the boiler stack-gas outlet, 4 sampling ports are installed. These ports are utilized to sample over the discrete time periods of stoker-boiler operation. Approximately 5 feet above the sampling ports a damper is installed to provide a control of the draft at boiler outlet. Provision for smoke and gaseous-emission sampling ports are provided at the base of the stack in addition to several ports for temperature and pressure measurements.

Fuel Analysis

Table 1 lists some properties of the coals that will be fired during this program. The analysis are reported on an "as received" basis and included the moisture content of the coals. This moisture content, can vary randomly from day-to-day depending on climatic condition, and is also dependent upon washing procedures used at the mine.

TABLE 1. COAL ANALYSES IN PERCENT

	C	H_2	S	Volatile Matter	Ash	Moisture	Free Swelling Index	Heating Value Btu/lb (kw/kg)
High-volatile bituminous	79.5	5.7	1.2	40	4.7	1.8	5	14,100
Low-volatile bituminous	84.7	4.7	.6	21.4	6.9	.9	7-1/2	14,700
Processed smokeless	67.9	1.7	.6	16.0	15.1	7.3	0	10,600
Western sub-bituminous	64.6	4.2	.7	37.4	9.2	8.0	1/2	11,400
Anthracite	79.4	2.0	.7	3.9	12.3	12.3	0	11,900

In general, however, the moisture content gives a measure of the inherent moisture content of the coal. The free swelling index is a measure of the caking properties of the coal as indicated by high values of the caking bituminous coals. The processed smokeless fuel is a lignite char briquette.

Characterization of Boiler Operation and POM Sampling

The operating cycle of a stoker-boiler creates a unique problem in obtaining meaningful emissions data. As discussed earlier, the stoker seldom operates at a steady-state condition. Transients occur not only during the starting and stopping of the stoker but throughout each "on" and "off" period of operation. In addition, and most importantly, during the "off" period, the fuel bed continues to burn as a sufficient amount of air is supplied by the natural draft of the stoker-boiler system.

Potential Experimental Runs

Initially, the stokers will be fired on several coals and at several boiler loads to establish potential operating conditions for the POM and particulate sampling. Listed below are 6 potential coal-stoker combinations to be investigated. In addition, the boiler will be operated at four loads for each of the coal-stoker combinations. Possible boiler loads to consider for a 60-minute operating cycle include:

On	Off
10 min	50 min
20 min	40 min
40 min	20 min
50 min	10 min
Continuous	(Anthracite only)

Accordingly, there is a potential of 24 operating conditions of which 8 will be selected for POM and particulate measurements. In an investigation of emissions from small commercial oil- and gas-fired furnaces(1), a load factor of 1/3 was used (10-minute on/20-minute off cycle). Accordingly for comparison purposes, the 20-minute on/40-minute off cycle could be selected as the basic cycle to evaluate the emissions from the firing of each coal.

Stack Probing

For the 8 conditions, the boiler stack will be probed to generate transient temperature and velocity profiles. In addition, for the bituminous-coal stoker combination, transient velocity and temperature profiles will be generated for several boiler loads.

Hot wire anemometry will be used to characterize stack flow as a function of time. Two probes will be used simultaneously. Probe 1 will be located approximately 2 feet (.6m) between the sampling port and contain a hot wire sensor set stationary on the centerline to monitor axial flow velocity with time. In addition, a thermocouple will be attached to Probe 1 to monitor temperature with time. These data will be used as a baseline measurement.

Probe 2, to be located at the sampling port, will contain a traversing hot wire sensor used to determine the radial velocity profile as a function of time. Initial traversing measurements will be made to establish the importance of swirl and temperature with respect to radial position. An existing traversing mechanism is currently being modified to accommodate the needs of this specific task.

Also, a correlation will be established to relate measurements of Probe 1 with Probe 2 so that meaningful undisrupted flow monitoring can be conducted during sampling. All hot wire sensors are quartz-coated hot film sensors, Model No. 1210-20 with an instantaneous response time.

POM Sampling

The transient stack-probe data will be analyzed to relate these profiles to stoker cycle operation. The transient stack-probe data will be integrated to determine an appropriate POM probe position (within the stack) and pumping rate for the time segment under consideration.

