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INTEGRATED DRY NO_x/SO_2 EMISSIONS CONTROL SYSTEM

LOW-NO_x COMBUSTION SYSTEM RETROFIT TEST REPORT

(Test Period: August 6 to October 29, 1992)

DOE Contract Number DE-FC22-91PC90550

Prepared by

R.A. Smith
L.J. Muzio
Fossil Energy Research Corp.
Laguna Hills, CA

T. Hunt
Public Service Company of Colorado
Denver, CO

Prepared for

Public Service Company of Colorado
Denver, CO

June 1993

Revised: October 1993
Final: April 1994

Patents Cleared by Chicago on MAY 16 1994

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Public Service

Public Service
Company of Colorado
5900 East 39th Avenue
Denver, CO 80207-1294

May 23, 1994

U.S. Department of Energy/PETC
Mail Stop 920L
P.O. Box 10940
Pittsburgh, PA. 15236

Attention: Mr. Thomas W. Arrigoni,PETC Technical Project Manager

Subj: Integrated Dry NO_x/SO_2 Emissions Control System
DOE I.D. DE-FC22-91PC90550

Gentlemen:

We are sending herewith the final version of the *Low-NO_x Combustion System Retrofit Test Report*. This final report has been modified to include your previous comments and has received the required patent clearance.

Please advise us if you have any questions.

Sincerely,

Terry Hunt

Terry Hunt, Project Engineer
Generation Engineering Services

Enclosure (2)

With enclosure:

cc: Mr. David L. Hunter (DOE)
Dr. C. Lowell Miller (DOE)
Mr. Howard Feibus (DOE)
Mr. Jeffrey Stallings (EPRI,2)
Mr. John Doyle (B&W)
Office of Technical Information Management (3)
Dr. S.N. Roger Rao (Burns and Roe Technical Group)

Mr. Steve Rohde (PSCC,2)
File CC-071G

DISCLAIMER

ACKNOWLEDGEMENTS

The authors would like to thank Mr. George Brown (Plant Manager), Mr. Brad Govert (Results Engineer), and the Arapahoe Station Maintenance and operating staff for the exceptional cooperation they have provided during this project. Special thanks are also deserved by Mr. Tom Arrigoni and Mr. David Hunter, at the PETC DOE office, whose advice and contributions are greatly appreciated. The advice and technical assistance provided by Mr. Jeff Stallings and Ms. Barbara Toole-O'Neil at EPRI have also been of great assistance throughout the project. Last, but definitely not least, is our appreciation to the many PSCC Engineering and Construction personnel and other contractors who have made the integrated Dry NO_x/SO_2 Emissions Control System a success.

ABSTRACT

The DOE sponsored Integrated Dry NO_x/SO_2 Emissions Control System program, which is a Clean Coal Technology III demonstration, is being conducted by Public Service Company of Colorado. The test site is Arapahoe Generating Station Unit 4, which is a 100 MWe, down-fired utility boiler burning a low-sulfur Western coal. The project goal is to demonstrate up to 70 percent reductions in NO_x and SO_2 emissions through the integration of: 1) down-fired low-NO_x burners with overfire air; 2) Selective Non-Catalytic Reduction (SNCR) for additional NO_x removal; and 3) dry sorbent injection and duct humidification for SO_2 removal. The effectiveness of the integrated system on a high-sulfur coal will also be investigated.

This report documents the third phase of the test program, where the performance of the retrofit low-NO_x combustion system is compared to that of the original combustion system. This third test phase was comprised of an optimization of the operating conditions and settings for the burners and overfire air ports, followed by an investigation of the performance of the low-NO_x combustion system as a function of various operating parameters. These parameters included boiler load, excess air level, overfire air flow rate and number of mills in service. In addition, emissions under normal load following operation were compared to those collected during the optimization and parametric performance tests under baseloaded conditions .

The low-NO_x combustion system retrofit resulted in NO_x reductions of 63 to 69 percent, depending on boiler load. The majority of the NO_x reduction was obtained with the low-NO_x burners, as it was shown that the overfire air system provided little additional NO_x reduction for a fixed excess air level. CO emissions and flyash carbon levels did not increase as a result of the retrofit.

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LIST OF DEFINITIONS

ACFM	Cubic Feet per Minute, gas flow
Btu	British Thermal Unit
B&W	Babcock & Wilcox
CEM	Continuous Emission Monitor
CFM	Cubic Feet per Minute
DCS	Distributed Control System
DOE	U. S. Department of Energy
DRB-XCL™	Dual Register Burner - Axially Controlled Low-NO_x
DSCF	Dry Standard Cubic Feet of gas
DSCFM	Dry Standard Cubic Feet per Minute of gas
EPRI	Electric Power Research Institute
FEGT	Furnace Exit Gas Temperature
FERCo	Fossil Energy Research Corporation
FGR	Flue Gas Recirculation
HVT	High Velocity Thermocouple, suction pyrometry

LNB	Low-NO_x Burner
LOI	Loss on Ignition
MMBtu	1,000,000 Btu
MMD	Mass Mean Diameter
MWe	MegaWatts (electrical)
MWg	MegaWatts (gross load)
OFA	Overfire Air
PLC	Programmable Logic Control
PM	Particulate Matter
PM_{10}	Particulate Matter under the 10 micron diameter size
ppm	Parts Per Million
ppm_c	Parts Per Million Corrected to 3 percent O_2 level
PSCC	Public Service Company of Colorado
RATA	Relative Accuracy Test Audit
SCF	Standard Cubic Foot, measured at 1 atmosphere and 60°F
SCFM	Standard Cubic Feet per Minute, measured at 1 atmosphere and 60°F
SNCR	Selective Non-Catalytic Reduction

EXECUTIVE SUMMARY

This test report summarizes the technical activities and results for one phase of a Department of Energy sponsored Clean Coal Technology III demonstration of an Integrated Dry NO_x/SO_2 Emissions Control System for coal-fired boilers. The project is being conducted at Public Service Company of Colorado's Arapahoe Generating Station Unit 4 located in Denver, Colorado. The project goal is to demonstrate up to 70 percent reductions in NO_x and SO_2 emissions through the integration of existing and emerging technologies including: 1) down-fired low-NO_x burners with overfire air; 2) Selective Non-Catalytic Reduction (SNCR) for additional NO_x removal; and 3) dry sorbent injection and duct humidification for SO_2 removal.

Due to the number of technologies being integrated, the test program has been divided into the following test activities:

- Baseline tests with the original combustion system
- Baseline tests with the original combustion system and SNCR
- Low-NO_x Burner (LNB)/Overfire Air (OFA) tests
- LNB/OFA/SNCR tests
- LNB/OFA/Calcium Injection tests
- LNB/OFA/Sodium Injection tests
- LNB/OFA/SNCR Dry Sorbent Injection tests (integrated system)
- High-Sulfur Coal tests with the integrated system

This report presents the results of the low-NO_x burner/overfire air tests performed after the combustion system retrofit on the Arapahoe Unit 4 boiler. The performance of the new combustion system is compared to that of the original system, as documented during the baseline test program.

The low-NO_x burner/overfire air test program was conducted over a twelve week period from August 6 to October 29, 1992. The test program consisted of two separate phases. During the first, optimum operating conditions and settings for the burners and overfire air ports were identified. The second phase consisted of a detailed series of tests to assess the performance of the low-NO_x combustion system as a function of various operating parameters. These parameters included boiler load, excess air level, overfire air flow rate, and number of mills in service. These parameters represent the primary factors influencing NO_x and CO emissions and flyash carbon levels. Immediately following the completion of the baseloaded optimization and parametric tests, the boiler was operated for two months (November and December 1992) under normal load following conditions. During this time, emissions data were collected automatically with a Continuous Emissions Monitor (CEM).

NO_x emissions with the retrofit combustion system were 63 to 69 percent lower than those for the original combustion system, depending on boiler load (Figure S-1). These results were obtained under baseloaded conditions with maximum overfire air (corresponding to 24 percent of the total secondary air flow at full load). OFA port cooling requirements precluded reducing the overfire air flow to zero at this particular installation, thereby limiting the minimum overfire air condition to 15 percent of the total secondary air. Increasing the overfire air flow from 15 to 25 percent resulted in only a 5 to 10 percent increase in NO_x removal. This suggests that the majority of the NO_x removal was due to the low-NO_x burners, and not the overfire air system. However, it must be realized that it was not possible to completely separate the relative roles of the burners and overfire air system at this particular installation due to the inability to reduce the overfire air flow to zero.

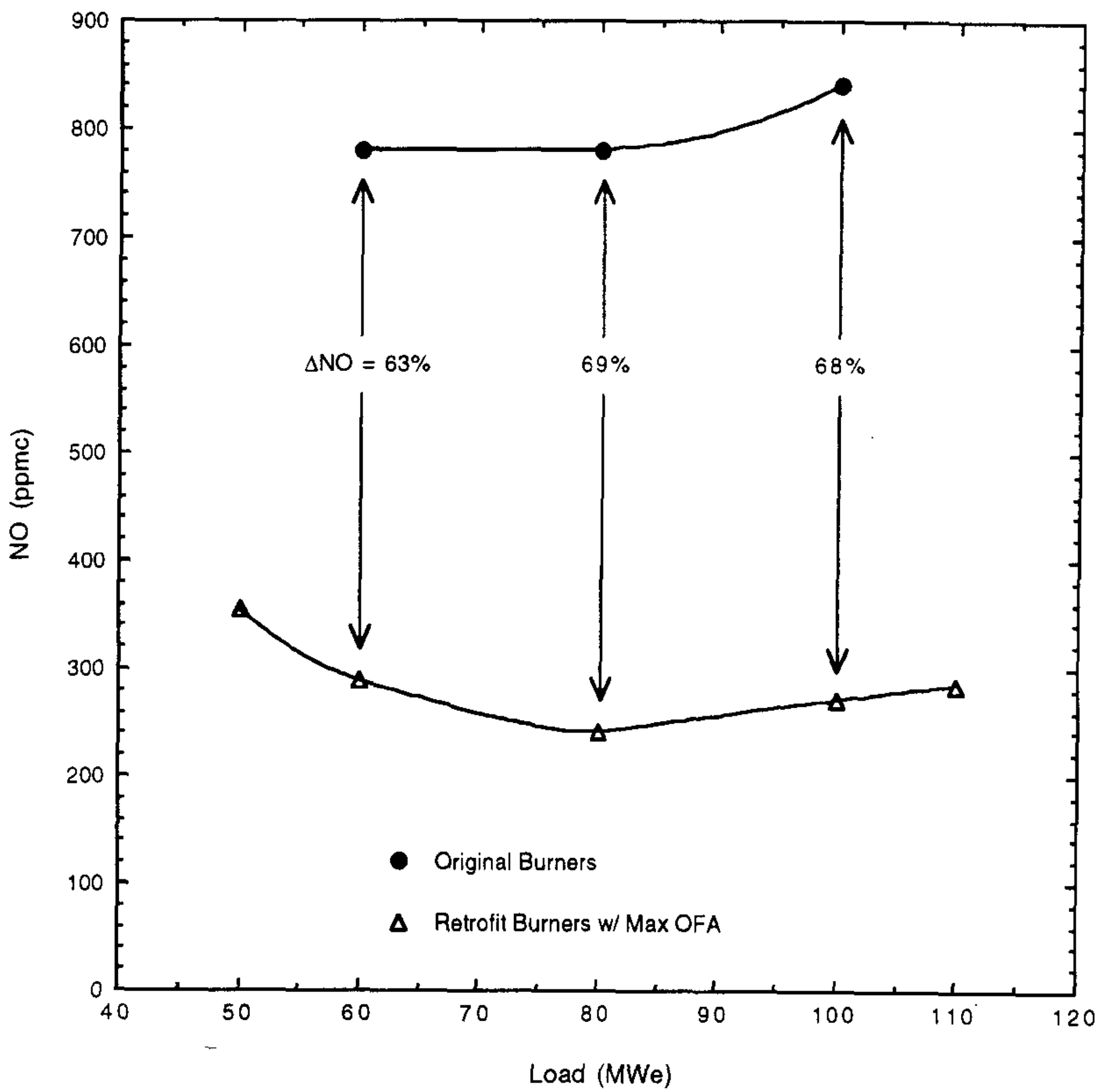


Figure S-1. NO_x Emissions as a Function of Boiler Load for the Original and Retrofit Combustion Systems.

The long-term CEM data showed that NO_x emissions increased by up to 20 percent during normal load following operation when compared to baseloaded conditions. The increase was due to the higher excess air levels normally maintained during load following operation. The long term data also showed that CO emissions increased substantially. Part of the increase was due to maldistribution of the overfire air, which will be corrected in the future. The remainder of the increase was due to variations in boiler operating parameters which are inherent in load following operation.

Limited testing showed that while firing natural gas, increases in overfire air flow result in decreased NO_x emissions and higher CO emissions. This NO_x/CO relationship was different from that seen for coal firing, and was attributed to a separation of the mixing effects of the low NO_x burners and overfire air ports due to the shorter combustion zone under gas-fired conditions.

No major operational problems have developed due to the boiler modifications, although the retrofit combustion system has resulted in a decrease in furnace exit gas temperature of approximately 200°F. This has resulted in an increase in the amount of excess air required to maintain adequate steam temperatures at reduced boiler loads.

1

INTRODUCTION

This report presents the results from one phase of the Public Service Company of Colorado (PSCC) and the Department of Energy (DOE) sponsored Integrated Dry NO_x/SO_2 Emissions Control System program. The DOE Clean Coal Technology III demonstration program is being conducted by Public Service Company of Colorado at PSCC's Arapahoe Generating Station Unit 4, located in Denver, Colorado. The intent of the demonstration program at Arapahoe Unit 4 is to achieve up to 70 percent reductions in NO_x and SO_2 emissions through the integration of existing and emerging technologies, while minimizing capital expenditures and limiting waste production to dry solids that are handled with conventional ash removal equipment. The technologies to be integrated are: 1) a down-fired low-NO_x burner system with overfire air; 2) Selective Non-Catalytic Reduction (SNCR) with urea and aqueous ammonia for additional NO_x removal; and 3) dry sorbent injection (calcium- and sodium-based compounds) and duct humidification for SO_2 removal. Figure 1-1 shows a simplified schematic of the integrated system as implemented at Arapahoe Unit 4.

During the demonstration program, these emissions control systems are being optimized and integrated with the goal of maximizing the reductions of NO_x and SO_2 emissions, while minimizing any negative effects resulting from the application of the various technologies. It is anticipated that the emissions control system will achieve these reductions at costs lower than other currently available technologies. It is also

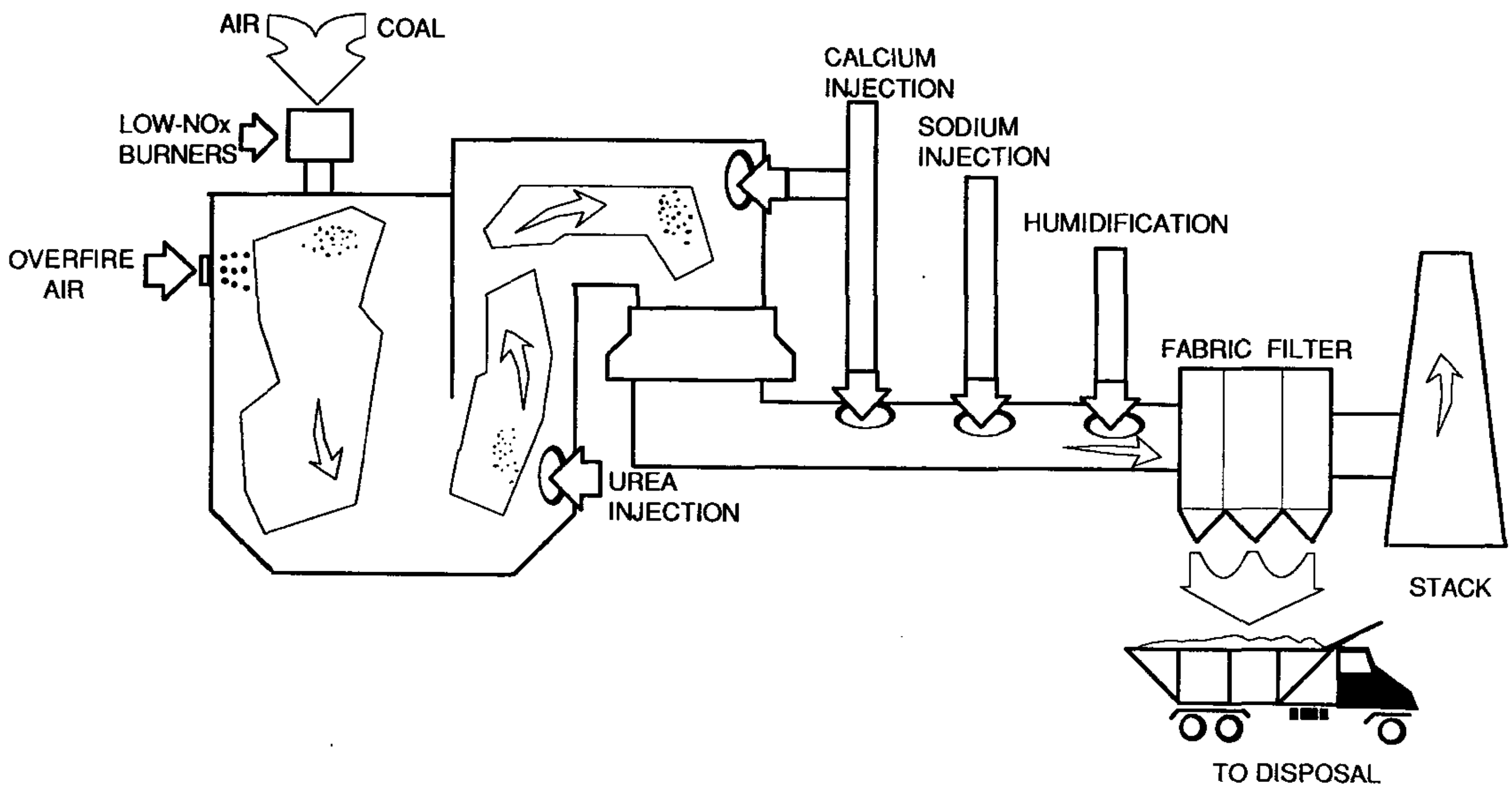


Figure 1-1. Arapahoe Unit 4 Integrated Dry NO_x/SO_2 Emissions Control System

anticipated that these technologies will integrate synergistically. For example, an undesirable side effect of sodium-based sorbent injection for SO_2 control has been oxidation of NO to NO_2, resulting in plume colorization. Pilot-scale testing, sponsored by the Electric Power Research Institute (EPRI), has shown that NH_3 can suppress the NO to NO_2 oxidation. In the integrated system, the byproduct NH_3 emissions from the urea injection system will serve to minimize NO_2 formation. An additional objective of this program is to test the effectiveness of the integrated system on a high-sulfur coal.

Due to the number of technologies being integrated, the test program has been divided into the following test activities:

- Baseline tests of the original combustion system. These results provide the basis for comparing the performance of the individual technologies as well as that of the integrated system. (completed)
- Baseline combustion system/SNCR tests. Performance of urea and aqueous ammonia injection with the original combustion system. (completed)
- Low-NO_x burner (LNB)/overfire air (OFA) tests. (subject of this report)
- LNB/OFA/SNCR tests. NO_x reduction potential of the combined low-NO_x combustion system and SNCR.
- LNB/OFA/calcium-based sorbent injection. Economizer injection and duct injection with humidification.
- LNB/OFA/sodium injection. SO_2 removal performance of sodium-based sorbent.
- Integrated Systems test. NO_x and SO_2 reduction potential of the integrated system using LNB/OFA/SNCR/dry sorbent injection using calcium- or sodium-based reagents. Integrated system performance.
- High-sulfur coal tests. NO_x and SO_2 reduction potential of the integrated system while using an eastern bituminous coal. Dry sorbent injection will be calcium-based using the most efficient injection location determined from previous testing.

In addition to investigation of NO_x and SO_2 emissions, the test program will also investigate air toxic emissions. Baseline air toxic emission levels will be obtained during the testing of the low-NO_x combustion system. Three additional tests will be conducted during the urea, calcium, and sodium injection tests to determine the potential air toxics removal of these pollution control technologies.

This report presents the results of the low-NO_x burner/overfire air tests performed after the combustion system retrofit on the Arapahoe Unit 4 boiler. The performance of the new combustion system is compared to that of the original system as documented during the first phase of the program.[1]

2

PROJECT DESCRIPTION

The following subsections will describe the key aspects of the technologies being demonstrated, the project participants, and the boiler and the original combustion system. Finally, a brief review of the results of the baseline tests with the original combustion system will be presented.

2.1 Process Description

The Integrated Dry NO_x/SO_2 Emissions Control system consists of five major control technologies that are combined to form an integrated system to control both NO_x and SO_2 emissions. NO_x reduction is accomplished through the use of low-NO_x burners, overfire air, and SNCR, while dry sorbent injection (using either calcium- or sodium-based reagents) is used to control SO_2 emissions. Flue gas humidification will be used to enhance the SO_2 removal capabilities of the calcium-based reagents. Each of these technologies is discussed briefly below.

Low-NO_x Burners

NO_x formed during the combustion of fossil fuels consists primarily of NO_x formed from fuel-bound nitrogen, and thermal NO_x. NO_x formed from fuel-bound nitrogen results from the oxidation of nitrogen which is organically bonded to the fuel molecules. Thermal NO_x forms when nitrogen in the combustion air dissociates and oxidizes at flame temperatures. Thermal NO_x is of primary importance at temperatures in excess of 2800°F.

To reduce the NO_x emissions formed during the combustion process, Babcock and Wilcox (B&W) Dual Register Burner-Axially Controlled Low-NO_x (DRB-XCL™) burners were retrofit to the Arapahoe Unit 4 boiler. Most low-NO_x burners reduce the formation of NO_x through the use of air staging, which is accomplished by limiting the availability of air during the early stages of combustion. This lowers the peak flame temperature and results in a reduction in the formation of thermal NO_x. In addition, by reducing the oxygen availability in the initial combustion zone, the fuel-bound nitrogen is less likely to be converted to NO_x, but rather to N_2 and other stable nitrogen compounds. The B&W DRB-XCL™ burner achieves increased NO_x reduction effectiveness by incorporating fuel staging in addition to air staging. Fuel staging involves the introduction of fuel downstream of the flame under fuel-rich conditions. This results in the generation of hydrocarbon radicals which further reduce NO_x levels. The fuel staging is accomplished through the design of the coal nozzle/flame stabilization ring on the burner. Additionally, combustion air to each burner is accurately measured and regulated to provide a balanced fuel and air distribution for optimum NO_x reduction and combustion efficiency. Finally, the burner assembly is equipped with two sets of adjustable spin vanes which provide swirl for fuel/air mixing and flame stabilization.

Overfire Air

Low-NO_x burners and overfire air reduce the formation of NO_x by controlling the fuel/air mixing process. While low-NO_x burners control the mixing in the near burner region, overfire air controls the mixing over a larger part of the furnace volume. By diverting part of the combustion air to a zone downstream of the burner, initial combustion takes place in a near stoichiometric or slightly fuel rich environment. The remaining air necessary to ensure complete combustion is introduced downstream of the primary combustion zone through a set of overfire air ports, sometimes referred to as NO_x ports. Conventional single-jet overfire air ports are not capable of providing adequate mixing across the entire furnace. The B&W dual-zone NO_x ports, however, incorporate a central zone which produces an air jet that penetrates across the furnace and a separate outer zone that diverts and disperses the air in the area of the furnace, near the NO_x port. The central zone is provided with a manual air control disk for flow control, and the outer zone incorporates manually adjustable spin vanes for swirl control.

The combined use of the low-NO_x burners and overfire air ports is expected to reduce NO_x emissions by up to 70 percent.

Selective Non-Catalytic Reduction

NO_x reduction in utility boilers can also be accomplished by Selective Non-Catalytic Reduction (SNCR). This process involves the injection of either urea or ammonia (anhydrous or aqueous) into the combustion products where the gas temperature is in the range of 1600 to 2100°F. In this range, NH_2 is released from the injected chemical which then selectively reacts with NO in the presence of oxygen, forming primarily N_2 and H_2O. A SNCR system is capable of removing 40 to 50 percent of the NO from the flue gas stream.

Urea and ammonia each have their own optimum temperature range within which NO_x reduction can occur. An example of such a temperature "window" is shown conceptually in Figure 2-1. At temperatures above the optimum, the injected chemical will react with O_2 forming additional NO_x, thereby reducing the NO_x removal efficiency. At temperatures below the optimum, the injected chemical does not react with NO, resulting in excessive emissions of NH_3 (referred to as ammonia slip). Chemical additives can be injected with the urea to widen the optimum temperature range and minimize NH_3 emissions.

The SNCR chemical of primary interest for the present program is urea. The urea is generally injected into the boiler as a liquid solution through atomizers. The atomizing medium can be either air or steam, although air is used in the current installation. The urea and any additives are stored as a liquid and pumped through the injection atomizers. At Arapahoe Unit 4, a system has also been installed to catalytically convert the urea solution to an aqueous ammonium compound.

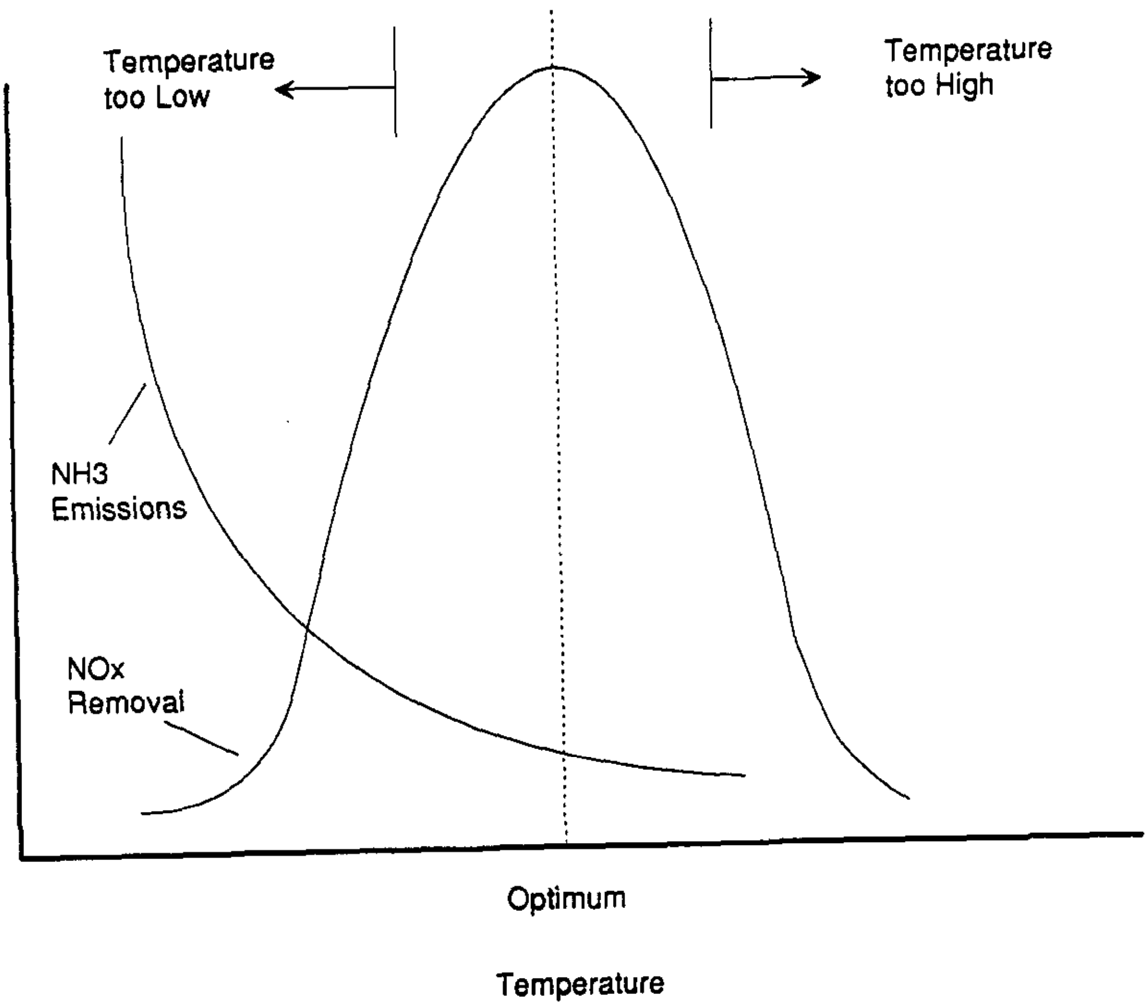


Figure 2-1. Conceptual Temperature Window for the SNCR Process

Dry Reagent SO_2 Removal System

The dry reagent injection system consists of equipment for storing, conveying, pulverizing and injecting calcium- or sodium-based reagents into the flue gas between the air heater and the particulate removal equipment, or calcium-based reagents between the economizer and the air heater. The SO_2 formed during the combustion process reacts with the sodium- or calcium-based reagents to form sulfates and sulfites. These reaction products are then collected in the particulate removal equipment together with the flyash and any unreacted reagent and removed for disposal. The system is expected to remove up to 70 percent of the SO_2 when using sodium-based products while maintaining high sorbent utilization.

Although dry sodium-based reagent injection systems reduce SO_2 emissions, NO_2 formation has been observed in some applications. NO_2 is a red/brown gas; therefore, a visible plume may form as the NO_2 in flue gas exits the stack. Previous pilot-scale tests have shown that ammonia slip from urea injection reduces the formation of NO_2 while removing the ammonia which would otherwise exit the stack.

In certain areas of the country, it may be more economically advantageous to use calcium-based reagents, rather than sodium-based reagents, for SO_2 removal. SO_2 removal using calcium-based reagents involves dry injection of the reagent into the furnace at a point where the flue gas temperature is approximately 1000°F. Calcium-based materials can also be injected into the flue gas ductwork downstream of the air heater, but at reduced SO_2 removal effectiveness.

Humidification

The effectiveness of the calcium-based reagent in reducing SO_2 emissions when injected downstream of the air heater can be increased by flue gas humidification. Flue gas conditioning by humidification involves injecting water into the flue gas downstream of the air heater and upstream of any particulate removal equipment. The water is injected into the duct by dual-fluid atomizers which produce a fine spray that can be directed downstream and away from the duct walls. The subsequent evaporation causes the flue gas to cool, thereby decreasing its volumetric flowrate and increasing its relative and absolute humidity. It is important that the water be injected in such a way as to prevent it from wetting the duct walls and to ensure complete evaporation before the gas enters the particulate removal equipment or contacts the duct turning vanes. Since calcium-based reagents are not as reactive as sodium-based reagents, the presence of water in the flue gas, which contains unreacted reagent, provides for additional SO_2 removal. Up to 50 percent SO_2 removal is expected when calcium-based reagents are used in conjunction with flue gas humidification.

2.2 Project Participants

PSCC is the project manager for the project, and is responsible for all aspects of project performance. PSCC has engineered the dry sorbent injection system and the modifications to the flyash system, provided the host site, trained the operators, provided selected site construction services, start-up services and maintenance, and is assisting in the testing program.

B&W was responsible for engineering, procurement, fabrication, installation, and shop testing of the low-NO_x burners, overfire air ports, humidification equipment, and associated controls. They are also assisting in the testing program, and will provide for commercialization of the technology. NOELL, Inc. was responsible for the engineering, procurement and fabrication of the SNCR system. Fossil Energy Research Corp. is conducting the testing program. Western Research Institute is characterizing the waste materials and recommending disposal options. Colorado School of Mines is conducting research in the areas of bench-scale chemical kinetics for the NO_2 formation reaction with dry sorbent injection. Stone & Webster Engineering is assisting PSCC with the engineering efforts. Cyprus Coal and Amax Coal are supplying the coal for the project, while Coastal Chemical, Inc. is providing the urea for the SNCR system.

2.3 Boiler and Original Combustion System Description

Arapahoe Unit 4 is the largest of four down-fired boilers located at the Arapahoe station and is rated at 100 MWe. The unit was built in the early 1950's and was designed to burn Colorado lignite or natural gas. Currently, the main fuel source for the station is a Colorado low-sulfur bituminous coal. Although the unit can be run at full load while firing natural gas, this fuel is only occasionally used to provide load when pulverizers or other equipment are out of service. An elevation view of the boiler is shown in Figure 2-2.

The original furnace configuration was a down-fired system employing 12 intertube burners located on the roof and arranged in a single row across the width of the furnace. A single division wall separates the furnace into east and west halves, each with six burners. Downstream of the burners, the flue gas flows down the furnace and then turns upward to flow through the convective sections on the boiler backpass. After reaching the burner level elevation, the gas passes through a horizontal duct and is then directed downward through a tubular air heater. After leaving the air heater, the flue gas passes through a reverse gas baghouse for particulate control. Induced draft fans are positioned downstream of the baghouse and deliver the flue gas into a common stack for Units 3 and 4.

The original intertube burners were not comparable to a more common wall-fired burner. Each burner consisted of a rectangular coal/primary air duct which was split into 20 separate nozzles arranged in a four by five rectangle that injected the coal/air mixture evenly across the furnace roof. A secondary air windbox surrounded each burner and allowed air flow around each of the individual coal nozzles, resulting in a checkerboard pattern of coal/primary air and secondary air streams. The burners had no provisions to control the rate of fuel and secondary air mixing.

The burners were numbered one through twelve from west to east. Each of the four attrition mills supplied primary air and coal to three of the burners. The coal piping

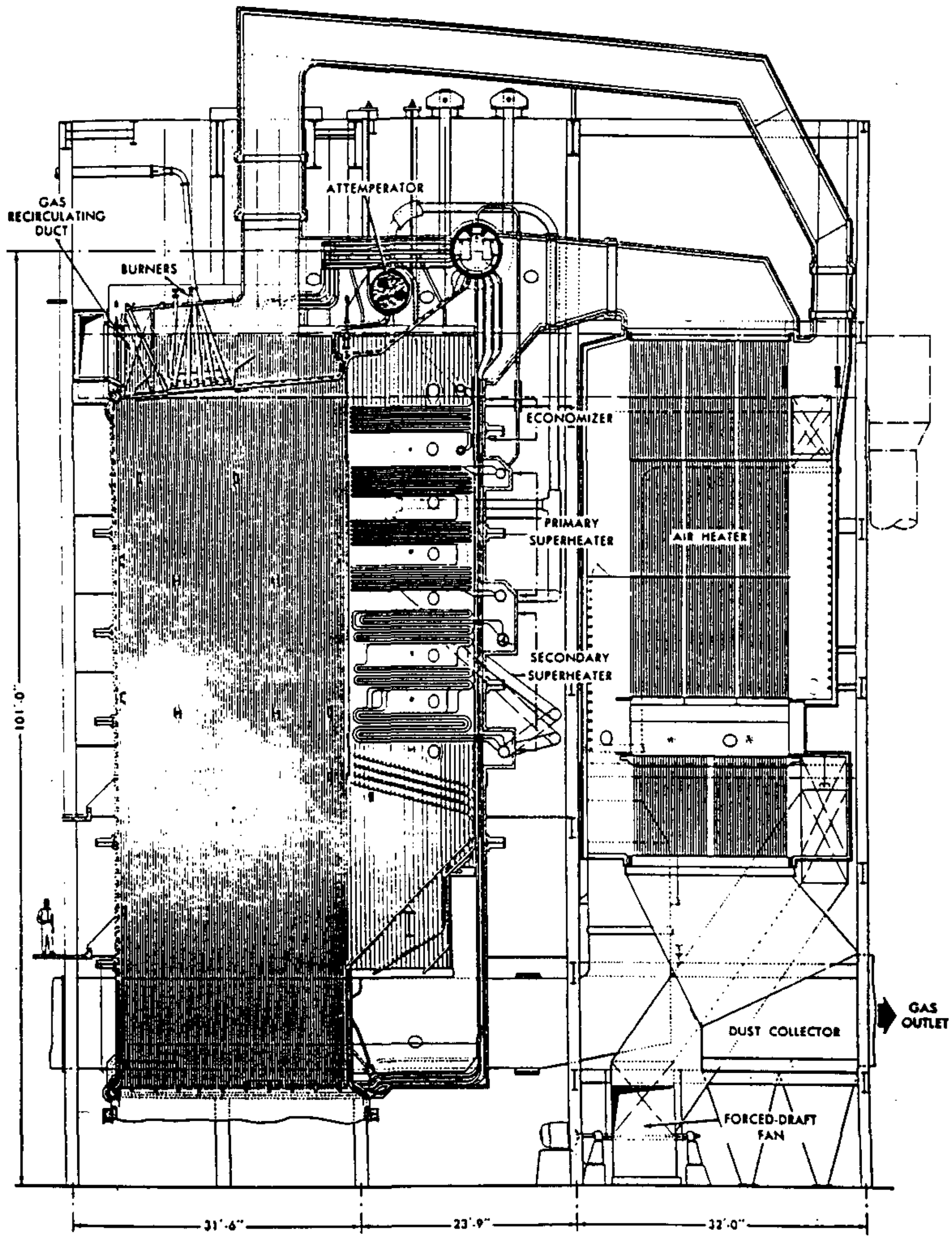


Figure 2-2. PSCC Arapahoe Unit 4

allowed each mill to supply two burners in one furnace half and one in the other half. Figure 2-3 shows the original burner firing configuration and coal distribution arrangement from the four mills. The secondary air ducts were positioned behind the burners and included a secondary air damper for each burner. When a single burner was removed from service, the secondary air flow was also stopped by closing the associated secondary air damper. The dampers were manually controlled at the burner deck and were intended for on/off duty only.

2.4 Baseline Burner Test Results

The baseline tests on Arapahoe Unit 4 were performed to document the initial emissions of NO_x and SO_2, without any modifications to the boiler or burner systems. These tests were performed during the period from November 11 to December 15, 1991, and the results pertinent to the current phase of testing, namely, the effect of load and excess O_2 levels on the baseline NO_x levels, are summarized in this section. Complete documentation of the baseline test results is contained in a separate report.[1]

The difference between NO and NO_x emissions was monitored on most tests during the baseline burner tests, and the difference was found to be not significant within the limits of detection. Thus, for the purposes of this report, NO and NO_x emissions are used interchangeably.

Figure 2-4 summarizes the baseline NO_x data as a function of economizer exit O_2 for three loads (60, 80, and 100 MWe). The Arapahoe Unit 4 boiler is used nearly exclusively for load regulation by the PSCC system dispatch center (i.e., the load is rarely constant for a long period of time). Therefore, the number of mills in service at the loads tested during the baseline tests were chosen to reflect the number normally in service when regulating at that particular load: four mills at 100 and 80 MWe, and 3 mills at 60 MWe.

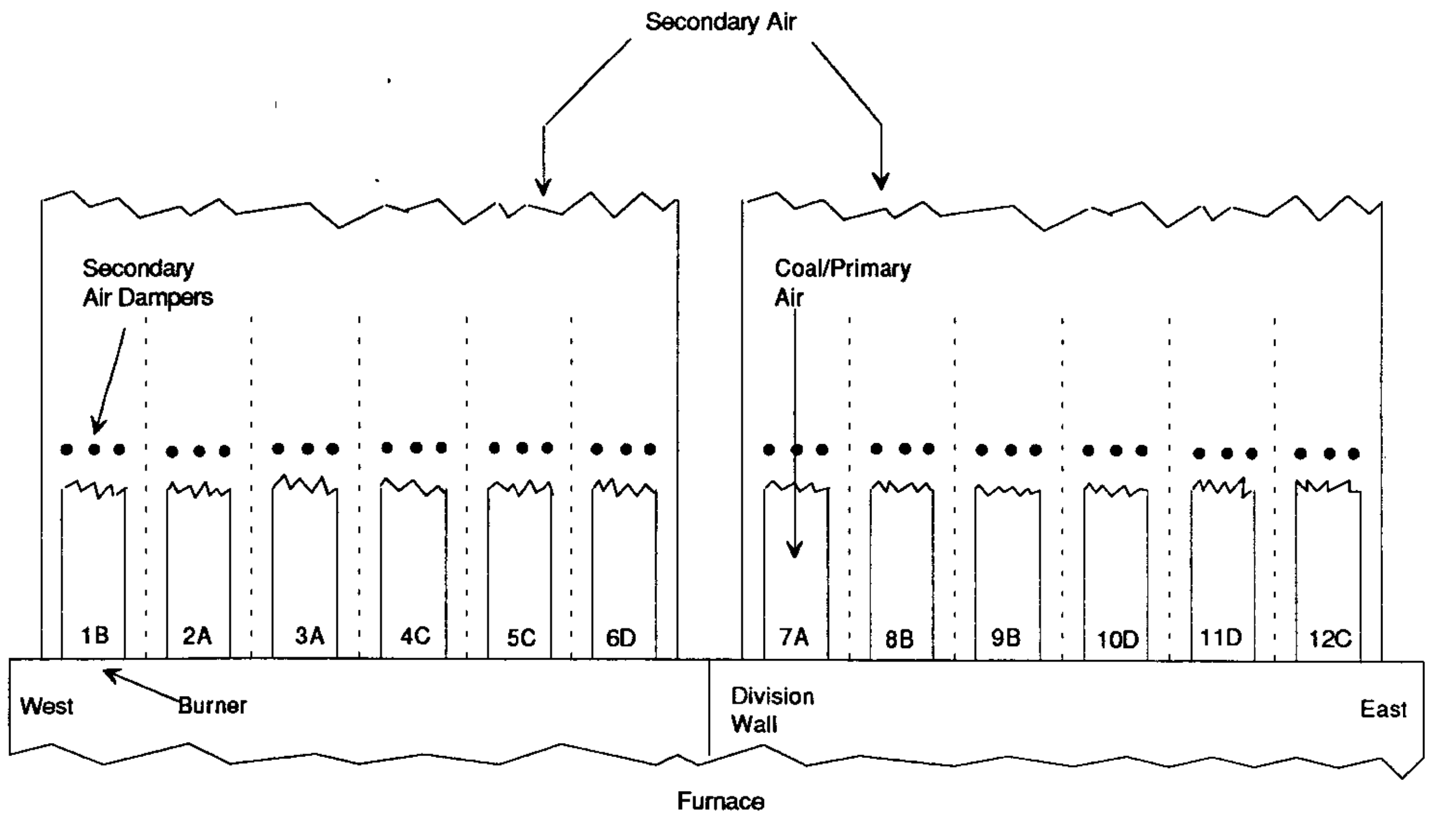


Figure 2-3. Original Burner-Mill Arrangement - Looking to the North
(Note: the letter next to each burner designates one of the four pulverizers)

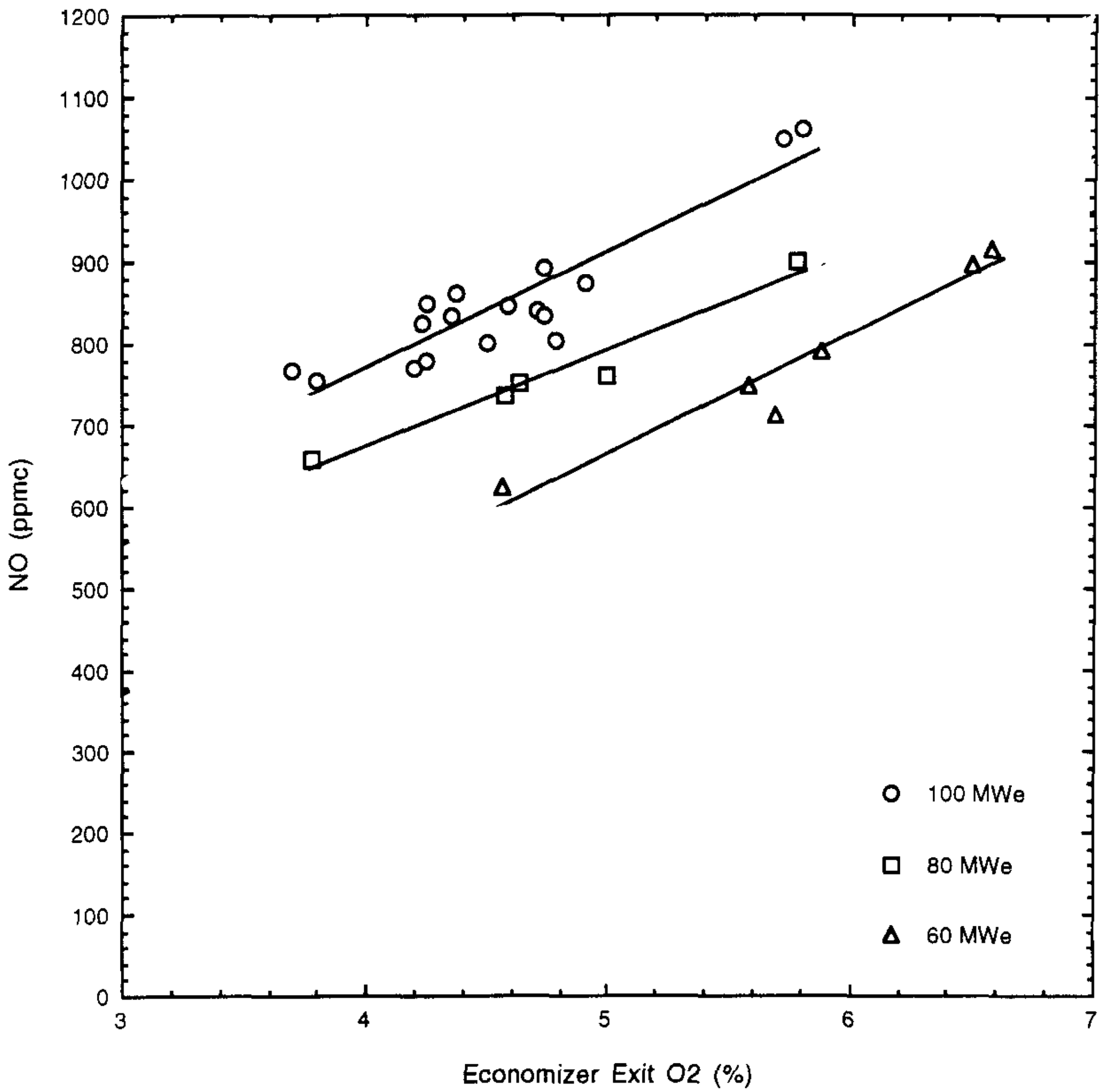


Figure 2-4. Baseline NO Emissions as a Function of Economizer Exit O_2

The data in Figure 2-4 indicate that the effect of excess air, or operating O_2 level, on the NO_x emissions was significant. The curves for the three boiler loads have similar NO_x versus O_2 slopes, nominally 145 ppmc (parts per million corrected to 3 percent O_2 concentration dry) NO_x/percent O_2. This represents a large effect of O_2 on NO_x compared to other furnace designs. For full load operation, this dependence on O_2 resulted in the NO_x emissions ranging from 760 ppmc at 3.7 percent O_2 to 1060 ppmc at 5.7 percent O_2. This O_2 effect was found to be the most important operational parameter affecting the baseline NO_x emissions with the original combustion system.

The data in Figure 2-4 also indicate that for a constant economizer exit O_2 level, the NO_x emissions decreased as the load was reduced. However, normal operation at Arapahoe Unit 4 required that O_2 levels be increased as the load was reduced in order to maintain steam temperatures. NO_x emissions at typical baseloaded operating O_2 levels are replotted in Figure 2-5 as a function of boiler load. The highest NO_x emissions occur at 100 MWe and the levels decrease as the load is reduced. Below 80 MWe, NO_x emissions decreased only slightly, due to the counteracting effects of increasing O_2 level and reduced heat release rate. The O_2 levels maintained during the typical baseloaded boiler operation are also included in Figure 2-4 and show that O_2 levels increased with decreasing load. Since the NO_x/O_2 relationship of Arapahoe Unit 4 was relatively steep, higher O_2 levels prevented significant NO_x reductions at reduced loads. At typical baseloaded operating O_2 levels, the NO_x emissions ranged from nominally 760 to 850 ppmc (1.04 to 1.16 lb/MMBtu) over the load range of 60 to 100 MWe.

Figure 2-6 summarizes CO emissions and flyash carbon levels as a function of boiler load for the typical baseloaded operating O_2 levels indicated in Figure 2-5. CO and flyash carbon levels are two factors affecting combustion efficiency, and are presented here in order to provide a basis from which to compare the performance of the new low-NO_x combustion system. The data show that CO emissions ranged from nominally 40 to 60 ppm, while flyash carbon levels increased from approximately 1.0 to 5.5 percent over the load range of 60 to 100 MWe.