Analysis of the POM samples will include, for example, the three- and four-star compounds assessed by NAS(2) as carcinogenic:

9,10 - Dimethylbenz(a)anthracene
3 - Methyl chloanthrene
Benz(a)pyrene
Dibenz(a)anthracene
Benz(c)phenanthrene
Dibenz(c,g)carbazole
Dibenz(a,i)pyrene
Dibenz(a,h)pyrene.

After analysis of these samples, data will be compiled into a composite picture of transient POM emission and integrated to yield the gross out-put levels. On-line gaseous and smoke emission data will be taken during these evaluation runs to assure a degree of repeatability in the experimental program. These data will also be compiled and integrated to yield the transient and time-averaged emissions.

Analytical Procedures

Particulate and POM sampling and analytical procedures (modified EPA Method 5 train with an adsorbent column) have been described by Jones and Giammar(3). Gaseous emissions were determined by: paramagnetic analysis for oxygen; flame ionization detection for unburned hydrocarbons; nondispersive infrared for carbon monoxide, carbon dioxide, and nitrogen oxide; and a dry electrochemical analyzer for sulfur dioxide. Smoke emissions were determined with a Bacharach smoke tester according to the ASTM filter-paper method for smoke measurements(4).

REFERENCES

(1) Barrett, R. E., Miller, S. E., and Locklin, D. W., "Field Investigation of Emissions from Combustion Equipment for Space Heating", EPA-R2-73-0846 and API Publication 4180 (1973).

(2) "Polycylic Particulate Organic Matter", National Academy of Sciences, Washington, D.C. (1972).

(3) Jones, P. W., Giammar, R. D., Strup, P. E., and Stanford, T. B., "Efficient Collection of Polycyclic Organic Compounds from Combustion Effluents", presented at the 68th Annual Meeting of the Air Pollution Control Association, Paper No. 75-33.3, Boston, June 15-20, 1975.

(4) Standard Method of Test for Smoke Density in the Flue Gases from Distillate Fuels, ASTM Designation: D 2156-65 (Reapproved 1970).

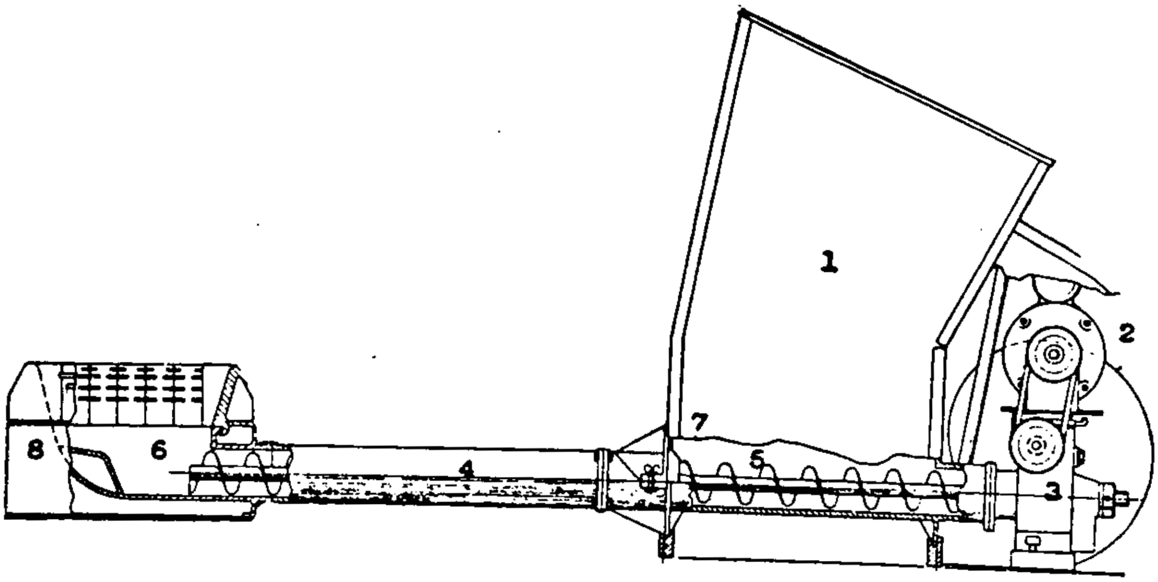

FIGURE 1. CONVENTIONAL STOKER ASSEMBLY (Side illustration showing various parts:

1. Hopper
2. Electric motor
3. Transmission
4. Coal feed tube
5. Feed worm
6. Retort
7. Clean out opening
8. Retort air chamber. Fan is partially hidden by the transmission and motor

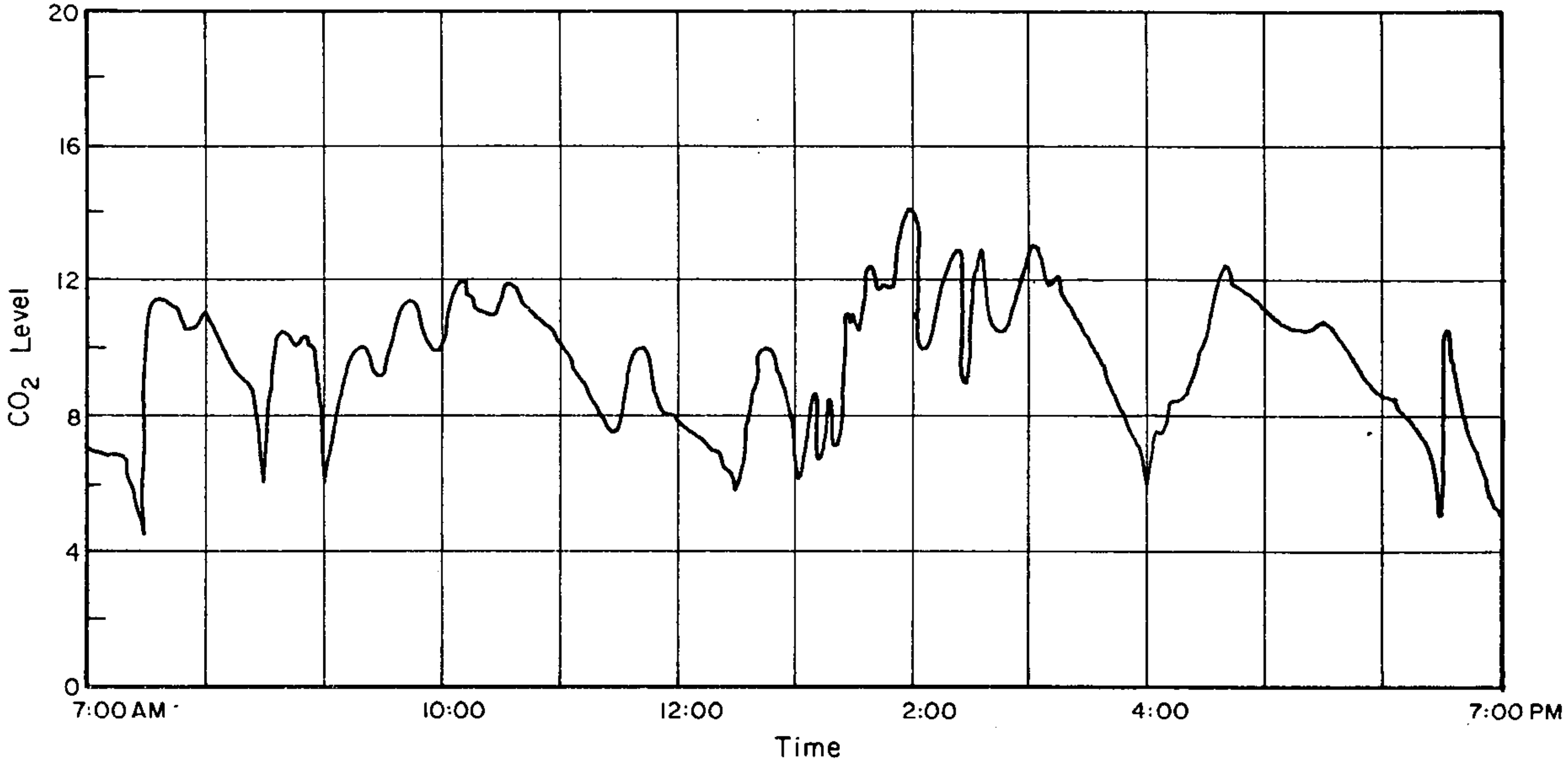

FIGURE 2. TYPICAL RECORD OF CO_2 CONTENT OF FLUE GASES FROM A SMALL STOKER OPERATING UNDER INTERMITTENT CONTROL