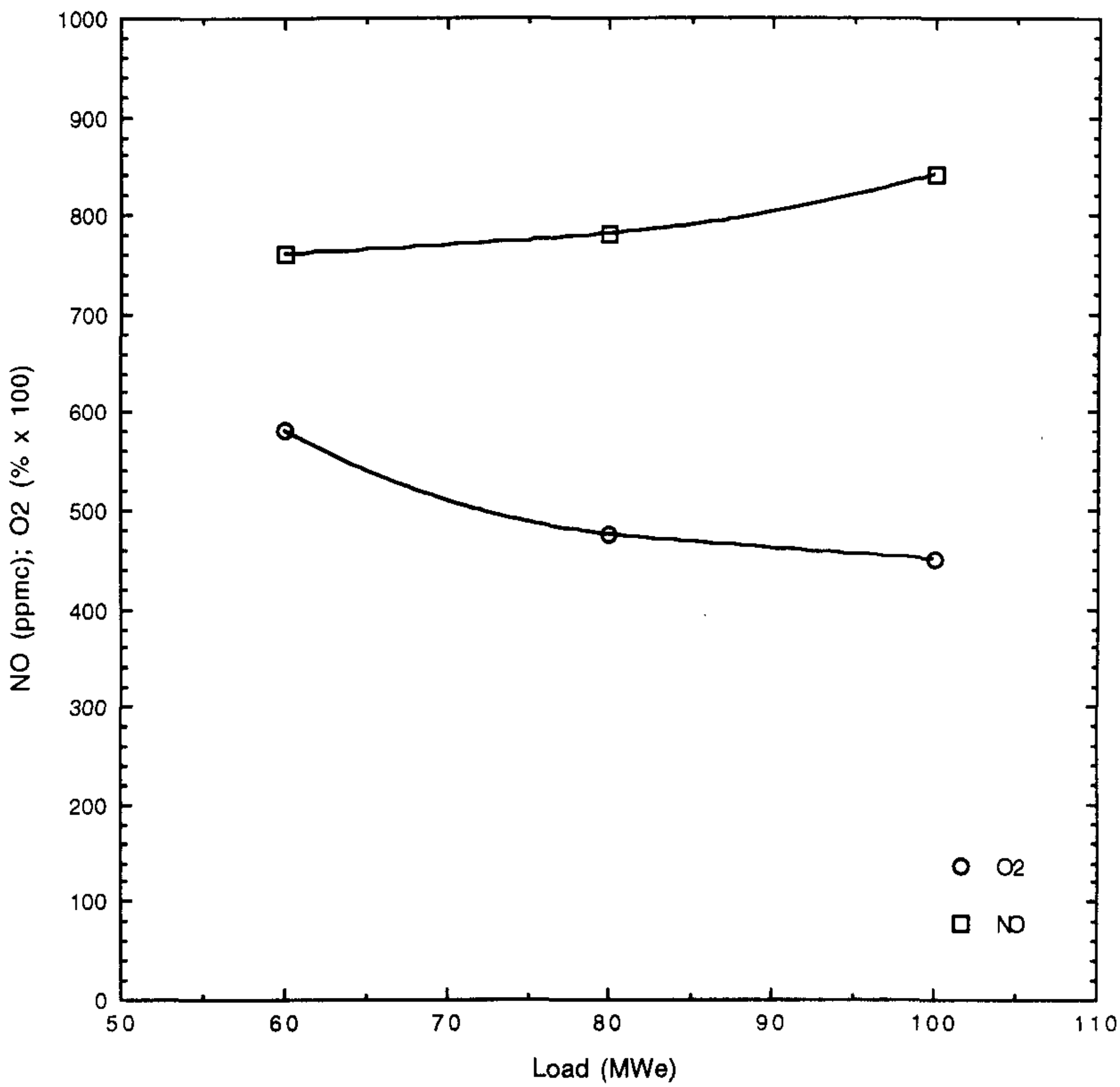


Figure 2-5. Baseline NO and O_2 Levels as a Function of Boiler Load with Typical Baseloaded Boiler Operation

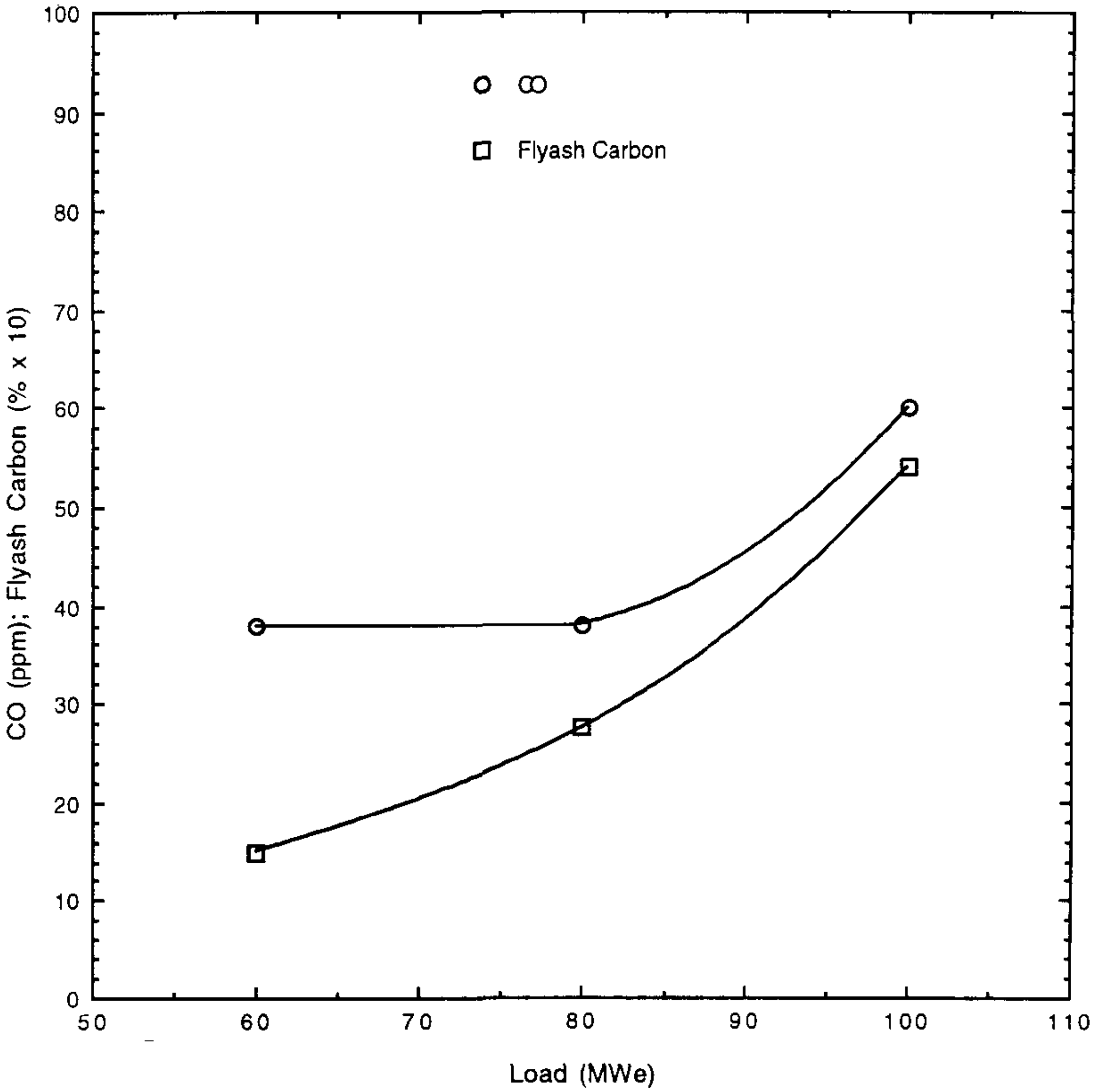


Figure 2-6. Baseline CO Emissions and Flyash Carbon Levels as a Function of Boiler Load with Typical Baseloaded Boiler Operation

3

LOW-NO_x COMBUSTION SYSTEM DESCRIPTION

3.1 Low-NO_x Burners

To reduce the NO_x emissions formed during the combustion process, B&W DRB-XCL™ burners were retrofit to the Arapahoe Unit 4 boiler. Figure 3-1 shows a simplified schematic of the burner. The burner has two main design features which limit the formation of NO_x. First is the addition of a sliding air damper. In many older burner designs, a single register is used to control both total secondary air flow to the burner and also the swirl (i.e., the rate of fuel/air mixing). The use of the sliding damper separates the functions and allows the secondary air flow to be controlled independently of the swirl. The burner includes a circular pitot tube array which provides a relative indication of the secondary air flow to each burner. The second feature is the addition of dual spin vane registers. The most important variable in controlling the formation of NO_x is the rate at which oxygen is mixed with the fuel. The dual spin vane registers provide a great amount of control over the amount of swirl imparted to the secondary air, and thus the rate of fuel/air mixing in the near-burner region.

An electric linear actuator is used to adjust the sliding damper which controls the total secondary air to each burner. The control system allows for three disc positions: cool, light and normal. The cool position is used while a burner is out of service and provides a minimum amount of cooling air so that the burner metal temperatures do not exceed the design limit of 1300°F. The light position is used to provide slightly more air while the gas ignitors are firing. The normal position is used while the burners are

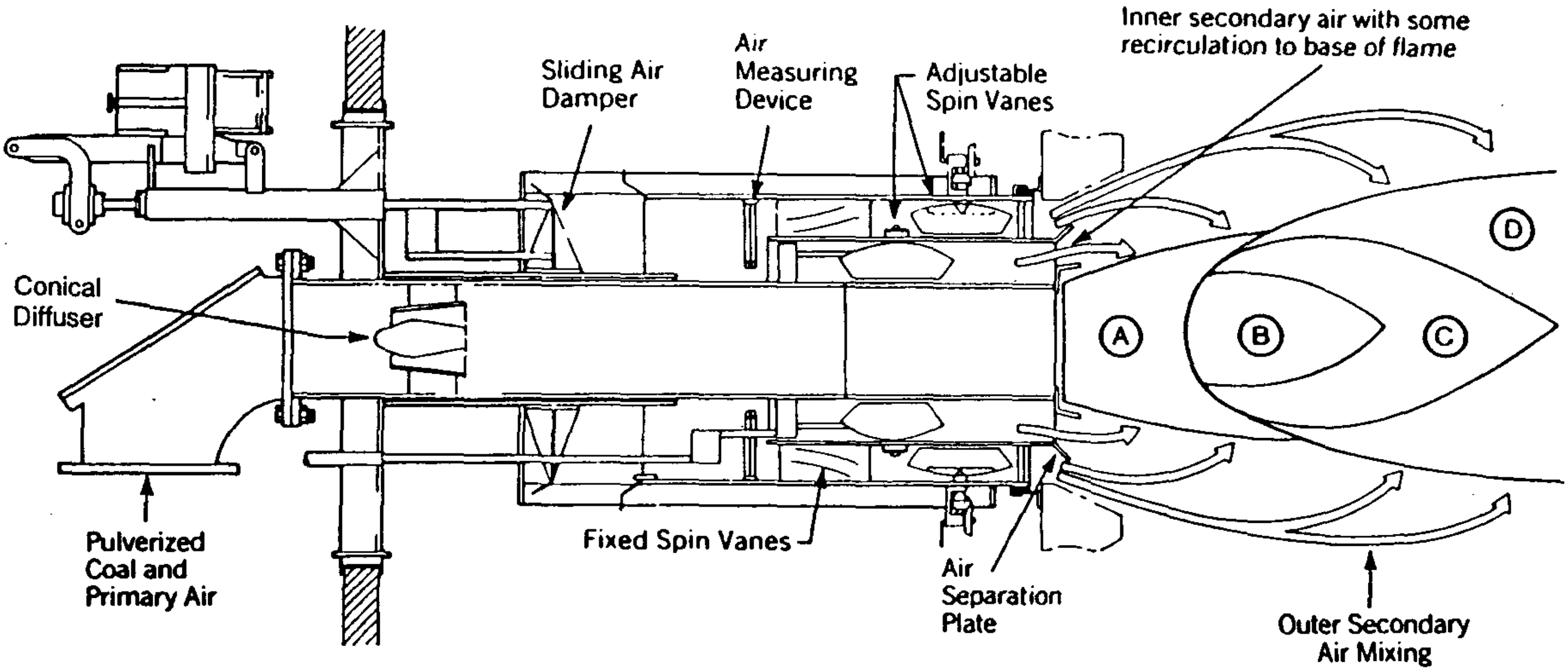


Figure 3-1. B&W DRB-XCL™ Low NO_x Burner

fired with either coal or natural gas. Limit switches in the actuator are used to adjust the three disk positions. The adjustment of these limit switches allows the secondary air to be individually adjusted at each burner, if burner-to-burner imbalances occur.

The low-NO_x combustion system retrofit at Arapahoe Unit 4 was much more involved than a similar modification to a normal wall- or tangential-fired unit. The original intertube burners were not comparable to "normal" burners, as they required only small openings in the roof tubes. The modifications began by removing everything from the boiler roof tubes to the roof of the boiler enclosure, including the windbox roof, coal and gas piping, and the secondary air supply duct. New roof tubes with twelve circular openings were welded in place to accommodate the new burners.

The burners were placed in 4 rows of 3 burners as shown in Figure 3-2. The boiler has a full division wall that separates the furnace into two approximately square sections. A major problem encountered during the retrofit was the limited space available for burner placement. The outer edge of the burners on each side of the division wall are located within a few inches of each other.

The secondary air duct originally entered the windbox at the rear (south side) of the furnace roof as shown in Figure 2-2. Since the new burners required significantly more roof area than the intertube burners, and there were now four burners where the secondary air duct was originally located, providing sufficient secondary air to the windbox became a challenge. The majority of the air is introduced through four "pant-leg" ducts as shown in Figure 3-3. The Arapahoe 4 boiler was originally designed to use flue gas recirculation (FGR) for steam temperature control. However, the system was no longer in use, so two abandoned FGR ducts which entered the front (south) wall of the windbox were used to provide the balance of the secondary air.

The retrofit also included new gas burners, gas ignitors and flame scanners. Arapahoe Unit 4 was originally designed with the ability to fire 100 percent natural gas. While

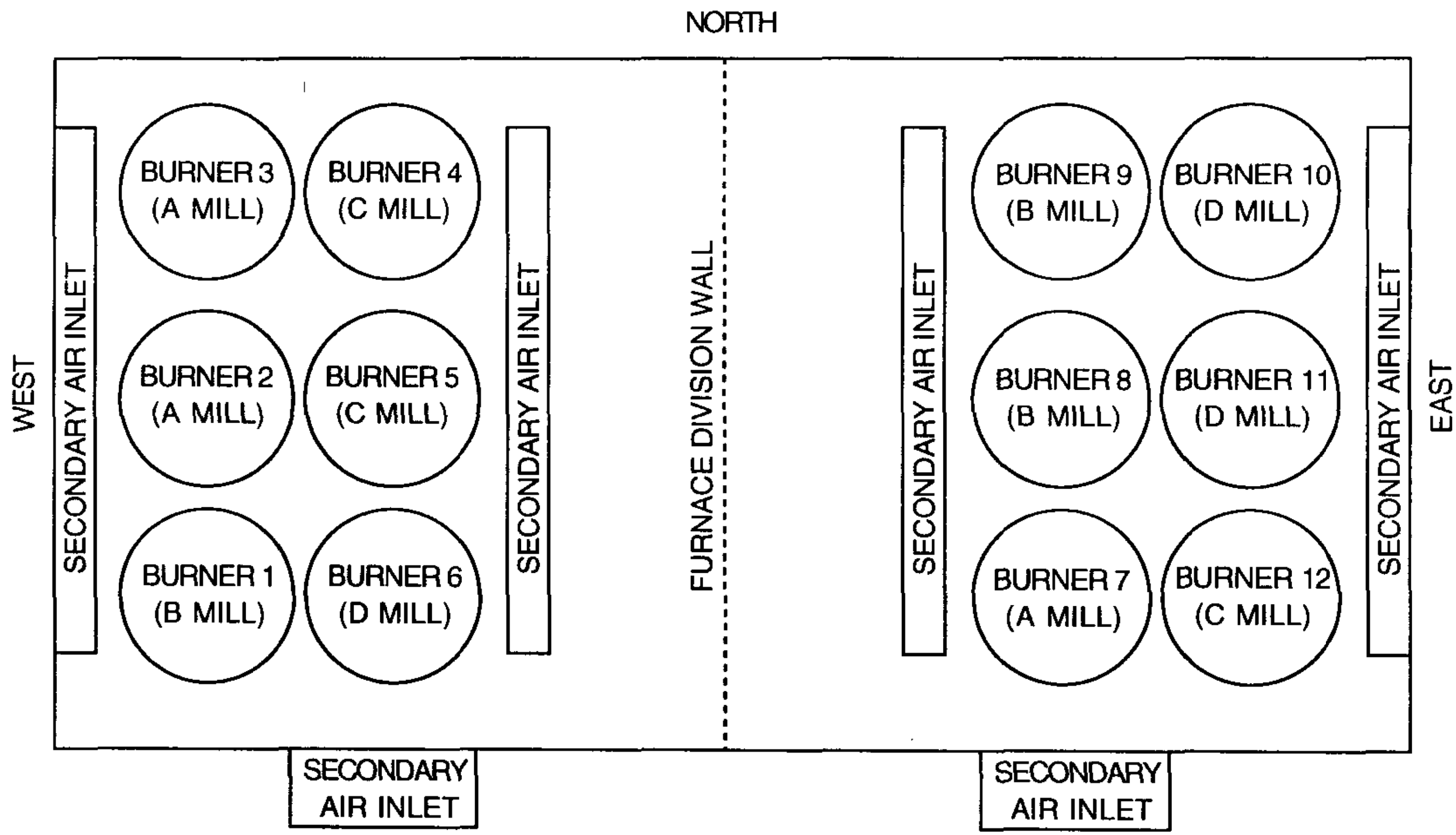


Figure 3-2. Plan View of Burner Arrangement after Retrofit

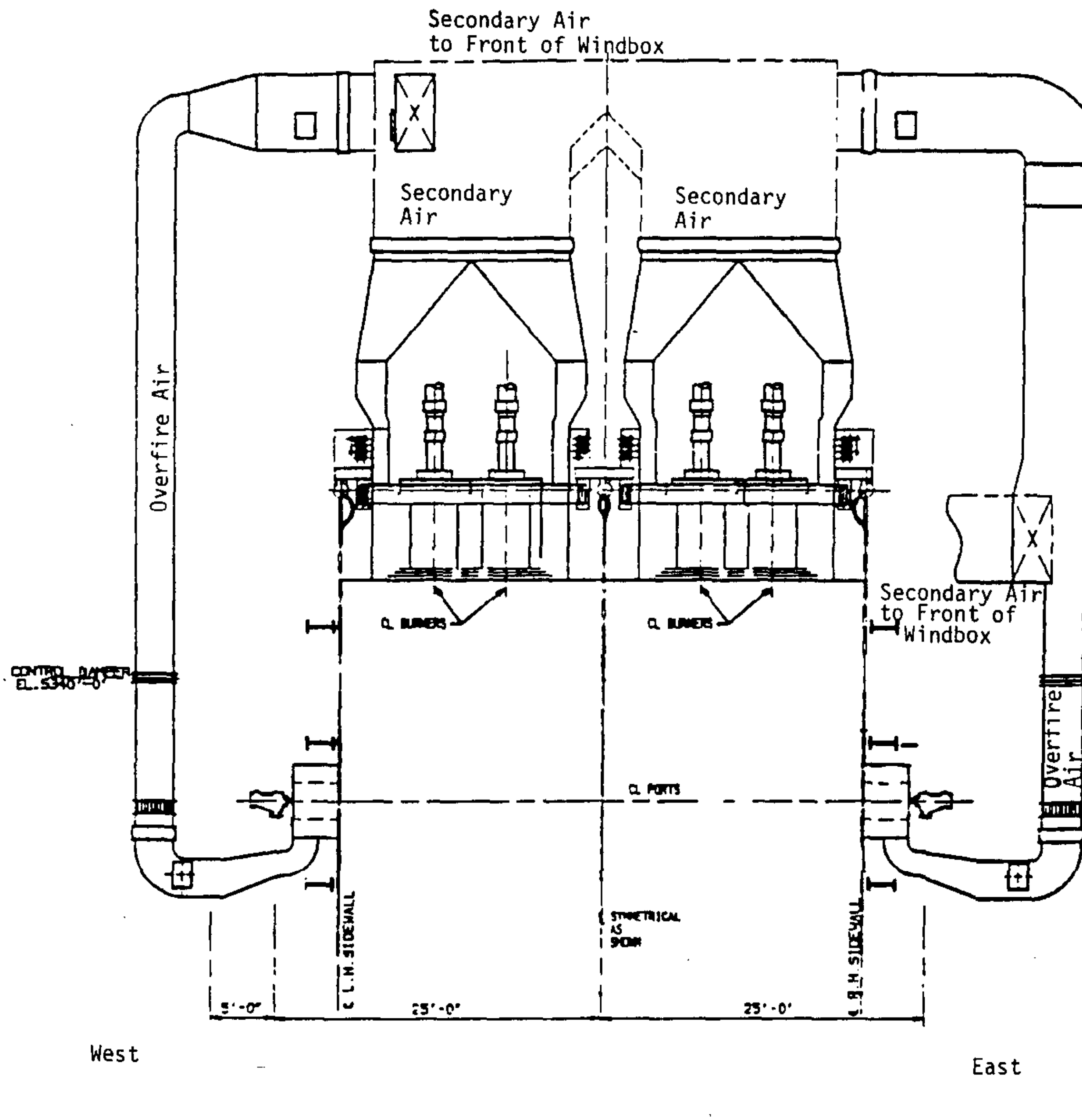


Figure 3-3. Front Sectional of View of Upper Furnace - Looking North

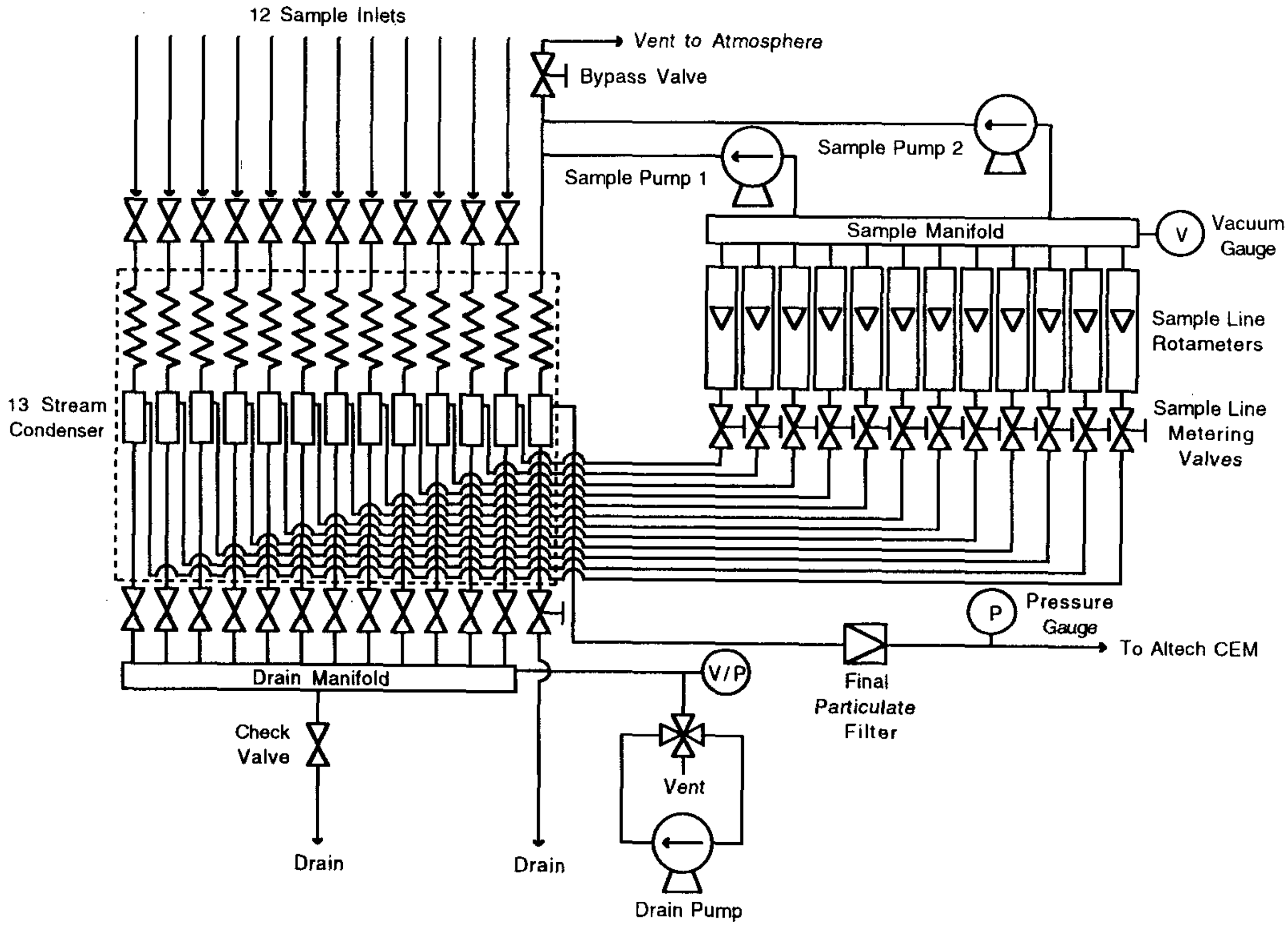


Figure 4-1. Sample Gas Conditioning System

(where the increased pressure aids in the removal of any remaining moisture), through a final particulate filter, and then to the Altech CEM for analysis.

The location of the unheated sample probes during the current phase of testing was identical to that for the baseline burner tests, namely: 12 at the exit of the economizer, 6 at the exit of the air preheater, and one in the fabric filter outlet duct leading to the stack. The sample probe grid in the horizontal duct at the economizer exit is shown in Figure 4-2. Although this duct is 40 feet wide, it is only 7 feet deep, so an array of probes positioned two high by six wide was deemed adequate to obtain a representative gas sample. The short probes were located at one-fourth of the duct depth, and the longer probes at three-fourths of the duct depth. This spacing vertically divided the duct into equal areas. The use of two probe depths also provided the opportunity to ascertain any vertical stratification of gas species within the duct. Individual sample probes consisted of stainless steel tubing with sintered metal filters on the ends. The sample lines which transported the gas to the sample conditioning system, consisted of polyethylene tubing which was heat traced and insulated to prevent freezing during the winter months.

Figure 4-2 also shows the location of the four PSCC O_2 probes at the economizer exit which are used for boiler trim control. The PSCC equipment uses *in situ* probes that determine the O_2 concentration on a wet basis. These probes (numbered A, B, C and D) are located approximately three feet upstream of the Fossil Energy Research Corp. (FERCo) grid, and very near probe numbers 3, 5, 7 and 9. Two additional sampling ports were available at the economizer exit which were used for limited SO_3 measurements.

The importance of the position of the 12-point grid relative to the four PSCC probes was realized during the baseline burner tests when it was found that the average O_2 measured from the grid was nominally one percent higher than the average indicated in the control room. This difference was attributed to the inability of the four PSCC

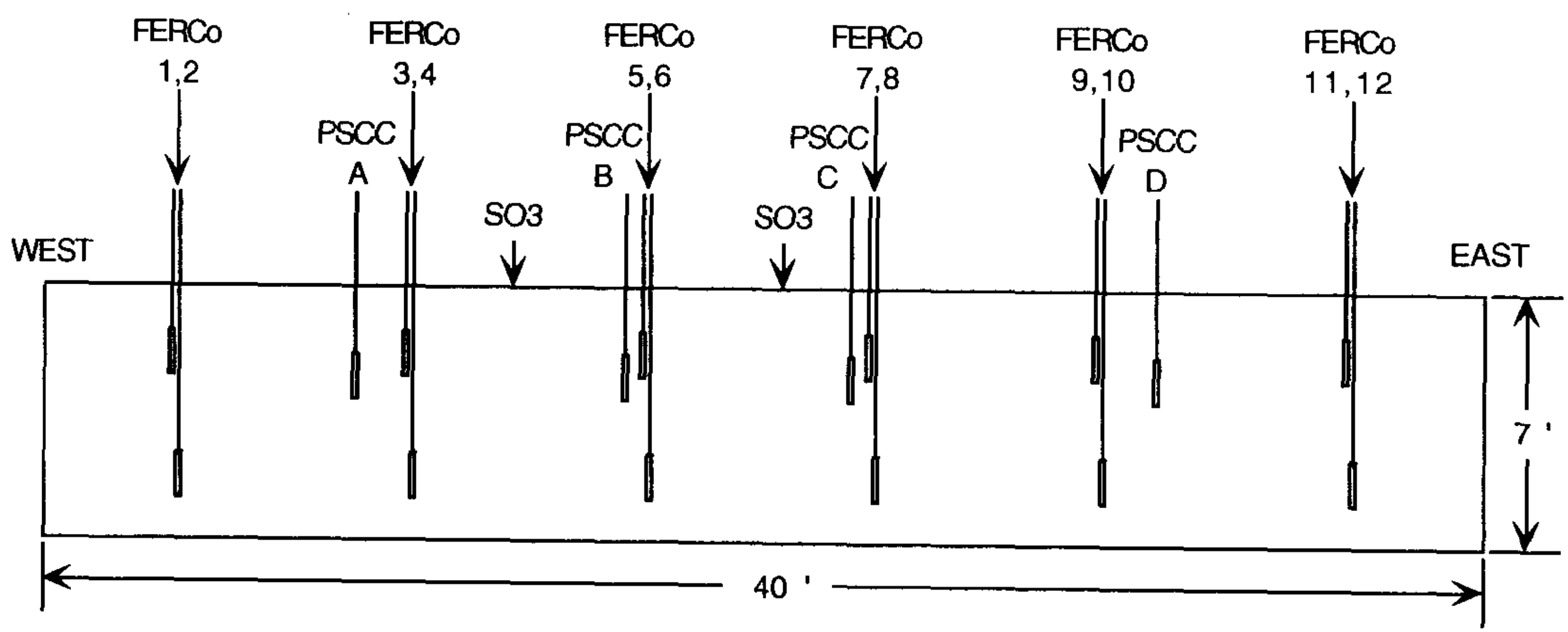


Figure 4-2. Economizer Exit Sampling Locations

probes to detect the elevated O_2 levels along the east and west sides of the duct which result from air in-leakage. A comparison between the control room and average economizer exit O_2 levels was made during the current phase of testing in order to determine if the retrofit had any effect on the difference between the two. This comparison also permitted correlation of the typical control room data with the results presented in this report. Figure 4-3 shows a comparison of the two average O_2 values for all the parametric tests performed during the retrofit burner characterization. The average economizer exit O_2 levels were again nominally one percent higher than those indicated from the four PSCC probes. Approximately 0.3 to 0.4 percent O_2 of this difference can be attributed to the wet versus dry measurement basis between the two analyzers. The balance of the difference is due to the non-uniform O_2 distribution across the duct, and the placement of the PSCC probes relative to the east and west walls. A significant amount of data scatter is seen in Figure 4-3, although it must be noted that variations in boiler operating parameters such as the number of mills in service or overfire air flow can affect the O_2 distribution, and thereby affect the difference in the average O_2 measured by each method.

Additional gas sample probes were installed at the air heater exit and the stack (fabric filter outlet duct) locations. Whereas, the 12-point economizer exit sampling grid would be utilized for detailed point-by-point measurements, the air heater exit and stack sampling probes would be used only to obtain general duct averages at these locations, and will be necessary during the subsequent NO_x and SO_2 reduction tests. Therefore, only a limited number of probes were utilized at these test locations; six at the air heater exit and a single probe at the stack location. Figure 4-4 shows the location of the probes at the air heater exit. These sample probes and tubing were similar to the installation at the economizer exit. The staggered probes were installed at one-fourth and three-fourths duct depths, similar to the economizer exit. The figure also shows the location of the heated probe for the CEM system at the exit of the air heater. This probe is not in the same plane as the six-point grid, but approximately 3 feet upstream. At the stack

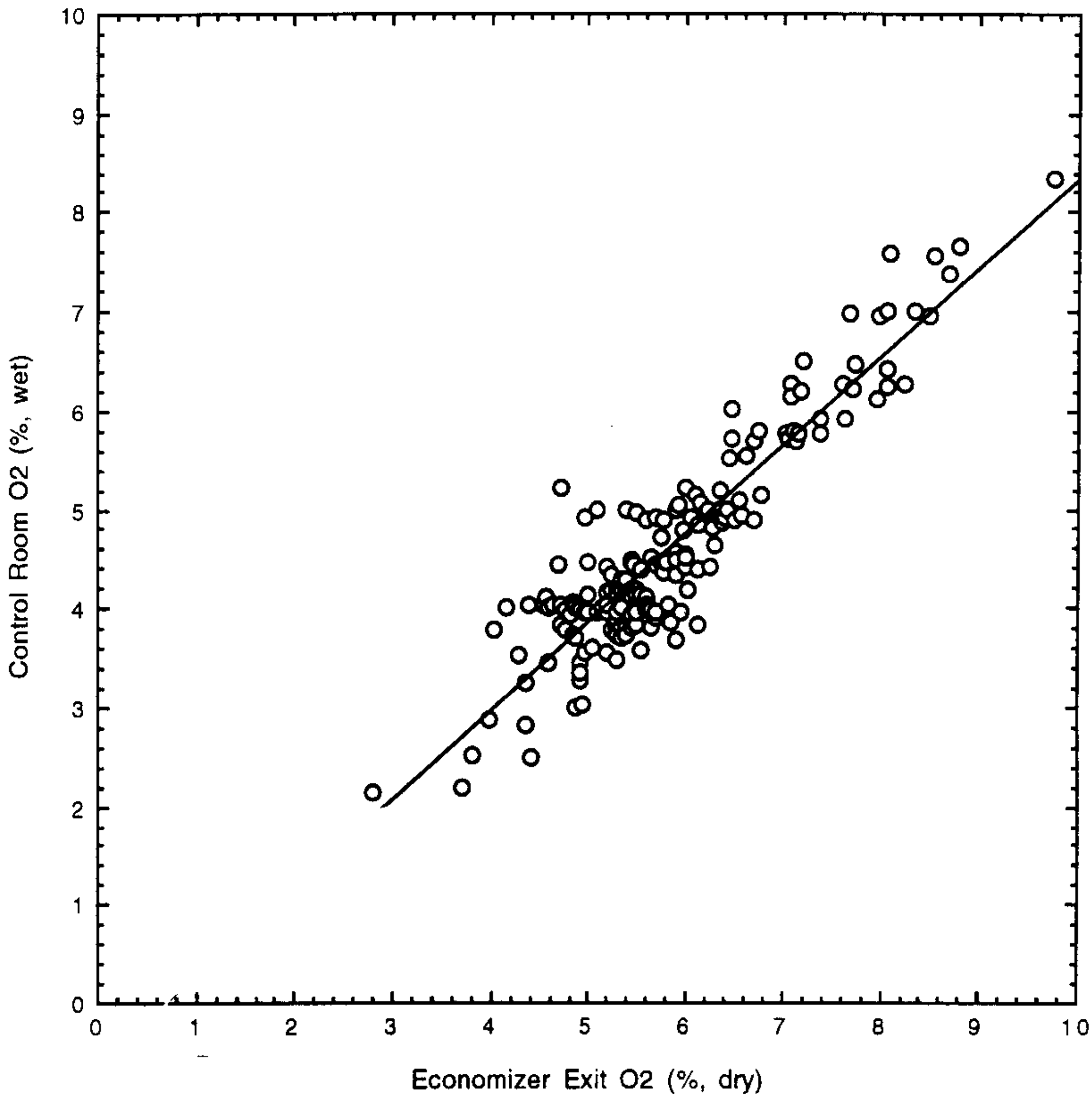


Figure 4-3. Comparison between Control Room O_2 and Economizer Exit Grid O_2 Measurements

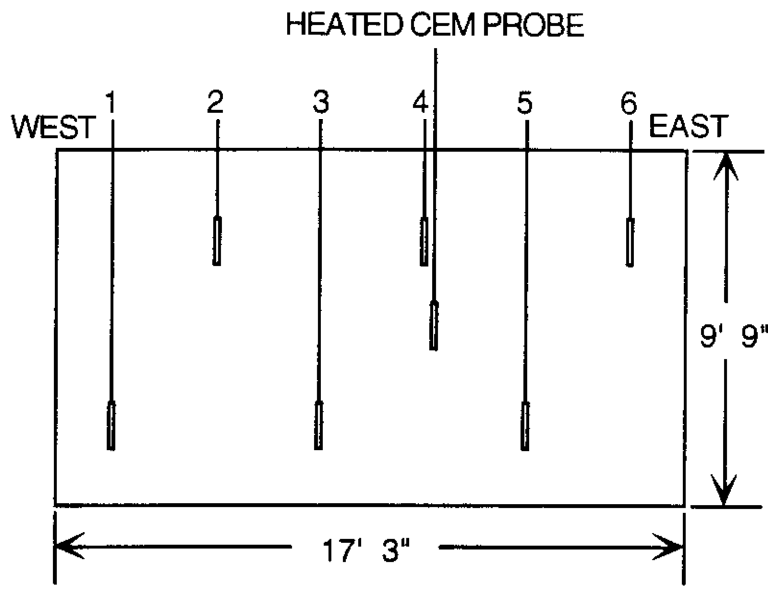


Figure 4-4. Air Heater Exit Sampling Locations

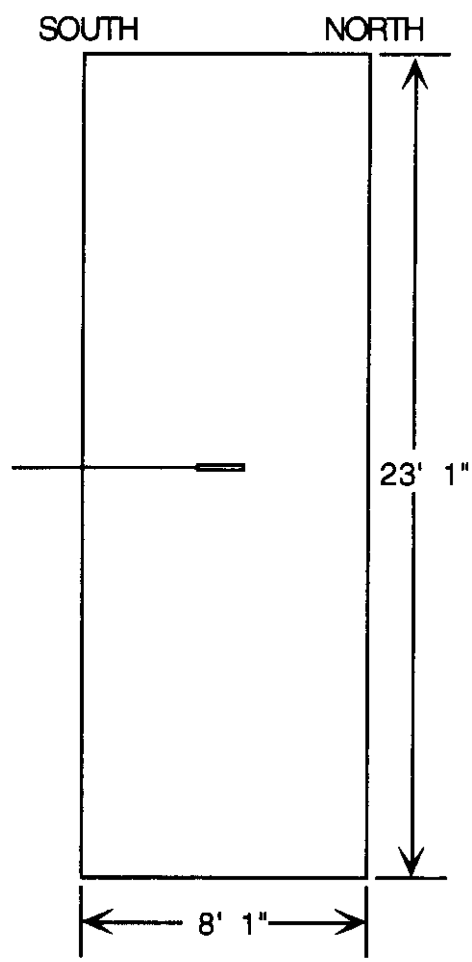


Figure 4-5. Fabric Filter Outlet Duct Sampling Location

sampling location, the heated probe for the CEM system is approximately 20 feet upstream of the unheated probe installed during the baseline burner tests. Only a single probe is used for both the CEM and the unheated probe locations since both are downstream of the fabric filter and induced draft fans where little stratification of the flue gas stream is expected. Figure 4-5 shows the installation of the unheated probe in the fabric filter outlet duct.

4.3 Flyash Carbon Measurements

Flyash carbon level measurements were performed for nearly every test during the current phase of the test program, as ash carbon levels in combination with CO emissions are an important indicator of incomplete combustion and can be used collectively to define a lower limit for the operating O_2 level. Flyash sampling was performed by extracting a composite high volume sample from the midpoint of all six ports at the air heater exit location, as was done during the baseline burner test program. However, unlike during the baseline tests where all carbon analyses were performed by an independent laboratory, the current analyses were performed on site utilizing a Loss on Ignition (LOI) analyzer developed by Fossil Energy Research Corp. for the specific purpose of providing a rapid turnaround of the data. This portable instrument can provide a preliminary estimate of the flyash LOI value in a matter of 15 to 30 minutes, depending on the number of replicate analyses performed.

The rapid turnaround of LOI samples was used to quickly diagnose and guide the test program during the optimization of the retrofit low-NO_x combustion system. A standard laboratory analysis would have required much longer turnaround times to obtain flyash LOI values, most likely well after the time when the information was most useful. A large number of samples were also submitted to the PSCC laboratory for LOI analysis in order to verify the performance of the on-site instrument. Figure 4-6 shows a crossplot of the LOI data from the two different methods. The results show a good correlation between the two, with the on-site instrument providing slightly higher values than those from the PSCC laboratory.

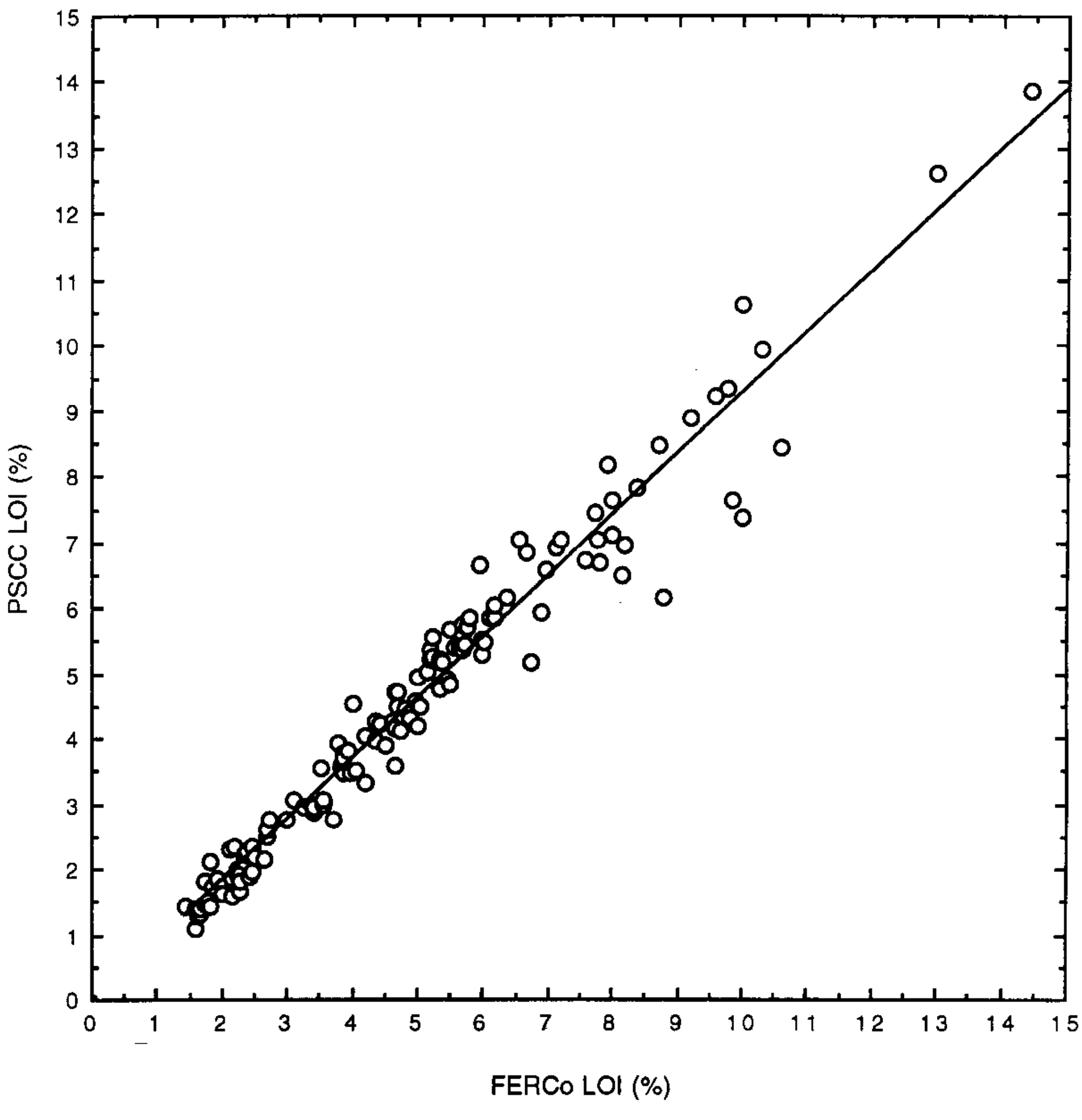


Figure 4-6. Crossplot of PSCC and FERCo LOI Analysis Results

Select samples were also sent to the same independent laboratory utilized during the baseline tests in order to provide a means of correlating the elemental carbon and LOI analysis data. A crossplot of the carbon and LOI data is shown in Figure 4-7. In both cases, the LOI analyses overpredicted the elemental carbon content of the flyash samples. This is to be expected since an LOI analysis is not carbon specific. Over the range of interest for this report (LOI values of 2 to 6 percent), the on-site LOI analysis tends to overpredict the elemental carbon content of the flyash by approximately 1.3 to 1.7 percent.

4.4 Furnace Exit Gas Temperature Measurements

During the course of the current test series, furnace exit gas temperature (FEGT) measurements were made in order to provide a comparison with those recorded during the baseline burner tests. Temperature measurements were made using both acoustic pyrometry and suction pyrometry (high velocity thermometry).

An acoustic pyrometry system, manufactured by Combustion Developments Ltd. of England, was utilized to provide a continuous assessment of the furnace exit gas temperatures. The acoustic pyrometer sends a sound pulse across the furnace; the transit time for the pulse is measured and thus, the mean speed of sound across the furnace is determined. The average temperature along the path can then be determined from the speed of the sound pulse. The acoustic temperature measurement technique requires a clear line of sight across the furnace at the measurement location. Since the boiler has a division wall running the length of the furnace, the first available location with acceptable access for the acoustic instrument was through a pair of ports just downstream of the first set of screen tubes (Location G in Figure 4-8).

In order to verify the acoustic data, high velocity thermocouple (HVT) measurements were made at selected operating conditions through the ports at Location G on both sides of the boiler. The HVT probe utilized for these measurements was of a standard water-cooled design, utilizing a single radiation shield and a type R thermocouple.

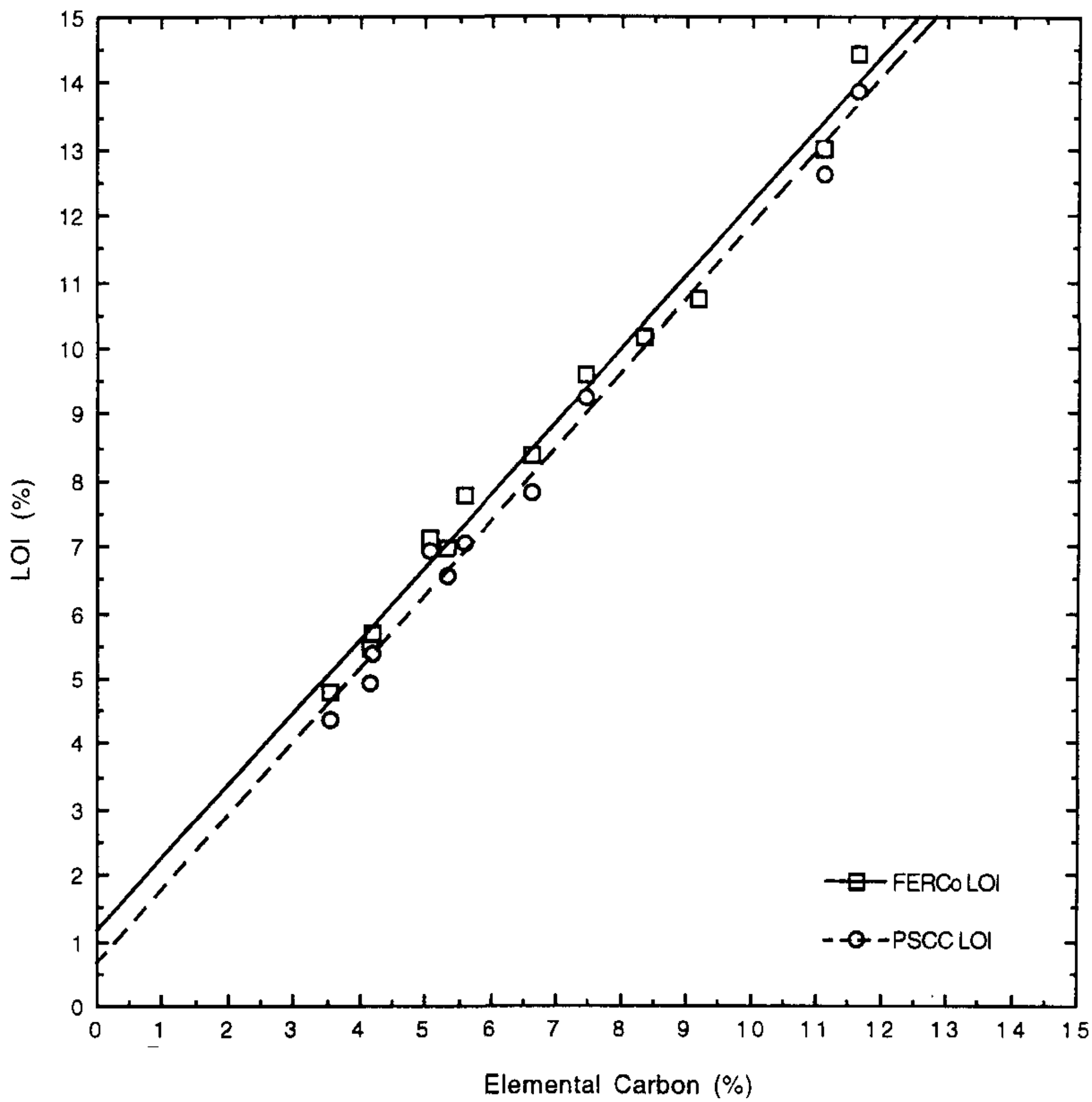


Figure 4-7. Crossplot of LOI and Elemental Carbon Analysis Results

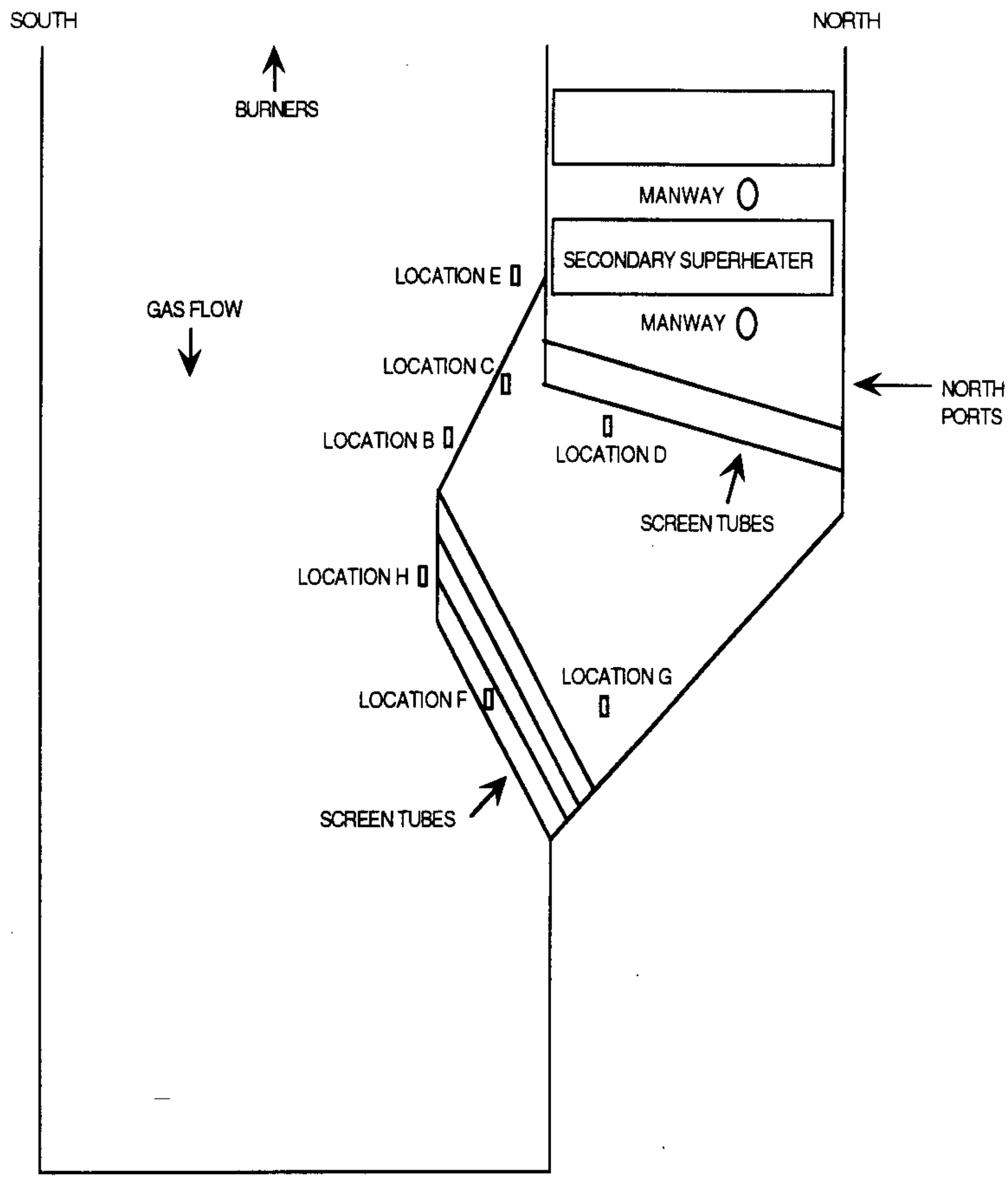


Figure 4-8. Flue Gas Temperature Measurement Locations

In addition to the measurements at Location G, HVT measurements were also made at Location H as well as through the set of eight ports along the north side of the boiler downstream of the second set of screen tubes (Figure 4-8).

5

RESULTS

The current test program consisted of two separate test phases. During the first, optimum operating conditions and settings for the burners and overfire air ports were identified. The second phase consisted of a detailed series of tests to assess the performance of the low-NO_x combustion system. The results of the second phase of testing are presented in three separate sections. The as-fired coal analysis and mill fineness measurements are discussed first, as these tests will be referred to on occasion during the presentation of the remainder of the results. Secondly, the performance of the low-NO_x combustion system as a function of various operating parameters is discussed. These parameters include boiler load, excess air level, overfire air flow rate, and number of mills in service. Finally the results of the detailed diagnostic tests performed during the second phase of testing are presented. The diagnostic tests included point-by-point gaseous traverses, FEGT, SO_3, and particulate size and mass loading measurements. The following four sections describe the results of each test phase, as outlined above.

5.1 Combustion System Optimization

Optimization of the low-NO_x combustion system was completed in two parts. A preliminary optimization was performed by B&W immediately after completion of the retrofit in June 1992. A more detailed optimization took place during the initial weeks of the formal test program which ran from August 6 through October 29, 1992.