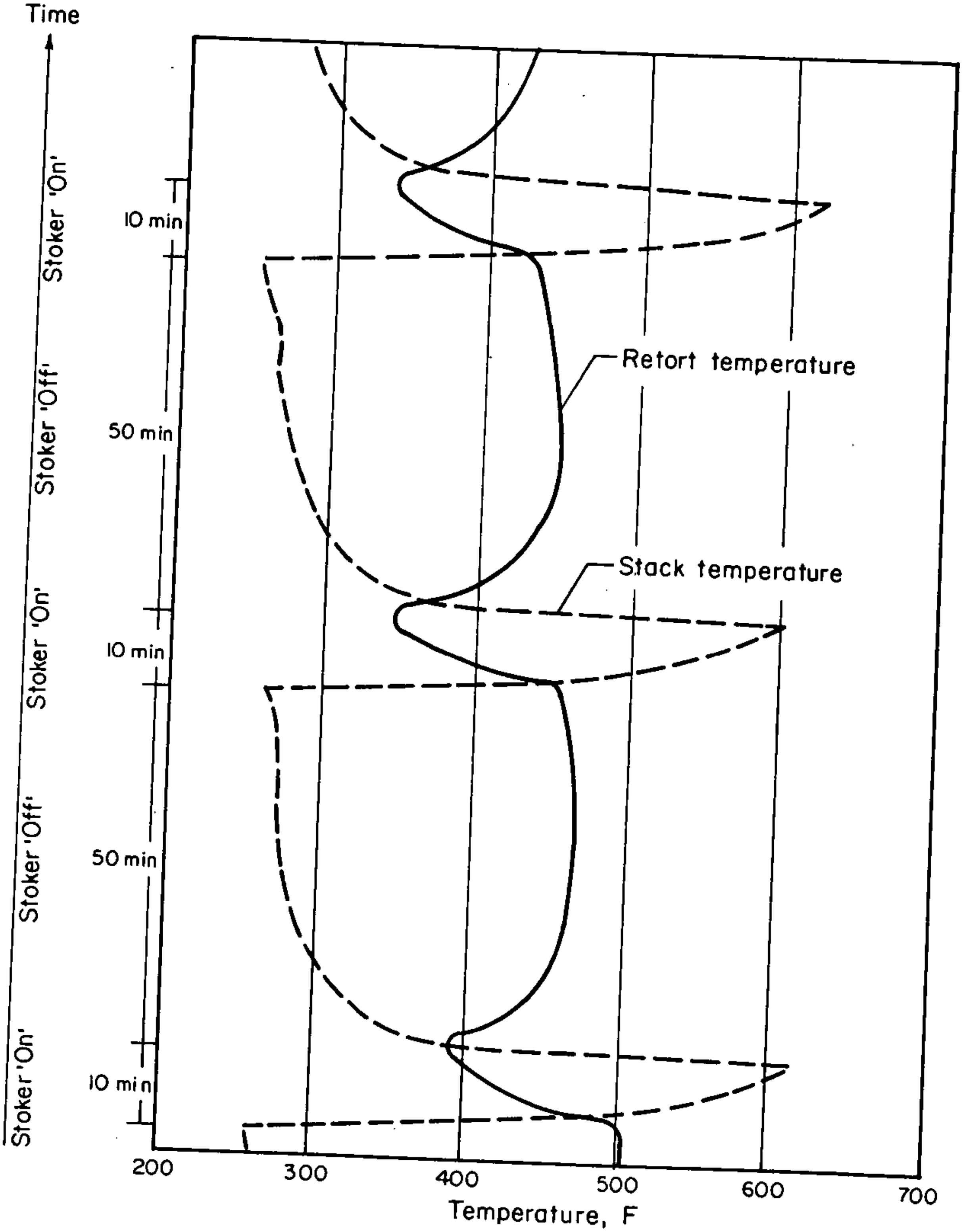

FIGURE 3. TYPICAL PLOT OF RETORT AND STACK TEMPERATURES DURING AN OVERNIGHT RUN OF A STOKER

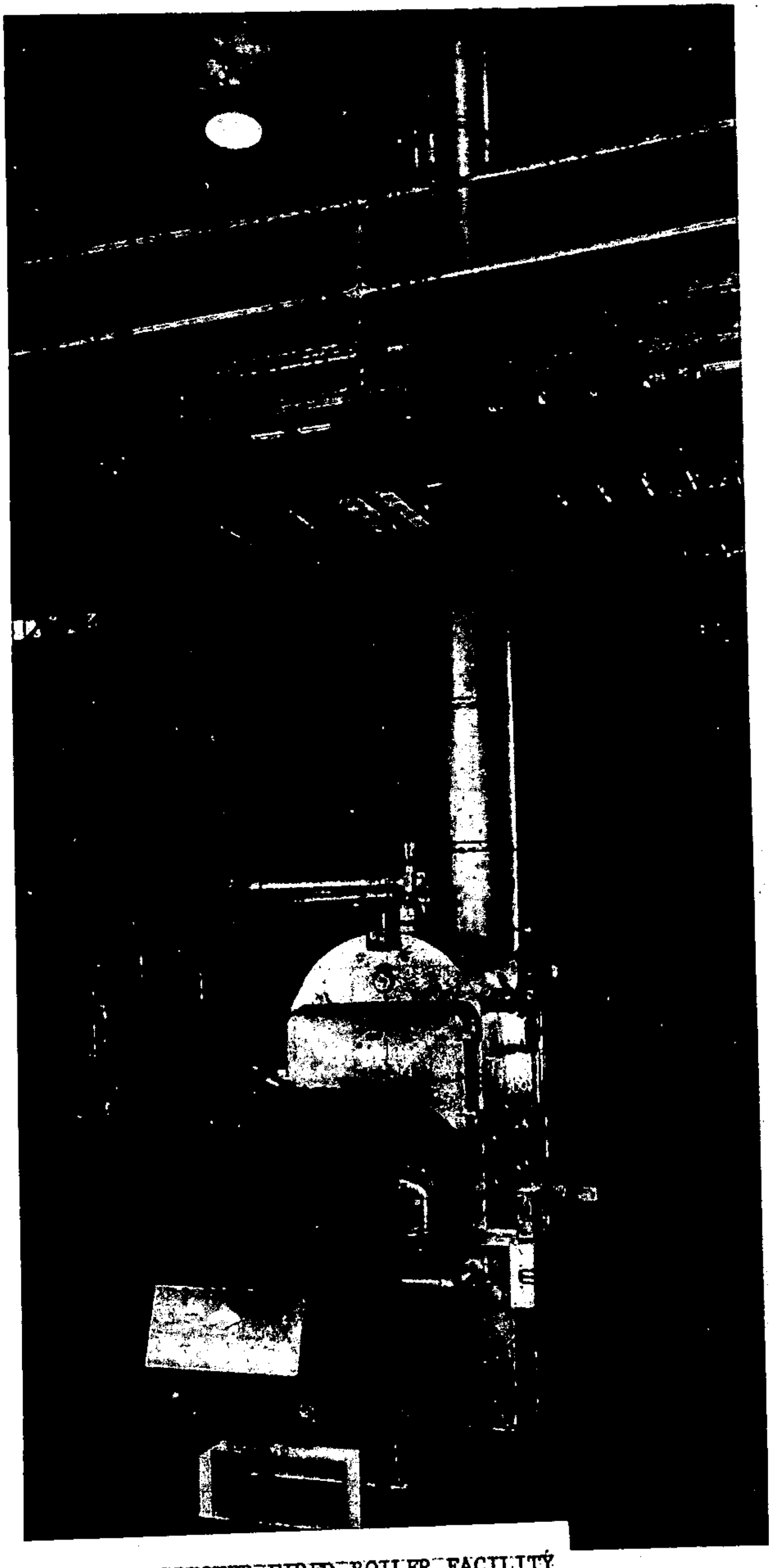

FIGURE 4. STOKER-FIRED BOILER FACILITY

2:20 p.m.
POM and Particulate Emissions
from Small Commercial Stoker-
Fired Boilers
Robert D. Giammar, Battelle, Columbus Laboratories

Q: Yesterday you presented some data on POM in gas and oil combustion systems and today in coal. Have you done any detailed analysis on any of your samples for distribution among the different species? Have you seen any differences between the three types of fuels?