Initial Optimization

Following the retrofit, B&W performed a series of tests to identify the optimum operating settings for the burners and overfire air ports. The goal of these tests was to minimize NO_x emissions, CO emissions, and unburned carbon in the ash, while maintaining acceptable boiler operating practices. A total of eleven tests were performed over a period of four days. Complete documentation of this preliminary test series is contained in a separate report, which is attached as Appendix A. A brief review of the results is presented in this section.

Initial tests during the preliminary optimization indicated that NO_x emissions were quite low, reflecting a 62 to 70 percent reduction from the baseline values, depending on the overfire air flow rate. However, flyash carbon levels were unacceptably high, with values ranging from 10 to 13 percent. These values dropped significantly once the burner settings were optimized. Determining the proper spin vane settings was the most significant factor in reducing the flyash carbon levels. During the initial tests, the inner and outer spin vanes were set at 45° and 60°, respectively. With the spin vanes at 45° for both the inner and outer zones, flyash carbon levels were reduced to 4 to 5 percent at full load. Since a lower spin vane angle indicates a higher level of swirl and enhanced fuel/air mixing, the reduction in flyash carbon levels was accompanied by a slight increase in NO_x emissions.

Overfire air port settings were optimized to provide the best balance of O_2 across the economizer exit. The optimized settings were determined to be with the center zone damper 100 percent open and the spin vanes at 45°. More importantly, the report states that the overfire air port metal temperatures should not be allowed to exceed 1300°F, and that closing the dampers which control the total overfire air flow rate to each side of the furnace to less than 30 percent would result in insufficient cooling air to the ports. This temperature requirement substantially limited the range of overfire air flow rates which could be investigated during the formal test program.

Detailed Optimization

A detailed optimization of the retrofit low-NO_x combustion system took place during the initial weeks of the formal test program. This provided an opportunity for a more detailed study of the effect of burner and overfire air port settings on combustion performance than was possible during the initial B&W optimization. The burner optimization consisted of an assessment of the effect of spin vane position over a wider range of settings, as well as an investigation of the effect of balancing the secondary air flow distribution to each burner. The overfire air port optimization addressed the effect of spin vane and core zone damper position, as well as the effect of balancing the overfire air flow to the upper furnace.

The details of the optimization tests are provided in Appendix B. The results indicate that a slight increase in burner swirl, achieved by changing the angle of the inner spin vanes to 30° with the outer vanes remaining at 45°, provided lower CO emissions and flyash LOI values than those for the swirl settings defined by B&W (inner and outer vanes at 45°). The burner swirl changes had an insignificant effect on NO emissions.

The burner optimization tests indicated a substantial variation in the burner-to-burner secondary air flow distribution with the sliding dampers in the full open position. Balancing the air flows resulted in slightly decreased NO emissions, and in two out of the three tests conducted, was shown to reduce CO emissions by nearly 20 ppm. Maintaining the burner balance which had been set manually for these tests would have required resetting the limit switches on the sliding damper actuator for each burner. This was not done due to a lack of substantial impact on the NO emissions and the lack of a consistent effect on CO emissions.

The overfire air port tests showed that optimal performance was not achieved with the spin vanes at 45°, but rather with them 100 percent open (corresponding to zero swirl). This effect is attributed to a substantial amount of air in-leakage through the east and west sides of the boiler (which can be seen in O_2 traverses at the economizer exit), creating a local O_2 deficit along the center of the boiler near the furnace division wall. With the new control system, the air flow rate is controlled to achieve a set point economizer exit O_2 value based on the average of the four PSCC O_2 probes (see Figure 4-2). Operating the overfire air ports with the core zone damper and spin vanes 100 percent open provides the maximum amount of penetration into the center of the furnace where the O_2 is needed most for carbon burnout.

5.2 Coal Analysis Results

Two types of coal samples were obtained during the low-NO_x combustion system retrofit testing: raw or feeder coal samples, and pulverized coal samples from the burner pipes. The feeder samples were obtained just upstream of the mill feeders and represent an as-fired coal sample. The pulverized coal samples were obtained to determine the coal fineness and evaluate the operation of the mills.

As-Fired Coal Composition

As-fired or feeder coal samples were obtained two to three times per week. These samples were used to determine if significant changes in the fuel composition occurred during the tests. Five samples were submitted to an independent laboratory for coal and ash analysis. Individual and average coal analysis results are presented in Table 5-1. In general, the individual analyses were consistent with each other, and indicate a fairly stable coal supply for the duration of the testing. The coal parameters which could affect the test results by directly affecting the operation of the boiler include the fuel heating value, fixed carbon or volatiles content or significant changes of the moisture content. The results indicate that these parameters remained relatively stable.

One coal parameter which varied during the retrofit burner tests was the fuel sulfur content, which directly affects boiler SO_2 emissions. The coal analyses indicate that with the exception of the sample for Test 378, the fuel sulfur content was constant at 0.44 percent. The coal fired during Test 378, however, had a sulfur content of 0.59 percent,

Table 5-1
As-Fired Coal Analysis Results

Test Number	206	279	330	371	378	Retrofit Burner Averages	Baseline Burner Averages
Date	8/11/92	9/19/92	10/4/92	10/22/92	10/26/92		
Time	1230	1300	1600	0905	0950		
Proximate Analysis							
% Moisture	10.79	12.32	10.27	10.97	11.25	11.12	10.99
% Ash	9.54	9.03	10.79	9.84	7.85	9.41	9.04
% Volatile	34.60	34.49	34.74	35.16	35.71	34.94	35.09
% Fixed Carbon	45.07	44.16	44.20	44.03	45.19	44.53	44.87
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	11082	10795	10950	10993	11111	10986	11097
FC/V[1]	1.30	1.28	1.27	1.25	1.27	1.27	1.28
Prox Analysis,							
MAF[2]	43.43	43.85	44.01	44.40	44.15	43.97	43.89
% Volatile	56.57	56.15	55.99	55.60	55.85	56.03	56.11
% Fixed Carbon	13909	13726	13870	13881	13735	13824	13877
HHV, Btu/lb							
Ultimate Analysis							
% Carbon	61.81	61.09	61.49	62.00	62.92	61.86	62.00
% Hydrogen	4.15	4.47	4.85	3.91	4.11	4.30	4.36
% Nitrogen	1.59	1.46	1.62	1.57	1.70	1.59	1.48
% Chlorine	0.01	0.00	0.00	0.00	0.00	0.00	0.01
% Sulfur	0.44	0.44	0.44	0.45	0.59	0.47	0.49
% Oxygen	11.68	11.19	10.54	11.26	11.58	11.25	11.64
% Ash	9.54	9.03	10.79	9.84	7.85	9.41	9.04
% Moisture	10.79	12.32	10.27	10.97	11.25	11.12	10.99
TOTAL	100.01	100.00	100.00	100.00	100.00	100.00	100.01
Ult Analysis, MAF –							
% Carbon	77.57	77.67	77.89	78.29	77.78	77.84	77.53
% Hydrogen	5.21	5.68	6.14	4.94	5.08	5.41	5.46
% Nitrogen	2.00	1.86	2.05	1.98	2.10	2.00	1.85
% Chlorine	0.01	0.00	0.00	0.00	0.00	0.00	0.02
% Sulfur	0.55	0.56	0.56	0.57	0.73	0.59	0.61
% Oxygen	14.66	14.23	13.35	14.22	14.31	14.15	14.55

(1) FC/V: Ratio of fixed carbon to volatiles
(2) MAF: Moisture and ash free

Table 5-1. (Continued)

Test Number Date Time	206 8/11/92 1230	279 9/19/92 1300	330 10/4/92 1600	371 10/22/92 0905	378 10/26/92 0950	Retrofit Burner Averages	Baseline Burner Averages
Hardgrove Grind	48	50	47	48	48	48	43
% Moisture	3.47	4.60	3.48	4.33	5.47	4.27	2.61
Fusion Temp Reducing							
Initial	2350	2414	2342	2375	2366	2369	2462
Softening	2393	2466	2443	2420	2409	2426	2531
Hemispherical	2447	2504	2519	2468	2465	2461	2581
Fluid	2601	2590	2641	2585	2510	2585	2668
Fusion Temp Oxidizing							
Initial	2394	2423	2431	2422	2435	2421	2532
Softening	2443	2489	2478	2458	2494	2472	2607
Hemispherical	2529	2532	2565	2480	2557	2533	2603
Fluid	2700	2607	2700	2607	2651	2653	2700
Ash Analysis							
SiO_2	57.08	56.83	58.50	57.68	51.44	56.31	56.21
Al_2O_3	24.10	24.73	23.75	23.85	26.70	24.63	24.73
Fe_2O_3	3.24	3.90	3.02	2.98	4.27	3.48	3.63
CaO	5.45	4.83	5.03	5.17	6.59	5.41	5.71
MgO	1.71	1.35	1.68	1.51	1.37	1.52	1.43
Na_2O	1.17	1.42	1.21	1.21	0.73	1.15	0.94
K_2O	1.15	1.35	1.28	1.16	0.94	1.18	0.91
TiO_2	0.80	0.75	0.73	0.77	0.83	0.78	0.75
MnO_2	0.07	0.08	0.07	0.07	0.07	0.07	0.07
P_2O_5	0.00	1.00	0.79	0.96	1.55	0.86	1.11
SO_3	3.57	3.07	3.27	3.10	4.76	3.55	3.60
StO	0.27	0.24	0.23	0.27	0.39	0.28	0.31
BaO	0.39	0.45	0.44	0.39	0.36	0.41	0.39
Undetermined	1.00	0.00	0.00	0.88	0.00	0.38	0.76
TOTAL	100.00	100.00	100.00	100.00	100.00	100.01	100.00
Base/Acid Ratio	0.16	0.16	0.15	0.15	0.18	0.16	0.15
Silica Value	84.59	84.93	85.74	85.65	80.79	84.34	84.60
T_{250} Temperature (°F)	2900+	2898	2900+	2900+	2787	2877	2882
Fouling Index	1.17	1.42	1.21	1.21	0.73	1.15	0.94
Slagging Index	2386	2438	2387	2396	2404	2402	2495

which is an increase of over 34 percent. Since the SO_2 emissions very closely follow the fuel sulfur content, the SO_2 would be expected to vary by the same magnitude.

The main fuel source for the Arapahoe Station is a Cyprus Yampa Valley coal. On occasion, coal from a different source (Edna mine) is utilized. The two coals are very similar, with the major difference being the sulfur content. The coal fired during test 378 was from the Edna mine.

The average coal analysis results from the baseline burner tests, where three samples were analyzed individually, are also presented in Table 5-1. Comparison of the average results from the two test phases show the analyses to be virtually identical, indicating that any change in performance measured during the retrofit combustion systems tests was not due to a change in coal properties.

Fineness Measurements

Pulverized coal samples were taken at full load conditions on two occasions during the current phase of the test program. Separate samples were taken from each of the 12 pipes supplying coal and primary air to each individual burner in accordance with the procedures outlined in ASTM Method D410-38. The samples from the three pipes for a given mill were then composited for a fineness analysis. The composited samples were sieved with 50, 100 and 200 mesh screens and plotted on a Rosin-Rammler graph. The fineness results for all four mills on each of the two separate test days are shown in Figures 5-1 and 5-2. The data show that the attrition mills ground the coal to an acceptable fineness during both tests. All four mills allowed a grind of less than 0.3 percent retained on the 50 mesh screen (better than 99.7 percent passing through 50 mesh), which indicates the general absence of the largest coal particle sizes. The large coal particles are particularly difficult to completely burn out and can contribute to excessive carbon losses (i.e., elevated CO emissions and flyash carbon levels). All mills yielded a fineness greater than 73 percent passing through a 200 mesh screen. The performance of A, B, and C Mills was nearly identical on both days, indicating very

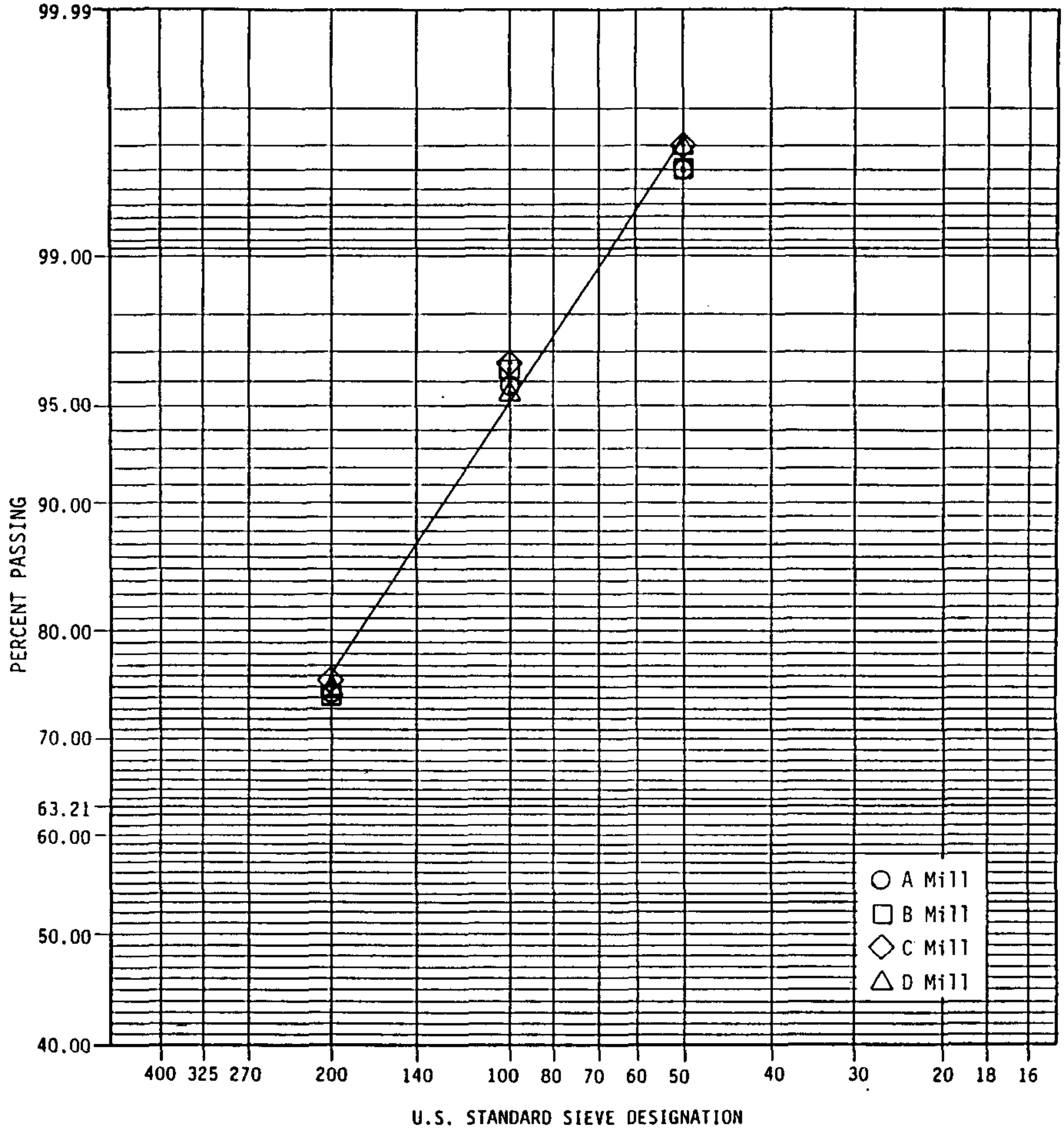


Figure 5-1. Mill Fineness Results, October 23, 1992

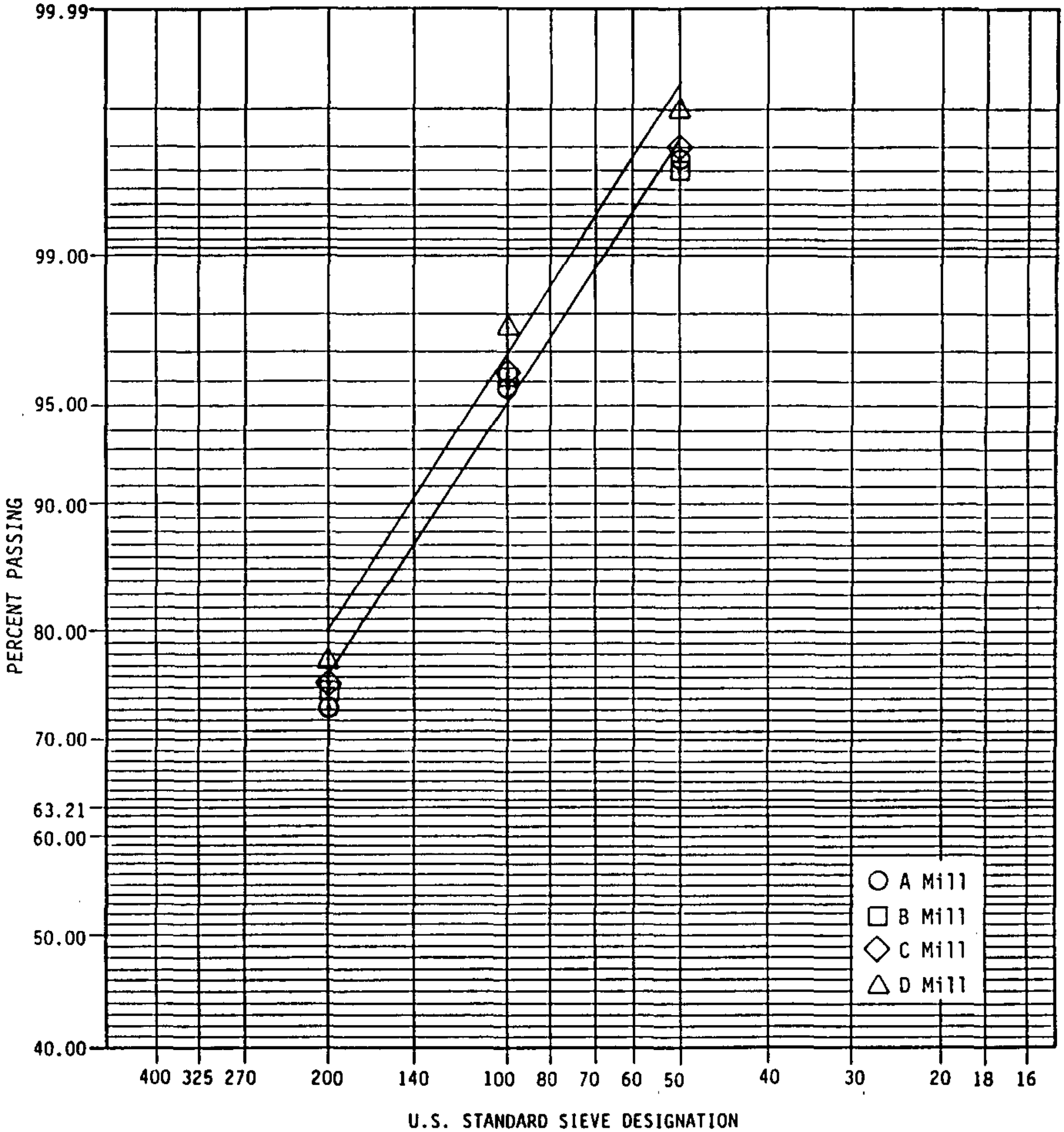


Figure 5-2. Mill Fineness Results, November 19, 1992

stable mill operation. D Mill performed similarly to the other three mills during the first test, and slightly better during the second. The reason for the improvement in the performance of D Mill is likely a hammer replacement which occurred on October 24th, the day after the first test.

The results of the fineness test performed during the baseline burner tests are presented in Figure 5-3. Comparison of these results indicates the current operation of the mills to be more consistent on a mill-by-mill basis. The inconsistencies in the mill-to-mill performance seen before the retrofit may be due to differences in the maintenance status of each mill at the time of the test. It is also possible that the new variable speed coal feeder drives installed during the retrofit provided a more uniform coal feed to each mill, resulting in more consistent mill-to-mill performance. However, there is no actual data to support this hypothesis, and since the post-retrofit fineness data (Figures 5-1 and 5-2) showed that mill maintenance can have an effect on performance, it is likely that differences in the maintenance status of each mill is the reason for the differences in mill-to-mill consistency seen before and after the retrofit.

Coal Distribution

The 12 pulverized coal burner pipe samples were individually weighed prior to compositing and sieving of the four mill fineness samples. Since the sampling times and flow rates for each pipe were equal, the individual sample weights provided an approximate coal flow distribution among the burner pipes exiting a single mill. Using this approximation, the relative coal flow to each burner during both tests was estimated and is shown in Figures 5-4a and 5-4b. These data are plotted as a function of burner location across the top of the furnace (recall Figure 3-2).

Ideally, each burner should receive 1/12, or 8.33 percent of the total coal flow. However, the coal feed system on Arapahoe Unit 4 does not include gravimetric feeders; therefore, the relative feeder flows cannot be easily determined or controlled. In actual operation, the relative coal split for each of the four mills could vary on a day-to-day,

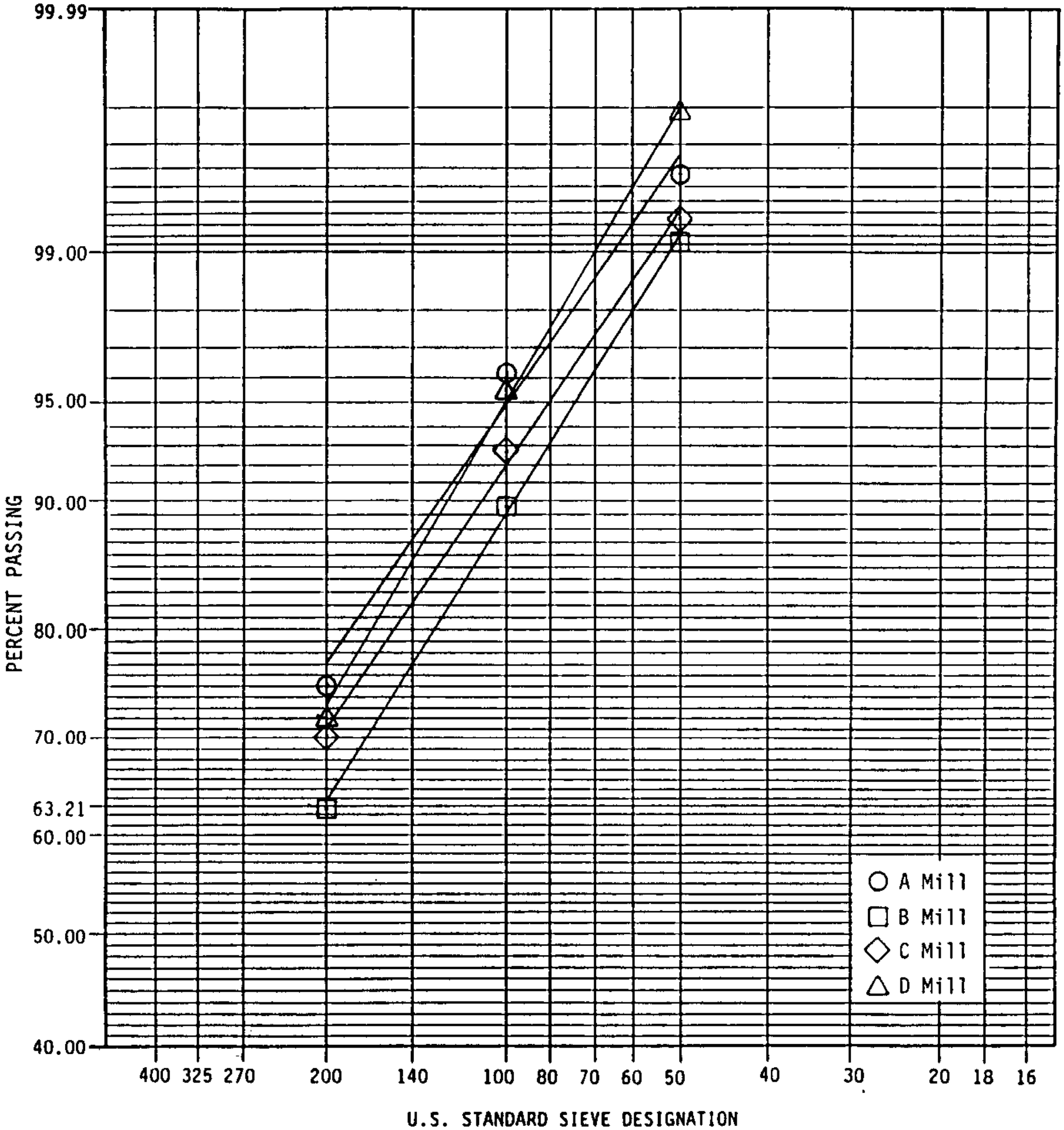


Figure 5-3. Mill Fineness Results from Baseline Burner Tests

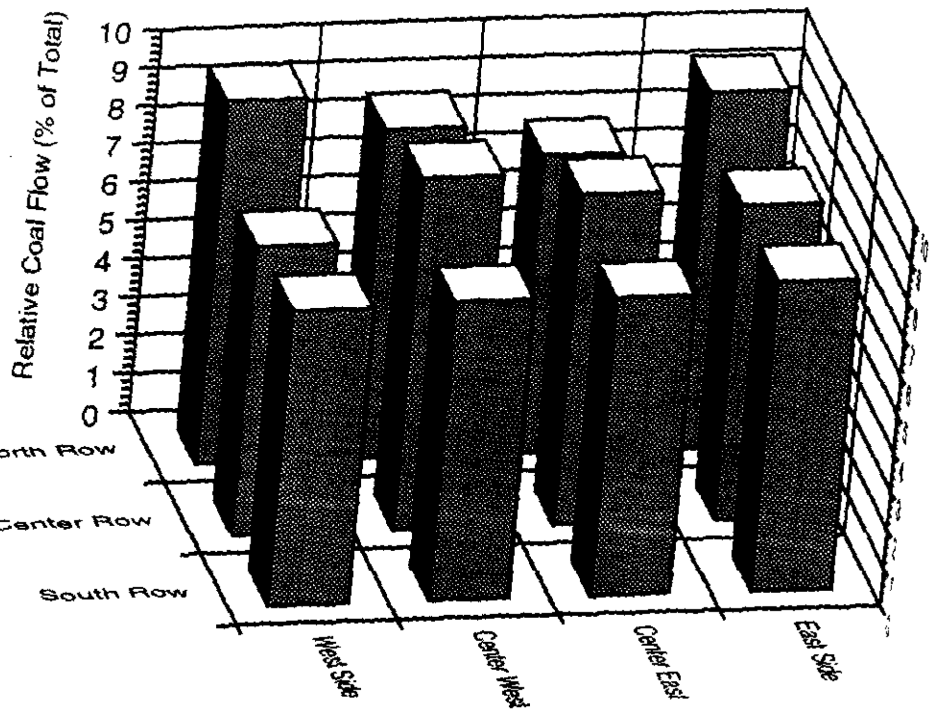


Figure 5-4a. Burner-to-Burner Coal Distribution Results, October 23, 1992

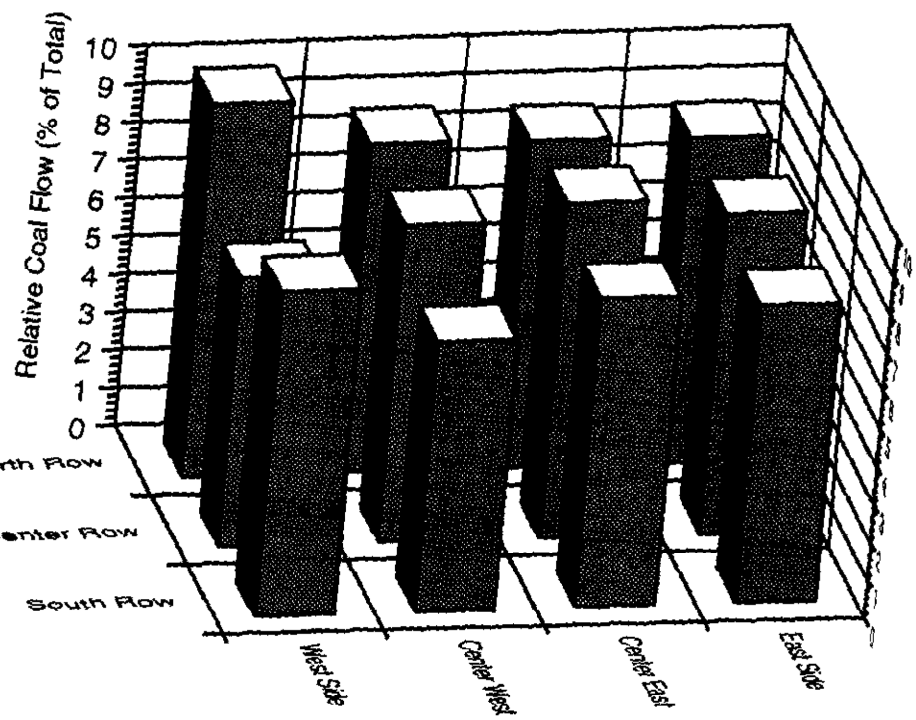


Figure 5-4b. Burner-to-Burner Coal Distribution Results, November 19, 1992

or hour-to-hour basis, depending upon the relative setting of the feeder controls or other coal feed variables which could not be held constant with any certainty. Comparison of the distributions in Figures 5-4a and 5-4b shows a day-to-day variation.

A similar coal distribution analysis was performed during the baseline burner tests. The results of this analysis are presented in Figure 5-5, where the arrangement of the data corresponds to the west to east orientation of the 12 original intertube burners (recall Figure 2-3). In order to better see the differences in the mill-to-mill and burner-to-burner distributions, the tabular data for Figures 5-4a, 5-4b and 5-5 are presented in Table 5-2. Although the mill-to-mill coal splits are different for all three tests, the variation is quite small. The data also show pipe-to-pipe distributions of coal exiting each mill which are not consistent among any of the three tests, indicating that the burner-to-burner distribution of coal from any one mill can vary on a day-to-day basis. Again, however, the variation is small.

Coal flow imbalances can have an effect on the efficiency of the combustion process as well as NO emissions. A significant imbalance can result in excessive carbon losses and/or a limitation to the minimum air flows which can be sustained within the limit of acceptable CO emissions or flyash carbon levels. Carbon burnout problems would be expected in areas of high coal concentration. In fact, a relatively small local region that has a high imbalance can dictate the minimum operating excess air level for the entire furnace. Conversely, regions with less coal and a greater availability of oxygen can lead to locally high NO emissions.

Although the data in Table 5-2 indicate that the day-to-day distribution of coal to the burners can vary, the magnitude of the variation is small. This variation in coal distribution in itself is likely not large enough to have a significant impact on boiler operation. However, if it were combined with significant variation in secondary air flow, carbon burnout or NO emissions could be affected.

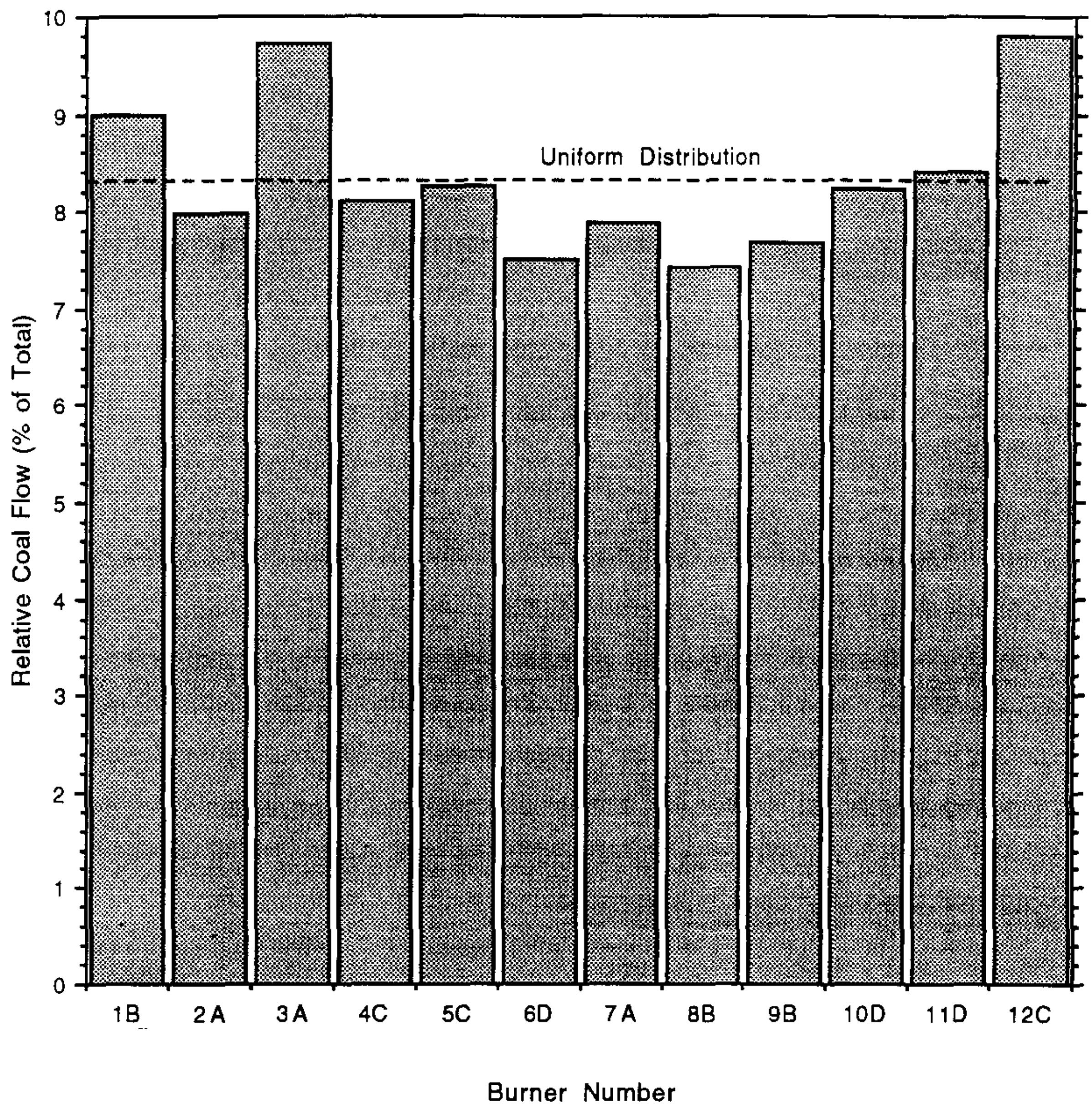


Figure 5-5. Burner-to-Burner Coal Distribution Results for Baseline Burner Tests

Table 5-2

Tabulated Burner-to-Burner Coal Distribution Data

Post-Retrofit - 23 Oct 92							
A Mill		B Mill		C Mill		D Mill	
Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal
2	7.5	1	7.7	4	8.6	6	7.8
3	9.5	8	8.6	5	9.1	10	9.3
7	7.8	9	7.8	12	8.1	11	8.2
Sum	24.8	Sum	24.1	Sum	25.8	Sum	25.3

Post-Retrofit - 19 Nov 92							
A Mill		B Mill		C Mill		D Mill	
Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal
2	7.1	1	8.6	4	8.6	6	7.1
3	9.8	8	8.8	5	8.4	10	8.5
7	8.2	9	8.6	12	7.9	11	8.4
Sum	25.1	Sum	26.0	Sum	24.9	Sum	24.0

Baseline Burner Tests							
A Mill		B Mill		C Mill		D Mill	
Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal	Burner Number	% of Coal
2	8.0	1	9.0	4	8.1	6	7.5
3	9.7	8	7.4	5	8.3	10	8.2
7	7.9	9	7.7	12	9.8	11	8.4
Sum	25.6	Sum	24.1	Sum	26.2	Sum	24.1

5.3 Parametric Performance Tests

The operating parameters which were varied during the parametric performance tests of the retrofit low-NO_x combustion system were boiler load, excess air level, overfire air flow rate, and mills out of service. These test parameters represent the primary factors influencing NO, CO and carbon emissions. The effect of each of the four parameters is discussed in the following sections. The first section presents "the big picture," that is, the performance of the optimized combustion system as a function of boiler load. Since it is necessary to be familiar with the effects of excess air level and overfire air flow rate in order to fully understand the effect of boiler load, a brief discussion of these two parameters is included in the first section. The three remaining sections are dedicated to in-depth discussions of the parametric effects of excess air level, overfire air flow rate and mills out of service.

Effect of Boiler Load

The NO emissions as a function of boiler load with the retrofit combustion system are compared to those measured with the original burners in Figure 5-6. A wider range of load was investigated during the post-retrofit test program. The Arapahoe Unit 4 boiler is used nearly continuously for load regulation under automatic control from the PSCC system dispatch center. During periods of high demand, the unit is sometimes run at boiler loads as high as 110 to 115 MWe. Likewise, during periods of very low demand, it is preferable to "idle" the boiler at approximately 50 MWe, rather than shut it down and then restart it as soon as demand increases. Although operation at either extreme is not frequent, tests were performed at 50 and 110 MWe in order to characterize the performance of the retrofit low-NO_x combustion system over the entire usable range of the boiler. Tests were not conducted at these boiler loads during the baseline burner tests.

The Arapahoe Unit 4 boiler is normally run with all four mills in service until load is reduced below 80 MWe, at which point, one mill is removed from service, and three are

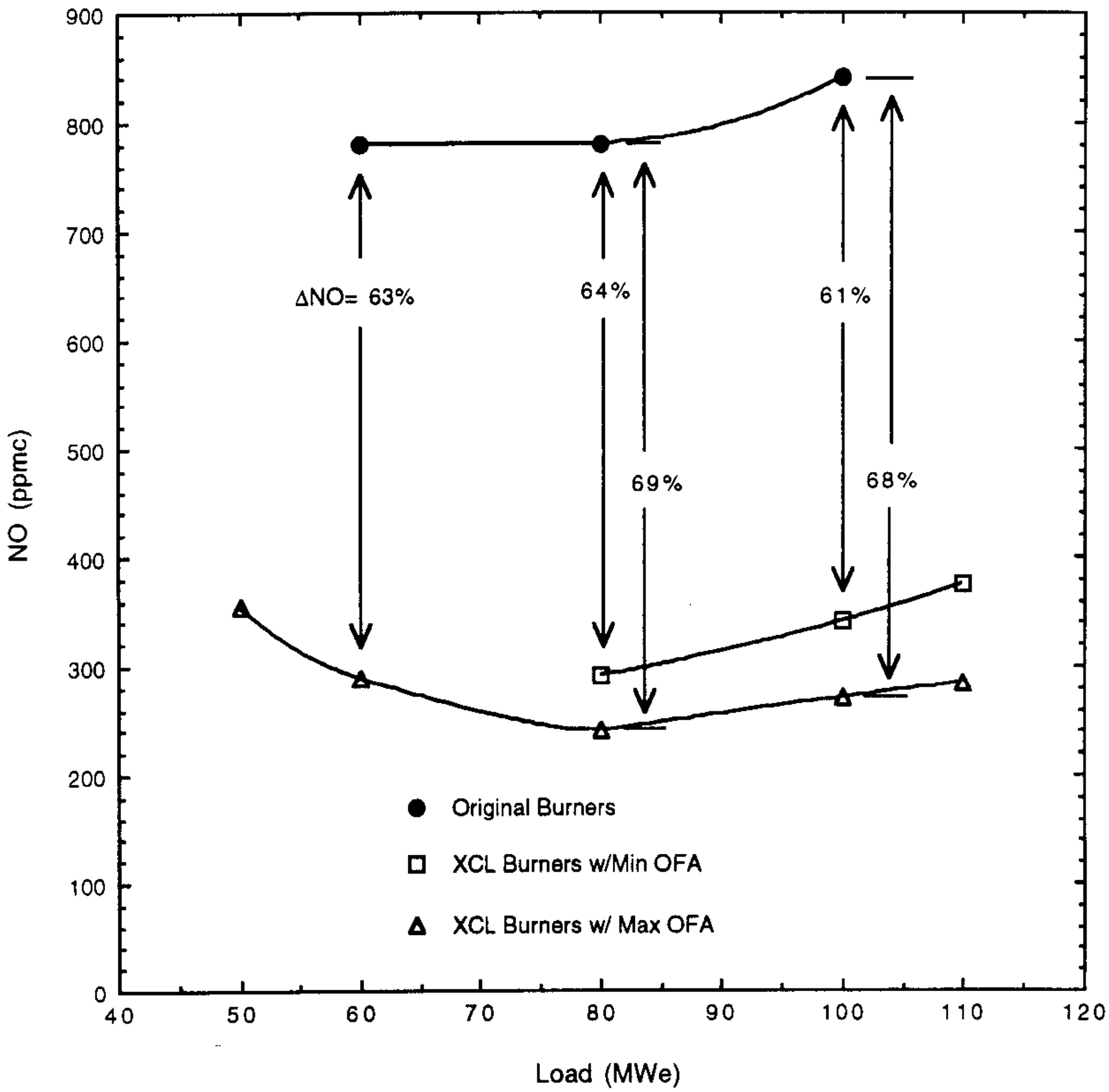


Figure 5-6. Pre- and Post-Retrofit NO Emissions as a Function of Boiler Load

used until load is reduced below 60 MWe. If the unit is load following under automatic control at or below 60 MWe, three mills are utilized to allow for rapid load increases.

If the unit is expected to be "idled" at a load below 60 MWe for a sufficient length of time, a second mill is removed from service. Unless otherwise noted, the data presented in this and the following sections for loads of 80 MWe and above are with all four mills in operation. The 60 MWe data is with three mill operation (B Mill out of service), and 50 MWe, with two mills in service (A and D Mills out of service). Refer to Figure 3-2 to see which burners are supplied by the individual mills.

NO emission data for the retrofit combustion system with both minimum and maximum overfire air flow rates are presented in Figure 5-6. Maximum overfire air is defined as having the overfire air control dampers full open. This corresponds to approximately 24 percent of the total secondary air at boiler loads of 80 MWe and above, and 28 and 32 percent for 60 and 50 MWe, respectively. The percentage of overfire air increases at the lower boiler loads because there are fewer mills in service at these conditions. When a mill is taken out of service, the secondary air flow dampers for the three burners fed by that particular mill are placed in the "cool" position. This increases the back pressure in the windbox and allows more of the secondary air to be diverted to the overfire air ports.

Minimum overfire air flow is defined as the amount necessary to maintain the port metal temperatures at an acceptable level. At 80, 100 and 110 MWe, 15 percent of the total secondary air was sufficient. Minimum overfire air tests were not performed at the lower loads for reasons which will be discussed below.

The data in Figure 5-6 show that with maximum overfire air, the NO reduction varies from 63 to 69 percent across the load range of 60 to 100 MWe. With minimum overfire air, the NO reduction is slightly lower, indicating that for this particular installation, the low-NO_x burners appear to provide the majority of the reduction in NO emissions. However, due to port temperature limitations, it was not possible to reduce the overfire air flow to zero. Although the data indicate that increasing the overfire air flow from 15 to 24 percent resulted in a 5 to 10 percent increase in NO removal, factors other than overfire air flow contribute to this effect. A detailed discussion of the effect of excess air level, which occurs later in this section, will show that the NO removal due to the effect of overfire air alone is even less than that indicated in Figure 5-6.

NO emission reductions achieved through a low-NO_x combustion system retrofit are achieved sometimes at the expense of higher CO emissions and increased flyash carbon levels. One goal of the retrofit test program at Arapahoe Unit 4 was to minimize NO emissions without significantly increasing carbon losses (CO emissions or ash carbon levels). This goal was achieved by imposing a CO emission limit of 50 ppm for what was to be defined as "normal" boiler operation at each load. Figure 5-7 shows a comparison of CO emissions before and after the retrofit. The data indicate that CO emissions were actually reduced with the new burners and maximum overfire air, especially at or below 80 MWe. A factor contributing to this reduction is that at reduced load, the boiler must be operated at higher excess air levels than those required with the original burners. Before the retrofit, it was necessary to increase the excess air slightly as load was reduced in order to maintain design steam temperatures. With the new combustion system, the air flow increase necessary to maintain steam temperature was found to be significantly greater.

Figure 5-8 shows the excess O_2 levels necessary to try to maintain both adequate steam temperature and limit CO emissions to 50 ppm with the retrofit combustion system, and compares them to the levels for normal operation with the original burners. With maximum overfire air, 50 ppm CO can be achieved at 100 MWe with an excess air level similar to that necessary with the original burners. However, as mentioned above, as boiler load is reduced, it is necessary to increase the excess air levels in order to maintain steam temperatures. With maximum overfire air, this increase in excess O_2 is approximately 0.7 percent at 80 MWe and 1.9 percent at 60 MWe. The increased oxygen levels result in better carbon burnout, and thus reduced CO emissions as load is reduced (Figure 5-7).

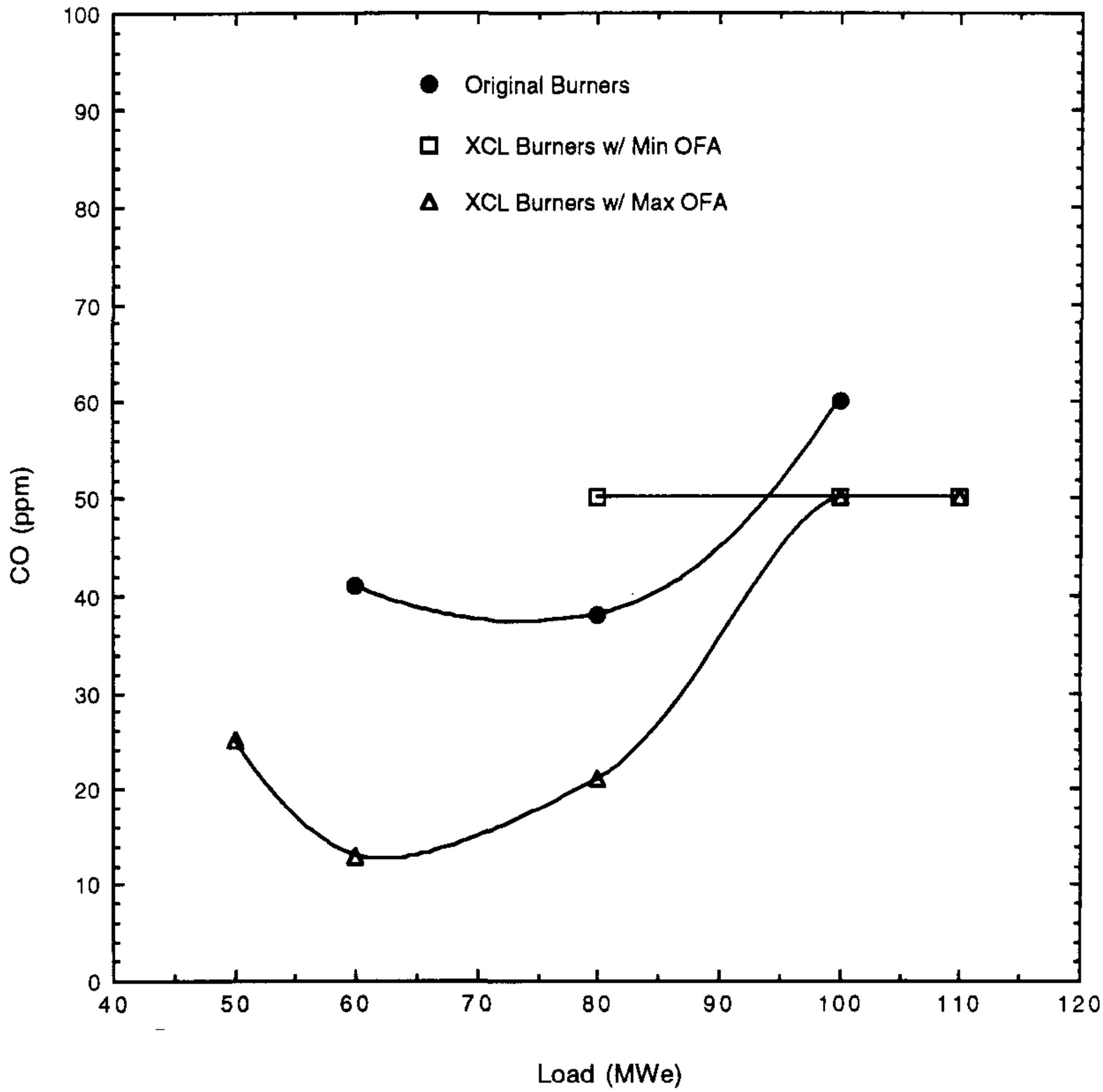


Figure 5-7. Pre- and Post-Retrofit CO Emissions as a Function of Boiler Load

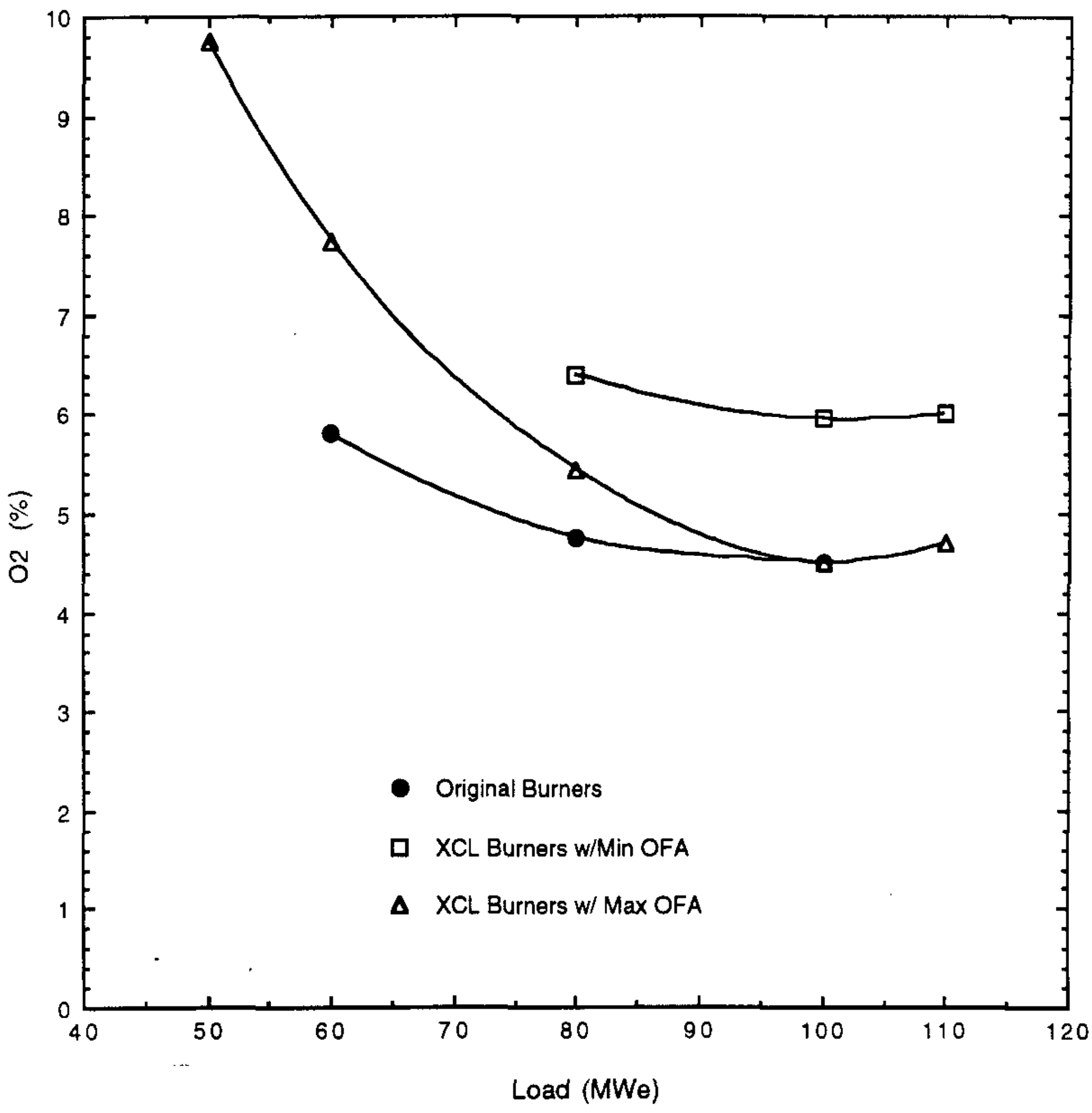


Figure 5-8. Pre- and Post-Retrofit Excess O_2 Levels for Normal Operation as a Function of Boiler Load

The excess O_2 levels shown in Figure 5-8 were more than sufficient to maintain design steam temperature (1000°F) at both 100 and 110 MWe with maximum overfire air. At both loads, the steam temperature was controlled by attemperation. At 80 MWe, the excess O_2 level was just below that necessary to keep the attemperation valves open, and steam temperature dropped slightly to 995°F. At Arapahoe Unit 4, the lower limit of the "adequate" steam temperature range is defined as 980°F. If the temperature falls below this value, an alarm is registered on the DCS. At 60 MWe, the steam temperature was approximately 980°F at the excess O_2 level shown in Figure 5-8. At both 60 and 80 MWe, the control operator may adjust the DCS O_2 trim system to increase the excess air level in order to raise the steam temperature to 1000°F. At 50 MWe with the O_2 trim at maximum, however, the steam temperature was only 945°F. The only way to raise the excess O_2 level further was to take the boiler out of automatic control and increase the speed of the fans manually. It was decided that this was beyond the scope of "normal" operation; therefore, only a single test was performed at 50 MWe.

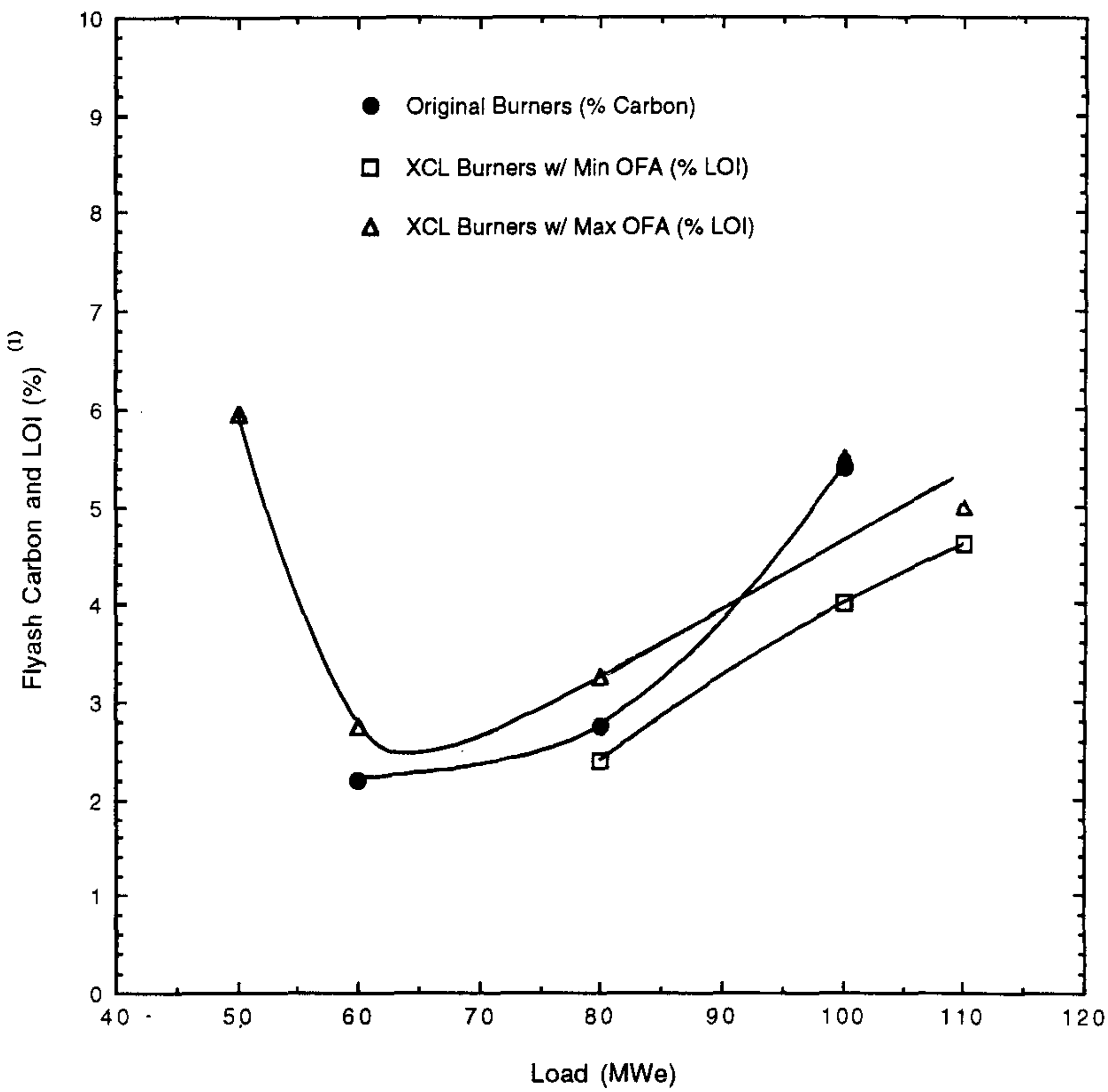
During the combustion system optimization tests, the penetration of the overfire air was found to be a critical factor in assuring adequate oxygen for sufficient carbon burnout at the center of the furnace, near the division wall. This effect is again apparent when reviewing the minimum overfire results in Figures 5-7 and 5-8. As seen in Figure 5-7, CO levels are in general lower with maximum overfire air. As the overfire flow is reduced, the penetration is also reduced, and an increase in excess air is necessary to maintain CO levels at 50 ppm. Since reduced overfire air flows resulted in increased CO and NO emissions at loads of 80 MWe and higher, minimum overfire air tests were not performed at 60 MWe with the optimized combustion system. However, a minimum overfire test was performed at 60 MWe during the optimization tests at a point in time when the burner settings were optimized, but the overfire air port settings were not. During this test, the overfire air flow was reduced from the maximum of 26 percent to 5 percent, while the economizer exit O_2 level was held constant. The decrease in overfire air flow resulted in an increase in CO and NO emissions of 52 ppm and 13 ppmc, respectively. Minimum overfire air tests were not performed at 50 MWe due to the inability to maintain steam temperature at that boiler load.

A comparison of the flyash carbon levels before and after the retrofit are presented in Figure 5-9. The data show that the combustion modifications did not significantly increase carbon levels above those measured during the baseline tests. In fact, a slight decrease is more appropriate when one recalls that the carbon levels from the LOI method are nominally 1.5 percent higher than an elemental carbon analysis (Figure 4-4b). When comparing the pre- and post-retrofit flyash carbon levels, it must also be noted that the performance of the coal mills was more consistent after the retrofit than before (recall Figures 5-1, 5-2 and 5-3), and this difference in performance may itself result in a slight decrease in carbon levels. The post-retrofit data show a general downward trend as boiler load is reduced which, as expected, is consistent with the trend seen for the CO emissions in Figure 5-7. However, an increase in both CO emissions and flyash carbon content is seen when load is reduced from 60 to 50 MWe, even though the excess O_2 level was increased nearly 2 percent. This is likely the result of changing from 3 mill to 2 mill operation. At 50 MWe, each mill still in operation is processing approximately 21 percent more coal than it was at 60 MWe. A decrease in the grinding efficiency would result in larger coal particles which would be more difficult to burn.

Comparison of data in Figures 5-7 and 5-9 shows another interesting result. Namely, while the CO emissions with maximum overfire air are less than or equal to those with minimum overfire air, the flyash carbon levels are lowest under the minimum overfire air condition. The reasons responsible for this effect were not immediately apparent, and the limited amount of testing time did not allow a more detailed investigation.

Effect of Excess Air Level

The effect of operating O_2 level on NO emissions is shown in Figure 5-10 for both the original and retrofit combustion systems. The data show that the NO emissions were significantly more sensitive to changes in O_2 before the low-NO_x combustion system was installed. With the original burners, a one percent change in O_2 resulted in approximately a 145 ppmc change in NO. With the low-NO_x burners, the sensitivity is on the order of only 40 ppmc NO per percent of O_2. This decreased sensitivity to O_2 is



(1) Recall that the LOI analysis tends to overpredict the elemental carbon content by 1.3 to 1.7 percent (Figure 4-7).

Figure 5-9. Pre- and Post-Retrofit Flyash Carbon Levels as a Function of Boiler Load

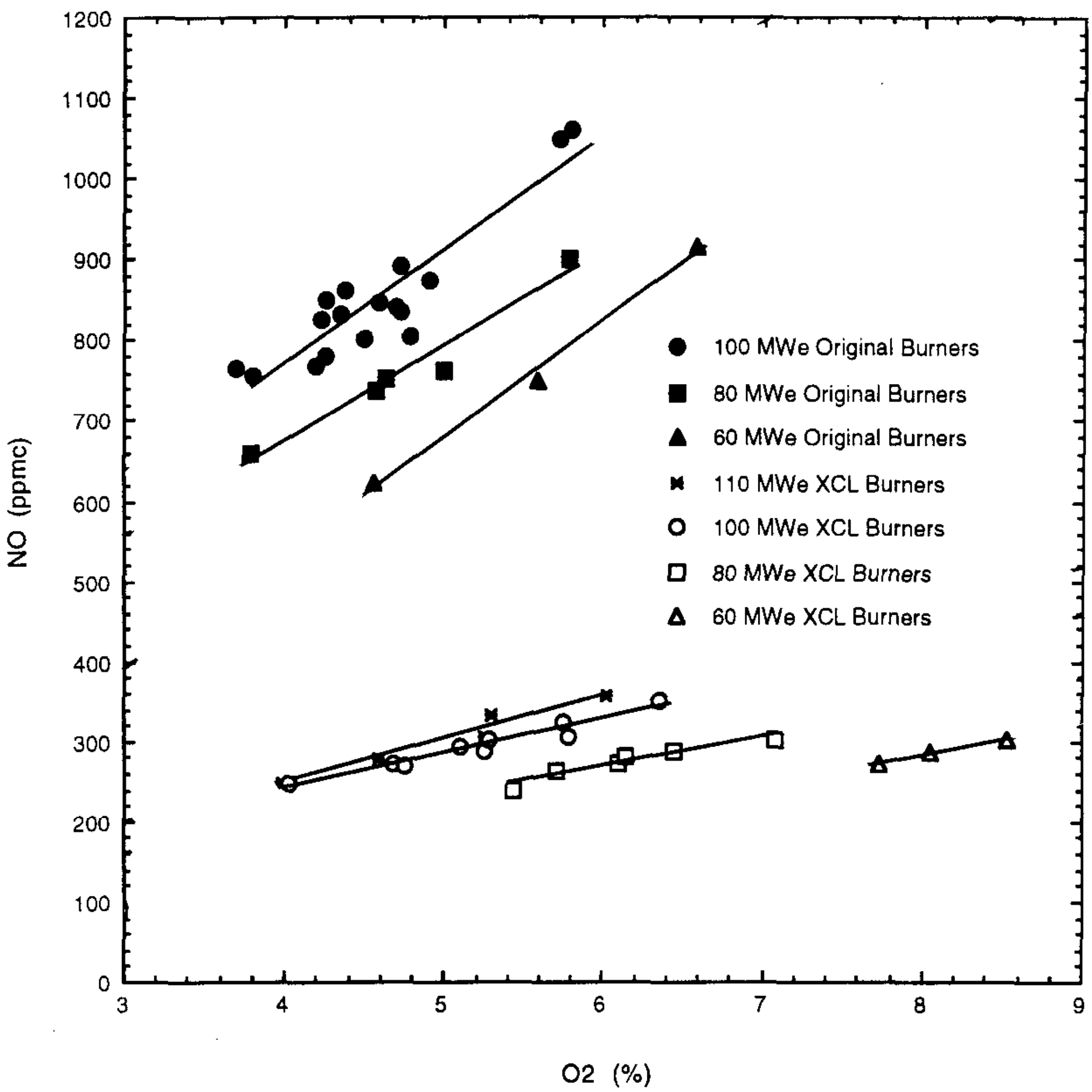


Figure 5-10. Effect of Excess O_2 on Pre- and Post-Retrofit NO Emissions

attributed to a more gradual mixing of fuel and air in the near burner region. It does not appear that the amount of overfire air has a significant effect on the NO/O_2 sensitivity, as the results shown in Figure 5-10 include the data for all overfire flow rates tested at each particular load.

In order to maintain adequate steam temperatures, as well as minimize NO, CO, and flyash carbon levels, the tests indicate that the recommended economizer exit excess O_2 levels as a function of boiler load should be set as shown in Table 5-3. The table also includes the corresponding control room O_2 set points, as well as the economizer exit and control room O_2 levels measured during the baseline tests for normal operation.

Table 5-3

Recommended Excess O_2 Levels as a Function of Boiler Load

Load (MWe)	Retrofit Combustion System		Original Burners	
	12-point Economizer Exit O_2 (%, dry)	Control Room O_2 (%, wet)	12-point Economizer Exit O_2 (%, dry)	Control Room O_2 (%, wet)
110	4.7	3.6	---	---
100	4.5	3.4	4.5	3.6
80	5.4	4.3	4.8	3.9
60	7.7	6.5	5.8	5.1

Effect of Overfire Air

Overfire air is generally expected to provide a significant NO reduction in addition to that achieved with low-NO_x burners alone. However, the results shown in Figure 5-6 indicated only a modest effect of overfire air flow on NO emissions, which suggests that, for this particular retrofit, the burners are responsible for the majority of the reduction in NO emissions. As mentioned previously, however, it was not possible to test with the overfire air flow reduced to zero due to port metal temperature limitations, thereby making it difficult to explicitly quantify the effect of overfire air. In addition to the absolute effect on NO emissions, the effectiveness of overfire air can also be assessed by looking at the effect on the NO/O_2 relationship. One would expect that as the fuel/air mixing is reduced, the sensitivity of NO emissions to excess O_2 levels would also diminish. This certainly was seen in Figure 5-10 when the performance of the retrofit combustion system was compared to that of the original burners.

Before discussing the results any further, a couple of comments regarding the operation of the boiler control system are appropriate. The O_2 trim control uses an average O_2 level calculated from the four individual PSCC O_2 probes shown in Figure 4-2. As discussed in Section 4.2, the four probes do not provide an accurate composite O_2 measurement at the economizer exit. This is particularly a problem when the overfire air flow rate is varied. In terms of the operation of the automatic O_2 trim system, the following scenario occurs as the overfire air flow is reduced:

- The overfire air flow is decreased (i.e., the control dampers are closed).
- With decreasing overfire air flow, the penetration into the center of the furnace decreases.
- As a consequence, the four PSCC O_2 probes (which are located toward the center of the furnace) see a lower average O_2 level.
- The lower indicated O_2 level tells the control system to increase the overall air flow rate, thereby increasing the overall O_2 level (as determined by the 12-point grid at the economizer exit).

Therefore, the increase in NO emissions seen with reduced overfire air flow rates in Figure 5-6 cannot be solely attributed to a reduction in overfire air flow since it was accompanied by an increase in the excess O_2 level (Figure 5-8). It was preferred that the tests be conducted with the control system in automatic, as this is the normal boiler operating mode. Therefore, in order to determine the amount of the increase in NO emissions which was due solely to the reduction in overfire air flow, it was necessary to adjust the minimum overfire air data in Figure 5-6 by subtracting the NO increase that was due to the difference in O_2 levels. The O_2 contribution was calculated by multiplying the difference in O_2 by the post-retrofit NO/O_2 sensitivity of 40 ppm/percent (recall Figure 5-10). The adjusted NO emission data for the minimum overfire air case are shown in Figure 5-11 along with the unadjusted data from Figure 5–6. The results indicate that the differences in NO emissions between the maximum and minimum overfire air conditions are due almost exclusively to the different excess O_2 levels for each condition.

Ideally, low-NO_x burners and overfire air should control the fuel/air mixing process over two separate regions of the furnace. The burners should control the mixing in the near-burner region, while the overfire air should control the mixing over a larger part of the furnace volume farther downstream. It is likely that at this particular installation, there is not sufficient distance between the burners and overfire air ports, and both are contributing to mixing in the near-burner region. This can be more clearly seen in Figure 5-12, where NO emissions are plotted as a function of burner stoichiometric ratio for the three overfire air flow rates tested at 100 MWe. The burner stoichiometric ratio is the ratio of the air and fuel supplied to the burners, and is thus the parameter controlling NO formation in the region upstream of the overfire air ports. If this is the case, then it would be expected that the burner stoichiometric ratio would have a large effect on NO emissions. However, the data in Figure 5-12 show only a weak dependency of approximately 7 ppmc NO per percent burner stoichiometric ratio. This suggests that the fuel/air mixing by the burners is sufficiently slow such that moving nominally 10 percent of the air from the burners to the overfire air ports has little affect on mixing. This further supports the previous statement that the burners are responsible for the majority of the NO reduction.

As mentioned previously, although increasing overfire air is generally expected to increase CO emissions and flyash carbon levels, quite the opposite was found to be true

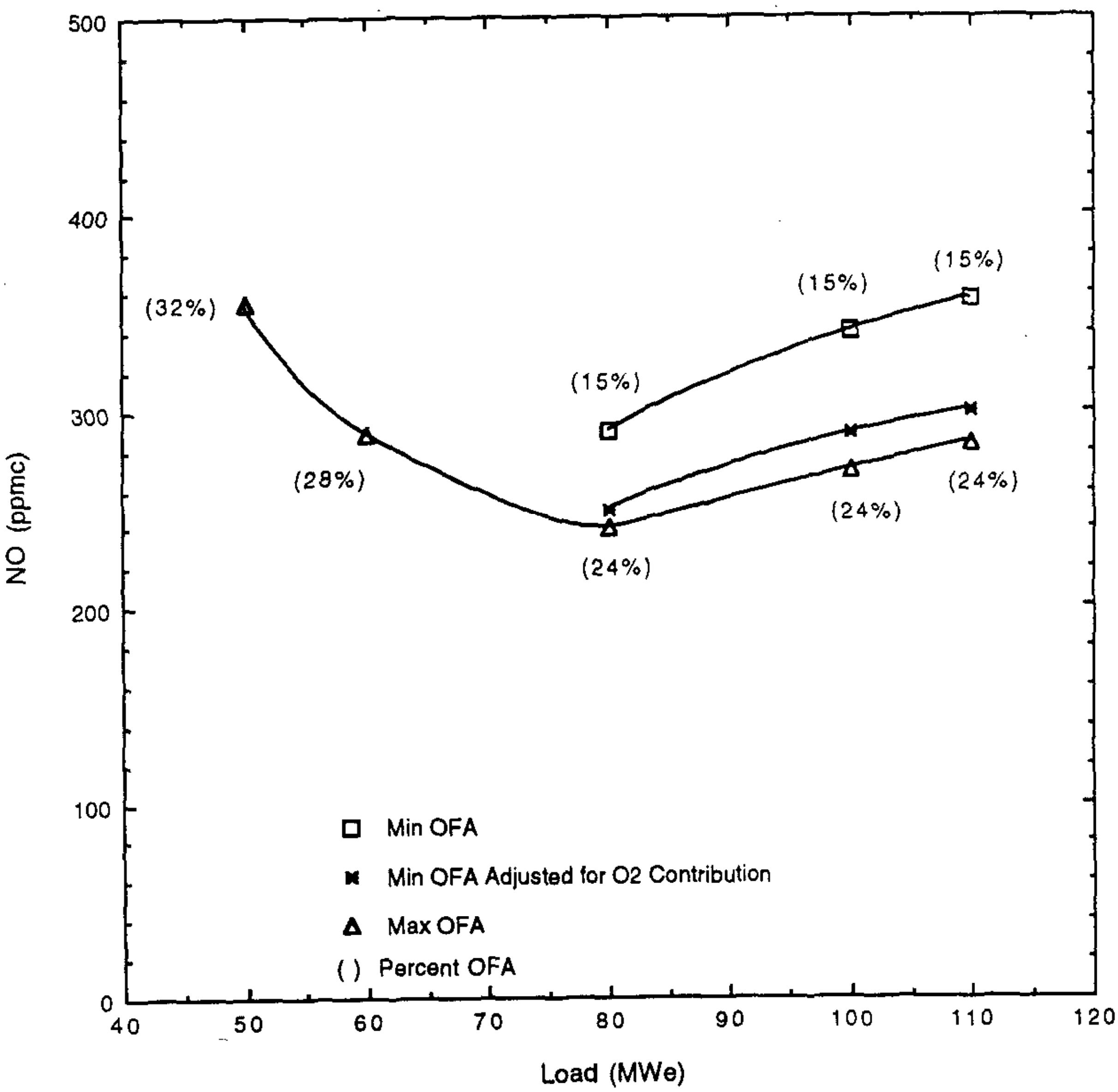


Figure 5-11. Post-Retrofit NO Emissions as a Function of Boiler Load

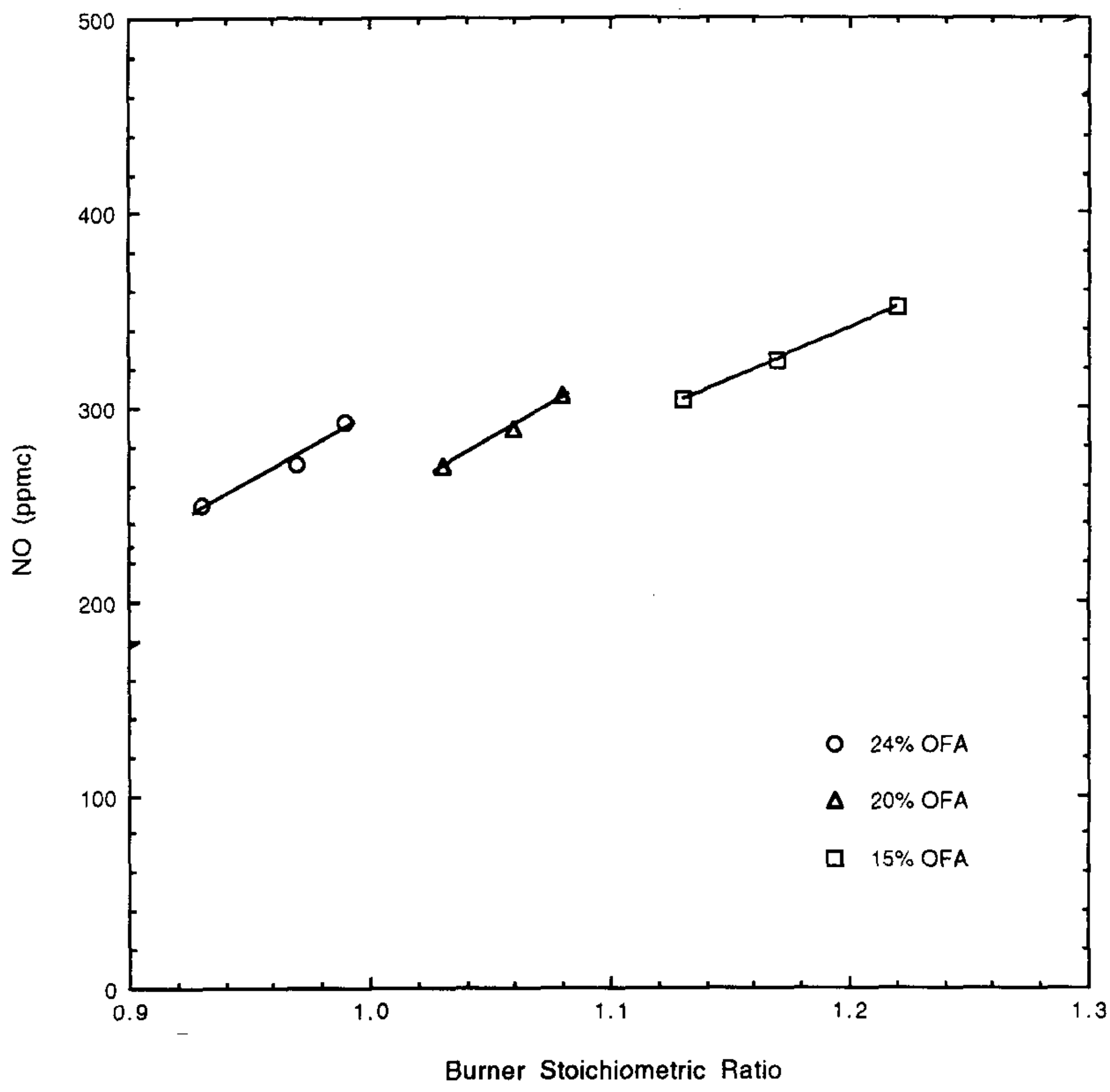


Figure 5-12. Effect of Burner Stoichiometry on NO Emissions at 100 MWe

for this particular installation. Figures 5-13a and 5-13b show the CO emissions and flyash carbon levels as a function of excess O_2 and overfire air for 110 MWe. Figures 5-14 and 5-15 show similar data for 100 and 80 MWe, respectively. The data show that at all three loads, increasing the overfire air at a fixed excess O_2 level results in decreased CO emissions and flyash carbon levels. Again, it is believed that the increase in penetration and mixing provided at the higher overfire air flows eliminates any locally fuel rich regions where carbon burnout would be impeded.

Based on the results of the parametric evaluation of the effect of overfire air flow rate, it is recommended that the maximum overfire air flow condition be maintained throughout the boiler load range as the data show that this condition results in the lowest NO and CO emissions, as well as the lowest O_2 requirement.

Effect of Mills Out of Service

The data reported thus far have been for four mill operation at boiler loads of 80 MWe and above, three mill operation (B Mill out of service) at 60 MWe, and two mill operation (A and D Mills out of service) at 50 MWe. Although these are the normal number of mills in operation for each load, it is important to investigate other mill in service configurations for two reasons. First, there is no guarantee that B Mill will always be the one taken out of service at 60 MWe, and the performance with any particular mill out of service needs to be documented. Second, although four mill operation is preferred, if any one mill happens to be out of service for maintenance reasons, three mill operation is possible at boiler loads up to 100 MWe. Therefore, three mill operation should also be investigated at 80 and 100 MWe and, similarly, two mill operation should be investigated at 60 MWe. Obviously, investigating all possible combinations of mill in service patterns at all boiler loads would have required an amount of time well beyond that which was available for the current test program. In order to minimize the amount of test time required while maximizing the amount of useful information provided, a relatively detailed characterization of the effect of mill

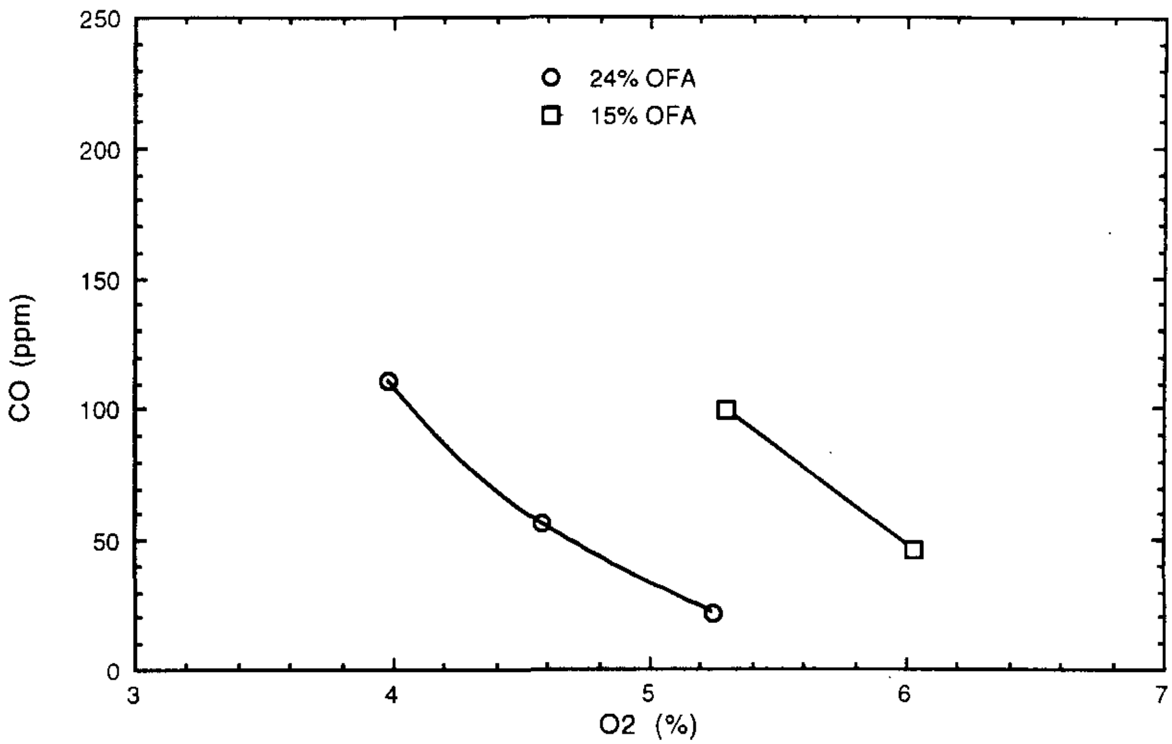


Figure 5-13a. Effect of Overfire Air on CO Emissions at 110 MWe

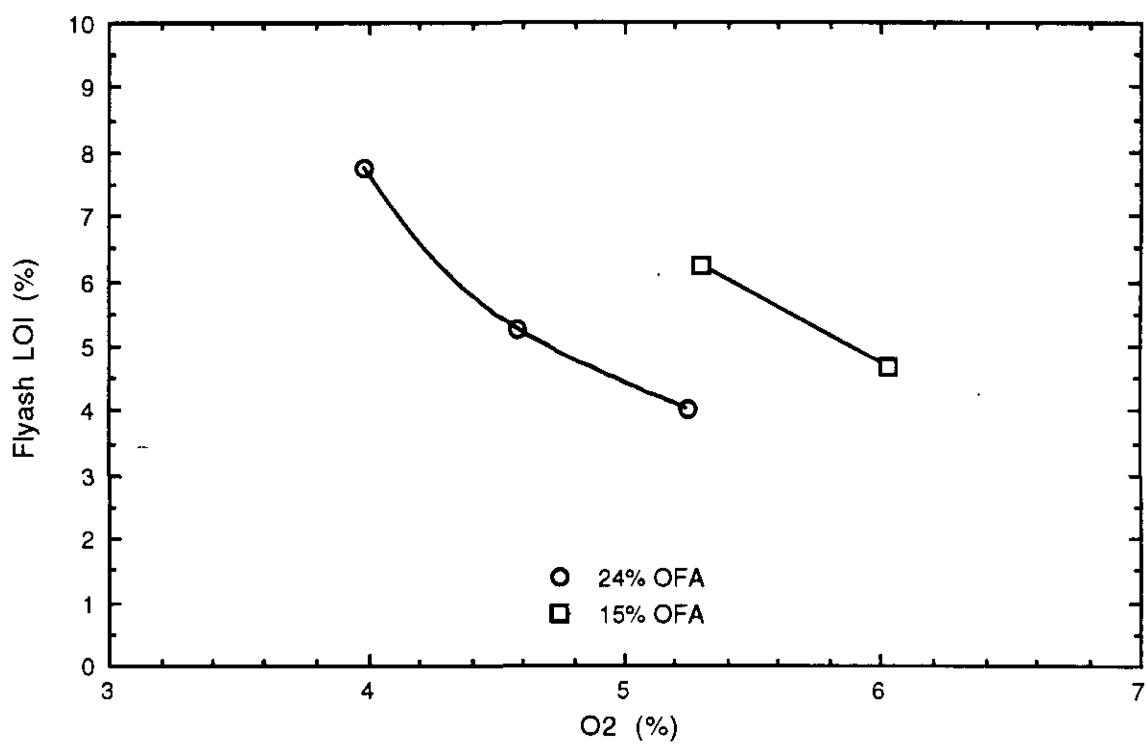


Figure 5-13b. Effect of Overfire Air on Flyash Carbon Levels at 110 MWe

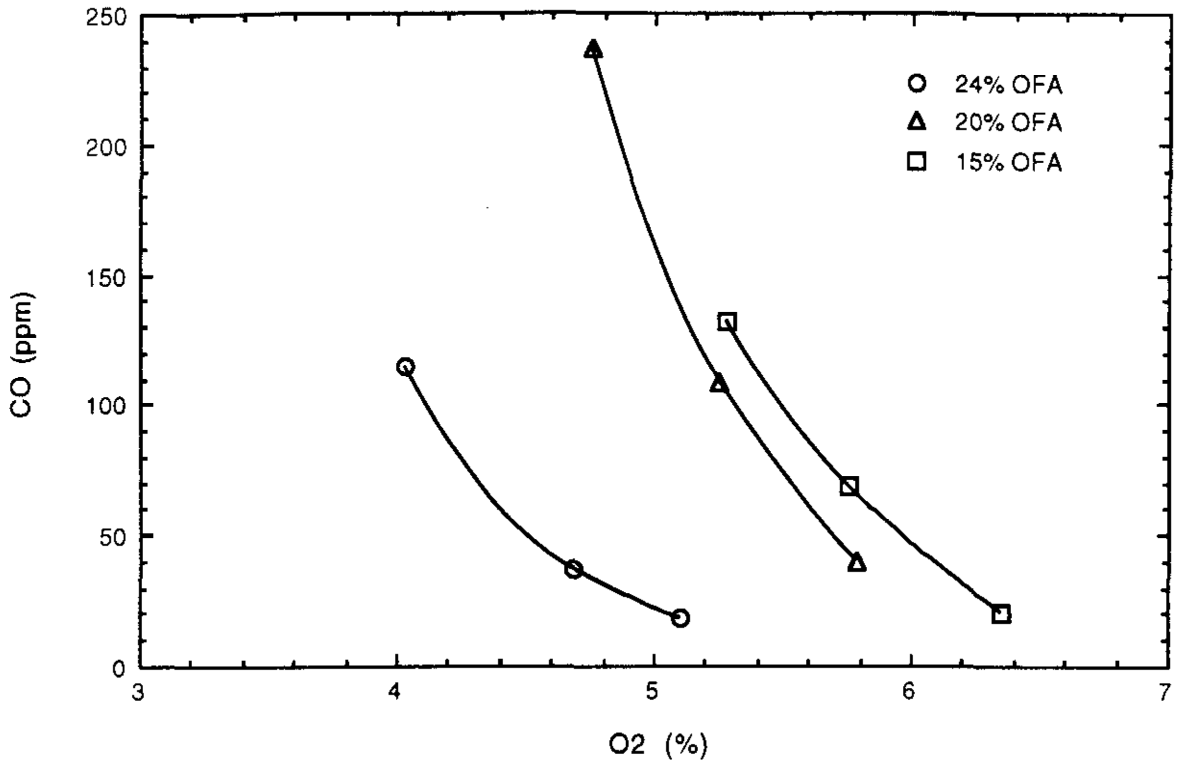


Figure 5-14a. Effect of Overfire Air on CO Emissions at 100 MWe

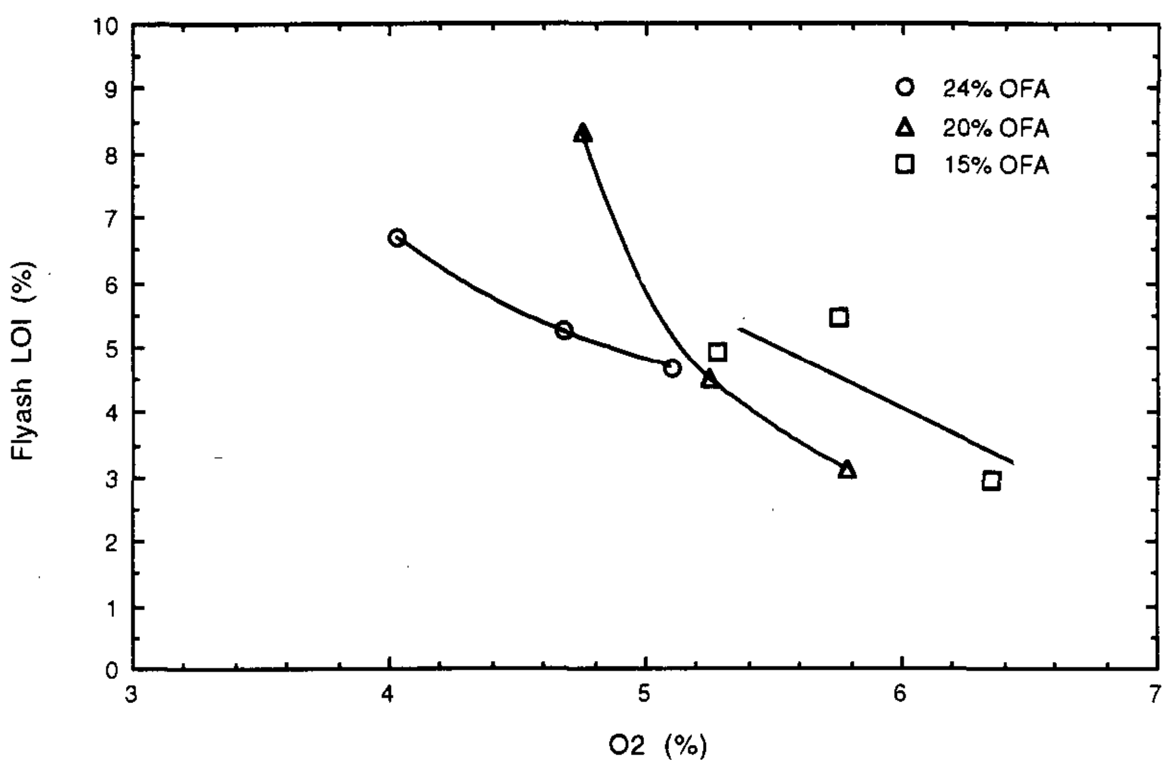


Figure 5-14b. Effect of Overfire Air on Flyash Carbon Levels at 100 MWe

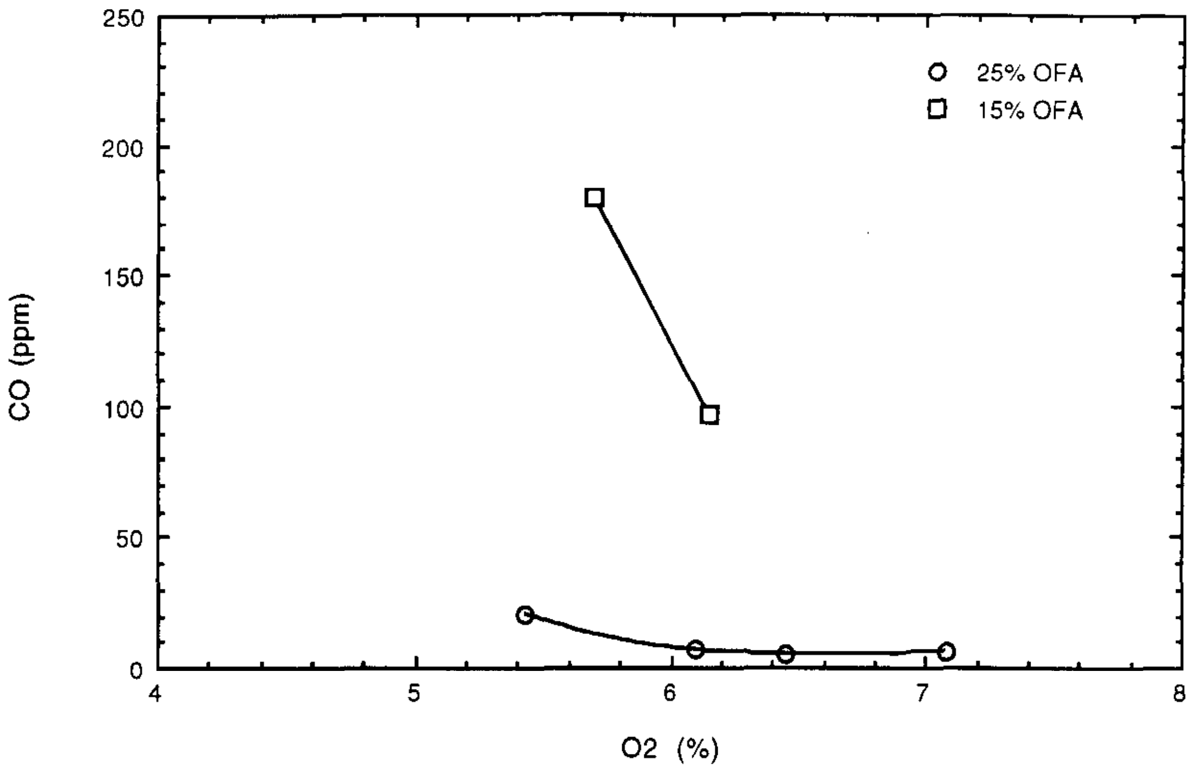


Figure 5-15a. Effect of Overfire Air on CO Emissions at 80 MWe

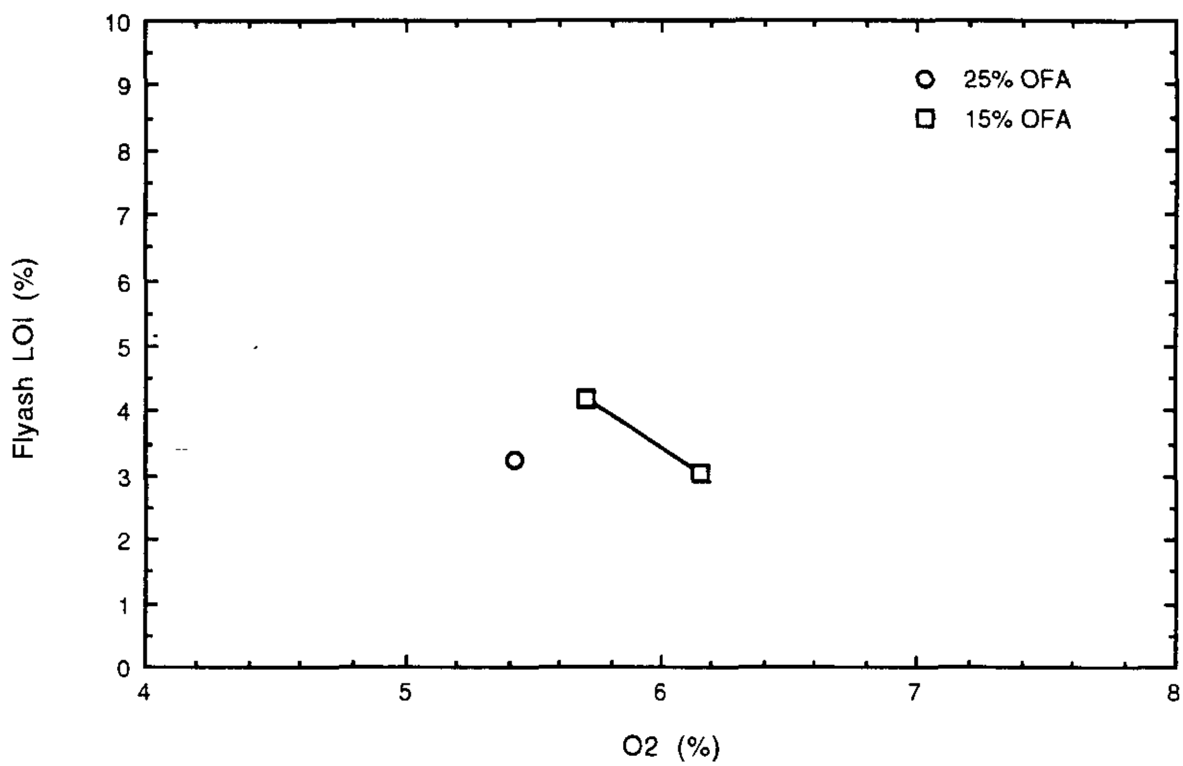


Figure 5-15b. Effect of Overfire Air on Flyash Carbon Levels at 80 MWe

in service pattern was conducted at 80 MWe, and less detailed characterizations conducted at 100 and 60 MWe. All three sets of tests were conducted with maximum overfire air which was shown previously to be the optimum operating condition.

The effect of mill in service pattern on NO emissions at 80 MWe is shown in Figure 5–16, where three mill operation with each of the four mills out of service is compared to operation with all four mills in operation. Although the data show a variation in NO emissions depending on which mill is removed from service, the variation is small and on the order of only 10 percent. In general, the NO emissions for three and four mill operation are similar. The effect of mill in service pattern on the CO emissions and flyash carbon levels at 80 MWe are shown in Figures 5-17a and 5-17b, respectively. The three mill data in each figure again show a small variation, depending on which mill is removed from service. However, both CO emissions and flyash carbon levels are substantially higher for three mill operation than for four mill operation. The increase in carbon losses seen with the switch from four to three mill operation is likely due to the combination of two effects. First, four mill operation provides a more uniform distribution of coal and air across the roof of the furnace, thereby minimizing the likelihood of any locally fuel rich regions where carbon burnout would be impeded. Second, with one mill out of service, each of the three remaining mills is processing approximately 33 percent more coal than at the four mill condition. The grinding efficiency of the three remaining mills is expected to be affected by the increased loading, resulting in larger coal particles, which take longer to burn.