A: Yes. We have. We are looking at 13 POM species. Some of these as rated by the National Academy of Science are ranked as 1-4 stars, where the 4 star has the highest potential for cancer-forming hydrocarbon. On the other question, the distribution of the POM species is different for coal in comparison to oil or gas. For oil and gas, appreciable quantities of pyrene and fluoranthene, both considered innocuous, were observed while very little B(a)P and other 3 and 4 star compounds were observed. With the oil and gas, we see essentially four innocuous species that comprise 99% of the total POM catch. With coal we have seen a wider distribution. We have identified 10 species, some of which are 3- and 4-star compounds contained in significant levels.

Q: About the report you gave yesterday, and it is probably appropriate here, would you comment about the sampling technique that you used and how that technique differs from the normal method five?

A: The sampling technique used is quite similar, if you are familiar with the method 5. We insert what we call an absorbent sampling device or a column packed with Tenax material in between the hot filter and the impingers. We then can use the probe wash and the filter catch to measure a total particulate; and we use the probe wash, the filter catch, and what is found in the packed column for our POM determination. Earlier studies indicated most of the POM was found in the packed column rather than in method 5 components. Another co-worker at Battelle and I presented a paper at APCA in Boston in June, describing the technique.

CONCLUDING REMARKS FOR
STATIONARY SOURCE COMBUSTION SYMPOSIUM

by

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CONCLUDING REMARKS FOR STATIONARY SOURCE COMBUSTION SYMPOSIUM

The Combustion Research Branch of EPA's Industrial Environmental Research Laboratory, RTP has sponsored this symposium on stationary source combustion as one of a series of similar meetings aimed at information exchange or transfer.

Early emphasis of our Combustion Control Program was directed to research and development of economical and efficient combustion modification techniques for controlling air polluting emissions of nitrogen oxides, combustibles (e.g., carbon, carbon monoxide, unburned hydrocarbons), smoke and particulate matter from major stationary combustion sources burning a variety of conventional and alternate fuels. More recently with the structuring of our Utility and Industrial Power Program, the emphasis, although still strongly aimed at control of NO_x and combustibles, has been expanded to encompass consideration of pollution from a multi-media viewpoint and to look at a broader range of potential pollutants, including hazardous pollutants, trace materials and others.

An earlier seminar in June 1973 was devoted entirely to coal combustion discussions. During the intervening period significant technical advances have been made on so many fronts that it appeared worthwhile to cover our entire program in the present meeting. Consequently, an agenda was arranged in which investigators on most of the research and development projects comprising the NO_x Control portion of the overall program were asked to present their up-to-date results. Since the meeting was intended not only for the dissemination of technical information among the investigators involved in our program, but was also planned for the exchange of ideas concerning the technical experience and related data of others, many representatives of industry, Government and the academic community were asked to attend.

The specific purpose of the meeting then has been to review and to exchange information on the Combustion Research Branch's in-house and contracted studies aimed toward the development of practical combustion modification technology for the control of NO_x and other combustion-generated pollutant emissions from major stationary combustion sources. For purposes of presentation the papers were grouped into sessions corresponding to the major subheadings of the NO_x Control program. These categories were: fundamental research, fuels research and development, process research and development, and field testing and surveys. To recapitulate very quickly the symposium has included the following subjects.