At 100 MWe, the effect of three mill operation was assessed with only B and C Mills out of service. The results of these tests are shown in Figures 5-18 and 5-19. Again, comparison of the three and four mill data show little effect on NO emissions, while a large increase in CO emissions and flyash carbon levels are seen when only three mills are in service. Although the three mill data show a variation in NO emissions which is on the same order as that seen at 80 MWe (approximately 10 percent), the variations in CO emissions and flyash carbon levels are much larger than those seen at the reduced

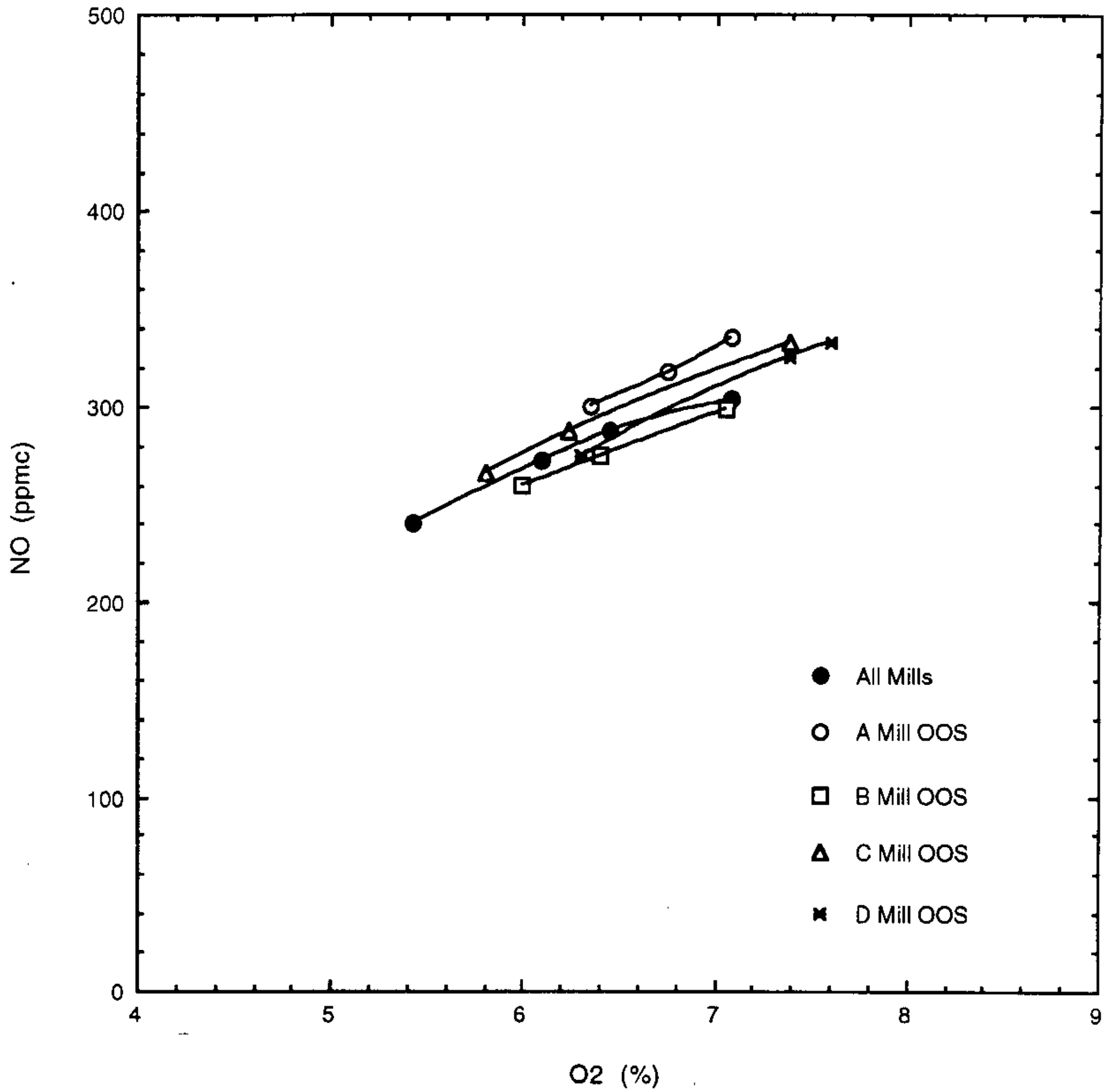


Figure 5-16. Effect of Mill in Service Pattern on NO Emissions at 80 MWe

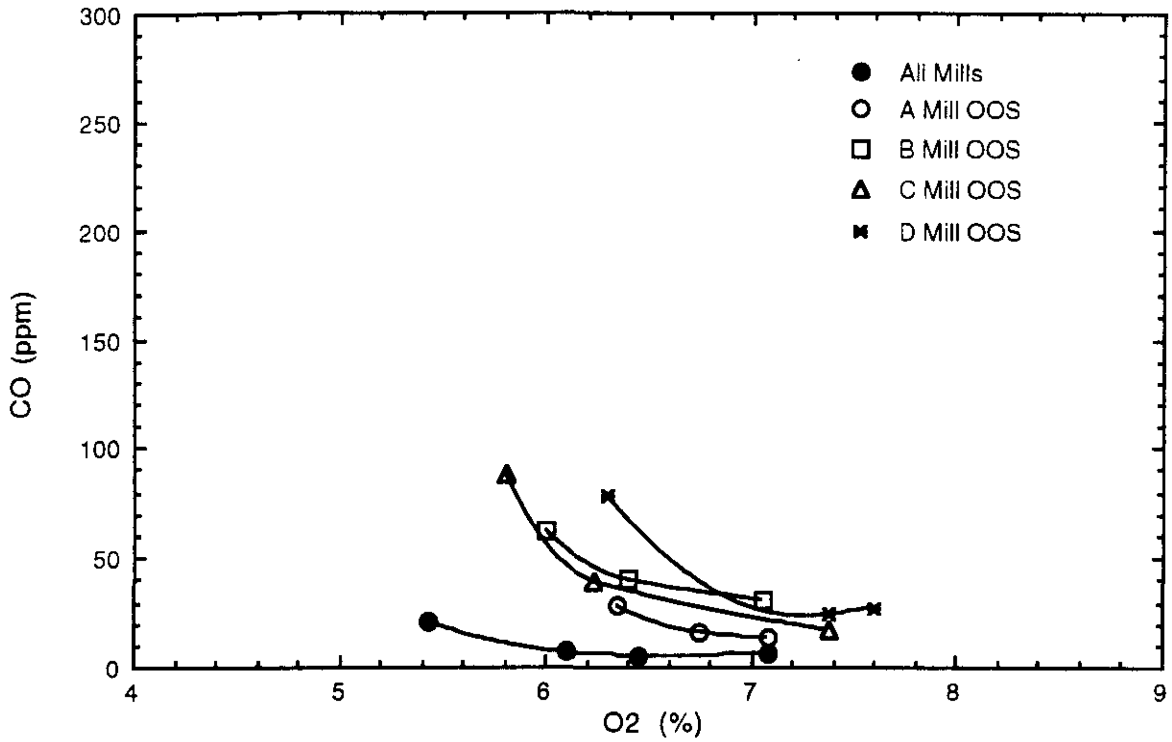


Figure 5-17a. Effect of Mill in Service Pattern on CO Emissions at 80 MWe

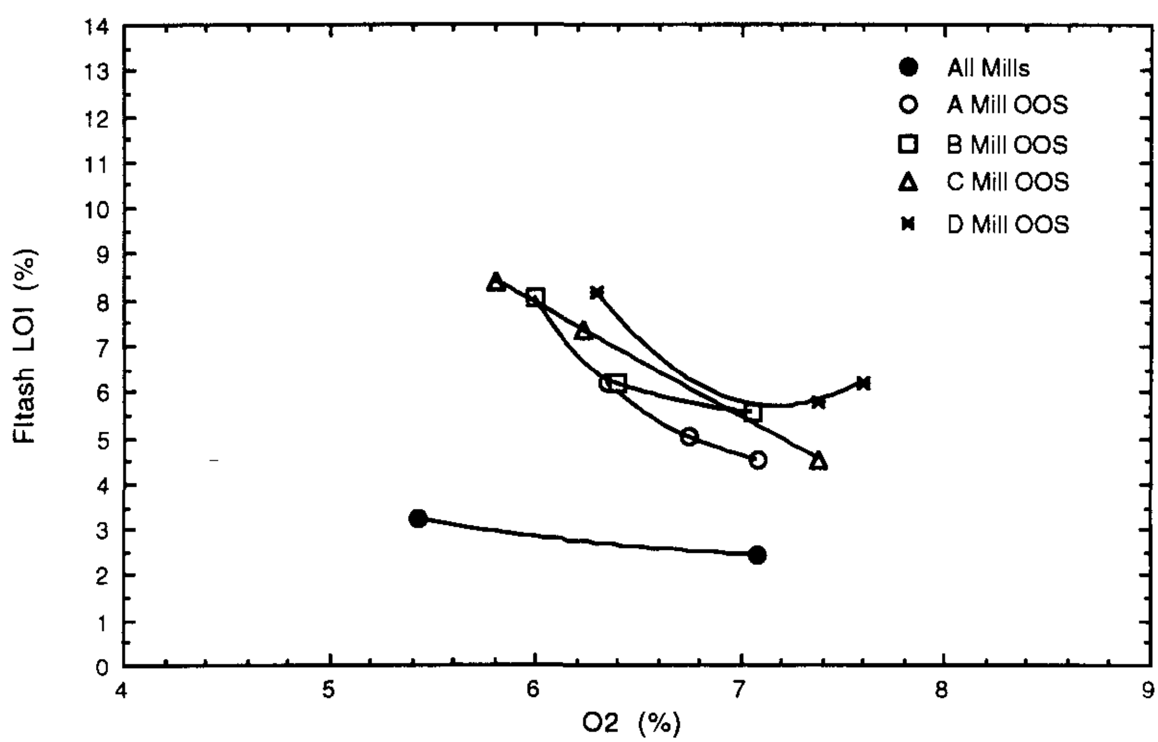


Figure 5-17b. Effect of Mill in Service Pattern on Flyash Carbon Levels at 80 MWe

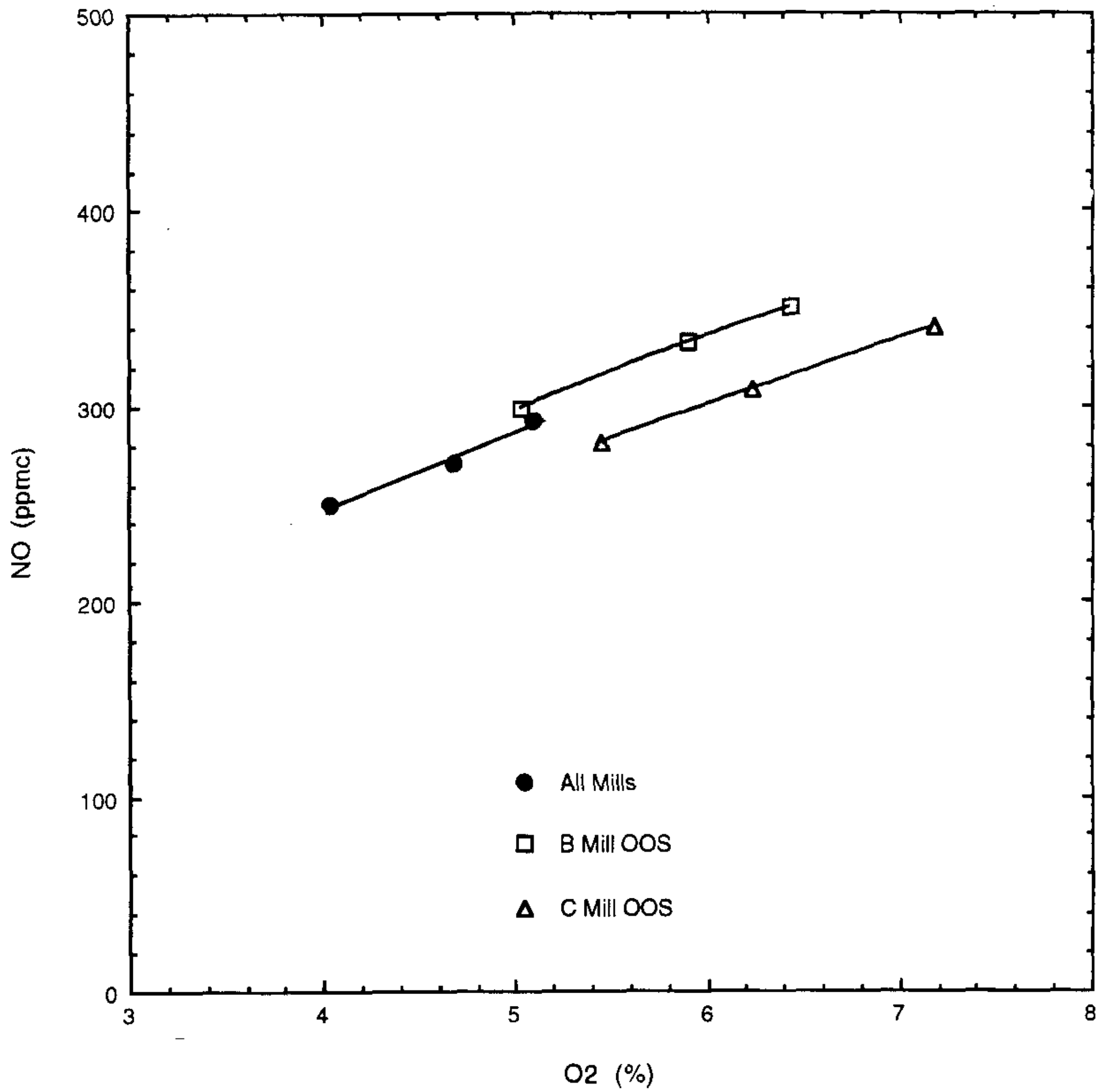


Figure 5-18. Effect of Mill in Service Pattern on NO Emissions at 100 MWe

loads cannot be made based solely upon the data presented in this report. It would be best made based upon the recent maintenance schedule and current operating performance of each mill as judged by plant operating personnel.

5.4 Detailed Diagnostic Tests

Throughout the parametric performance evaluation, various detailed diagnostic tests were occasionally performed, usually in order to gain a better understanding of a particular process variable, or to provide data for comparison to similar measurements obtained during the baseline tests. Point-by-point gaseous sampling traverses across the economizer exit duct, burner-to-burner coal and secondary air distribution measurements, and furnace exit gas temperature traverses are examples of the former types of tests; while SO_3, flyash mass loading and particle sizing measurements are examples of the latter.

Point-by-Point Gaseous Traverses

As mentioned previously, after the low-NO_x combustion system retrofit, increases in overfire air were found to reduce CO emissions and flyash carbon levels, rather than increase them as originally expected. In an effort to better understand this effect, point-by-point gaseous traverses were conducted at the economizer exit sampling location. Figures 5-22 and 5-23 show the O_2 and CO data for traverses at 100 MWe with the original burners and low-NO_x combustion system, respectively. Each point represents a composite sample from the upper and lower probes at each of the six sampling points on top of the economizer exit duct (recall Figure 4-2). With the original burners (Figure 5–22), the O_2 profile across the center of the furnace was relatively flat, indicating a fairly even distribution of secondary air through the burners. The increase in O_2 from nominally 4 to 6 percent at the two outer sampling locations was attributed to in-leakage through the numerous sootblower openings and observation doors on the east and west sides of the boiler. A local region of high CO emissions corresponding to an area of low excess O_2 was found in the center of the west side of the furnace. The shape of the O_2 and CO profiles for the retrofit combustion system with maximum overfire air (Figure 5-23) was found to be quite different from that measured during the

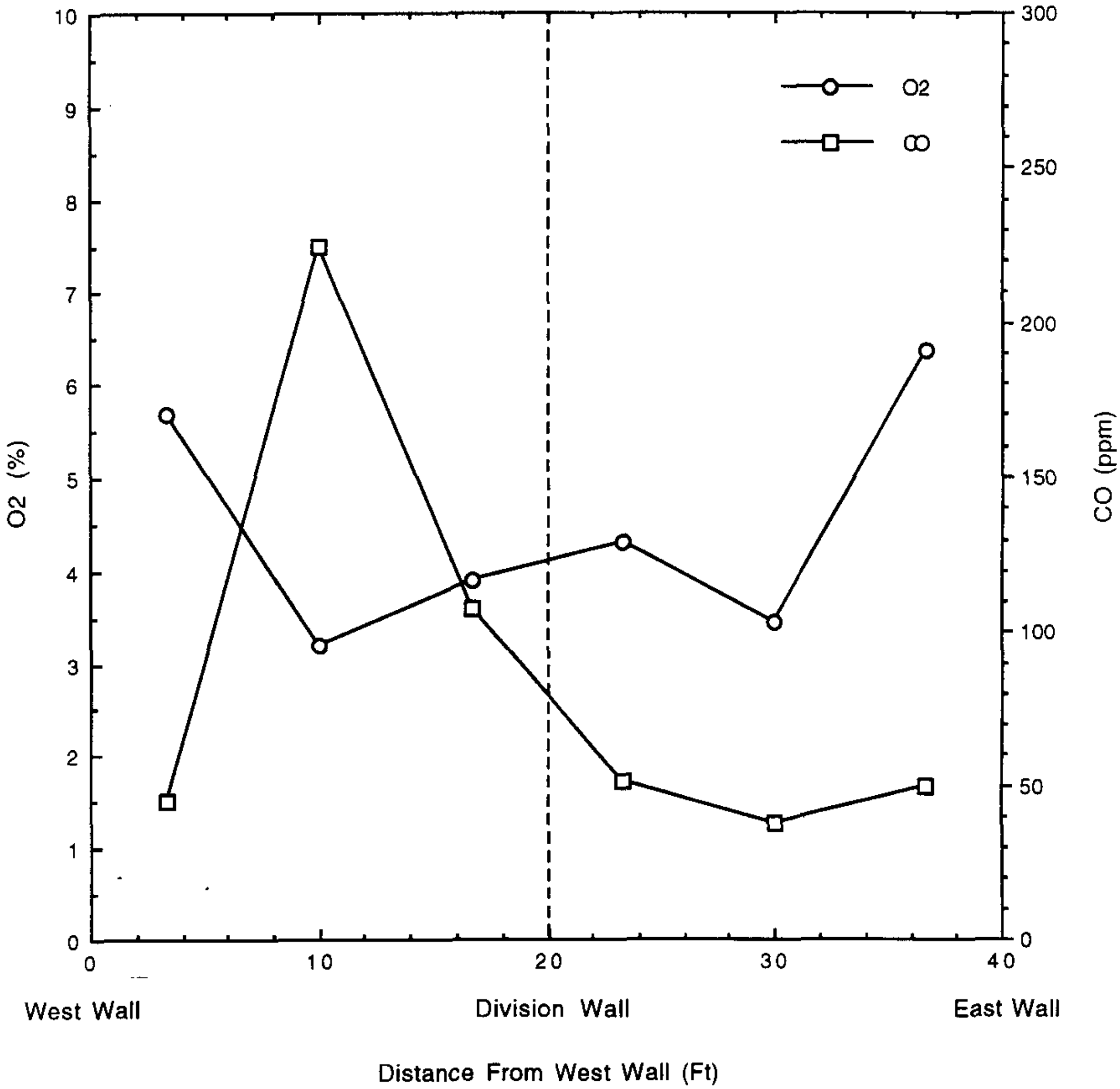


Figure 5-22. Pre-Retrofit O_2 and CO Traverses at 100 MWe

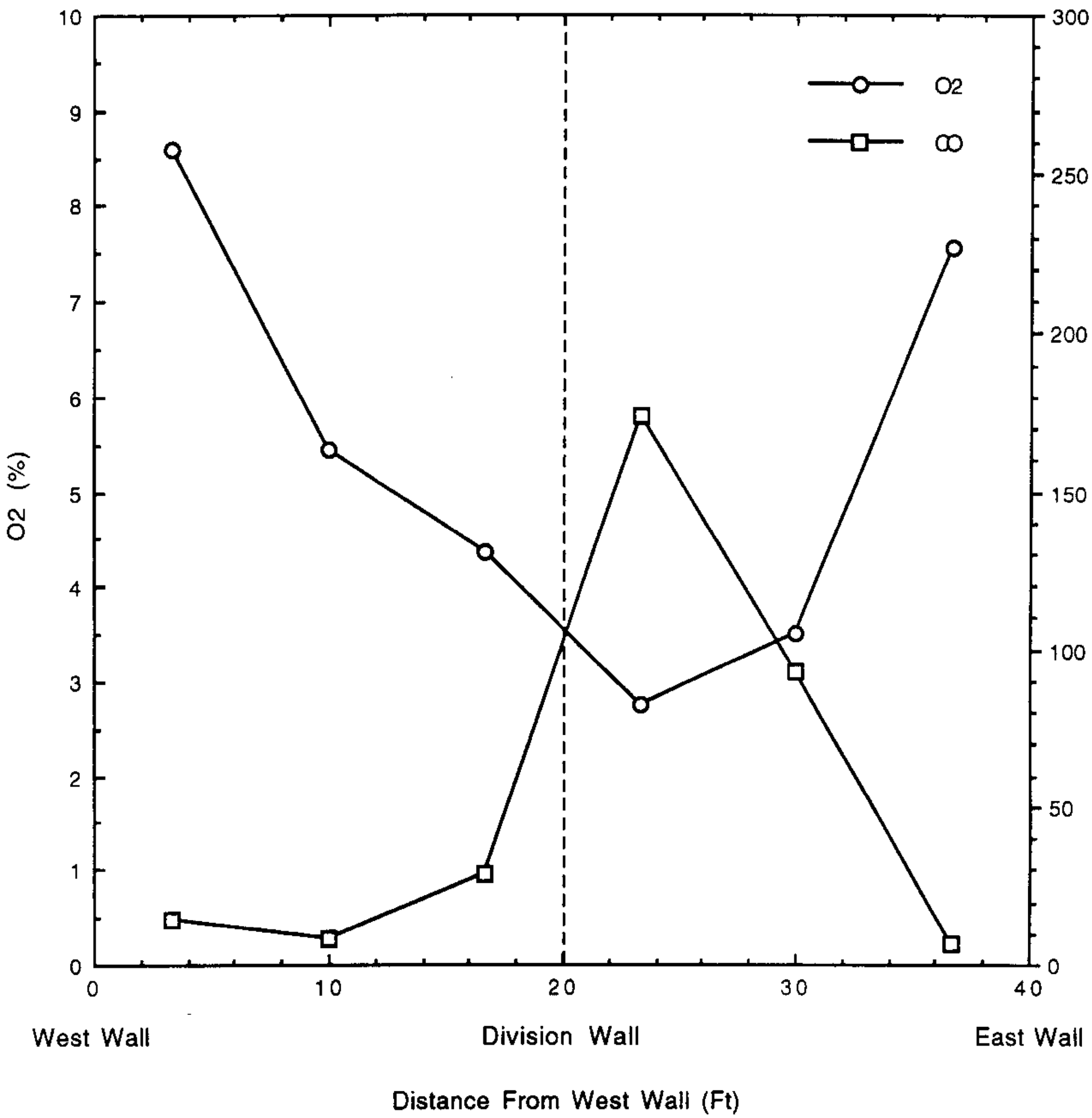


Figure 5-23. Post-Retrofit O_2 and CO Traverses at 100 MWe with Maximum Overfire Air

baseline tests. The post-retrofit O_2 profile shows a much greater increase in O_2 at the two outer sampling locations. In addition, a continual decrease in O_2 is seen as the economizer exit duct is traversed from either side wall toward the center. The data show that even with maximum overfire air, there is an O_2 deficit in the center of the furnace near the division wall which results in a local region of high CO emissions. Comparison of the O_2 profiles before and after the retrofit indicates that the penetration of the overfire air into the bulk combustion gas flow is very weak, and a significant amount of the overfire air never penetrates farther than 10 feet into the boiler.

The NO profiles for the pre- and post-retrofit sampling traverses are shown in Figure 5-24. The data for the original combustion system show a decrease in NO emissions near the outside walls. This is consistent with the assertion that the elevated O_2 levels seen near the outside walls with the original combustion system (Figure 5-22) were due to in-leakage. Since this in-leakage occurred downstream of the near burner region (i.e., the region where NO formation occurs), it would be expected that the NO emissions near the walls would have been decreased due to dilution. The data for the retrofit combustion system show an increase in both O_2 and NO emissions (Figures 5-23 and 5–24, respectively) near the outside walls. The existence of high O_2 and NO emissions in the same region confirms the belief that the overfire air ports at Arapahoe Unit 4 are located within the near-burner region (i.e., the region where NO formation is susceptible to increases in available O_2), and are not penetrating all the way to the furnace division wall.

Coal and Secondary Air Distribution Measurements

Burner-to-burner coal and secondary air flow imbalances can have an effect on the efficiency of the combustion process as well as NO emissions. A significant imbalance can result in excessive carbon losses and/or a limitation to the minimum air flows which can be sustained within the limit of acceptable CO emissions or flyash carbon levels. Carbon burnout problems would be expected in areas of high coal concentration. In fact, a relatively small local region that has a high imbalance can dictate the minimum

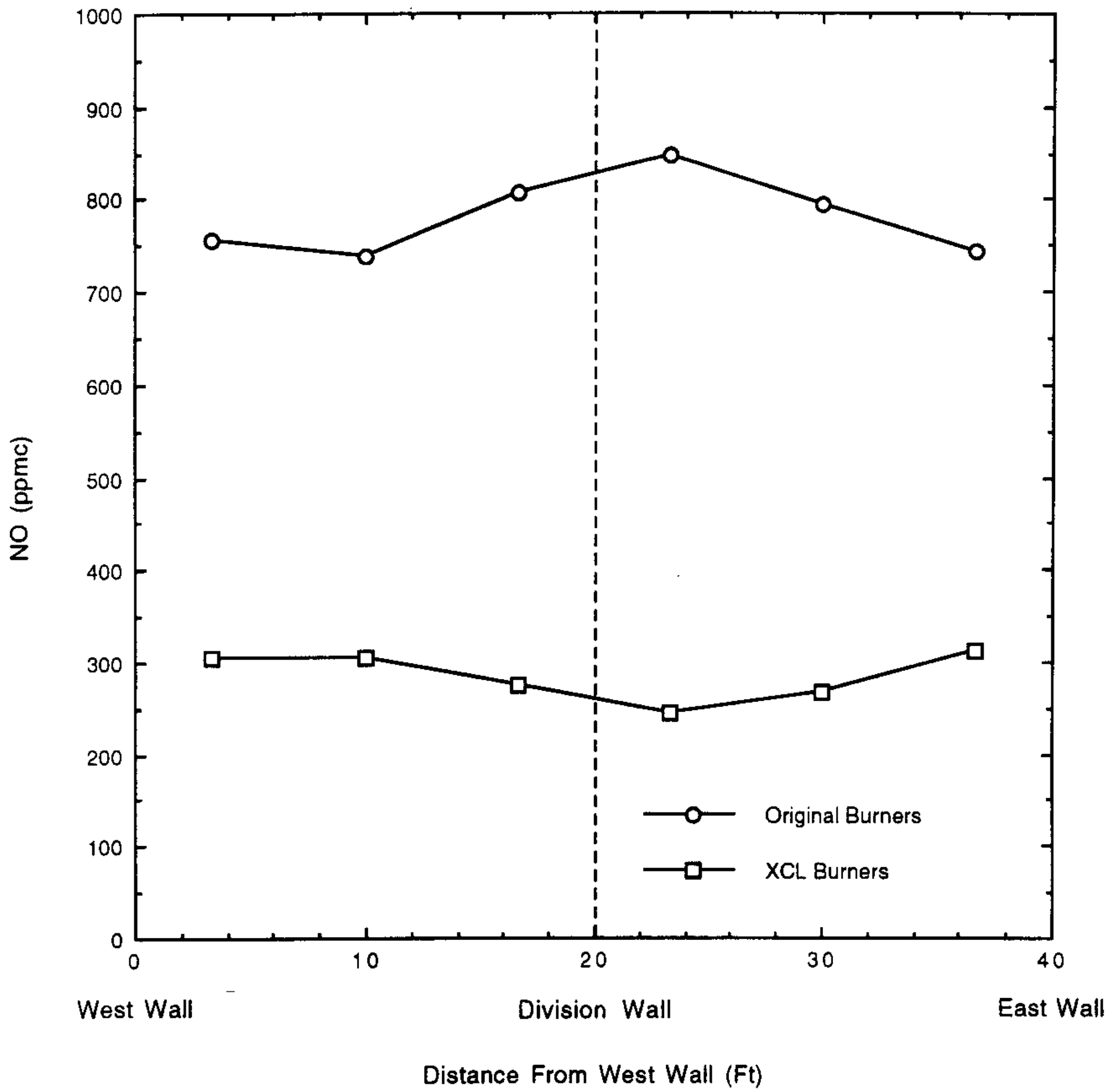


Figure 5-24. Pre- and Post-Retrofit NO Traverses at 100 MWe (Post-Retrofit with Maximum Overfire Air)

operating excess air level for the entire furnace. Conversely, regions with less coal and a greater availability of O_2 can lead to locally high NO emissions.

An approximate burner-to-burner stoichiometric ratio distribution can be achieved by plotting the ratio of the secondary air and coal flows to each individual burner. The resulting distribution would likely be valid only for the day that the coal and air flow measurements were made, since the burner-to-burner coal distribution has been shown to change on a day-to-day basis (Figures 5-4a and 5-4b). However, the distribution would provide an indication of the magnitude of the burner-to-burner variation in stoichiometric ratio.

Figures 5-25a and 5-25b show the burner-to-burner secondary air and coal distributions measured at 100 MWe with maximum overfire air on November 19, 1992. Since the secondary air pitot tubes on each burner are intended to provide only an indication of relative air flow and are not actually calibrated, the relative air flow to each burner was calculated as a percent of the total indicated air flow. The method used to determine the burner-to-burner coal distribution was discussed previously in Section 5.2. The distribution of the ratios of the relative secondary air and coal flows is shown in Figure 5-26. The data indicate a very large variation in the approximated air/fuel ratio across the roof of the furnace. In order to better see the burner-to-burner differences, the tabular data for Figure 5-26 are shown in Table 5-4. The data are presented in an orientation consistent with that in the figure, namely, west is to the left, and east is to the right. The data show a large burner-to-burner variation, with the ratio for burner number six being on the order of twice that calculated for either burner number three or twelve. The standard deviation of the approximated air/fuel ratios is nearly 21 percent of the mean. Additionally, the data show that the ratios for the three burners along the east wall (numbers ten, eleven and twelve) are quite low. In fact, the average ratio for the east side of the furnace is approximately 12 percent less than that for the west side. This indicates that the east side of the furnace, and in particular the area adjacent to the outside wall, will be an area where carbon burnout is limited. Unusual

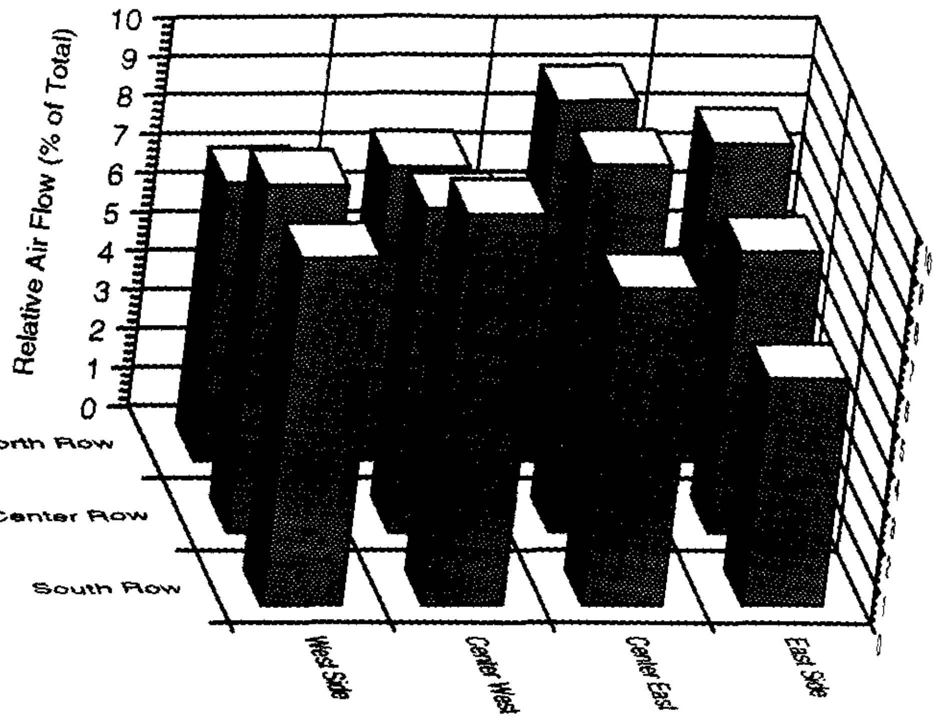


Figure 5-25a. Burner-to-Burner Secondary Air Distribution Results
November 19, 1992

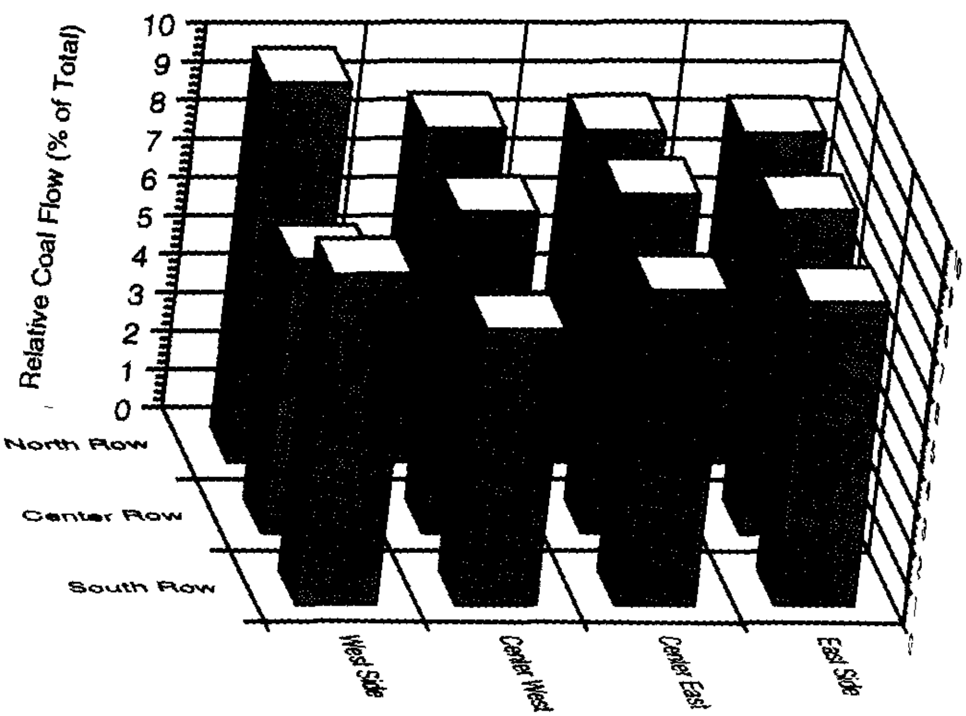


Figure 5-25b. Burner-to-Burner Coal Distribution Results
November 19, 1992

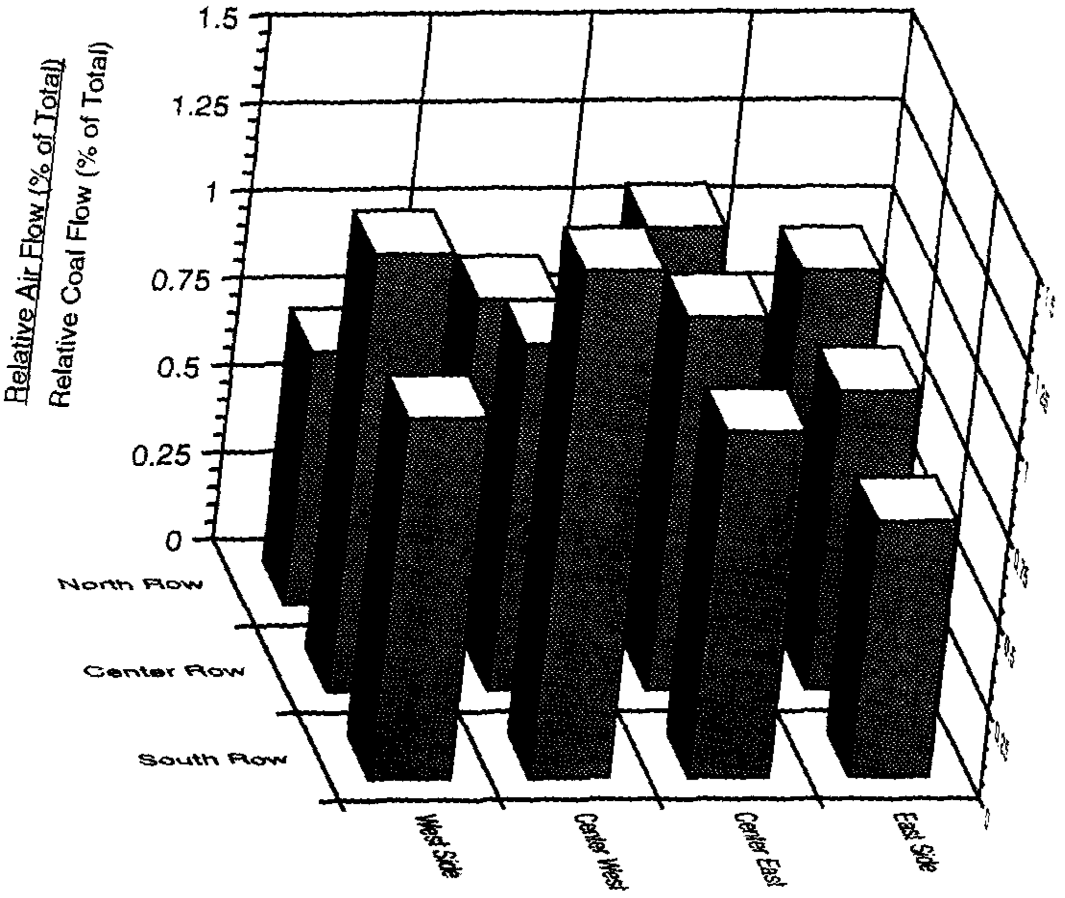


Figure 5-26. Approximate Burner-to-Burner Air/Fuel Ratios
November 19, 1992

flame patterns were also noted at the furnace exit through the ports at Location G (recall Figure 4-7). When looking from the west side, the furnace was clear of flames and the division wall could easily be seen. When looking from the east side, however, flames obscured the division wall, and in some cases limited the view to only 3 or 4 feet into the furnace. The point-by-point CO traverse discussed in the previous section (Figure 5-23) also indicates that the east side of the furnace was an area of limited carbon burnout.

Table 5-4

Tabulated Approximate Burner-to-Burner Air/Fuel Ratio Data

	Burner	Ratio	Burner	Ratio	Burner	Ratio	Burner	Ratio
	3	0.72	4	0.88	9	1.08	10	0.95
	2	1.24	5	0.98	8	1.07	11	0.86
	1	1.16	6	1.47	7	0.99	12	0.73
Average	1-3	1.04	4-6	1.11	7-9	1.05	10-12	0.85
Average	West 1.08				East 0.95			

In order to decrease the variation seen in Figure 5-26, it would be necessary to balance both the burner-to-burner secondary air and coal flow distributions. Balancing the secondary air can be achieved relatively easily by adjusting the limit switches on the linear actuator controlling the position of the air damper on each burner. However, providing a uniform and consistent coal distribution is well beyond the capability of the 1950's vintage coal handling equipment, even with the new distributed control and burner management systems in place.

During the combustion system optimization tests, three tests were run where the burner-to-burner secondary air flow distribution was balanced "temporarily" by moving secondary air dampers by hand. The results (Figure B-2) showed that in all three cases, balancing the air flow resulted in little or no effect on NO emissions. However, in two of the three tests, CO emissions were reduced by nearly 20 ppm. A more detailed discussion of these tests is contained in Appendix B.

Furnace Exit Gas Temperature Measurements

After the combustion system retrofit, it was found that the increases in excess air necessary to maintain steam temperature at reduced boiler loads were significantly greater than those that were required with the original burners. This is an indication that the furnace exit gas temperatures were reduced after the retrofit. In order to confirm and quantify the temperature decrease, temperature measurements were made using both acoustic and suction pyrometry techniques. This data was then compared to similar data collected during the baseline burner tests.

The results of the acoustic measurements at the furnace exit (Location G in Figure 4-6) are shown in Figure 5-27. Although a large amount of data was collected at numerous boiler operating conditions with the acoustic instrument, much of it was collected before the optimization of the burner and overfire air port settings was complete. Only the data collected with the optimized low-NO_x combustion system are presented in Figure 5-27. The data show that the gas temperatures have decreased by approximately 170°F across the entire load range. This decrease is responsible for the additional excess air necessary to maintain steam temperature at reduced boiler loads, and has also reduced the amount of steam attemperation required at full load.

Suction pyrometry (HVT) measurements were made through the same two ports utilized for the acoustic measurements in order to verify the data provided by the acoustic instrument. Restricted access to the sample port of the east side of the boiler limited the overall probe length to 10.5 feet, resulting in a maximum insertion depth of 8 feet from each side. The boiler is approximately 40 feet wide, so roughly 60 percent of the gas flow along the centerline of the unit was unreachable. Data was taken at 2-, 4-, 6- and 8-foot depths, with a repeat of the 4-foot point as the probe was withdrawn. The verification tests were conducted on three separate occasions at boiler loads of 60, 80 and

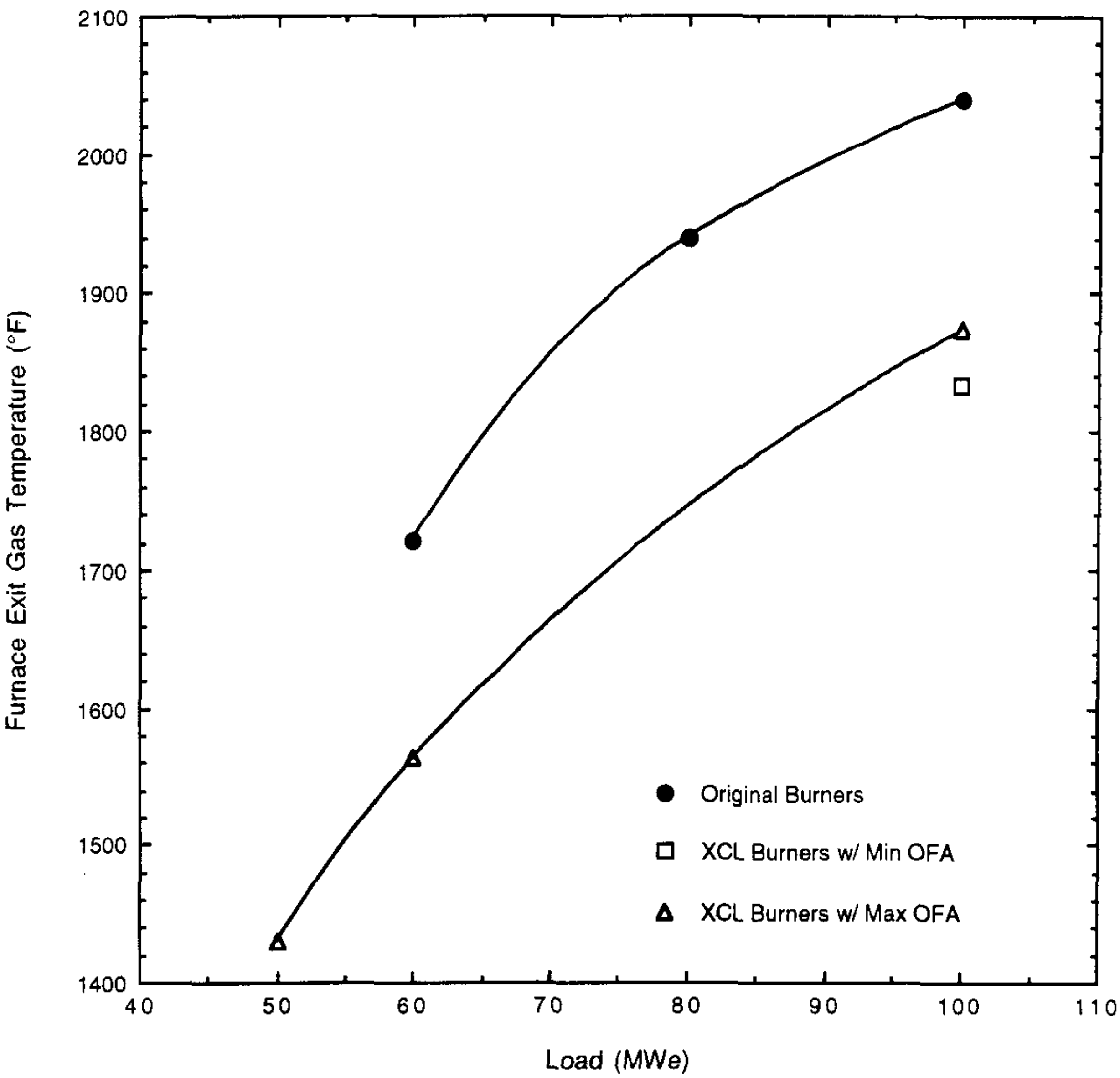


Figure 5-27. Pre- and Post-Retrofit Furnace Exit Gas Temperatures as a Function of Boiler Load (Location G, refer to Figure 4-6)

110 MWe. The acoustic data for 80 and 110 MWe were collected before completion of the combustion system optimization, and therefore do not appear in Figure 5-27.

The results of the verification tests are shown in Figure 5-28. In each case, the acoustic measurement yielded a line of sight average temperature which is in good agreement with, albeit slightly higher than, the average which may be inferred from the partial HVT traverses. The difference seems to be on the order of 20 to 60°F, but again, the HVT probe could only cover 40 percent of the distance across the furnace. The average temperature derived from acoustic measurements is expected to be consistently slightly higher than the average derived from a complete HVT traverse, because 1) the acoustic instrument provides a measurement averaged across the entire path, 2) the acoustic measurement is an average of the square root of the temperature which will slightly bias the computed value to a higher temperature, and 3) there are radiation and conduction heat loss errors associated with the HVT technique which do not affect the acoustic measurement. Overall, the agreement between the two techniques is good.

In order to confirm the decrease in furnace exit gas temperature measured at location G with the acoustic instrument, HVT traverses were conducted at location H (see Figure 4–7) and compared to similar measurements made during the baseline burner tests. Figure 5-29 shows the results of the pre- and post-retrofit HVT traverses at 60 MWe with C Mill out of service. The data show that after the retrofit, the temperatures on the west side were reduced by approximately 150°F, while the decrease on the east side was on the order of 350°F. The difference in the pre-retrofit east and west profiles is due to the arrangement of the original burners on the roof of the furnace (recall Figure 2-3). With the original burners and C Mill out of service, lower temperatures would be expected in the regions immediately adjacent to the east wall and in the center of the west side of the furnace. With the three-by-four arrangement of the new burners (recall Figure 3-2), removing a mill from service has much less of an impact on the temperature

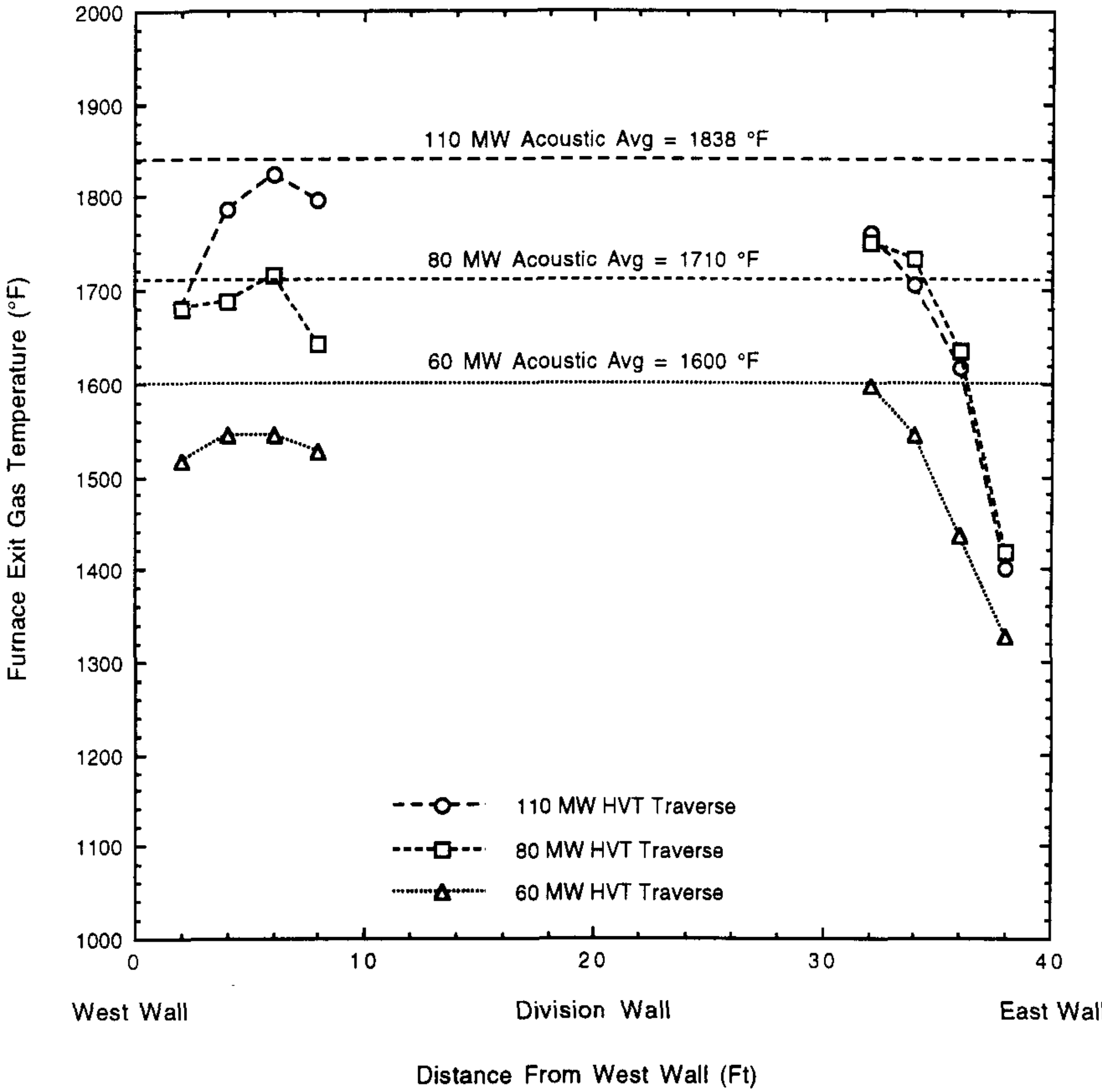


Figure 5-28. Comparison of Acoustic and HVT Temperature Measurements at Location G

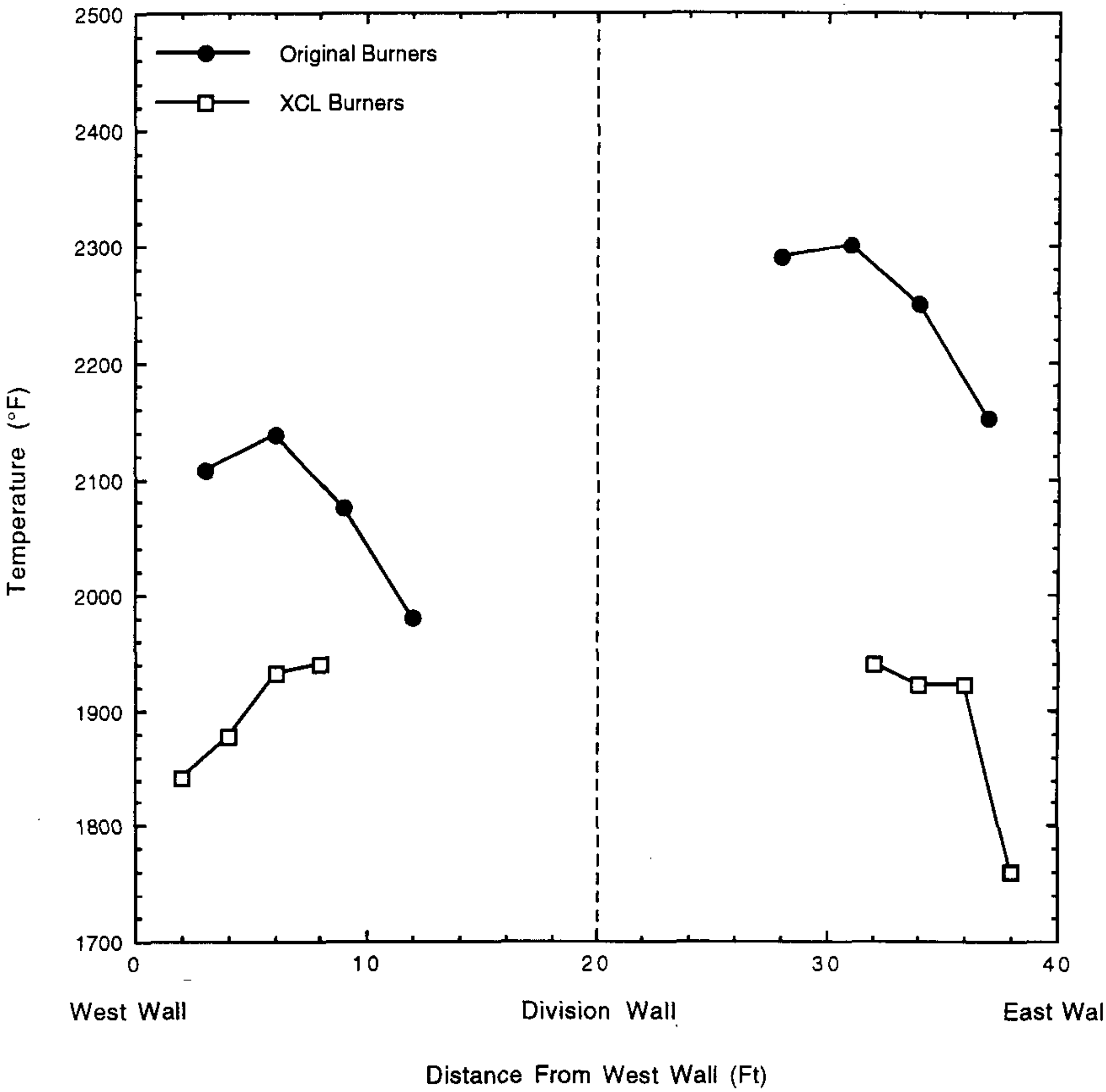


Figure 5-29. Pre- and Post-Retrofit Temperature Traverses at Location H (see Figure 4-6), for 60 MWe with C Mill Out of Service

distribution within the furnace. The data at 80 MWe with four mills in service (Figure 5-30) show a more even east-west temperature distribution with the original burners, as well as a decrease in temperature of approximately 200°F on the west side. Data were not collected on the east side at 80 MWe during the current test program. Finally, Figure 5-31 compares the traverses made during the baseline burner tests at 100 MWe to those made after the retrofit at 110 MWe. Even at the higher firing rate, the post-retrofit data show a decrease in temperature of approximately 200°F on both sides of the furnace.

HVT temperature traverses were also made through the eight ports along the north side of the boiler downstream of the second set of screen tubes (Figure 4-7). These measurements were made to assess the effect of the retrofit on the flue gas temperatures in the immediate vicinity of the urea injection nozzles.

Measurements at 2, 4, 6, and 8-foot depths were made at each of the eight ports, resulting in a 32-point grid. Figure 5-32 shows the average of the 32 temperature measurements as a function of boiler load, and compares the results to those found during the baseline burner tests. The data show a post-retrofit decrease in temperature on the order of 250°F across the load range. Figure 5-33 shows the average west-to-east temperature profiles at the north port location for 60, 80, and 110 MWe. In this figure, each point represents the average of the four measurements made through a particular port. Excluding the points near the outside walls, all three curves show a temperature variation across the boiler on the order of 200°F. The variation at 60 MWe is the greatest, and is likely due to the three mills in service operating condition.

Overall, it appears that the retrofit has resulted in a furnace exit gas temperature decrease on the order of 200°F. This has impacted the amount of excess air required to maintain steam temperature at reduced loads, and is also expected to impact the performance of the SNCR system.

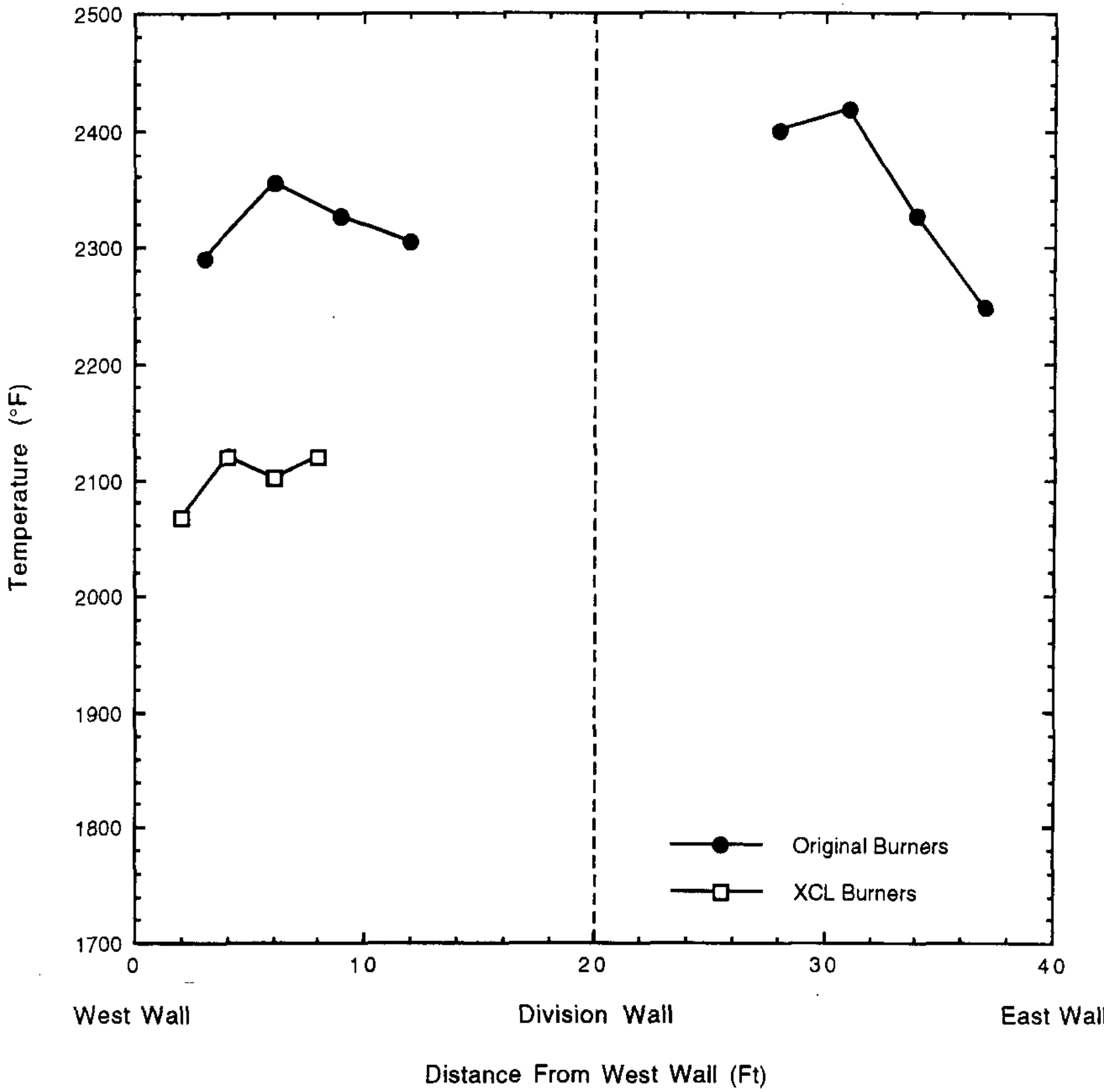


Figure 5-30. Pre- and Post-Retrofit Temperature Traverses at Location H (see Figure 4-6) for 80 MWe

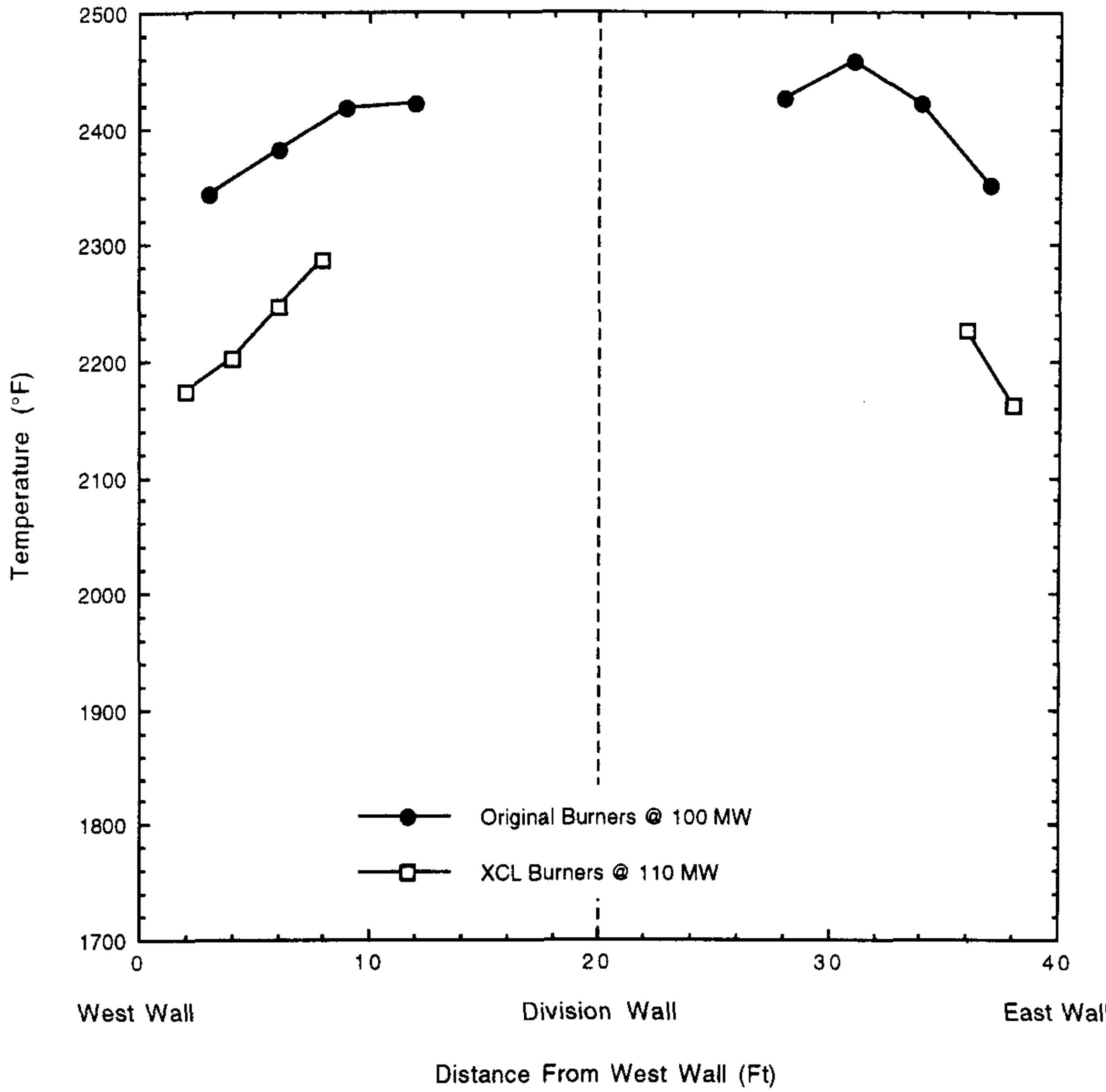


Figure 5-31. Pre- and Post-Retrofit Temperature Traverses at Location H (see Figure 4-6) for 100 MWe and 110 MWe (100 MWe pre-retrofit; 110 MWe post-retrofit)

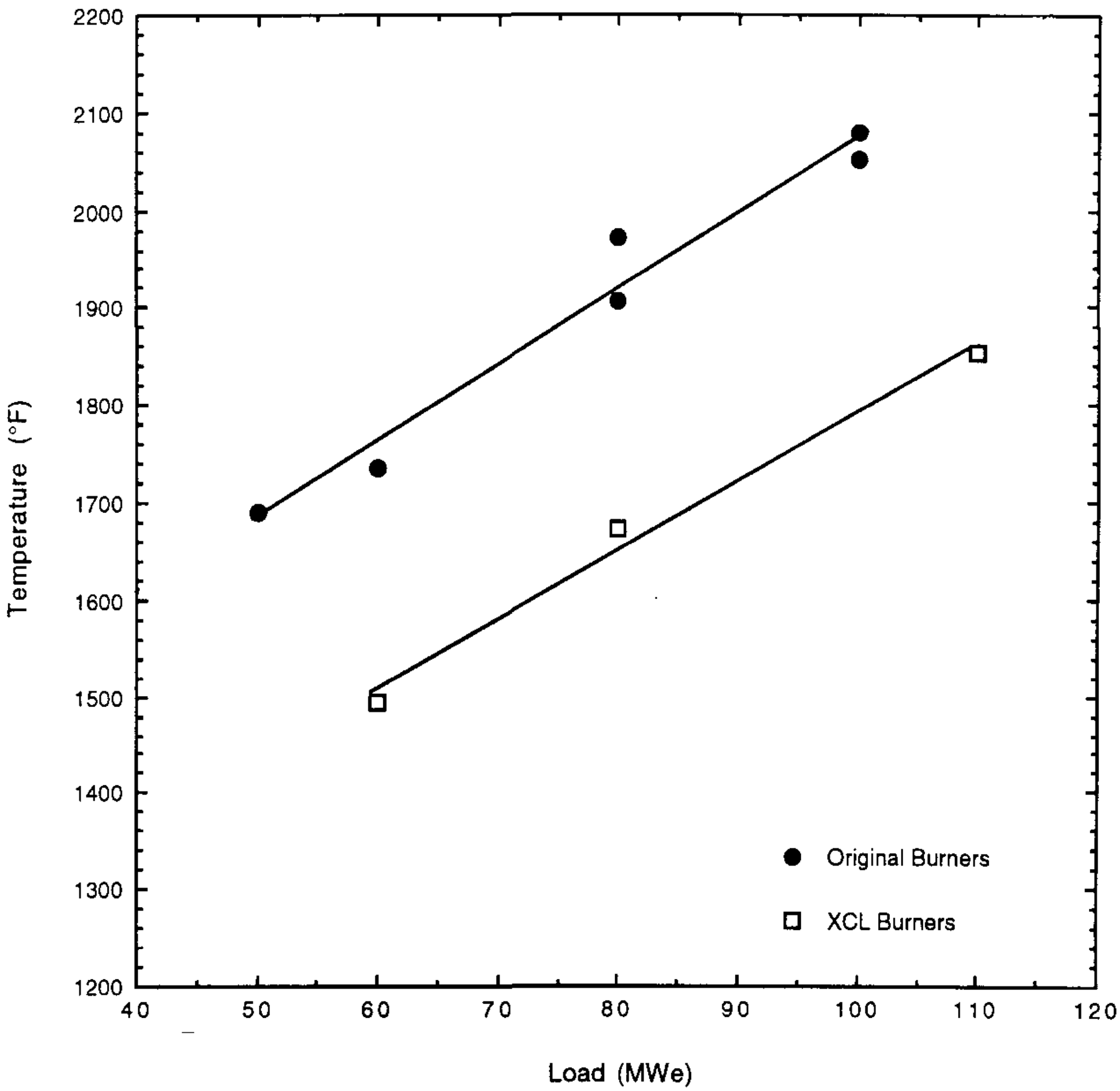


Figure 5-32. Pre- and Post-Retrofit North Port Average Temperatures as a Function of Boiler Load

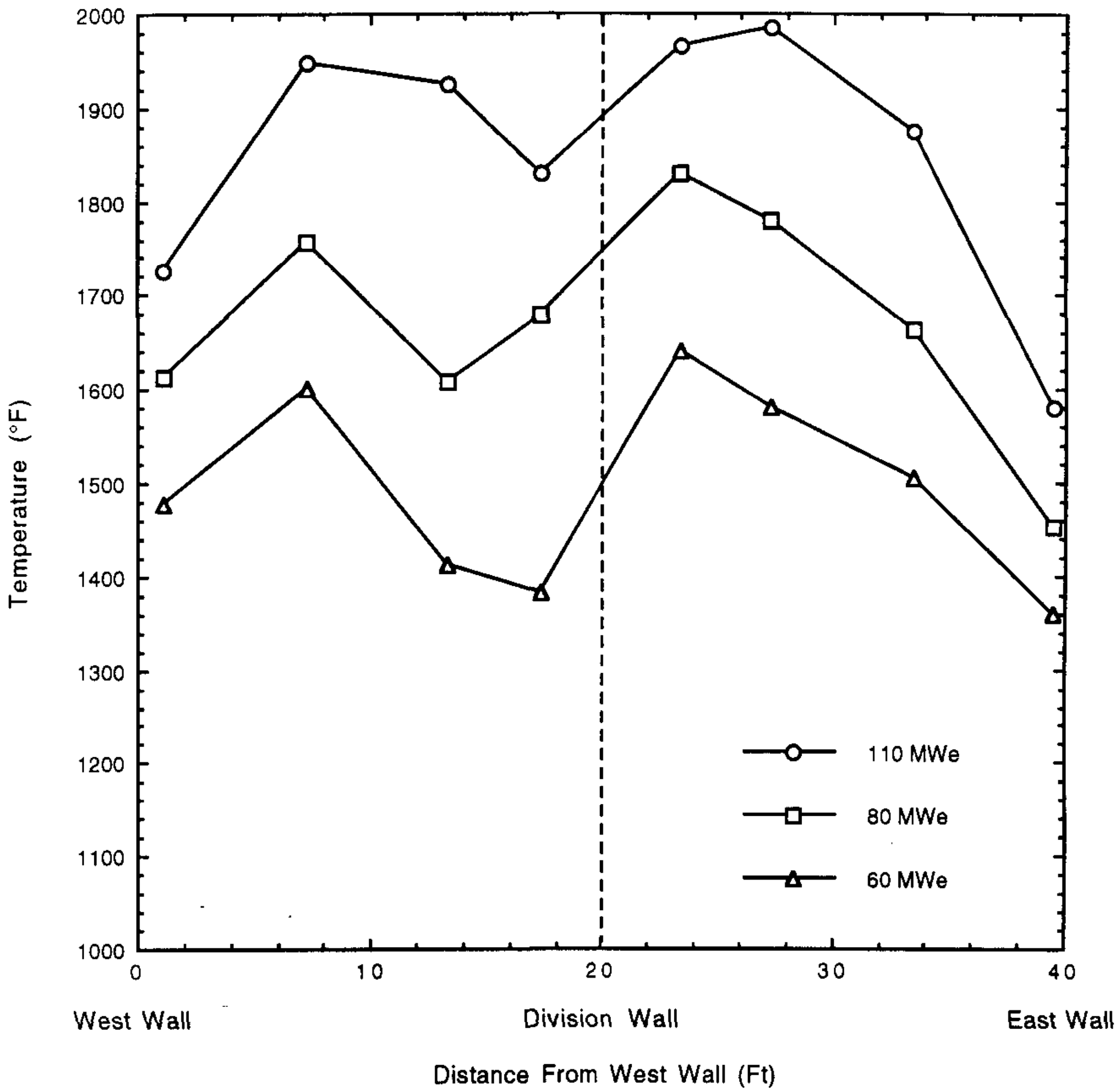


Figure 5-33. Post-Retrofit Average North Port Temperature Traverses at 60, 80, and 110 MWe

SO_3 Measurements

SO_3 levels can play an important role in the formation of corrosive deposits and corrosion of low temperature equipment. With the SNCR system in operation, SO_3 can react with NH_3 emissions to form ammonium sulfate and/or ammonium bisulfate. The formation of these compounds can lead to increased corrosion as well as air heater deposition. SO_3 can be formed directly from the fuel sulfur during the combustion process. Additionally, SO_3 can be formed by the oxidization of SO_2 downstream of the flame zone. In coal-fired systems, SO_3 can be absorbed into the flyash, which can mitigate some of the detrimental effects. For a western coal-fired utility boiler, the alkaline nature of the ash tends to promote SO_3 absorption, and therefore low levels of SO_3 may be expected.

SO_3 was measured at the economizer exit using the controlled condensation technique. Triplicate samples were taken through the 4-inch ports at the economizer exit shown in Figure 4-2. Tests were performed at 100 MWe with both maximum and minimum overfire air. The average results are presented in Table 5-5, where they are compared to the SO_3 measurements made during the baseline burner tests.

Table 5-5

Pre- and Post-Retrofit SO_3 Emissions at 100 MWe

Test	Overfire Air (%)	Port	O_2 (%)	SO_3[1] (ppm)	SO_3[1] (ppm)
10	Original Burners	Center	4.25	0.1	0.1
35	OriginalBurners	Center	4.70	0.1	0.1
370	24	Center	3.90	0.6	0.7
		West	3.63	0.3	0.3
371	24	Center	4.68	0.7	0.8
		West	3.83	0.5	0.5
378	15	Center	3.33	1.3	1.3
		West	5.88	1.3	1.6
379	15	West	5.22	0.7	0.8

[1] Average of triplicate test results

In general, all of the measured SO_3 levels in Table 5-5 are low (less than 1 ppm in nearly every case). Although the results indicate that the low-NO_x combustion system retrofit resulted in a slight increase in SO_3 emissions, it is very difficult to make a concrete conclusion with differences which are generally less than 1 ppm.

Particulate Mass Loading Measurements

Particulate mass loading and size distribution measurements were made at 100 MWe with both maximum and minimum overfire air. The measurements were performed by TRC Environmental Corp. at the inlet and outlet of the baghouse, and the test report (without its associated appendices) is attached to this report as Appendix C. TRC also performed similar measurements during the baseline burner tests. The average inlet and outlet mass loading results for the two overfire air conditions are tabulated and compared to those for the original burners in Table 5-6.

Table 5-6

Summary of Pre- and Post-Retrofit Particulate Mass Loading Results at 100 MWe

Parameter		Baghouse Inlet			Baghouse Outlet		
		XCL Burners w/25% OFA	XCL Burners w/15% OFA	Baseline Burners	XCL Burners w/25% OFA	XCL Burners w/15% OFA	Baseline Burners
Concentration (gr/DSCF)	Test 1	2.44	1.33	1.87	0.0014	0.0027	0.0002
	Test 2	3.26	2.49	2.31	0.0016	0.0014	0.0011
	Test 3	2.72	---	---	0.0017	0.0006	---
	Average	2.81	2.49(1)	2.09	0.0016	0.0006(1)	0.0007
Emissions (lb/hr)	Average	5635	5186(1)	3935	3.16	1.29(1)	1.42
Collection Efficiency (%)		---	---	---	99.94	99.98	99.96

(1) Averages based on one test only, due to significant variations in coal properties.

EPA Method 17 was used for the mass loading determinations during the baseline burner tests. However, after review of the results, PSCC indicated that the outlet loadings appeared to be lower than expected for Arapahoe Unit 4. Although a review of the measurements did not uncover any significant discrepancy, prior measurements by PSCC using EPA Method 5 sampling had indicated a particulate loading at the baghouse outlet closer to 9 to 10 lb/hr at full load. Although there should be no difference in the results obtained from the two methods in a coal-fired application, EPA Method 5 was used during the current phase of testing at the request of PSCC.

An effort was made to obtain a triplicate series of tests at each sampling location and overfire air condition during the post-retrofit particulate characterization. This was not possible at the inlet condition with minimum overfire air due to an emergency load increase requested by the PSCC system dispatch center. The individual inlet and outlet results for the minimum overfire air condition show significantly more scatter than those for the maximum overfire air case. The minimum overfire air tests were run over a period of two days, and a review of the gaseous data collected during this time indicated that the SO_2 emissions were approximately 25 percent higher on the first day than on the second, which suggested a change in coal properties. The results of the laboratory analysis of the raw coal sample collected on that particular day (October 26, 1992) was shown in Table 5-1, along with the analysis results for four other samples collected during the parametric tests. The sample in question had sulfur and ash contents which were 34 percent higher and 20 percent lower, respectively, than the average of the other four samples. The magnitude of these variations was sufficient reason to question the mass loading measurements performed on the first day of the minimum overfire air tests. Although the results of these tests are shown in Table 5-4, the average concentration and emission values are based only on the tests performed on the following day when the SO_2 emissions were back within the normal range.

The data in Table 5-6 show that the inlet grain loadings are on the order of 20 to 30 percent higher with the retrofit combustion system. This would be consistent with the lower measured furnace exit gas temperatures, which suggest less slag accumulation in the radiant section of the furnace. The outlet concentrations show that baghouse collection efficiency was unaffected by the retrofit, with efficiencies for both the maximum and minimum overfire air conditions exceeding 99.94 percent.

Particulate Size Distribution Measurements

Inlet and outlet particulate size distributions were measured by two different methods. A cascade impactor was used for the baghouse inlet measurements, while EPA Method 201A was used to determine the PM_{10} emissions at the baghouse outlet.

A University of Washington Pilat Mark V cascade impactor with a right angle precutter was used to obtain the inlet size samples. The impactor has a maximum aerodynamic cutpoint of 15.9 microns. In order to obtain the size distribution above the maximum cutpoint, the data are extrapolated with a standard impactor cubic spline fit program. During the baseline tests, a program supplied by the University of Washington was used to provide the extrapolation. Since that time, the program pcCIDRS (written by J. McCain of Southern Research Institute) has been released and is becoming regarded as the best impactor spline fit program available. The post-retrofit particulate size data were reduced using the pcCIDRS program, and in order to provide an accurate basis for comparison, the baseline data were rerun through the same program.

A total of five separate impactor runs were made at the maximum overfire air condition at the baghouse inlet. The additional runs were conducted due to a "heavy loading" on the initial impactor stages for the second and third tests. After reducing the data, these two runs were combined into the overall average, as the results indicated similar trends. Three tests were conducted at the minimum overfire air condition.

The average differential particle size distribution for the baseline tests, as well as those for the retrofit tests, with maximum and minimum overfire are shown in Figure 5-34. In this figure, the quantity dM/dlogD50 refers to the change in mass with respect to the log of the diameter. The baseline distribution is wider than either of the retrofit distributions, with a significant amount of mass found above 100 microns. Although the

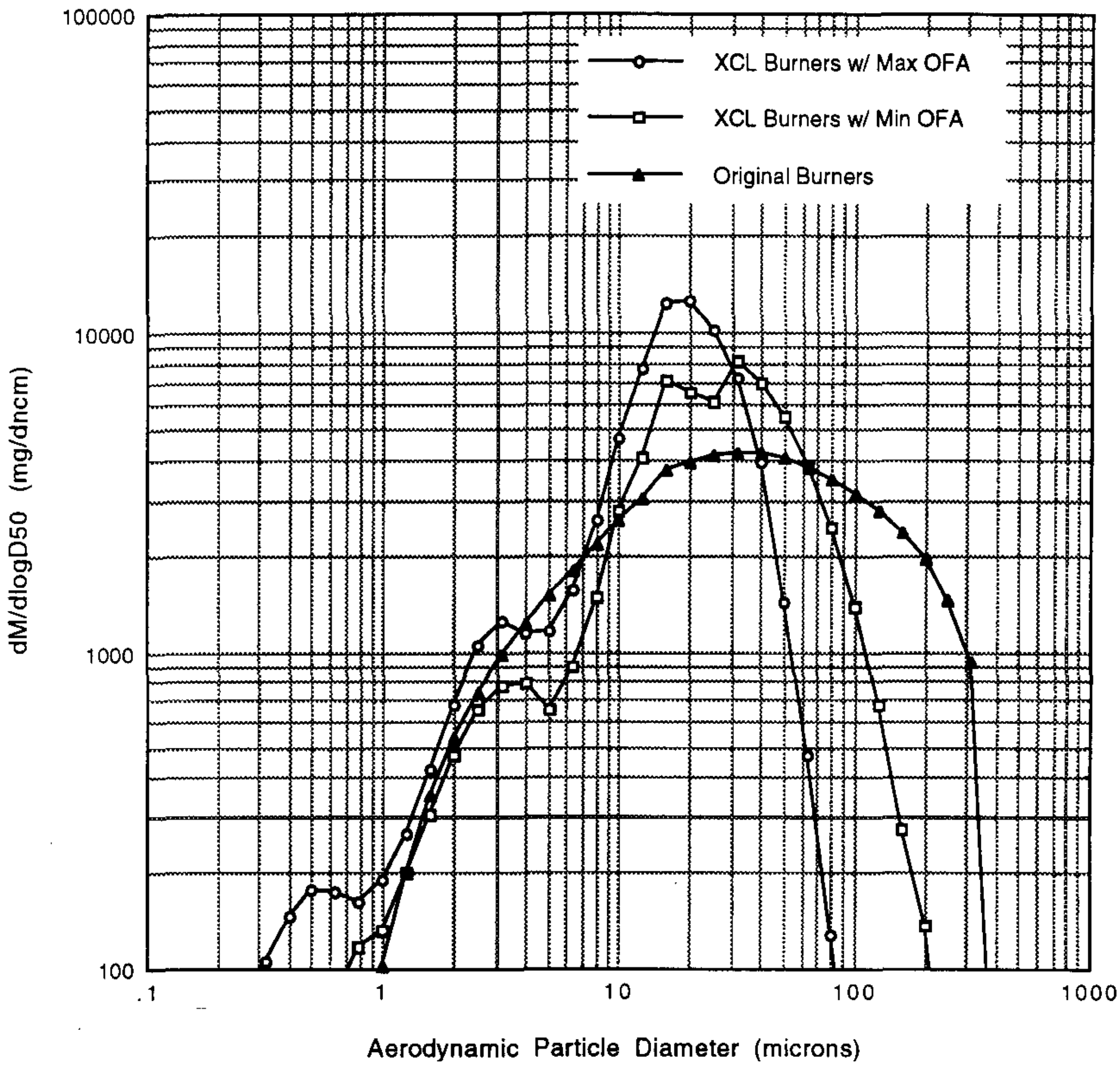


Figure 5-34. Pre- and Post-Retrofit Baghouse Inlet Differential Particle Size Distributions at 100 MWe

shapes of the maximum and minimum overfire air distributions are similar, the minimum overfire air case is shifted to slightly higher diameters.

The mass mean diameter (MMD) for each condition can be determined from the cumulative particle size distributions, shown in Figure 5-35. MMD's of 31, 26 and 18 microns were measured for the baseline burner, and minimum and maximum overfire air cases, respectively. The decrease in MMD after the retrofit may be attributed to many different effects. The improved fuel/air mixing may have improved carbon burnout, or it may have caused more of the larger diameter particles to be caught in the slag layer on the furnace walls. The decrease may also have been due to improved mill operation, since the fineness test results (Figures 5-1 to 5-3) showed that the mills were operating more consistently after the retrofit. Unfortunately, there is not enough data available to indicate precisely which effect is responsible.

Baghouse exit PM_{10} measurements determine the particulate matter (PM) emissions which are attributable to particles having an aerodynamic diameter equal to or less than 10 microns. This determination (EPA Method 201A) is made through a combination of an EPA Method 17 mass measurement and an impactor size measurement. In addition to the solid particulate matter included in these mass emissions, Method 201A also includes "condensible" particulate emissions from the impinger washes. The condensible emissions are recovered from the washes by drying the collected water and weighing the residue. These additional condensible emissions are added to the sub-10 micron solid emissions determined from the impactor and Method 17 measurements.

A total of three separate tests were conducted at the maximum overfire air condition at the baghouse outlet. Minimum overfire air tests were not performed, due to the emergency load increase requested by the PSCC system dispatch center. A University of Washington Pilat Mark III cascade impactor with a right angle precutter was used to obtain the outlet size samples. The Mark III impactor has fewer "stages" than the Mark V impactor used for the inlet size measurements. A greater number of stages was necessary at the inlet in order to avoid overloading the initial stage when sampling at

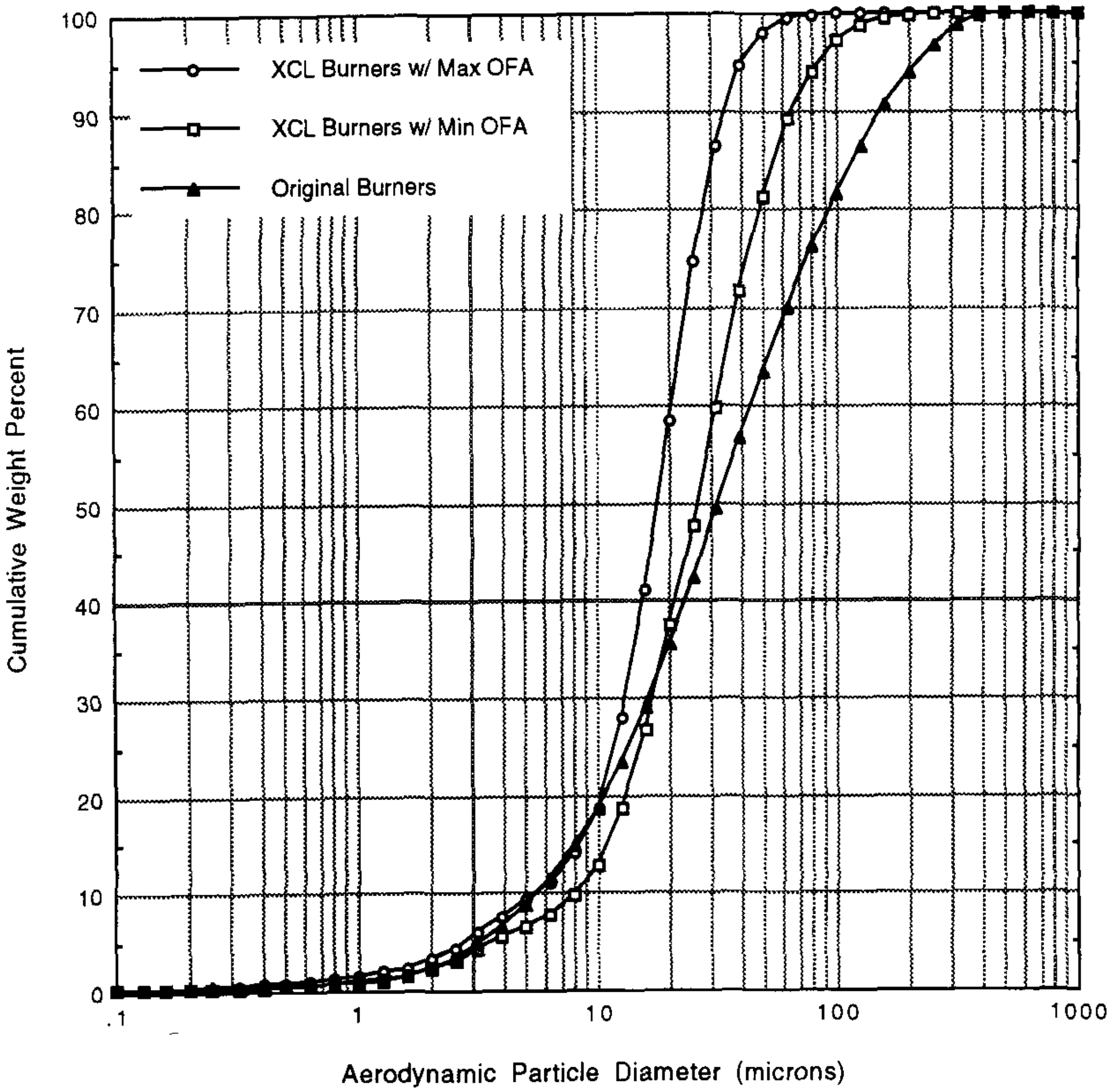


Figure 5-35. Pre- and Post-Retrofit Baghouse Inlet Cumulative Particle Size Distributions at 100 MWe

the higher particle densities. Unfortunately, during the analysis of all three outlet samples, the back-half (condensible) fractions could not be quantified due to the formation of a residual organic in the final wash. With this occurrence, the final weights could not be achieved, and a "true" condensible fraction could not be quantified.

Table 5-7 presents a summary of the baghouse outlet PM_{10} measurements conducted during the baseline and post-retrofit combustion system tests. Although analytical interferences did not affect the quantification of the condensible fractions during the baseline tests, only the non-condensible PM_{10} fractions are reported in the table for a direct comparison to the post-retrofit measurements.

In an effort to enhance the particulate collection efficiency and sensitivity over that seen during the baseline tests, each individual post-retrofit PM_{10} test was conducted over an extended period of time (three hours versus two hours). However, the results indicate nearly an order of magnitude decrease in PM_{10} emissions for the retrofit combustion system with maximum overfire air. A decrease of this magnitude was not expected since the outlet mass loading measurements (Table 5-6) showed higher mass emissions for the maximum overfire air case, and the inlet cumulative particle size distributions (Figure 5-35) show that for both the baseline and maximum overfire air cases, 18 percent of the collected mass was found below 10 microns. In reviewing the PM_{10} results, however, it should be emphasized that during both the pre- and post-retrofit tests, only a very small amount of mass was collected, with the total mass from all the stages being on the order of only 1 to 3 mg. For a more accurate particle size measurement, it would be desirable to have approximately 5 mg per stage or about 40 mg overall. Substantially extended runs (possibly up to 24 hours in duration) may be required to collect sufficient PM_{10} mass for accurate and reproducible data.

Table 5-7

Summary of Pre- and Post-Retrofit Baghouse Outlet PM_{10} Results at 100 MWe

BASELINE BURNERS

		Test 1	Test 2	Average
Temperature (°F)		268.0	253.0	260.5
Sample Volume (DSCF)		60.81	60.29	60.55
Gas Velocity (ft/sec)		42.87	40.41	44.42
Volumetric Flow Rate (ACFM)		473,576	461,168	467,372
Volumetric Flow (DSCFM)		254,180	255,547	254,864
Stage	Cutpoint	Mass Collected (milligrams)		
1	15.927 micron	2.72	0.73	1.73
2	9.438 micron	0.06	0.15	0.11
3	3.519 micron	0.17	0.14	0.16
4	1.824 micron	0.04	0.12	0.08
5	1.012 micron	0.00	0.10	0.05
6	0.469 micron	0.07	0.08	0.08
7	0.151 micron	0.62	0.88	0.75
Non-Condensible (NC) Fraction (In-stack)				
Mass Collected (mg)		3.68	2.20	2.94
Mass Collected (mg) < 10 micron		0.96	1.47	1.22
Percent < or = 10 micron		26.09%	66.82%	46.45%
Total Impactor (< 15.927 micron)				
NC PM_{10} Conc. (g/DSCF)		6.05E-05	3.53E-05	4.79E-05
NC PM_{10} Conc. (gr/DSCF)		9.34E-04	5.45E-05	4.94E-04
NC PM_{10} Emission Rate (lbs/hr)		2.0339	1.2186	1.6263
From Impactor Stage 2 (< 9.438 micron)				
NC PM_{10} Conc. (g/DSCF)		1.58E-05	2.34E-05	1.96E-05
NC PM_{10} Conc. (gr/DSCF)		2.44E-04	3.61E-04	3.03E-04
NC PM_{10} Emission Rate (lbs/hr)		0.5308	0.7906	0.6070

XCL BURNERS W/25% OFA

		Test 1	Test 2	Test 3	Average
Temperature (°F)		270.3	255.1	258.0	273.0
Sample Volume (DSCF)		75.883	79.124	76.723	77.243
Gas Velocity (ft/sec)		41.37	40.41	42.44	44.42
Volumetric Flow Rate (ACFM)		456,681	446,087	468,522	454,705
Volumetric Flow (DSCFM)		258,465	260,872	271,867	251,248
Stage	Cutpoint	Mass Collected (milligrams)			
1	16.617 micron	1.39	0.42	1.04	0.950
2	10.541 micron	0.13	0.07	0.14	0.113
3	3.949 micron	0.00	0.02	0.12	0.047
4	2.106 micron	0.00	0.00	0.03	0.01
5	1.199 micron	0.00	0.00	0.00	0.00
6	0.577 micron	0.00	0.00	0.00	0.00
7	0.204 micron	0.00	0.00	0.00	0.00
Non-condensible (NC) Fraction (In-stack)					
Mass Collected (mg)		1.52	0.51	1.33	1.12
Mass Collected (mg) < 10 micron		0.13	0.09	0.29	0.17
Percent < or = 10 micron		8.55%	17.65%	21.80%	15.80%
Total Impactor (< 16.617 micron)					
NC PM_{10} Conc. (g/DSCF)		2.00E-05	6.45E-06	1.73E-05	1.46E-05
NC PM_{10} Conc. (gr/DSCF)		3.09E-04	9.95E-05	2.25E-04	2.25E-04
NC PM_{10} Emission Rate (lbs/hr)		0.6584	0.2225	0.6245	0.5108
From Impactor Stage 2 (< 10.541 micron)					
NC PM_{10} Conc. (g/DSCF)		1.17E-06	1.14E-06	3.78E-06	2.21E-06
NC PM_{10} Conc. (gr/DSCF)		2.65E-05	1.76E-05	5.83E-05	3.41E-05
NC PM_{10} Emission Rate (lbs/hr)		0.0586	0.0393	0.1360	0.0779

6

NATURAL GAS FIRING

Arapahoe Unit 4 is generally fired with a low-sulfur Colorado bituminous coal, but has the capability to fire 100 percent natural gas. A brief series of tests (8 hours total test time) was conducted to ensure that the boiler could maintain full load with the retrofit combustion system, as well as document the NO and CO emissions under gas-fired conditions. As natural gas firing was not included as part of the detailed test plan, no baseline data with the original burners was available for comparison. With natural gas, the flame zone is shorter and less luminous than that for coal firing. This results in a lower radiant heat loading on the overfire air ports, and therefore, a lower minimum overfire air flow can be achieved before port metal temperatures become a concern.

Figure 6-1 shows the effect of excess O_2 and overfire air on NO emissions for gas firing at 100 MWe. Two things are noteworthy with natural gas firing compared to coal firing. First, with natural gas there is a large effect of overfire air on NO emissions. The data show that NO emissions decrease by approximately 55 percent as the overfire air flow is increased from minimum to maximum for a given excess O_2 level. This effect is attributed to a more rapid mixing of fuel and air in the near-burner region. Second, the data also show that overfire air has an effect on the sensitivity of NO emissions to changes in excess O_2 (recall that with coal firing little effect was observed). At the minimum overfire air condition, the sensitivity is on the order of 115 ppm NO per percent of O_2.

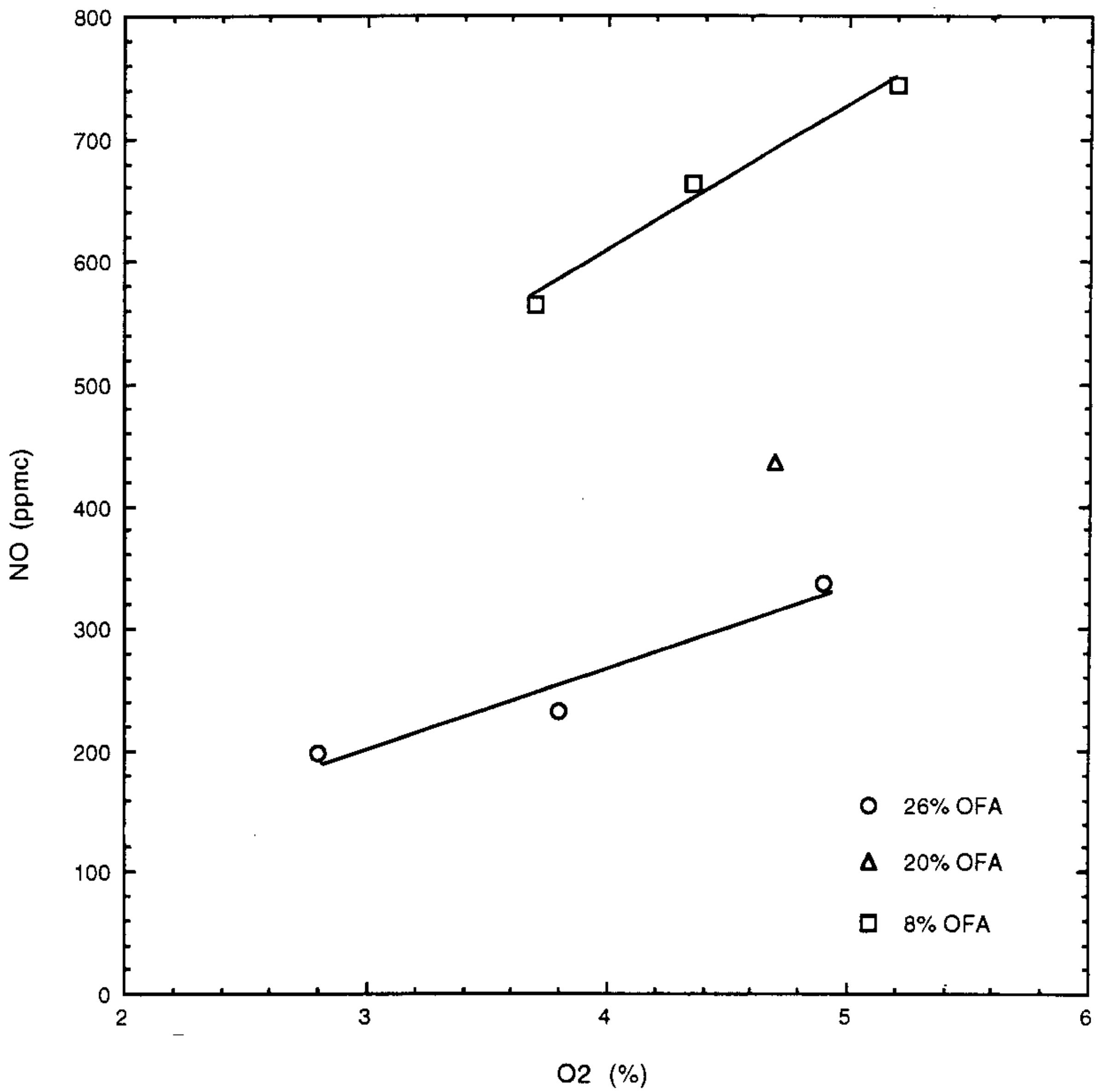


Figure 6-1. Effect of Excess O_2 and Overfire Air on NO Emissions for Natural Gas Firing at 100 MWe

When the overfire air is increased to the maximum level, the sensitivity is reduced to approximately 65 ppm per percent.

As mentioned above, the flame zone with natural gas is much shorter than that for coal firing. This results in a more compact near-burner region, and therefore, a better separation of the mixing effects of the burners and overfire air ports. This can be more clearly seen in Figure 6-2, where the NO emissions are shown as a function of burner stoichiometric ratio. With natural gas firing, the NO emissions show a strong dependency on burner stoichiometry. Whereas with coal firing, only a weak dependency was seen (recall Figure 5-12).

The effect of excess O_2 and overfire air on CO emissions for full load, natural gas firing is shown in Figure 6-3. The data show that increasing the overfire air at a fixed excess O_2 level results in increased CO emissions. This is more in line with the expected effect of a large scale staging of the fuel and air in the furnace, and is again, different from the behavior seen with coal firing. However, the increase in CO emissions is very small in comparison to reduction in NO emissions, and therefore, maximum overfire air still provides the "optimum" performance.

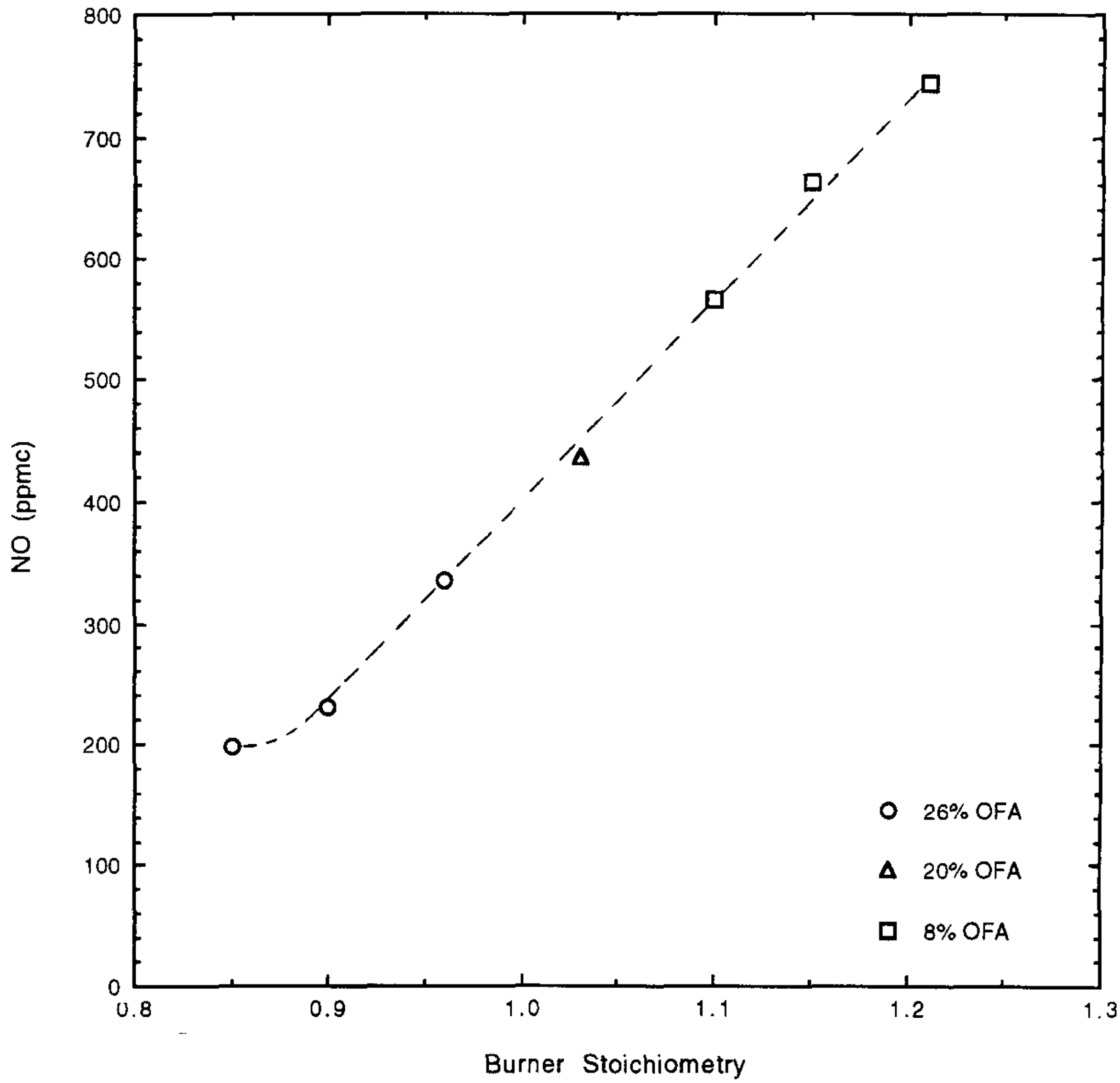


Figure 6-2. Effect of Burner Stoichiometric Ratio on NO Emissions for Natural Gas Firing at 100 MWe

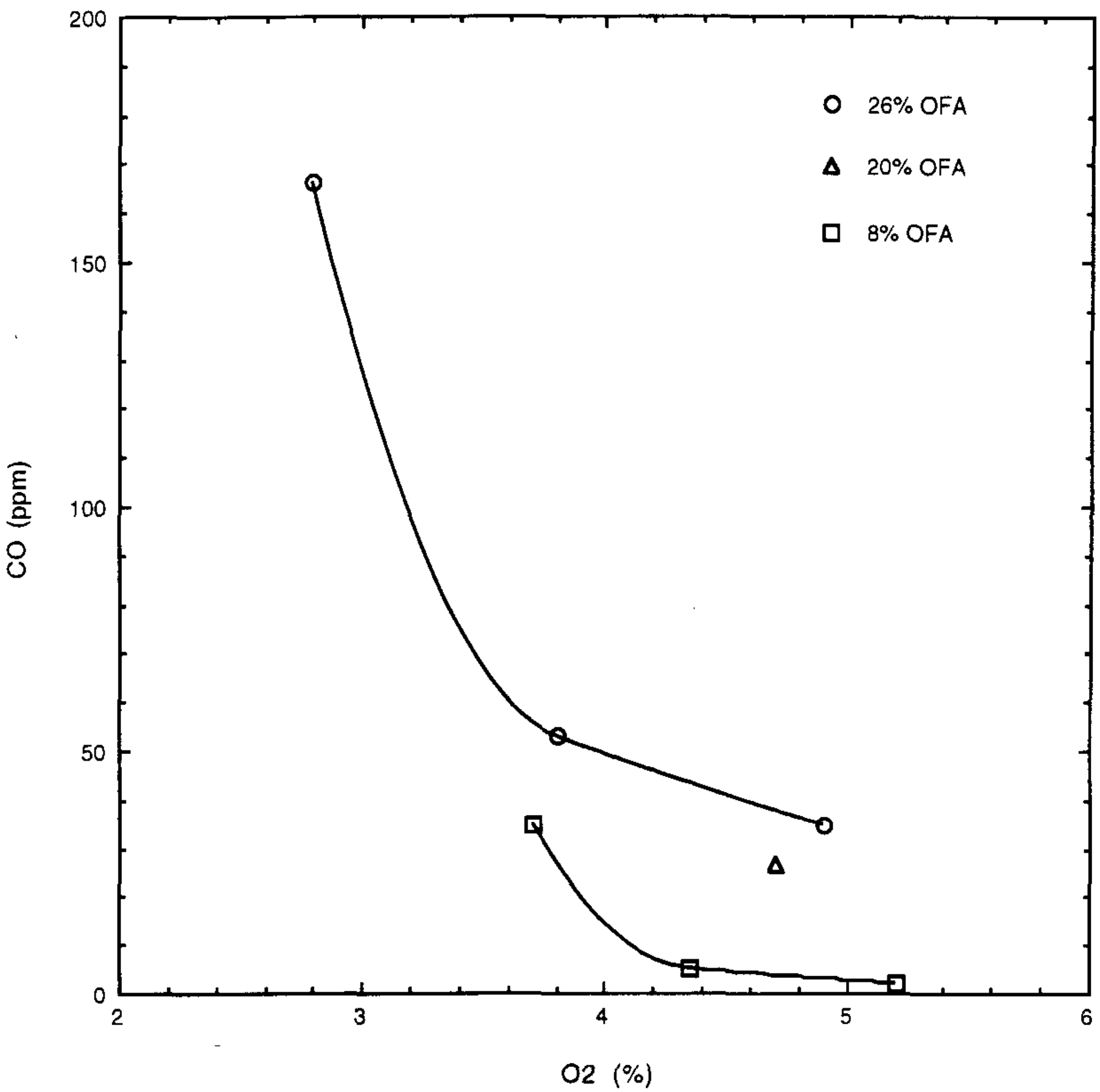


Figure 6-3. Effect of Excess O_2 and Overfire Air on CO Emissions for Natural Gas Firing at 100 MWe

7

LONG TERM LOAD FOLLOWING TEST RESULTS

The results of the parametric tests presented in the previous section were obtained at baseloaded operating conditions with testing personnel closely monitoring all boiler variables. However, Arapahoe Unit 4 is generally operated in a load following mode under automatic control. Under these conditions, oxygen levels can vary significantly and rapidly. This mode of operation tends to increase CO emissions and can also lead to higher NO emissions. Immediately following completion of the baseloaded parametric tests, the boiler was operated for two months (November and December 1992) under normal load following conditions. There were no test personnel on site during this time, so data were collected automatically with the CEM alternating between the two heated sampling locations at the air heater exit and stack. PSCC personnel monitored daily CEM calibrations and data collection to ensure accuracy of the data. The long term data presented here are from the stack location, and have been corrected to dry conditions for comparison to the results from the parametric tests.