Discussions in the fundamental research area have covered the study of the mechanisms and kinetics of the formation of NO_x during methane-air combustion by Exxon Research and Engineering and the investigation of chemical reactions in the conversion of fuel nitrogen to NO_x by Rocketdyne. The Jet Propulsion Laboratory has reported on the role of flame interactions in pollutant formation. United Technology Research Center has discussed the effect of the interactions between fluid dynamics and chemistry in pollutant formation as well as two dimensional combustor modeling. Aerotherm has reviewed their work on prediction of the kinetics of premixed laminar flat flames and Stanford Research Institute has reported on the estimation of rate constants. MIT has described their research on the fate of fuel nitrogen during the pyrolysis and oxidation of coal and on the formation of soot and polycyclic aromatic hydrocarbons during combustion. The University of Arizona has reported on investigations of the effect of fuel sulfur on NO_x emissions.

In the area of fuels R&D the Institute of Gas Technology has reported on burner design criteria to control pollutant emissions from natural gas flames, while Ultrasystems has discussed their investigations to optimize burner design to reduce NO_x emissions from pulverized coal and residual oil flames, along with their work to control emissions from packaged boiler systems. Rocketdyne has reviewed their work on an integrated low emission residential furnace system. Aerotherm has discussed investigations they are initiating to study a pilot scale combustion modification technique applicable to industrial and utility boilers and also catalytic combustion concepts for residential and industrial applications. EPA's in-house study on the assessment of the combustion and emission characteristics of alcohols and other alternate fuels has been summarized.

The process R&D work which involves studies with commercial or prototype combustion systems to develop cost and design information for the application of NO_x control technology to classical combustion systems and which form the basis for future demonstrations were reported yesterday. Combustion Engineering reported on their investigations of the use of overfire air as a means of controlling NO_x in tangential coal-fired utility boilers. TVA described their investigations of staged combustion as a technique for controlling NO_x formation in wall coal-fired utility boilers. Ultrasystems reviewed their study addressing pollutant formation and furnace design in low Btu gas fired boilers. Battelle-Columbus has discussed the effectiveness of fuel additives as a means of reducing pollutant emissions.

The field testing and surveys are studies designed to determine what can be achieved currently to control NO_x emissions with state-of-the-art control technology. Among the papers in this area, Exxon has presented their findings on the effect of combustion modifications on pollutant emissions and on the performance of utility boilers. KVB, Inc. has reported on the effect of combustion modification on pollutant emissions from industrial boilers and on the use of Western coals in small and intermediate size boilers. Aerospace Corporation has reviewed their analysis of test data for utility boilers burning gas, oil and coal. EPA's in-house assessment of the emission characteristics of small gas turbine engines has been discussed. Battelle-Columbus has told us of the emissions from small commercial stoker-fired coal-burning boilers;

and IGT has presented their survey findings on industrial process heating combustion equipment data and emissions control.

The goal of all of these studies (even indirectly of the fundamental research is ultimately the development and assessment of economical and efficient combustion modification techniques which will find practical application for the control of NO_x and other combustion-generated pollutants. Our real purpose is to effectively solve the problems of pollution of the environment. To accomplish this we need data and information which will guide us to the development and application of practical and effective control methods. Many of the results reported here are quite informative and show that good progress is being made in some areas toward abating NO_x and other pollutants without adversely affecting the performance of the energy conversion systems in other critical respects. On the other hand a number of the R&D efforts, while obtaining answers to some of the questions and providing data for some of the unknowns, are opening up new questions which will require answers. In fact, we see that some of the data, at least on first scrutiny, appear to be in conflict or saying different things. There are many areas, I feel sure, where the information presented here will indicate directions which will be carefully considered by us in planning future work. I feel we are making good progress, both in the basic research and modeling of the combusiton processes and pollutant reactions and in the development and assessment of practical control techniques. There has been great evidence of the interest on the part of the various investigators and the participants as shown by the large number of questions and the enthusiasm of the follow-up discussions. I really believe the main purpose of our meeting which was information exchange has to a large degree been achieved. We must conclude however that much work remains to be done and we need to move ahead vigorously with our R&D activities in order to solve the many stationary combustion source pollution problems which still remain.