Figure 7-1 shows a comparison of the NO emissions during baseloaded and load following operation. The CEM was programmed to calculate and record 10-minute averages for all the measured gas species, as well as boiler load. The load following data presented in Figure 7-1 are averages of all of the 10-minute CEM averages which are within a 10 MWe range (i.e., the 100 MWe data point is the average of all of the

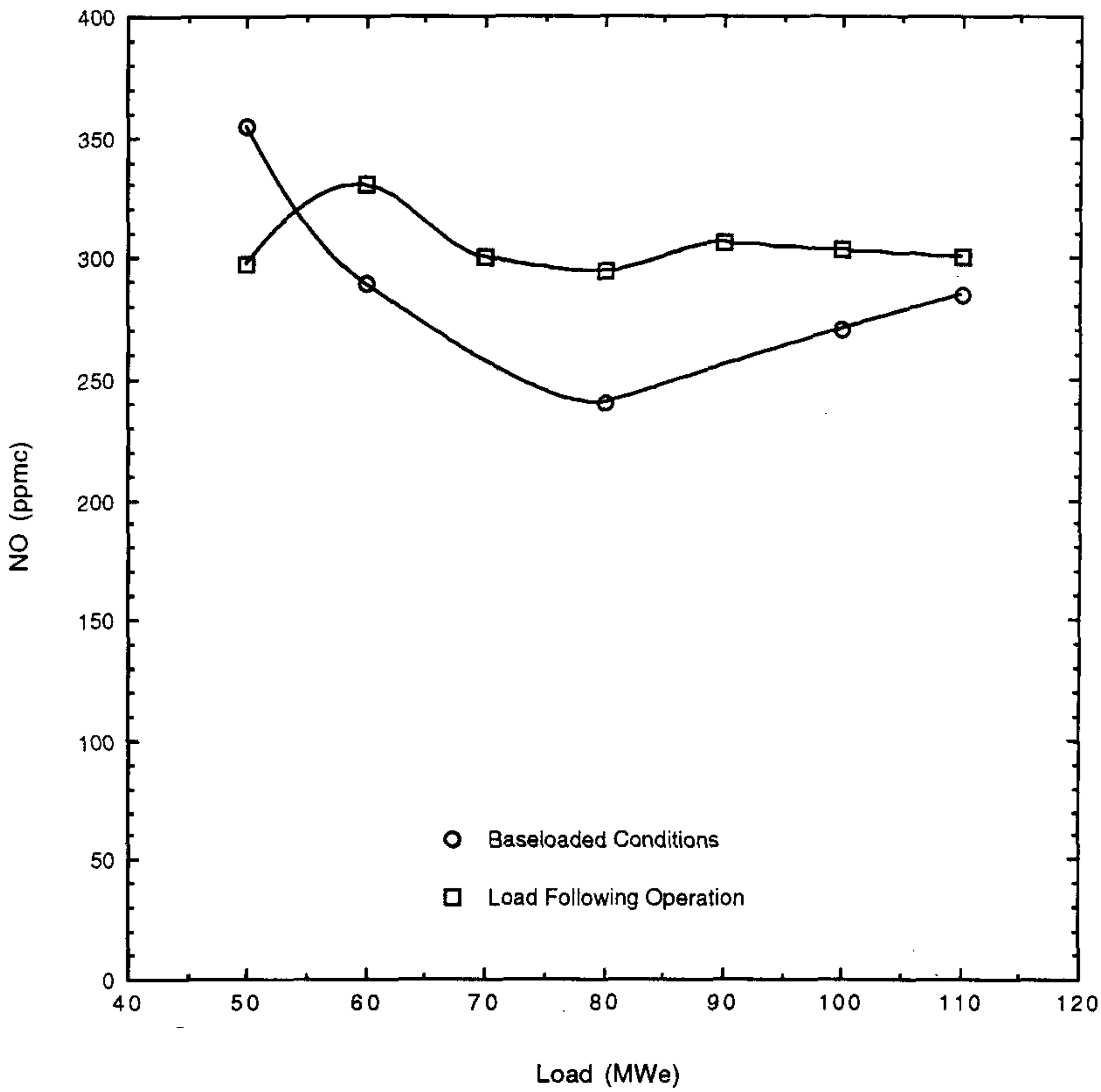


Figure 7-1. Comparison of NO Emissions for Baseloaded and Load Following Operation

CEM points between 95 and 105 MWe). In general, the data show that the NO emissions are 10 to 20 percent (30 to 60 ppm) higher under load following conditions. The increase is likely due to the higher excess O_2 levels which are maintained during normal load following operation. Figure 7-2 shows a comparison of the excess O_2 levels maintained during baseload and load following operation. Although the baseload and load following data were collected at two different locations (the economizer exit and stack, respectively), any error due to air in-leakage between the two is not a concern. During the majority of the parametric tests, data were collected at the air heater and stack sampling locations, as well as at the economizer exit. Review of the average O_2 data from these tests showed that there was negligible in-leakage downstream of the economizer exit at all boiler loads. This was expected since nearly all of the sootblower openings and observation doors are located upstream of the economizer exit sampling location. The results in Figure 7-2 show that, in general, excess O_2 levels are 1 to 1.5 percent higher during load following operation. The NO/O_2 sensitivity with the new low-NO_x burners (40 ppmc NO per percent O_2) is most probably responsible for the increase in NO emissions.

It would be reasonable to assume that the 1 to 1.5 percent increase in excess O_2 levels would result in reduced, or at least similar, CO emissions under load following conditions. However, as shown in Figure 7-3, the CO emissions increased dramatically, most notably at the upper and lower thirds of the load ranges. The increases are likely due to a combination of a number of effects. First, as stated above, load following operation often entails significant and rapid changes in air and fuel flow rates. If the fans do not respond as quickly as the coal feeders, as is often the case, the overall boiler stoichiometry may temporarily decrease during a rapid load increase until the fans catch up with the feeders. Second, the baseloaded parametric data at 80 and 100 MWe were collected with all four mills in operation. Three mill operation at these loads is not uncommon, and it was previously shown that this operating condition results in substantial increases in CO emissions (Figures 5-17a and 5-19a). Data are not

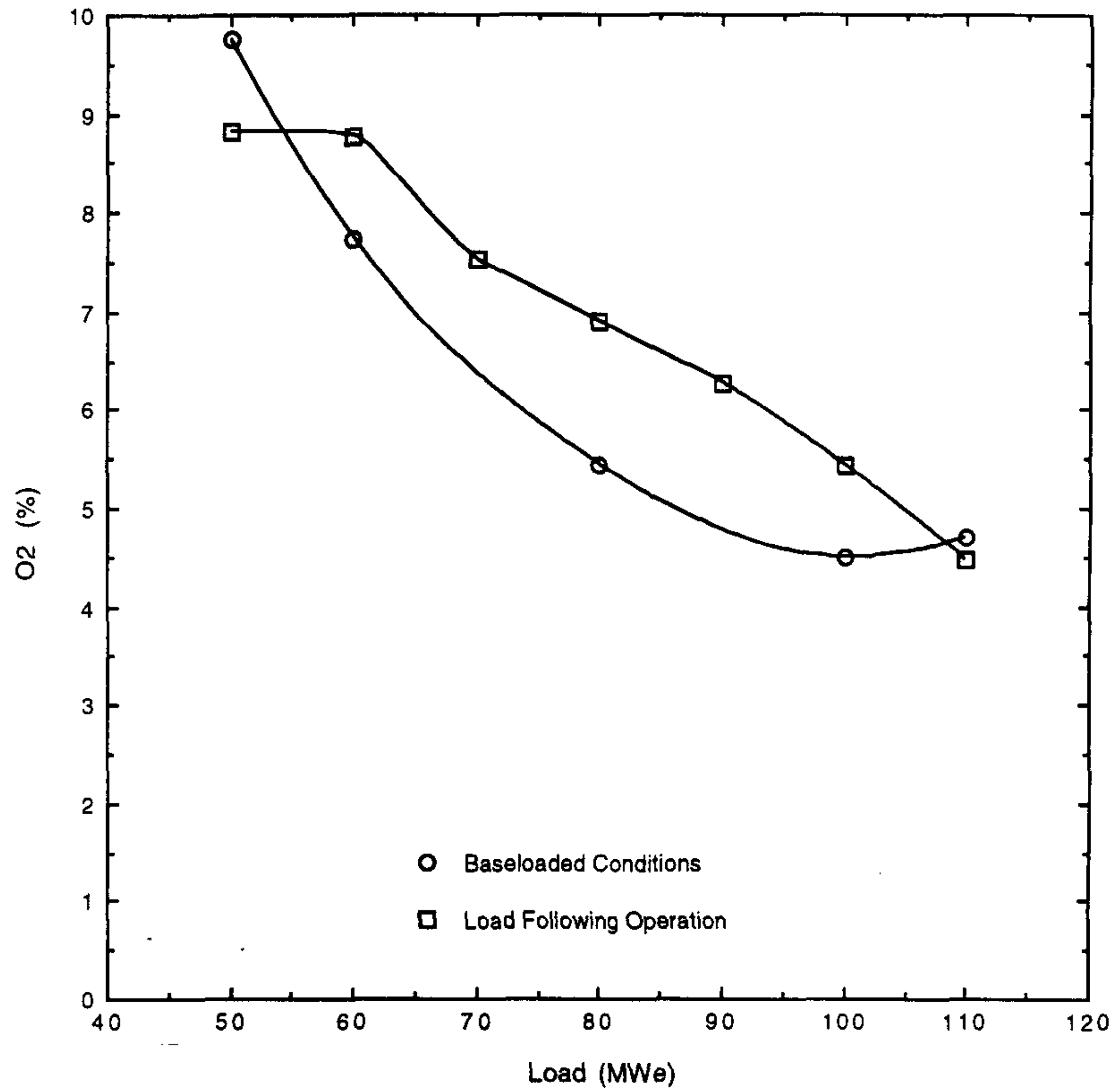


Figure 7-2. Comparison of Excess O_2 Levels for Baseloaded and Load Following Operation

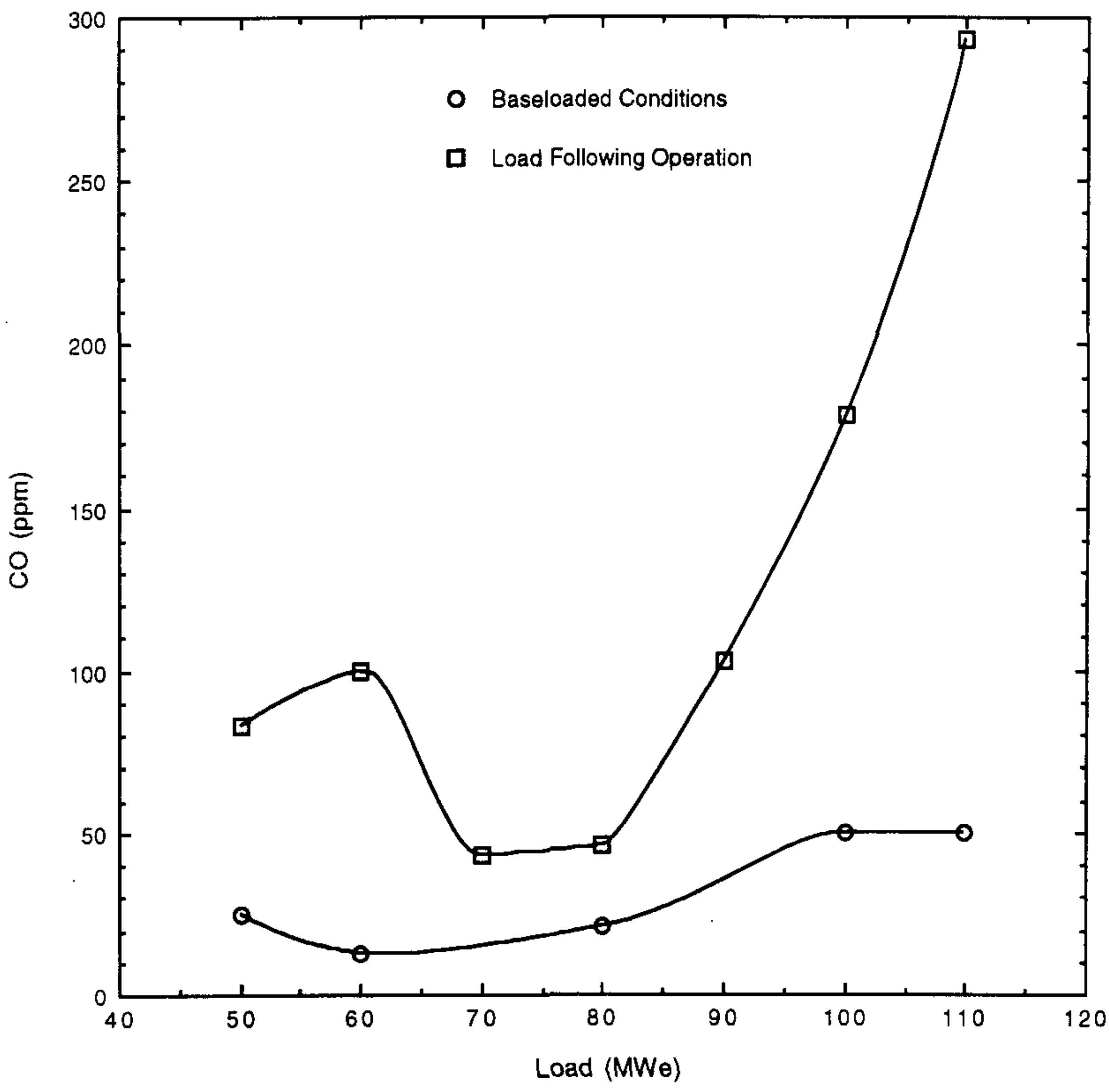


Figure 7-3. Comparison of CO Emissions for Baseloaded and Load Following Operation

available to track which mills were in operation during the load following tests, so this effect could not be investigated further. The increased CO emissions at 110 MWe cannot be attributed to three mill operation, but are likely due in part to the lower excess O_2 level maintained during the load following tests (Figure 7-2).

The increased CO emissions at 50 and 60 MWe may be due to a third effect, which resulted from a combination of an operational change occasionally made in an effort to maintain adequate steam temperatures at reduced loads, and the inability of the four PSCC O_2 probes at the economizer exit to accurately assess the O_2 levels near the outside walls. During the long term tests, plant personnel found that steam temperatures at low loads could be increased, without increasing the O_2 trim setpoint, by partially closing the overfire air control dampers. It was believed that the total air flow had remained constant with this change, since the O_2 trim setpoint had not been moved. The increase in steam temperature was attributed to a "vertical" redistribution of the air within the furnace. After the conclusion of the load following tests, this effect was investigated further, and it was found that the higher steam temperatures were in fact due to an increase in total air flow resulting from a "horizontal" redistribution of the overfire air. As discussed previously, when the amount of overfire air is reduced by closing the control dampers, the penetration of the air toward the furnace division wall also decreases. This results in a distribution of more of the air in the regions near the outside walls where it is not seen by the two outermost PSCC O_2 probes (Figure 4-3). This redistribution is perceived as a decrease in O_2 by the control system, and the total air flow is increased in an effort to "maintain" the O_2 trim setpoint. The increase in air flow results in better heat transfer in the convective section, hence higher steam temperatures. Although the effect of variations in overfire air flow was not investigated at 50 and 60 MWe, the results at 80 MWe and above have shown that decreases in overfire air result in significant increases in CO emissions (Figures 5-13a, 5-14a, and 5-15a). Since the overfire air damper settings are not currently recorded on the DCS, their position during the long-term tests cannot be verified.

A final effect which may have contributed to the increased CO emissions under load following operation is also related to the distribution of the overfire air across the furnace. During the parametric tests, small adjustments in the position of the overfire air control dampers were often necessary throughout a test day to maintain relatively equal air flow to the east and west sides of the furnace. It was found that an imbalance of 10 to 15 percent could lead to a local O_2 deficiency on one side of the division wall as a result of reduced overfire air penetration on that particular side. The local O_2 deficit would lead to an area of very high CO and, therefore, an increase in the average CO emissions. During the load following tests, the overfire air control dampers were operated manually as an automatic control function had not yet been defined. PSCC control operators changed damper position as they felt appropriate, but likely did not carefully balance the flow between the east and west sides. This potential imbalance in air flow may have resulted in an increase in average CO emissions across the load range. In fact, the operators were not aware of CO emissions as the CO concentration was not displayed in the control room during the test period, and thus no effort was made to minimize CO emissions.

It is recommended that the automatic control system be programmed so that the overfire air control dampers are positioned in such a manner as to balance the flow between the east and west sides of the furnace. It is also recommended that the control operators be made aware of CO emissions and attempt to correct operational problems which lead to conditions of high CO emissions. However, it is not expected that the CO levels under load following conditions will be reduced to levels comparable to those measured during the baseloaded parametric tests without an increase in the operating excess air level in order to compensate for the rapid increases in load and operation with a reduced number of mills in service.

8

OBSERVATIONS AND RECOMMENDATIONS

Observations

The following observations can be made regarding the performance of the retrofit low NO_x combustion system on Arapahoe Unit 4.

- NO reduction during baseloaded operation ranged from 63 to 69 percent, depending on boiler load.
- CO emissions and flyash carbon levels did not increase during baseloaded operation as a result of the combustion system retrofit.
- The NO/O_2 sensitivity of the new combustion system (40 ppm/percent O_2) was much less than that for the original burners (145 ppm/percent O_2).
- The results indicate that over the range of overfire air flow rates investigated (15 to 24 percent), the majority of the NO reduction was obtained with the low-NO_x burners, as the overfire air system was shown to provide little additional NO reduction at equivalent excess air levels. However, since port temperature limitations precluded testing at overfire air flow rates below 15 percent, it was not possible to totally separate the effects of the low-NO_x burners and the overfire air system.
- Significant reductions in CO emissions and flyash carbon levels were seen with increasing overfire air flow rates. This was contrary to what was expected, and is attributed to increased overfire air penetration and mixing at the higher flow rates.
- NO emissions increased by up to 20 percent during normal load following operation when compared to baseloaded conditions. The increase was due to the higher excess O_2 levels normally maintained during load following operation.

- CO emissions increased substantially during normal load following operation when compared to baseloaded conditions. Part of the increase was due to maldistributions of the overfire air, which will be corrected in the future. The remainder of the increase was due to variations in boiler operating parameters which are inherent in load following operation.

- No major operating problems have developed due to the boiler modifications, although the retrofit combustion system has resulted in a decrease in furnace exit gas temperature of approximately 200°F. This has resulted in an increase in the amount of excess air required to maintain adequate steam temperatures at reduced boiler loads (approximately 0.7 percent excess O_2 at 80 MWe, and 2.0 percent excess O_2 at 60 MWe). The reduced temperatures are also expected to impact the performance of the SNCR system.

- Limited testing showed that, while firing natural gas, increases in overfire air flow result in decreased NO emissions and higher CO emissions. This NO/CO relationship was different from that seen for coal firing, and was attributed to a separation of the mixing effects of the low-NO_x burners and overfire air ports due to the shorter combustion zone under gas fired conditions.

Recommendations

Based on the tests conducted to date, the following recommendations can be made regarding operation of Arapahoe Unit 4 with the retrofit low-NO_x combustion system.

- In order to maintain adequate steam temperatures, as well as minimize NO, CO, and flyash carbon levels, the control room O_2 setpoints should be set as follows:

Load (MWe)	Control Room O_2 Setpoint (percent)
110	3.6
100	3.4
80	4.3
60	6.5

- Maximum overfire air flow should be maintained throughout the load range.

- The overfire air flow should be equally distributed between the east and west sides of the furnace. This is especially important to minimizing CO emissions and flyash carbon levels at 100 and 110 MWe.

- It is recommended that the limit switches on the secondary air sliding damper actuator for each burner be reset such that the indicated air flow to all burners is equal when the dampers are in the "normal" position. It is also recommended that the current differential pressure gauges on each burner be replaced with units with a smaller range (0 to 2 inches of water) in order to provide a more accurate indication of relative air flow.

- CO emissions should be prominently displayed on the DCS operating screens, and PSCC control operators should be trained to minimize CO emissions by adjustment of the O_2 trim control.

9

REFERENCES

1. Shiomoto, G.H., Smith, R.A., "Integrated Dry NO_x/SO_2 Emissions Control System Baseline Test Report," DOE Contract Number DE-FC22-91PC90550, March 1992.

2. "Performance Test Final Report, Continuous Emissions Monitoring System Evaluation, Public Service Company of Colorado, Arapahoe Generating Station, Unit 4, Denver, Colorado," TRC Environmental Corp., August 1993.

APPENDIX A

INITIAL COMBUSTION SYSTEM OPTIMIZATION REPORT

DRB-XCL™ BURNER START-UP AND OPTIMIZATION TESTING

PUBLIC SERVICE COMPANY OF COLORADO

ARAPAHOE UNIT #4

JULY 1992

Prepared By:
D. M. Perry
Babcock & Wilcox

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INTRODUCTION

In May of 1992, Public Service Company of Colorado (PSCC) - Arapahoe Unit #4 was retrofit with twelve (12) DRB-XCL™ burners and six (6) Dual-Zone NOx ports. The purpose of the burner retrofit was to provide PSCC a means to reduce NOx emissions at Arapahoe #4 via low-NOx burners and staged combustion. Following the retrofit, B&W performed a series of preliminary tests to identify the optimum operating conditions and settings for the burners and NOx ports. Formal testing for optimization and evaluation of the low-NOx combustion system is scheduled for August 1992.

The goal of the preliminary test program was to minimize NOx/CO emissions and unburned carbon in the ash, while maintaining acceptable boiler operating practices. Test data was collected and evaluated at various conditions. A total of eleven emissions tests were performed and are summarized in the results section of this report. Emissions data for tests 1-6 on June 9, 1992 were obtained by traversing the economizer outlet with a portable analyzer provided by PSCC. The accuracy of the portable analyzer is unknown. Emissions data for tests 1-5 on June 16/17/18, 1992 was obtained with the newly installed continuous emissions monitor (CEM). The CEM sampled flue gas from a twelve point grid located at the economizer outlet. The CEM was routinely calibrated and is believed to be accurate.

RESULTS AND DISCUSSION

Initial testing during the burner optimization indicated that NOx emissions were well below expected levels. However, unburned carbon (UBC) levels were unacceptably high. Baseline carbon levels ranged from 3.5-11.5% with an average of about 5.5% carbon in ash at 100% boiler load with all burners in service. Unburned carbon levels with the XCL burners was initially 10-13%, but dropped significantly once the burner settings were optimized. Determining the proper spin vane settings was the most significant factor in reducing the UBC. With the spin vanes at 45° for both the inner and outer zones, UBC dropped to 4-5%.

Several tests were performed to identify the solution to the high UBC levels. Test parameters included primary air flow, burner spin vane settings, NOx port settings, and burner stoichiometries. These tests are summarized in Table 1, and include tests 1-6 on June 9, 1992. NOx emissions varied during these tests as a function of the various settings. However, UBC levels were essentially unchanged.

As another possible cause of the high UBC levels, the pulverizers were checked for coal fineness and distribution from burner line to burner line. Coal fineness levels were found to be consistent with baseline levels. Burner line flow balance for each mill was checked and significant imbalances were identified. Adjustments were made to the mill discharge dampers to improve burner line balancing. A summary of the flow balancing test data is presented in Appendix A.

Coal flow balancing did not have a significant effect in reducing UBC levels and additional testing was performed to evaluate burner spin vane settings and stoichiometries. The spin vanes were set at 45° for the inner and outer zones of the burners and test data was collected. Results from analysis of the ash samples indicated that UBC levels had dropped to 4-5%. Additional testing was conducted to confirm that these spin vane settings were responsible for the reduction in UBC levels. Test results with the optimized burner settings are presented in Table 2.

PUBLIC SERVICE COMPANY OF COLORADO - ARAPAHOE UNIT #4

TEST CONDITIONS: 82% BOILER LOAD
9 BURNERS IN SERVICE

06/09/92 TEST #1	NORMAL PA FLOW (6000 FPM CLEAN/APPROX.4800 FPM DIRTY) NOx PORT DAMPER 100% OPEN APPROX. STOICH. 1.15 SPIN VANES 45-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	6.9	4.6	5.75
CO @ 3% O2	83	132	108
NOx @ 3% O2	216	182	199
NOx LB/MKB	0.296	0.249	0.273
LOI %	7.59	13.84	10.72

06/09/92 TEST #2	*REDUCED PA FLOW (5250 FPM CLEAN/APPROX.4200 FPM DIRTY) NOx PORT DAMPER 100% OPEN APPROX. STOICH. 1.13 SPIN VANES 45-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	6.4	4.5	5.45
CO @ 3% O2	418	431	425
NOx @ 3% O2	299	244	272
NOx LB/MKB	0.410	0.334	0.372
LOI %	6.3	9.79	8.05

06/09/92 TEST #3	REDUCED PA FLOW (5250 FPM CLEAN/APPROX.4200 FPM DIRTY) *NOx PORT DAMPER 30% OPEN APPROX. STOICH. 1.28 SPIN VANES 45-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	6.5	5.1	5.80
CO @ 3% O2	165	351	258
NOx @ 3% O2	283	263	273
NOx LB/MKB	0.388	0.360	0.374
LOI %	8.75	13.71	11.23

06/09/92 TEST #4	REDUCED PA FLOW (5250 FPM CLEAN/APPROX.4200 FPM DIRTY) NOx PORT DAMPER 30% OPEN APPROX. STOICH. 1.23 *SPIN VANES 30-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	6.1	4.5	5.30
CO @ 3% O2	152	469	311
NOx @ 3% O2	239	217	228
NOx LB/MKB	0.327	0.297	0.312
LOI %	7.24	13.16	10.20

TABLE 1

06/09/92 TEST #5	REDUCED PA FLOW (5250 FPM CLEAN/APPROX.4200 FPM DIRTY)		
	•NOx PORT DAMPER 100% OPEN APPROX. STOICH. 1.05		
	SPIN VANES 30-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	5.5	3.7	4.60
CO @ 3% O2	21	130	76
NOx @ 3% O2	209	169	189
NOx LB/MKB	0.286	0.232	0.259
LOI %	10.25	16.04	13.15

06/09/92 TEST #6	•NORMAL PA FLOW (6000 FPM CLEAN/APPROX.4800 FPM DIRTY)		
	NOx PORT DAMPER 100% OPEN APPROX. STOICH. 1.07		
	SPIN VANES 30-INNER 60-OUTER		
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	6.4	3.7	5.05
CO @ 3% O2	163	153	158
NOx @ 3% O2	254	187	221
NOx LB/MKB	0.348	0.256	0.302
LOI %	7.94	11.13	9.54

TABLE 1 CONT'D

PUBLIC SERVICE COMPANY OF COLORADO - ARAPAHOE UNIT #4

TEST CONDITIONS: 100% BOILER LOAD
ALL BURNERS IN SERVICE

06/16/92 TEST #1	NOx PORT DAMPER 100% OPEN SPIN VANES 45-INNER 45-OUTER		APPROX. STOICH. 1.06
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	5.33	4.36	4.85
CO @ 3% O2	11	2	7
NOx @ 3% O2	285	288	286
NOx LB/MKB	0.391	0.394	0.392
LOI %	4.09	4.75	4.42

06/16/92 TEST #2	NOx PORT DAMPERS 40% OPEN SPIN VANES 45-INNER 45-OUTER		APPROX. STOICH. 1.18
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	5.68	5.07	5.38
CO @ 3% O2	22	7	15
NOx @ 3% O2	338	312	325
NOx LB/MKB	0.462	0.428	0.445
LOI %	3.59	4.75	4.17

06/17/92 TEST #3	NOx PORT DAMPER 100% OPEN SPIN VANES 45-INNER 45-OUTER		APPROX. STOICH. 1.04
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	5.1	4.4	4.75
CO @ 3% O2	67	24	45
NOx @ 3% O2	269	255	262
NOx LB/MKB	0.368	0.349	0.359
LOI %	4.8	6.03	5.42

06/17/92 TEST #4	NOx PORT DAMPER 100% OPEN SPIN VANES 45-INNER 60-OUTER		APPROX. STOICH. 1.06
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	5.3	4	4.65
CO @ 3% O2	341	351	346
NOx @ 3% O2	279	231	255
NOx LB/MKB	0.382	0.316	0.349
LOI %	8.23	12.99	10.61

06/18/92 TEST #5	NOx PORT DAMPER 100% OPEN SPIN VANES 45-INNER 45-OUTER		APPROX. STOICH. 0.88
	LEFT SIDE AVG	RIGHT SIDE AVG	UNIT AVG.
O2 % (DRY-VOL)	4.16	4.49	4.33
CO @ 3% O2	42	7	24
NOx @ 3% O2	251	280	266
NOx LB/MKB	0.344	0.384	0.364
LOI %			

TABLE 2

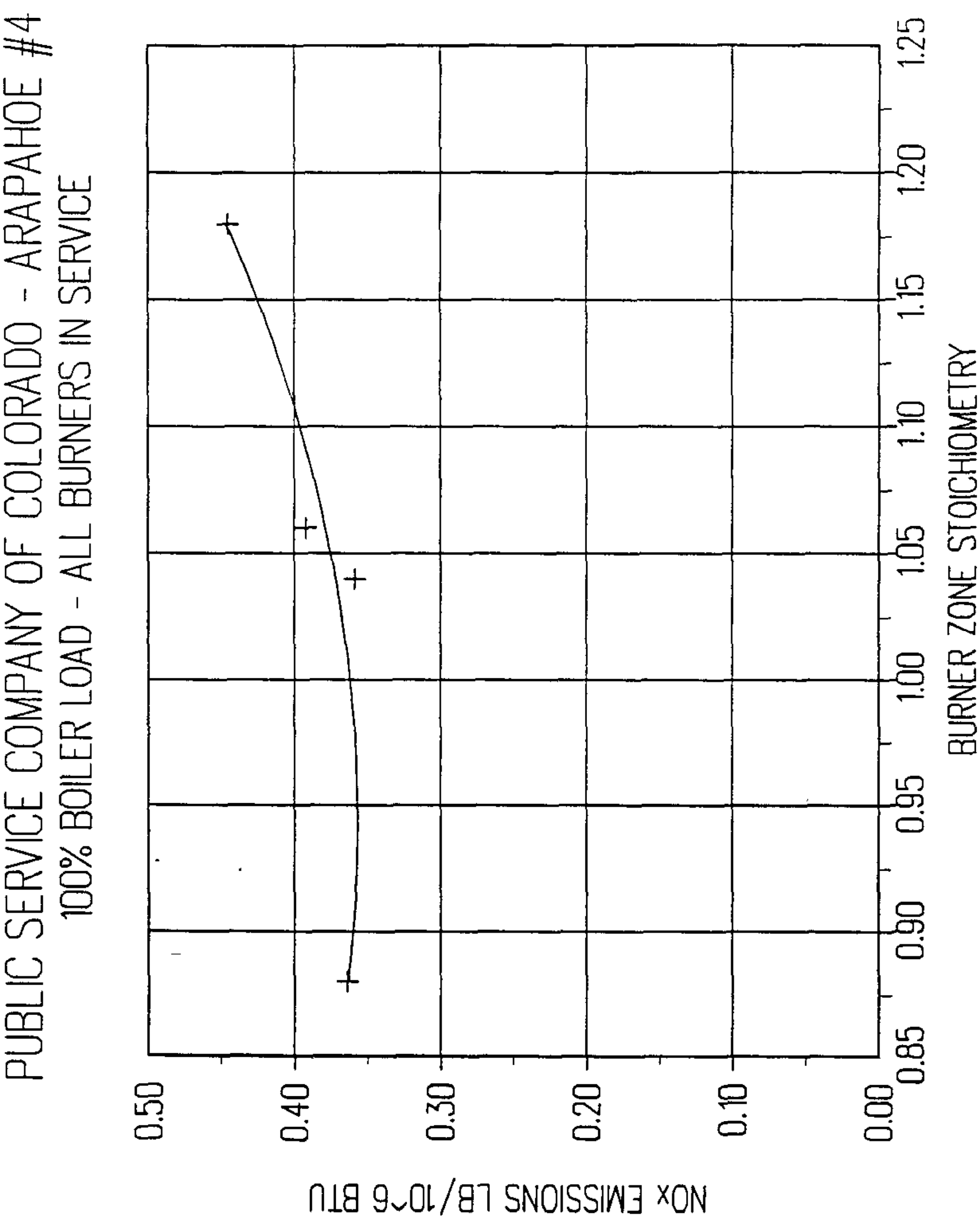
PUBLIC SERVICE COMPANY OF COLORADO - ARAPAHOE #4
100% BOILER LOAD - ALL BURNERS IN SERVICE
0.50
0.40
0.30
0.20
0.10
0.00
NOx EMISSIONS LB/10^6 BTU
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
1.25
BURNER ZONE STOICHIOMETRY

FIGURE 1

CONCLUSIONS AND RECOMMENDATIONS

NOx emissions were significantly reduced with the XCL burners and Dual-Zone NOx ports. Baseline NOx emissions averaged about 1.15 lbs/10^6 Btu. NOx emissions with the XCL burners were measured as 0.44 unstaged and 0.35 staged. This represents a 62% reduction with minimum air to the NOx ports and a 70% reduction with the NOx port dampers 100% open.

Unburned carbon levels and CO emissions remained consistent with baseline levels with the optimized burner settings. Unburned Carbon in the ash was 4-5%, and CO emissions less than 45 ppm. The optimized burner settings were with the inner and outer spin vanes at 45° of spin.

Numerous variations in burner settings and NOx port settings were evaluated during preliminary testing to determine their effect on NOx/CO emission and unburned carbon. The optimized settings for the spin vanes are believed to be 45° for both the inner and outer spin vanes. NOx port settings were optimized to provide the best balance of economizer outlet O_2. The optimized NOx port settings were determined to be with the core zone damper 100% open and the spin vanes at 45%. Evaluation of numerous additional spin vane combinations is not recommended during the formal test program. Spin vane variations should be limited to a few different settings to confirm those settings identified in preliminary testing. The recommended spin vane settings for the formal testing should be limited to testing with the spin vanes at 30° for both the inner and outer vanes, 45° for the inner and outer vanes, and 60° for the inner and outer vanes. NOx port settings can be varied to ensure that the optimum balance in economizer outlet O_2 is achieved.

Flame scanner operation may be affected by spin vane adjustments resulting in a pulverizer trip if left uncorrected. When adjusting spin vanes, it may be necessary to readjust the angle of the flame scanner head to ensure flame detection.

The NOx port control dampers were varied during preliminary testing to evaluate the effect of the NOx ports. With the NOx port dampers 100% open and normal excess air, the burner zone stoichiometry was reduced to 1.04. To reduce stoichiometry further, it was necessary to move the individual burner secondary air dampers to the light-off position which forced more air to the NOx ports. With the burner dampers throttled to the light-off setting, burner zone stoichiometry was reduced to 0.88. The minimum NOx port damper position identified during preliminary testing was 30-40% open. Closing the NOx port damper to less than 30%, results in insufficient cooling air to the NOx ports. NOx port temperatures should not exceed 1300 °F, and should be monitored during the formal test program.

APPENDIX A - COAL FLOW BALANCING DATA

ARAPAHOE UNIT #4 - COAL FLOW BALANCING

MILL A TEST 1 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 2	PIPE 2	PIPE 3	PIPE 3	PIPE 7	PIPE 7
0.732	0.8556	0.627	0.7918	0.554	0.7443
0.759	0.8712	0.835	0.9138	0.454	0.6738
0.774	0.8798	0.700	0.8367	0.502	0.7085
0.908	0.9529	0.803	0.8961	0.539	0.7342
0.942	0.9706	0.935	0.9670	0.617	0.7855
0.759	0.8712	0.898	0.9476	0.515	0.7176
0.695	0.8337	0.739	0.8597	0.432	0.6573
0.481	0.6935	0.690	0.8307	0.419	0.6473
1.110	1.0536	0.932	0.9654	0.495	0.7036
1.479	1.2161	0.778	0.8820	0.268	0.5177
1.154	1.0742	0.820	0.9055	0.339	0.5822
1.098	1.0479	0.690	0.8307	0.429	0.6550
0.937	0.9680	0.839	0.9160	0.502	0.7085
0.830	0.9110	0.617	0.7855	0.537	0.7328
0.649	0.8056	0.573	0.7570	0.454	0.6738
0.695	0.8337	0.576	0.7589	0.429	0.6550
AVERAGE	0.9274		0.8653		0.6811
REL. FLOW	112.47%		104.93%		82.60%
SUM SQRS	2.474				
AVERAGE	0.8246				

MILL A TEST 2 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 2	PIPE 2	PIPE 3	PIPE 3	PIPE 7	PIPE 7
0.583	0.7635	0.437	0.6611	0.659	0.8118
0.795	0.8916	0.632	0.7950	0.463	0.6804
0.795	0.8916	0.686	0.8283	0.483	0.6950
0.893	0.9450	0.742	0.8614	0.520	0.7211
0.825	0.9083	0.842	0.9176	0.585	0.7649
0.932	0.9654	0.639	0.7994	0.520	0.7211
0.803	0.8961	0.573	0.7570	0.451	0.6716
0.705	0.8396	0.598	0.7733	0.471	0.6863
0.991	0.9955	0.625	0.7906	0.573	0.7570
1.264	1.1243	0.644	0.8025	0.468	0.6841
1.093	1.0455	0.776	0.8809	0.573	0.7570
1.159	1.0766	0.712	0.8438	0.612	0.7823
0.852	0.9230	0.625	0.7906	0.651	0.8068
0.805	0.8972	0.532	0.7294	0.605	0.7778
0.710	0.8426	0.517	0.7190	0.544	0.7376
0.786	0.8866	0.512	0.7155	0.468	0.6841
AVERAGE	0.9308		0.7916		0.7337
REL. FLOW	113.69%		96.69%		89.62%
SUM SQRS	2.456				
AVERAGE	0.8187				

ARAPAHOE UNIT #4 - COAL FLOW BALANCING

MILL A TEST 3 — 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 2	PIPE 2	PIPE 3	PIPE 3	PIPE 7	PIPE 7
0.813	0.9017	1.125	1.0607	0.551	0.7423
0.695	0.8337	0.810	0.9000	0.451	0.6716
0.749	0.8654	0.537	0.7328	0.456	0.6753
0.752	0.8672	0.627	0.7918	0.505	0.7106
0.966	0.9829	0.732	0.8556	0.424	0.6512
0.825	0.9083	0.744	0.8626	0.456	0.6753
0.810	0.9000	0.529	0.7273	0.451	0.6716
0.752	0.8672	0.551	0.7423	0.517	0.7190
1.113	1.0550	0.605	0.7778	0.417	0.6458
1.799	1.3413	0.703	0.8385	0.419	0.6473
1.142	1.0686	0.603	0.7765	0.441	0.6641
1.040	1.0198	0.688	0.8295	0.488	0.6986
1.035	1.0173	0.666	0.8161	0.566	0.7523
0.839	0.9160	0.695	0.8337	0.607	0.7791
0.889	0.9429	0.632	0.7950	0.507	0.7120
0.754	0.8683	0.598	0.7733	0.502	0.7085
AVERAGE	0.9597		0.8196		0.6953
REL. FLOW	116.35%		99.36%		84.29%
SUM SQRS	2.475				
AVERAGE	0.8249				

MILL A TEST 4 — 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 2	PIPE 2	PIPE 3	PIPE 3	PIPE 7	PIPE 7
0.498	0.7057	0.412	0.6419	0.703	0.8385
0.625	0.7906	0.700	0.8367	0.581	0.7622
0.661	0.8130	0.629	0.7931	0.566	0.7523
0.690	0.8307	0.710	0.8426	0.566	0.7523
0.803	0.8961	0.712	0.8438	0.590	0.7681
0.717	0.8468	0.649	0.8056	0.532	0.7294
0.698	0.8355	0.620	0.7874	0.478	0.6914
0.664	0.8149	0.656	0.8099	0.485	0.6964
1.079	1.0387	0.629	0.7931	0.366	0.6050
0.720	0.8485	0.715	0.8456	0.595	0.7714
0.698	0.8355	0.639	0.7994	0.598	0.7733
0.671	0.8191	0.654	0.8087	0.573	0.7570
0.793	0.8905	0.634	0.7962	0.588	0.7668
0.747	0.8643	0.573	0.7570	0.607	0.7791
0.725	0.8515	0.502	0.7085	0.498	0.7057
0.698	0.8355	0.595	0.7714	0.495	0.7036
AVERAGE	0.8448		0.7901		0.7408
REL. FLOW	106.68%		99.77%		93.55%
SUM SQRS	2.376				
AVERAGE	0.7919				

ARAPAHOE UNIT #4 - COAL FLOW BALANCING

MILL B TEST 1					06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 1	PIPE 1	PIPE 8	PIPE 8	PIPE 9	PIPE 9
0.857	0.9257	0.886	0.9413	1.105	1.0512
0.715	0.8456	1.171	1.0821	0.952	0.9757
0.700	0.8367	1.010	1.0050	0.888	0.9423
0.886	0.9413	1.123	1.0597	1.025	1.0124
0.937	0.9680	1.076	1.0373	1.074	1.0363
0.925	0.9618	0.925	0.9618	1.110	1.0536
0.808	0.8989	0.852	0.9230	1.020	1.0100
0.854	0.9241	0.793	0.8905	0.976	0.9879
0.905	0.9513	0.659	0.8118	0.986	0.9930
0.942	0.9706	1.186	1.0890	0.986	0.9930
0.859	0.9268	1.132	1.0640	1.106	1.0517
0.998	0.9990	1.159	1.0766	1.074	1.0363
1.037	1.0183	0.861	0.9279	0.896	0.9466
1.079	1.0387	0.730	0.8544	0.813	0.9017
1.042	1.0208	0.683	0.8264	0.927	0.9628
0.954	0.9767	0.603	0.7765	0.754	0.8683
AVERAGE	0.9503		0.9580		0.9889
REL. FLOW	98.40%		99.20%		102.40%
SUM SQRS	2.897				
AVERAGE	0.9657				

ARAPAHOE UNIT #4 – COAL FLOW BALANCING

MILL C	TEST 1				06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 4	PIPE 4	PIPE 5	PIPE 5	PIPE 12	PIPE 12
0.922	0.9602	1.132	1.0640	0.991	0.9955
1.413	1.1887	1.023	1.0114	1.037	1.0183
0.825	0.9083	0.690	0.8307	0.991	0.9955
0.854	0.9241	0.679	0.8240	0.976	0.9879
0.837	0.9149	0.722	0.8497	1.001	1.0005
0.800	0.8944	0.683	0.8264	1.047	1.0232
0.761	0.8724	0.683	0.8264	0.910	0.9539
0.732	0.8556	0.634	0.7962	0.891	0.9439
0.756	0.8695	0.849	0.9214	0.803	0.8961
0.979	0.9894	0.747	0.8643	0.964	0.9818
0.962	0.9808	0.681	0.8252	0.847	0.9203
0.927	0.9628	0.659	0.8118	0.791	0.8894
0.859	0.9268	0.712	0.8438	1.049	1.0242
0.832	0.9121	0.673	0.8204	1.181	1.0867
0.808	0.8989	0.576	0.7589	0.981	0.9905
0.730	0.8544	0.595	0.7714	0.957	0.9783
AVERAGE	0.9321		0.8529		0.9804
REL. FLOW	101.12%		92.53%		106.36%
SUM SQRS	2.765				
AVERAGE	0.9218				

MILL C	TEST 2				06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 4	PIPE 4	PIPE 5	PIPE 5	PIPE 12	PIPE 12
1.401	1.1836	1.042	1.0208	1.032	1.0159
1.577	1.2558	0.764	0.8741	0.786	0.8866
0.876	0.9359	0.766	0.8752	0.900	0.9487
0.937	0.9680	0.710	0.8426	0.944	0.9716
0.725	0.8515	0.771	0.8781	1.052	1.0257
0.693	0.8325	0.620	0.7874	0.915	0.9566
0.769	0.8769	0.593	0.7701	0.908	0.9529
0.744	0.8626	0.595	0.7714	0.886	0.9413
0.759	0.8712	0.932	0.9654	0.720	0.8485
0.827	0.9094	0.981	0.9905	0.866	0.9306
0.827	0.9094	0.615	0.7842	0.861	0.9279
0.962	0.9808	0.712	0.8438	0.832	0.9121
1.030	1.0149	0.629	0.7931	0.969	0.9844
1.008	1.0040	0.686	0.8283	0.954	0.9767
0.905	0.9513	0.698	0.8355	0.964	0.9818
0.881	0.9386	0.576	0.7589	0.854	0.9241
AVERAGE	0.9592		0.8512		0.9491
REL. FLOW	104.28%		92.54%		103.18%
SUM SQRS	2.759				
AVERAGE	0.9198				

ARAPAHOE UNIT #4 - COAL FLOW BALANCING

MILL D	TEST 1				06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 6	PIPE 6	PIPE 10	PIPE 10	PIPE 11	PIPE 11
0.432	0.6573	0.778	0.8820	0.700	0.8367
0.468	0.6841	0.686	0.8283	0.571	0.7556
0.515	0.7176	0.749	0.8654	0.676	0.8222
0.615	0.7842	0.710	0.8426	0.720	0.8485
0.529	0.7273	0.715	0.8456	0.783	0.8849
0.500	0.7071	0.615	0.7842	0.756	0.8695
0.485	0.6964	0.542	0.7362	0.698	0.8355
0.493	0.7021	0.522	0.7225	0.722	0.8497
0.512	0.7155	0.776	0.8809	0.561	0.7490
0.429	0.6550	0.854	0.9241	0.549	0.7409
0.532	0.7294	0.725	0.8515	0.622	0.7887
0.529	0.7273	0.759	0.8712	0.715	0.8456
0.712	0.8438	0.808	0.8989	0.639	0.7994
0.688	0.8295	0.754	0.8683	0.744	0.8626
0.578	0.7603	0.681	0.8252	0.571	0.7556
0.512	0.7155	0.647	0.8044	0.649	0.8056
AVERAGE	0.7283		0.8395		0.8156
REL. FLOW	91.67%		105.67%		102.66%
SUM SQRS	2.383				
AVERAGE	0.7945				

MILL D	TEST 2				06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 6	PIPE 6	PIPE 10	PIPE 10	PIPE 11	PIPE 11
0.380	0.6164	0.510	0.7141	0.808	0.8989
0.473	0.6877	0.734	0.8567	0.720	0.8485
0.542	0.7362	0.686	0.8283	0.795	0.8916
0.583	0.7635	0.778	0.8820	0.634	0.7962
0.605	0.7778	0.795	0.8916	0.643	0.8019
0.642	0.8012	0.825	0.9083	0.683	0.8264
0.560	0.7483	0.759	0.8712	0.524	0.7239
0.476	0.6899	0.683	0.8264	0.593	0.7701
0.485	0.6964	0.788	0.8877	0.905	0.9513
0.466	0.6826	0.991	0.9955	0.881	0.9386
0.437	0.6611	0.793	0.8905	0.725	0.8515
0.603	0.7765	0.940	0.9695	0.813	0.9017
0.642	0.8012	0.866	0.9306	0.761	0.8724
0.549	0.7409	0.769	0.8769	0.678	0.8234
0.493	0.7021	0.651	0.8068	0.673	0.8204
0.490	0.7000	0.664	0.8149	0.419	0.6473
AVERAGE	0.7239		0.8719		0.8353
REL. FLOW	89.33%		107.60%		103.07%
SUM SQRS	2.431				
AVERAGE	0.8104				

ARAPAHOE UNIT #4 – COAL FLOW BALANCING

MILL D TEST 3 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 6	PIPE 6	PIPE 10	PIPE 10	PIPE 11	PIPE 11
0.322	0.5675	0.463	0.6804	0.705	0.8396
0.292	0.5404	0.732	0.8556	0.739	0.8597
0.385	0.6205	0.805	0.8972	0.725	0.8515
0.358	0.5983	0.798	0.8933	0.673	0.8204
0.312	0.5586	0.756	0.8695	0.627	0.7918
0.310	0.5568	0.800	0.8944	0.551	0.7423
0.295	0.5431	0.752	0.8672	0.483	0.6950
0.305	0.5523	0.659	0.8118	0.422	0.6496
0.292	0.5404	0.822	0.9066	0.871	0.9333
0.253	0.5030	0.888	0.9423	0.617	0.7855
0.285	0.5339	0.791	0.8894	0.593	0.7701
0.317	0.5630	0.839	0.9160	0.720	0.8485
0.322	0.5675	0.886	0.9413	0.730	0.8544
0.256	0.5060	0.754	0.8683	0.673	0.8204
0.256	0.5060	0.727	0.8526	0.607	0.7791
0.234	0.4837	0.800	0.8944	0.358	0.5983
AVERAGE	0.5463		0.8738		0.7900
REL. FLOW	74.16%		118.61%		107.23%
SUM SQRS	2.210				
AVERAGE	0.7367				

MILL D TEST 4 06/15/92

VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 6	PIPE 6	PIPE 10	PIPE 10	PIPE 11	PIPE 11
0.515	0.7176	0.581	0.7622	0.734	0.8567
0.527	0.7259	0.568	0.7537	0.671	0.8191
0.581	0.7622	0.712	0.8438	0.578	0.7603
0.544	0.7376	0.708	0.8414	0.622	0.7887
0.490	0.7000	0.693	0.8325	0.661	0.8130
0.527	0.7259	0.625	0.7906	0.747	0.8643
0.526	0.7253	0.505	0.7106	0.747	0.8643
0.520	0.7211	0.559	0.7477	0.703	0.8385
0.583	0.7635	0.725	0.8515	0.649	0.8056
0.505	0.7106	0.781	0.8837	0.752	0.8672
0.410	0.6403	0.669	0.8179	0.512	0.7155
0.454	0.6738	0.864	0.9295	0.585	0.7649
0.603	0.7765	0.896	0.9466	0.676	0.8222
0.727	0.8526	0.854	0.9241	0.664	0.8149
0.583	0.7635	0.725	0.8515	0.561	0.7490
0.568	0.7537	0.673	0.8204	0.559	0.7477
AVERAGE	0.7344		0.8317		0.8057
REL. FLOW	92.89%		105.20%		101.91%
SUM SQRS	2.372				
AVERAGE	0.7906				

ARAPAHOE UNIT #4 - COAL FLOW BALANCING

MILL D TEST 5					06/15/92
VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW	VELOCITY PRESSURE	RELATIVE FLOW
PIPE 6	PIPE 6	PIPE 10	PIPE 10	PIPE 11	PIPE 11
0.483	0.6950	0.781	0.8837	0.876	0.9359
0.512	0.7155	0.813	0.9017	0.551	0.7423
0.539	0.7342	0.771	0.8781	0.647	0.8044
0.627	0.7918	0.815	0.9028	0.705	0.8396
0.715	0.8456	0.781	0.8837	0.795	0.8916
0.583	0.7635	0.717	0.8468	0.765	0.8746
0.588	0.7668	0.722	0.8497	0.678	0.8234
0.539	0.7342	0.581	0.7622	0.732	0.8556
0.585	0.7649	0.837	0.9149	0.700	0.8367
0.478	0.6914	0.896	0.9466	0.666	0.8161
0.493	0.7021	0.673	0.8204	0.720	0.8485
0.639	0.7994	0.717	0.8468	0.725	0.8515
0.669	0.8179	0.771	0.8781	0.791	0.8894
0.585	0.7649	0.690	0.8307	0.798	0.8933
0.522	0.7225	0.671	0.8191	0.761	0.8724
0.412	0.6419	0.698	0.8355	0.656	0.8099
AVERAGE	0.7470		0.8625		0.8491
REL. FLOW	91.15%		105.25%		103.61%
SUM SQRS	2.459				
AVERAGE	0.8195				

APPENDIX B

DETAILED COMBUSTION SYSTEM OPTIMIZATION RESULTS

APPENDIX B

DETAILED COMBUSTION SYSTEM OPTIMIZATION RESULTS

A detailed optimization of the retrofit low-NO_x combustion system took place during the initial weeks of the formal test program. This provided an opportunity for a more detailed study of the effect of burner and overfire air port settings on combustion performance than was possible during the initial B&W optimization. The burner optimization consisted of an assessment of the effect of spin vane position over a wider range of settings, as well as an investigation of the effect of balancing the secondary air flow distribution to each burner. The overfire air port optimization addressed the effect of spin vane and core zone damper position, as well as the effect of balancing the overfire air flow to the upper furnace.