We want to express our appreciation to the authors and especially to the speakers for their efforts in preparing and presenting the highly informative papers. Also, we want to thank the featured speakers and participants in the panel discussions, including Adel Sarofin, Tom Tyson, Stan Cuffe, Tom Helms, Bob Collon, T. T. Kason and Bob Rosenberg, for their thought-provoking presentations. For all of the attendees, we are particularly gratified that you were able to take the time to meet with us and that you were responsive in participating in the discussion periods. That is what really makes a meeting of this type successful. We also would like to commend the staff of A. D. Little, particularly Marjorie Maws and Anita Lord, and Mr. Robert Hall of the CRB staff who was project officer and vice-chairman of the symposium, and all of the others who have been instrumental in planning and arranging the details of the program and facilities for the meeting. Special mention should be made of the outstanding facilities and services provided by the Fairmont Colony Square.

It is planned that the papers presented here and the related discussions will be compiled and issued as proceedings of the symposium. This EPA report, which will include a list of attendees, will be sent to each of you. However, because of the effort involved in preparing the documentation, you may not receive it until late November or December. Additional copies will be available through the NTIS.

This meeting has provided an additional opportunity for participation by industry and other Government agencies in our program activities. We shall welcome any further comments or recommendations you may have regarding the technical activities as well as future meetings. With regard to available technical information, our studies generate a large number of reports and related documents. A listing of the Industrial Environmental Research Laboratory reports is issued in a Report Abstracts document which is published monthly and may be obtained by contacting W. W. Whelan of IERL-RTP. Although future meetings have not yet been planned, it is anticipated that we will continue our practice of holding symposia as a means of exchanging technical information at appropriate times in the future. In order to help us improve our meetings and make them more responsive to all our needs, I would like to remind you of the Meeting Rating Form which was placed in your program schedule. Would you please take the few minutes needed, perhaps on your trip home, to fill out responses to the various questions and send the form to us. In this way perhaps we can uncover suggestions which will improve the quality of future meetings.

Again, let me thank each of you for coming here and taking part in this meeting. I hope it has proved for each of you to be a worthwhile experience. I wish you a safe and pleasant journey home and on that note we shall consider the meeting adjourned.

SPEAKERS LIST

(NOTE: To facilitate their identification, speakers are listed alphabetically together with the name of the organization they represent. The complete address of each organization represented at the conference appears at the end of the list of attendees.)

LIST OF SPEAKERS

Name	Representing
Axworthy, Dr. Arthur E.	Rockwell International, Rocketdyne Division
Bittner, James D.	Massachusetts Institute of Technology
Bowen, Dr. Joshua A.	EPA, IERL, Combustion Research Branch
Bowman, Dr. Craig T.	United Technology Research Center
Brown, Richard A.	Acurex, Aerotherm Division
Burchard, Dr. John K.	EPA, IERL
Cato, Glenn A.	KVB, Inc.
Collom, Jr., Robert H.	State of Georgia, Department of Natural Resources
Combs, L. Paul	Rockwell International, Rocketdyne Division
Crawford, Allen R.	Exxon Research and Engineering
Cuffe, Stanley T.	EPA, Office of Air Quality Planning and Standards
Dykema, Owen W.	The Aerospace Corporation
England, Dr. Christopher	Jet Propulsion Laboratory
Engleman, Dr. Victor S.	Exxon Research and Engineering
Giammar, Robert P.	Battelle-Columbus Laboratories
Hall, Robert E.	EPA, IERL, Combustion Research Branch
Heap, Dr. Michael P.	Ultrasystems
Helms, G. Thomas	EPA, Region IV, Air and Hazardous Materials Division
Hollinden, Dr. Gerald A.	Tennessee Valley Authority
Kason, T.T.	City of Chicago, Department of Environmental Control
Kendall, Dr. Robert M	Acurex, Aerotherm Division
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16. ABSTRACT The proceedings document the 37 presentations made during the Stationary Source Combustion Symposium held in Atlanta, Ga., September 24-26, 1975. Sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory--RTP, the symposium dealt with subjects related both to developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and to improving equipment efficiency. The symposium was divided into four parts and the proceedings were issued in three volumes: Volume I--Fundamental Research, Volume II--Fuels and Process Research and Development, and Volume III--Field Testing and Surveys. The symposium was intended to provide contractor, industrial, and Government representatives with the latest information on EPA in-house and contract combustion research projects related to pollution control, with emphasis on reducing nitrogen oxides.

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Carbon Monoxide, Hydrocarbons, Boilers	Unburned Hydrocarbons	07C 13A
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