Burner Spin Vane Position

The detailed burner spin vane optimization was conducted at 100 MW with 20 percent overfire air. Since the spin vane settings have an effect on the secondary air split between the burners and overfire air ports, the tests were conducted with the overfire air control dampers closed down slightly in order to provide the ability to compensate for the changing burner windbox pressure drop while maintaining a constant overfire air ratio. It should also be noted that the O_2 levels (as measured by the 12-point economizer exit grid) were held constant during the tests. Four different spin vane configurations were tested and the results are shown in Figure B-1. The initial B&W burner optimization resulted in both the inner and outer spin vanes being set at 45°. However, the results of the detailed optimization showed that a slight increase in burner swirl, achieved by changing the angle of the inner spin vanes to 30°, provided lower CO

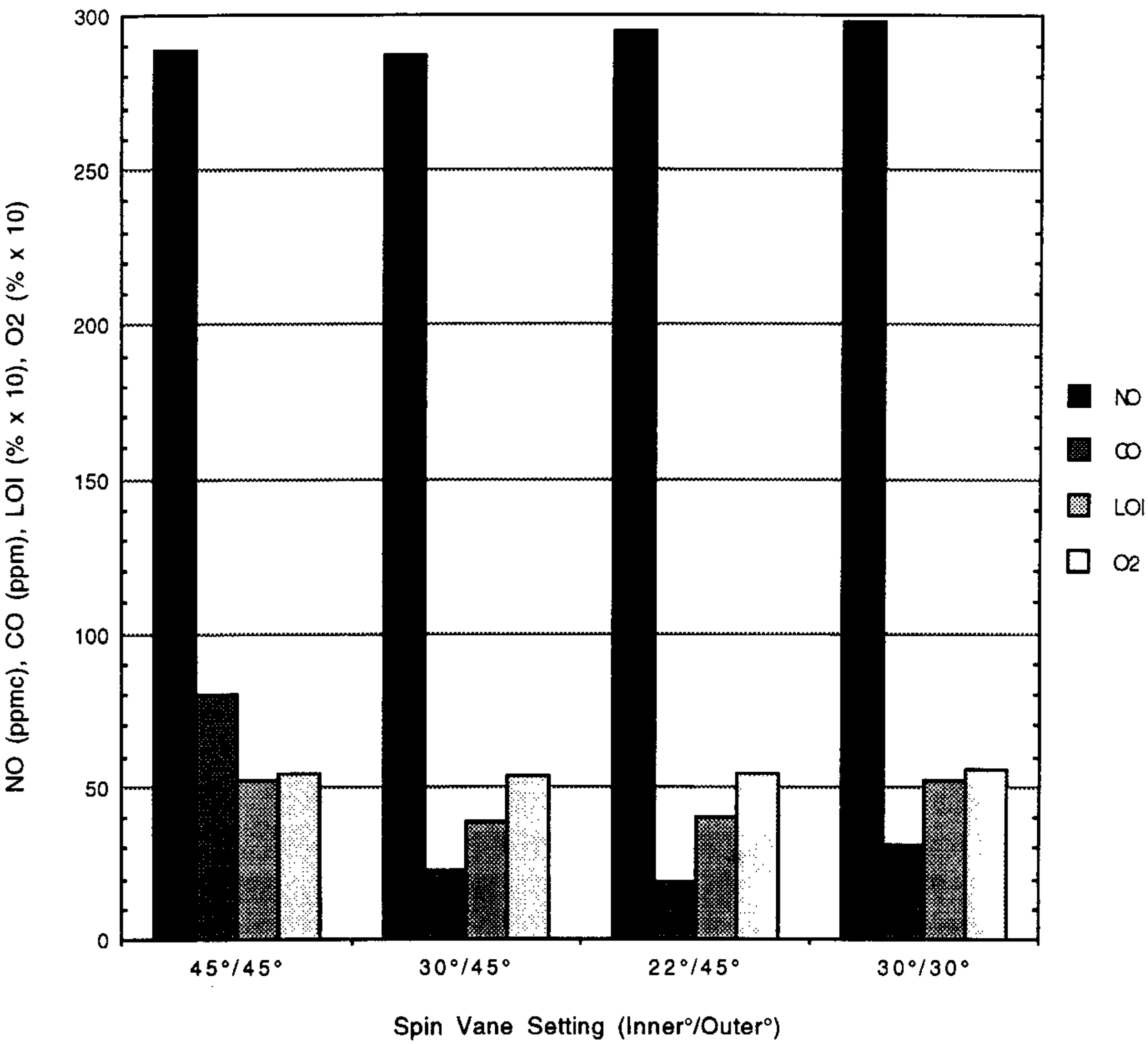

Figure B-1. Effect of Burner Spin Vane Position at 100 MWe with 20% Overfire Air emissions and fly ash LOI values, while having an insignificant effect on NO emissions. Increasing the swirl further by moving the inner spin vanes to 22° resulted in little change in the CO emissions or LOI values, and a slight increase in NO emissions. In the final case, the inner vanes were returned to 30°, and the swirl increased by decreasing the outer vanes' angle from 45° to 30°. This configuration resulted in increased CO and NO emissions as well as higher fly ash LOI values. The results indicate that the optimum burner configuration was with the inner and outer spin vanes set at 30° and 45°, respectively.

Burner Secondary Air Distribution

The burner optimization tests also indicated a substantial variation in the burner-to-burner secondary air flow distribution with the sliding dampers in the full open position (see Figure 5-25a). Each burner includes a circular pitot tube array, which provides a relative indication of the total secondary air flow to each burner. Differential pressure gauges with a range of 0 to 10 inches of water were installed on each burner during the retrofit. Unfortunately, this range is far greater than necessary, since when operating at 110 MWe, the burner pressure drop readings range only from approximately 0.6 to 1.2 inches. On three separate occasions, once at 110 MWe and twice at 100 MWe, the burners were put into a "manual control mode" by disconnecting the power to the electric actuators which position the sliding air dampers. The position of the sliding dampers on each burner were then adjusted by hand such that the secondary air flow distribution was balanced. An inclined manometer, with a range of 0 to 2 inches of water, was used to provide the pressure drop indications with a better resolution than that provided by the existing gauges.

The results of the three tests are shown in Figure B-2. In each of the three cases, balancing the air flows resulted in slightly decreased NO levels. It should be noted that no effort was made to hold either the O_2 or overfire air flow ratio constant during these tests. In each case, balancing the burner air flows resulted in a slight increase in overfire

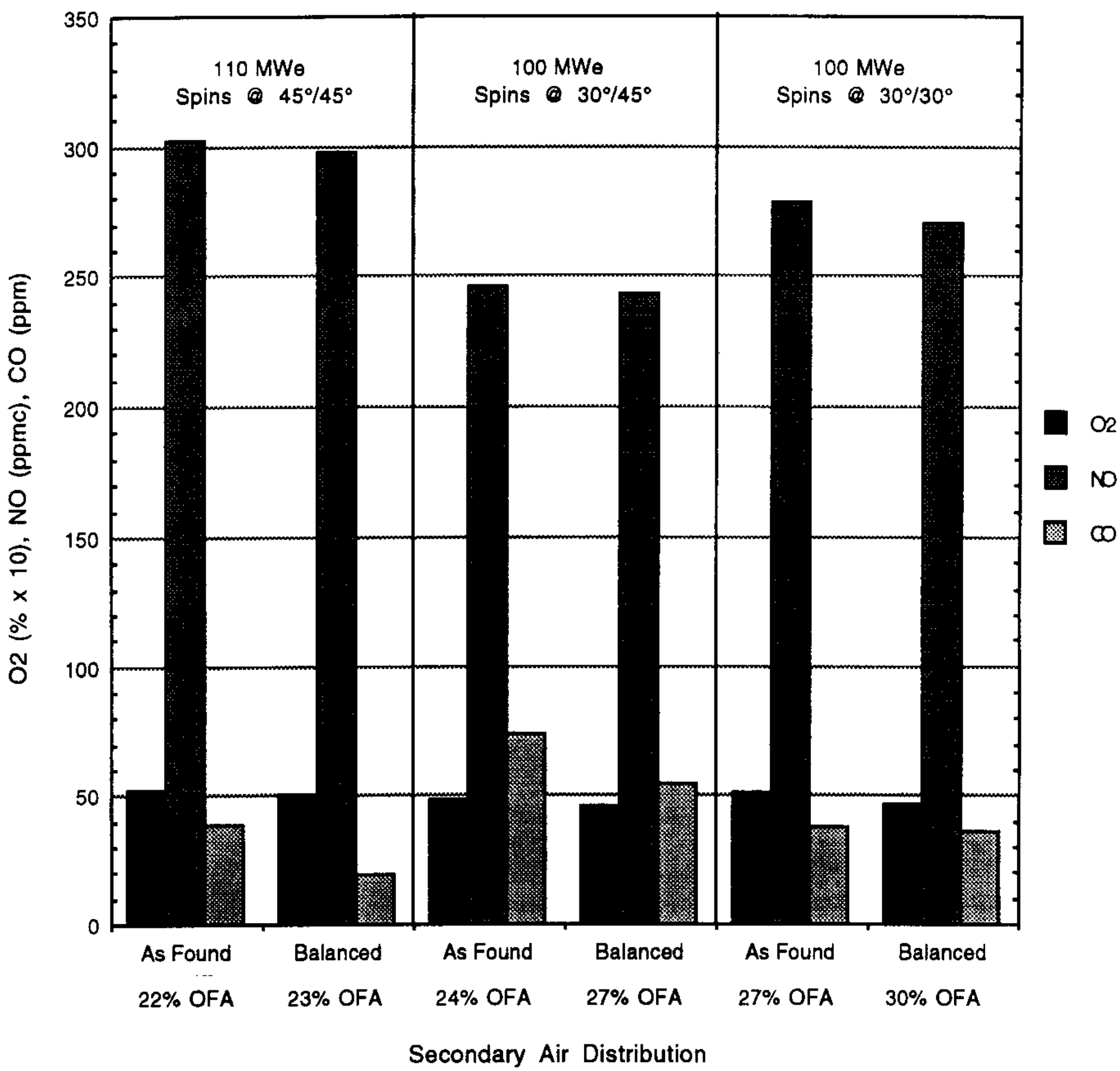

Figure B-2. Effect of Balancing the Secondary Air Flow to All Burners air and a small reduction in the operating O_2 levels. This decrease in O_2 is a consequence of the location of the plant's O_2 monitors and the control system. As was shown in Figure 5-11, small changes in overfire air flow at a fixed O_2 level result in negligible changes in NO emissions. Although the reductions in operating O_2 level were relatively small (ranging from 0.20 to 0.45 percent), the NO/O_2 sensitivity of approximately 40 ppmc/percent (see Figure 5-10) will result in NO reductions which are greater than the net NO reductions shown in Figure B-2 for each of the three tests. Therefore, once the effect of the reduced operating O_2 level is accounted for, it can be argued that the act of balancing the burner air flows actually resulted in a slight increase in NO emissions. However, the increase is very small and not of great concern.

In the first two tests shown in Figure B-2, balancing the air flows was shown to reduce CO emissions by nearly 20 ppm. In the third case, there was a negligible reduction in CO emissions. It is not likely that the lack of an effect in the third test was due to a different burner-to-burner coal distribution (which resulted in a different response to the balancing of the secondary air flows), since the second and third tests were run on the same day with one test immediately preceding the other. The lack of an effect on the CO emissions in the third test may be due to an increased furnace windbox pressure, which was a result of lower spin vane settings. However, there is not sufficient data to conclusively support this hypothesis. Recall that a lower spin vane angle indicates a higher level of swirl, since the vanes are further "closed". This closing action increases the air flow resistance through the burners, resulting in an increased wind box pressure (as evidenced by a higher overfire air flow). It is possible that this additional resistance evened-out the secondary air flow distribution through the burners to a point where the act of balancing the sliding air dampers by hand provided no additional benefit from the perspective of reducing CO emissions.

After each of the three tests, power was reconnected to the electric actuators and the sliding dampers automatically returned to their original positions as set by B&W. Maintaining the burner balance which had been set by hand would have required resetting the limit switches on the sliding damper actuator for each burner before reconnecting the power. This was not done due to a lack of a substantial impact on NO emissions, and the lack of a consistent effect on CO emissions. However, it is recommended that this adjustment be made from the perspective of good boiler operating practices. Although it has been shown that maintaining relatively equal or constant burner-to-burner coal feed rates is not possible at Arapahoe Unit 4, balancing the distribution of secondary air to each burner is a relatively simple task (1 or 2 days worth of work) and is also the first step in attempting to achieve an equal coal/air distribution across the top of the furnace. If many more "balanced secondary air" tests were run, it is not likely that CO emissions would have been reduced for every single test, since the burner-to-burner coal distribution can vary on a day-to-day basis. On the average, however, it is likely that CO emissions would have been reduced since the chance of pairing an "above average" coal flow with a "below average" air flow at any one particular or burner would have been reduced by providing more uniform distribution of secondary air. It is also recommended that the current differential pressure gauges on each burner be replaced with units with a smaller range (0 to 2 inches of water) in order to provide a more accurate indication of relative air flow.

Overfire Air Port Spin Vane Position

The overfire air port optimization tests were conducted at 100 MWe with maximum overfire air. The initial B&W combustion system optimization resulted in the overfire air ports being set with the core zone dampers 100 percent open, and the spin vanes at 45°. However, detailed O_2 traverses at the economizer outlet revealed a local O_2 deficit along the center of the boiler near the furnace division wall which resulted in a region of high CO levels. In an effort to increase the penetration of the overfire air into the center of the boiler, the spin vanes were opened up to 100 percent. The results (Figures B-3a and B-3b) showed that the "wide open" (spin vanes and core zone damper) configuration resulted in a large decrease in CO emissions and a slight increase in NO emissions for a fixed operating O_2 level. In order to maximize the overfire air penetration, a third series of tests was run with the spin vanes closed completely. In

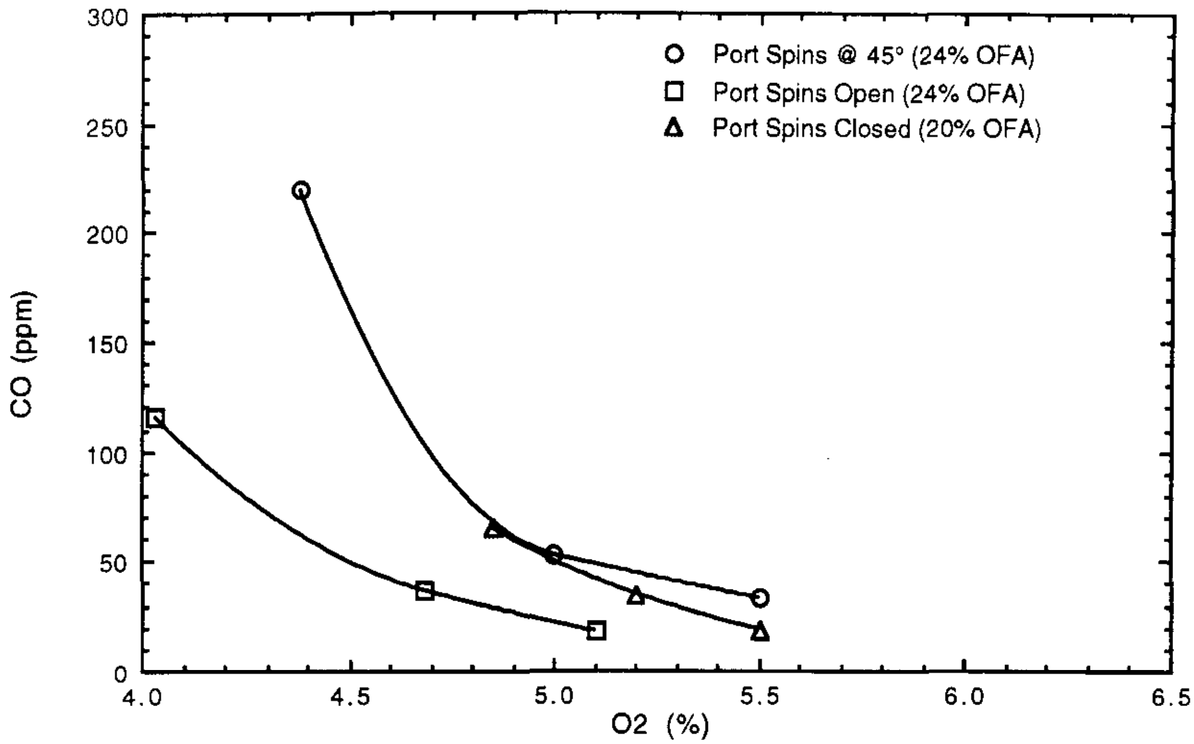

Figure B-3a. Effect of Overfire Air Port Spin Vane Configuration on CO Emissions at 100 MWe with Maximum Overfire Air

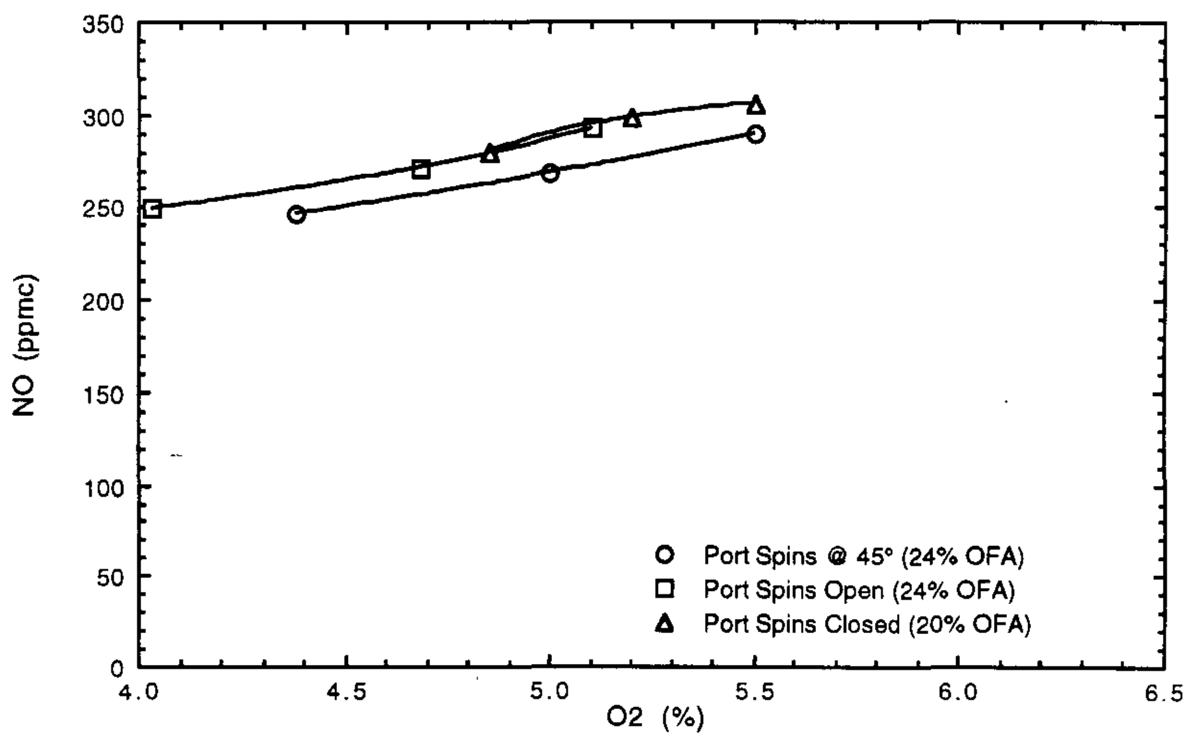

Figure B-3b. Effect of Overfire Air Port Spin Vane Configuration on NO Emissions at 100 MWe with Maximum Overfire Air theory, this should have forced all of the overfire air through the smaller diameter core zone, thereby substantially increasing the velocity and, consequently, the momentum of the jets. In practice, however, the increased back-pressure on the overfire air port wind boxes forced more of the secondary air to the burners, and the maximum overfire air ratio was reduced from 24 to 20 percent. Therefore, the increase in velocity and momentum actually realized was less than expected. The results show that with the spin vanes closed, the NO emissions were unchanged, and the CO emissions increased to the levels seen with the spin vanes at 45°. It is likely that the reduced overfire air flow more than offset any benefit of increased velocity, and the penetration of the jets was reduced. In order to determine the optimal configuration, it was necessary to compare the results on an equal basis. A CO emission limit of 50 ppm was chosen as this basis, since PSCC had expressed the desire to limit CO emissions to that level. Table B-1 shows the O_2 level required for operating at or below the 50 ppm limit, as well as the corresponding NO levels for each of the three overfire air port spin vane configurations. The data show that operating with spin vanes wide open results in the lowest NO emissions as well as the lowest O_2 requirement.

Table B-1

Operating O_2 Levels and NO Emissions
Required to Maintain 50 ppm CO at 100 MWe with Maximum Overfire Air

Spin Vane Setting	Operating O_2 (%)	NO (ppm)	OFA Ratio (%)
45°	5.10	273	24
Open	4.50	264	24
Closed	5.00	290	20

In order to separate the effects of reduced overfire air flow and spin vane position in the configuration where the spin vanes were closed, the three series of tests were run again at a constant overfire air ratio of 20 percent. The results of these tests (Figures B-4a and B-4b) show that as the ports are closed (which increases overfire air penetration), the CO levels decrease while NO emissions increase slightly. Table B-2 shows the O_2 level required for operating at or below 50 ppm CO, as well as the corresponding NO levels, for the three NO_x port spin vane configurations shown in Figure B-4a and B-4b. With

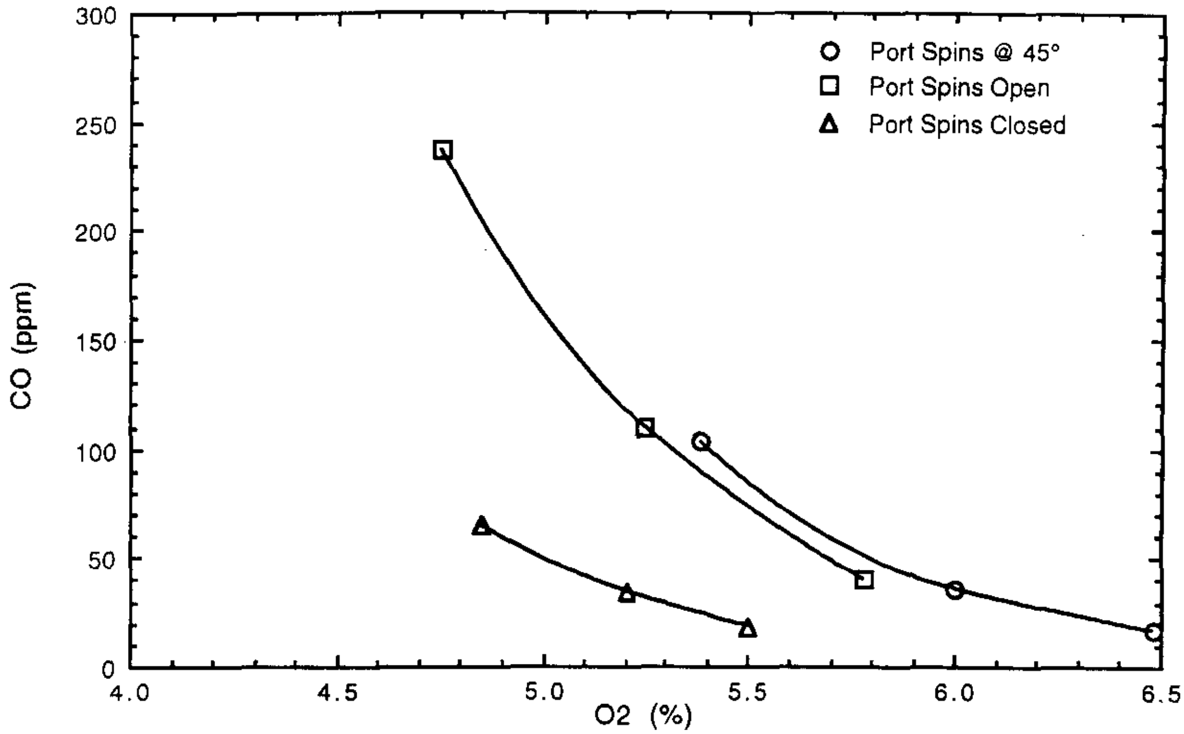

Figure B-4a. Effect of Overfire Air Port Spin Vane Configuration on CO Emissions at 100 MWe with 20 Percent Overfire Air

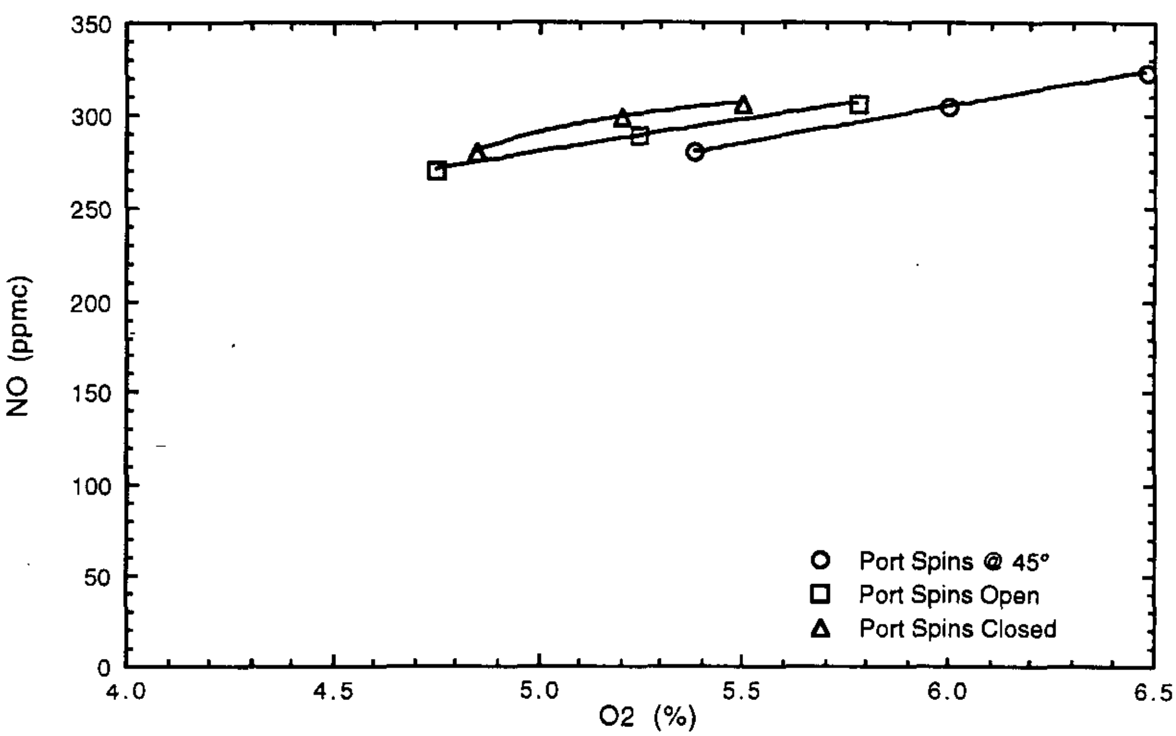

Figure B-4b. Effect of Overfire Air Port Spin Vane Configuration on NO Emissions at 100 MWe with 20 Percent Overfire Air equal overfire air ratios, operating with the spin vanes closed results in the lowest NO emissions as well as the lowest operating O_2 requirement. However, Table B-1 shows that it is better to operate at a higher overfire air flow with the spin vanes wide open than with 20% overfire air flow with the spin vanes closed, since the boiler can be operated at a lower excess air level (i.e., more efficiently) and with lower NO emissions for the same CO emission limit of 50 ppm. Therefore, the spin vanes were fixed in the open position for the remainder of the test program. The core zone dampers were not moved from the 100 percent open position during the overfire air port optimization tests, since doing so would reduce both overfire air flow and overfire air penetration and, therefore, result in increased NO and CO emissions.

Table B-2

Operating O_2 Levels and NO Emissions
Required to Maintain 50 ppm CO at 100 MWe with 20 Percent Overfire Air

Spin Vane Setting	Operating O_2 (%)	NO (ppm)
45°	5.82	297
Open	5.72	305
Closed	5.02	292

Overfire Air Port Secondary Air Distribution

The overfire air port optimization tests revealed that there was a bias of the overfire air port air flow toward the north side of the boiler. Each overfire air port has two separate circular pitot tube arrays which provide a relative air flow measurement between the inner and outer flow areas. With the core zone dampers and spin vanes for each overfire air port set similarly, the inner and outer flows indicated for the southernmost ports were lower than those indicated for the northernmost ports. The flow bias results from the manner in which the secondary air is supplied to each overfire air port windbox. Existing structural steel necessitated that the duct enter the bottom of each wind box at its northernmost end (see Figure 3-5).

A single test was performed at 100 MWe to examine the effect of balancing the overfire air port flows. This required reducing the flows to the northernmost ports on each side of the furnace. The air flow through the outer area of each port could not be reduced without changing the angle of the spin vanes, which would in turn alter the distribution of the air between the regions near and far from the ports. Therefore, the test was conducted with the spin vanes closed and the flows through each port equalized by adjusting the core zone dampers. The test was started with the overfire air control dampers closed down slightly to provide the ability to compensate for the increase in pressure drop across the ports while maintaining a constant overfire air ratio. It should also be noted that the economizer exit O_2 level was held constant during the test. The results of the test (Figure B-5) show that balancing the flows through each overfire air port resulted in a large increase in CO emissions and no effect on NO emissions.

Although one would expect little or no effect on NO emissions since the operating O_2 and overfire air levels were held constant, the increase in CO emissions was unexpected. Since the results indicate that boiler operation is actually improved when the overfire air is biased to the north side of the furnace, no further attempts were made to balance the individual overfire air port flows during the remainder of the test program.

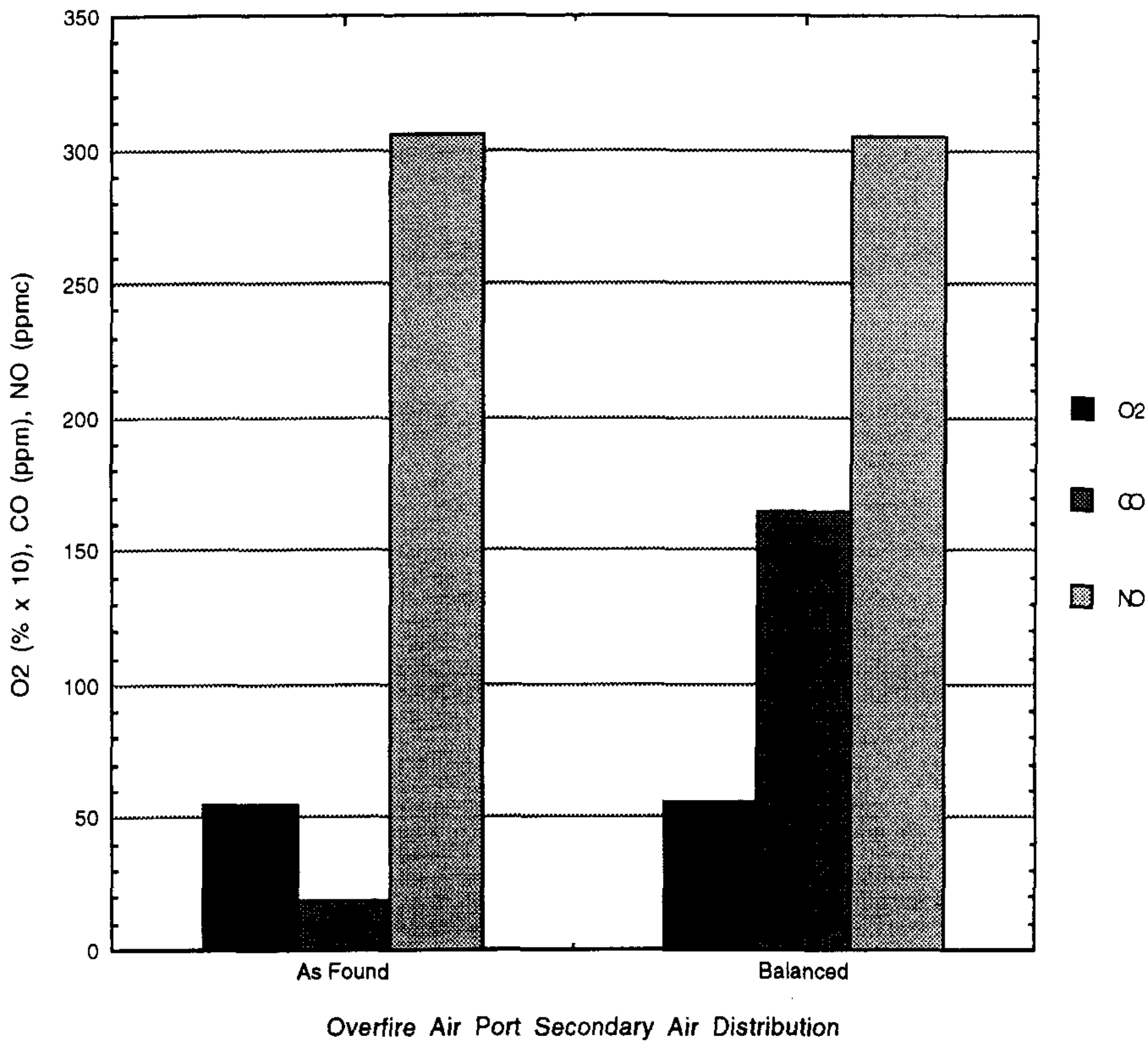

Figure B-5. Effect of Balancing Overfire Air Port Flows at 100 MWe with 19 Percent Overfire Air and Port Spin Vanes Closed

APPENDIX C

PARTICULATE MASS LOADING AND SIZE DISTRIBUTION REPORT

MEASUREMENT PROGRAM
MASS LOADING and PARTICLE SIZE EVALUATIONS
ARAPAHOE UNIT 4

TEST RESULTS

Prepared for:

FOSSIL ENERGY RESEARCH CORPORATION
23342 South Pointe
Suite C
Laguna Hills, California 92653

Prepared by:

TRC ENVIRONMENTAL CORPORATION
ENVIRONMENTAL MEASURMENTS DIVISION
Englewood, Colorado

November 15, 1992

TRC

TRC Environmental Corporation

7002 South Revere Parkway, Suite 60
Englewood, CO 80112
☎ (303) 792-5555 Fax (303) 792-0122

SUMMARY OF RESULTS

MASS LOADING MEASUREMENTS - EPA RM 5

A summary of the test results for the mass loading testing during process conditions 1 and 2 are provided in tables:

- Table 1 ; Baghouse Inlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 1
- Table 2 ; Baghouse Inlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 2
- Table 3 ; Baghouse Outlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 1
- Table 4 ; Baghouse Outlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 2

In each table, measured stack parameters along with average concentrations and emission rates for total particulates are presented. Detailed data summaries, and raw field data sheets of each test, are provided in the Appendix of this report (Appendix A).

Outlet Location; Condition 1 and 2

A total of three separate tests were conducted for each process condition at the outlet location. Condition 1 tests were conducted during the period of October 21, 1992 through October 22, .1992. Condition 2 tests were conducted October 26, 1992 through October 27, 1992. All baghouse outlet tests were sampled over increased period of three hours to assist in enhancing the particulate collection and sensitivity of the mass loading tests. All tests were valid for process and sampling conditions. The results of the mass loading and average stack parameters are provided in *Table 1* and *Table 2*.

Inlet Location; Condition 1

A total of five separate tests were conducted for the Condition 1 process condition at the inlet location. The tests were conducted during the period of October 21, 1992 through October 23, 1992. All five tests are reported in the accompanying table and Appendix of this document. Test 1, Test 4, and Test 5 are the tests that are used for the "valid" test series of parameter averaging and reporting. Test 2 was voided due to failure in passing the final (post) leak check. Test 3 was not included in the final averages and required the execution of an additional mass loading test in that it was determined that soot blowing interrupted the final 20 minutes of the extraction period of the test. Test 2 and Test 3, although omitted from the data averages provided valid information for measured stack parameter. The particulate concentrations and resultant emission may be biased due to the leak and soot blow conditions. Test results are provided in *Table 3*.

Inlet Location ; Condition 2

A total of two separate tests were conducted for the Condition 2 process condition at the outlet location. Due to facility operational changes, completion of the third test of the triplicate series could not be completed under the required controlled Condition 2 variables. All tests were valid for process and sampling conditions. The results of the mass loading (inlet) are provided in *Table 4*.

Table 1
Baghouse Outlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 1

Parameter	Test 1 10/21/92 1030-1345	Test 2 10/21/92 1512-1823	Test 3 10/22/92 1049-1215	Average
Stack Temperature (°F)	267.7	274.2	260.9	267.6
Stack Gas Velocity (ft/sec)	38.39	38.04	37.05	37.83
Actual Volumetric Flow Rate (ACFM)	423,807	420,002	409,011	417,607
Standard Volumetric Flow (DSCFM)	236,644	234,344	232,823	234,604
Stack Gas Molecular Weight (dry)	29.30	29.36	29.20	29.29
Stack Gas Moisture (% by volume)	7.96	6.91	7.60	7.49
Oxygen Content (% by volume)	5.3	6.2	7.9	6.47
Carbon Dioxide (% by volume)	12.9	12.2	11.3	12.13
Nitrogen Content (% by volume)	81.8	81.6	80.8	81.4
Particulate Concentration (gr/DSCF)	0.0014	0.0016	0.0017	0.0016
Particulate Concentration (gr/ACF)	0.0008	0.0009	0.0010	0.0009
Particulate Concentration (g/DSCM)	0.0032	0.0036	0.0040	0.0036
Particulate Concentration (g/ACM)	0.0018	0.0020	0.0023	0.0020
Mass Emission Rate (lbs/hr)	2.8312	3.1749	3.4594	3.1552
Mass Emission Rate (lbs/DSCF)	1.99E-07	2.26E-07	2.48E-07	2.24E-07

Table 2
Baghouse Outlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 2

Parameter	Test 1 10/26/92 0855-1140	Test 2 10/26/92 1335-1645	Test 3 10/27/92 0816-1145	Average
Stack Temperature (°F)	248.3	263.4	251.9	254.53
Stack Gas Velocity (ft/sec)	39.27	41.22	38.50	39.66
Actual Volumetric Flow Rate (ACFM)	433,550	455,042	424,991	437,861
Standard Volumetric Flow (DSCFM)	249,767	258,292	243,733	250,597
Stack Gas Molecular Weight (dry)	29.18	29.28	29.34	29.27
Stack Gas Moisture (% by volume)	7.82	6.80	7.44	7.35
Oxygen Content (% by volume)	7.5	7.4	6.3	7.07
Carbon Dioxide (% by volume)	11.4	11.3	12.5	11.73
Nitrogen Content (% by volume)	81.1	81.3	81.2	81.20
Particulate Concentration (gr/DSCF)	0.0027	0.0014	0.0006	0.0016
Particulate Concentration (gr/ACF)	0.0016	0.0008	0.0004	0.0009
Particulate Concentration (g/DSCM)	0.0062	0.0032	0.0014	0.0036
Particulate Concentration (g/ACM)	0.0036	0.0018	0.0008	0.0021
Mass Emission Rate (lbs/hr)	5.7826	3.0561	1.2915	3.3767
Mass Emission Rate (lbs/DSCF)	3.86E-07	1.97E-07	8.83E-08	2.24E-07

Table 3

Baghouse Inlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 1

Parameter	Test 1 10/21/92 1140-1409	Test 2 10/21/92 1559-1725	Test 3 10/22/92 1049-1215	Test 4 10/22/92 1433-1557	Test 5 10/23/92 0852-1015	Average (1)
Stack Temperature (°F)	279.6	282.1	277.7	280.9	275.4	278.63
Stack Gas Velocity (ft/sec)	41.12	39.65	41.20	41.44	42.05	41.54
Actual Volumetric Flow Rate (ACFM)	420,946	405,941	421,807	424,197	430,532	425,225
Standard Volumetric Flow (DSCFM)	229,142	222,445	232,298	235,147	237,114	229,567
Stack Gas Molecular Weight (dry)	29.58	29.63	29.57	29.68	29.31	29.52
Stack Gas Moisture (% by volume)	6.84	5.54	6.19	5.14	7.44	6.47
Oxygen Content (% by volume)	4.0	5.1	6.0	6.1	6.3	5.47
Carbon Dioxide (% by volume)	14.2	13.2	13.1	12.9	12.3	13.13
Nitrogen Content (% by volume)	81.8	81.7	80.9	81.0	81.4	81.40
Particulate Concentration (gr/DSCF)	2.4431	1.3973	2.2916	3.2646	2.7205	2.8094
Particulate Concentration (gr/ACF)	1.3297	0.7655	1.2618	1.8093	1.4980	1.5457
Particulate Concentration (g/DSCM)	5.6181	3.2130	5.2696	7.5071	6.2559	6.4604
Particulate Concentration (g/ACM)	3.0576	1.7603	2.9015	4.1607	3.4448	3.5544
Mass Emission Rate (lbs/hr)	4,797.59	2,663.59	4,561.98	6,578.91	5,528.13	5,634.87
Mass Emission Rate (lbs/DSCF)	3.49E-04	2.00E-04	3.27E-04	4.66E-04	3.89E-04	4.01E-04

(1) Average values for the entire test series were derived from the arithmetic mean of Test 1, Test 4, and Test 5. Test 2 was omitted from the average values due to failure of post leak check of sample train that may affect the particulate concentrations. Test 3 was omitted from the average values due to soot blow activities during the final 20 minutes of the test period. All physical stack parameters (temperature, flow, molecular weigh) are accurate for the entire five test series.

Table 4
Baghouse Inlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 2

Parameter	Test 1 10/26/92 1419-1555	Test 2 10/27/92 0906-1029	Average
Stack Temperature (°F)	273.7	267.9	270.8
Stack Gas Velocity (ft/sec)	44.24	42.79	43.52
Actual Volumetric Flow Rate (ACFM)	452,890	438,046	445,468
Standard Volumetric Flow (DSCFM)	243,811	243,376	243,594
Stack Gas Molecular Weight (dry)	29.24	29.59	29.42
Stack Gas Moisture (% by volume)	8.03	6.12	7.08
Oxygen Content (% by volume)	6.3	5.9	6.1
Carbon Dioxide (% by volume)	12.3	13.2	12.8
Nitrogen Content (% by volume)	81.4	80.9	81.2
Particulate Concentration (gr/DSCF)	1.3270	2.4864	1.9067
Particulate Concentration (gr/ACF)	0.7142	1.3812	1.0477
Particulate Concentration (g/DSCM)	3.0515	5.7176	4.3846
Particulate Concentration (g/ACM)	1.6424	3.1760	2.4092
Mass Emission Rate (lbs/hr)	2,772.61	5,185.83	3,979.22
Mass Emission Rate (lbs/DSCF)	1.89E-04	3.55E-04	2.72E-04

PARTICLE SIZING

A summary of the test results for the particle sizing tests at inlet and outlet locations during process Conditions 1 and 2 are provided in the following tables:

- Table 5 ; Baghouse Inlet Particle Size Measurements ARAPAHOE UNIT 4; Condition 1
- Table 6 ; Baghouse Inlet Particle Size Measurements ARAPAHOE UNIT 4; Condition 2
- Table 7 ; Baghouse Outlet Mass Loading Measurements ARAPAHOE UNIT 4; Condition 1

Due to the specific power demand requirements of Unit 4, Condition 2 sample period was reduced from the scheduled 3 days. Due to the reduced time frame, the particle size sampling could not be accomplished at the outlet location.

Detailed data summaries and raw field data sheets of each particle size test are provided in the Appendix of this report (Appendix B).

Inlet Location; Condition 1 and Condition 2

A total of five separate particle size runs were conducted for the Condition 1 process condition at the inlet location. All impactor runs at the inlet location were sampled using the University of Washington Pilat MARK V cascade impactor. The tests were conducted during the period of October 21, 1992 through October 23, 1992. All five tests are reported in the accompanying *Table 5* and *Table 6* and with supporting documentation in Appendix B of this document. Addition runs were conducted due to the "heavy loading" on initial stages for Test 2 and Test 3. After reducing the data, these two runs were combined into the overall average as results indicated similar trends. Three tests were conducted during the second condition prior to the Unit going off line. Due to the heavy loading, extreme care was taken to not "overload" impactors. Sample runs were reduced to approximately 3 to 5 minutes to ensure representative particle size samples were collected. Individual sample runs and associated data reduction of test runs using pcCIDRS written by J. McCain are provided in Appendix B.

Outlet Location ; Condition 1

A total of three separate tests were conducted for each Condition 1 at the outlet location. Condition 1 tests were conducted during the period of October 21, 1992 through October 22, 1992. All particle size runs at the outlet location were conducted using the University of Washington Pilat MARK III cascade impactor. Condition 2 tests were not performed due to time constraints on the required process condition. All baghouse outlet tests were sampled over increased period of three hours to assist in enhancing the particulate collection and sensitivity. However, it is recommended, due to the extremely light loading, that extended runs, of up to 24 hours may be required to collect sufficient PM_{10} (in-stack) mass or accurate and reproducible data.

PM_{10} data is provided as that of in-stack measurements only. The back half (condensible) fractions, for the particle size tests conducted during Condition 1, could not be quantified due to formation of a residual organic in the final wash. With this occurrence, final weights could not be achieved and "true" condensibles could not be quantified. The results of the tests are located in *Table 7* with the accompanying individual sample impactor runs found in Appendix B.

Table 5
Baghouse Inlet Particle Size Measurements ARAPAHOE UNIT 4; Condition 1

Parameter	Test 1 10/21/92 1859-1905	Test 2 10/22/92 0841-0846	Test 3 10/22/92 0920-0925	Test 4 10/23/92 1108-1111	Test 5 10/23/92 1210-1213	Average
Stack Temperature (°F)	274.3	271.0	280.7	273.0	284.5	276.70
Stack Gas Velocity (ft/sec)	45.50	43.29	41.07	44.42	44.49	43.75
Actual Volumetric Flow Rate (ACFM)	465,856	443,230	420,443	454,705	455,431	447,933
Standard Volumetric Flow (DSCFM)	252,959	244,141	227,620	251,248	247,762	244,746
Aerodynamic Particle Diameter	Cumulative Mass; Percent < or = Stated Particle Size					
15.85 μicron	31.28	42.66	46.36	37.86	38.95	41.00
10.00 μicron	17.52	18.65	24.52	16.99	19.04	18.65
5.01 μicron	10.27	7.99	12.42	8.65	9.28	9.21
2.51 μicron	5.05	3.82	6.07	3.51	4.75	4.30
1.00 μicron	1.72	1.37	2.60	0.97	1.85	1.58
0.50 μicron	0.74	0.67	1.67	0.38	1.24	0.87
0.25 μicron	0.31	0.23	0.68	0.21	0.45	0.34
0.10 μicron	0.19	0.10	0.15	0.16	0.10	0.13

Table 6
Baghouse Inlet Particle Size Measurements ARAPAHOE UNIT 4; Condition 2

Parameter	Test 6 10/26/92 1110-1113	Test 7 10/26/92 1200-1203	Test 8 7 10/2~~2~~/92 0920-0925	Average
Temperature (°F)	268.0	264.0	280.7	273.0
Gas Velocity (ft/sec)	49.03	50.26	41.07	44.42
Volumetric Flow Rate (ACFM)	501,929	514,497	420,443	454,705
Volumetric Flow (DSCFM)	273,766	282,171	227,620	251,248
Aerodynamic Particle Diameter				
	Cumulative Mass; Percent < or = Stated Particle Size			
15.85 μicron	16.41	39.98	32.08	37.86
10.00 μicron	7.44	19.02	18.52	16.99
5.01 μicron	3.76	9.02	8.75	8.65
2.51 μicron	1.84	4.42	3.43	3.51
1.00 μicron	0.57	1.20	1.01	0.97
0.50 μicron	0.26	0.78	0.47	0.38
0.25 μicron	0.12	0.48	0.18	0.21
0.10 μicron	0.08	0.30	0.10	0.16

Table 7
Baghouse Outlet Particle Size (PM_{10}) Measurements ARAPAHOE UNIT 4
Condition 1 ; October 1992

Parameter		Test 1 10/22/92 1434-1756	Test 2 10/23/92 0806-1116	Test 3 10/23/92 1312-1622	Average
Temperature (°F)		270.3	255.1	258.0	273.0
Sample Volume (DSCF)		75.883	79.124	76.723	77.243
Gas Velocity (ft/sec)		41.37	40.41	42.44	44.42
Volumetric Flow Rate (ACFM)		456,681	446,087	468,522	454,705
Volumetric Flow (DSCFM)		258,465	260,872	271,867	251,248
Stage/Cutpoint		Mass Collected (milligrams)			
1	16.617 μicron	1.39	0.42	1.04	0.950
2	10.541 μicron	0.13	0.07	0.14	0.113
3	3.949 μicron	0.00	0.02	0.12	0.047
4	2.106 μicron	0.00	0.00	0.03	0.01
5	1.199 μicron	0.00	0.00	0.00	0.00
6	0.577 μicron	0.00	0.00	0.00	0.00
7	0.204 μicron	0.00	0.00	0.00	0.00
Non-condensible (NC) Fraction (In-stack)					
Mass Collected (mg)		1.52	0.51	1.33	1.12
Mass Collected (mg) < 10 μicron		0.13	0.09	0.29	0.17
Percent < or = 10 μicron		8.55%	17.65%	21.80%	15.80%
Total Impactor (< 16.617 μicron)					
NC PM_{10} Conc. (g/DSCF)		2.00E-05	6.45E-06	1.73E-05	1.46E-05
NC PM_{10} Conc. (gr/DSCF)		3.09E-04	9.95E-05	2.25E-04	2.25E-04
NC PM_{10} Emission Rate (lbs/hr)		0.6584	0.2225	0.6245	0.5108
From Impactor Stage 2 (< 10.541 μicron)					
NC PM_{10} Conc. (g/DSCF)		1.17E-06	1.14E-06	3.78E-06	2.21E-06
NC PM_{10} Conc. (gr/DSCF)		2.65E-05	1.76E-05	5.83E-05	3.41E-05
NC PM_{10} Emission Rate (lbs/hr)		0.0586	0.0393	0.1360	0.0779

APPENDIX D

DATA SUMMARY
FOR
DETAILED OPTIMIZATION AND
PARAMETRIC PERFORMANCE TESTS

Arapahoe 4 Retrofit Burner Data Summary

Test	Date & Time		Description	Load MWe	Mills OOS	Burner Spin Vanes Inner/outer	OFA Dmprs % Open West/East	CR O2 % wet	Total Air kpph	OFA Flow %	O2 %	CO ppm	NOc ppm@ 3% O2	CO2 %	SO2c ppm@ 3% O2	Airhtr O2 %	Stack O2 %	LOI FERCo %	Acoustic FEGT °F
200	08/06/92	15:08	80-90 MW dispatch, As Found			45°/45°	100/100	5.22	629		4.70	125	303	13.4	367				
202	08/07/92	11:41	100-116 MW dispatch, As Found			45°/45°	100/100	3.89	949		5.45	165	290	12.9	377			11.3	
203	08/10/92	08:28	As Found	100		45°/45°	100/100	4.05	862	23	5.35	57	288	12.9	370	5.20	5.40	7.3	
204	08/10/92	14:38	OFA Dampers to 40%	100		45°/45°	40/40	3.99	898	14	5.60	42	310	12.9	375	5.40	5.60	5.7	
205	08/11/92	08:23	As Found	100		45°/45°	100/100	3.96	875	22	5.10	48	277	13.2	374				
206	08/11/92	10:00	Secondaries to light-off	100		45°/45°	100/100	3.96	892	27	5.20	27	290	13.1	374				
207	08/11/92	14:40	Secondaries @ light-off, Reduced OFA	99		45°/45°	50/53	3.97	890	21	5.15	40	285	13.0	372				
208	08/12/92	14:00	Repeat 207 Next Day	100		45°/45°	52/52	3.89	928	20	5.30	103	288	13.1	372				
209	08/12/92	15:05	B Group Secondaries to Normal	100		45°/45°	52/52	4.12	911	21	5.00	322	269	13.2	371				
210	08/12/92	16:12	C Group Secondaries to Normal	100		45°/45°	52/52	3.95	916	20	5.30	62	291	13.0	376				
211	08/13/92	09:58	104 MW As Found, Aborted due to Dispatch	104		45°/45°	100/100		899	22	5.30	64	288	13.1	371				
212	08/13/92	10:38	110 MW, As Found	110		45°/45°	100/100	4.03	970	22	5.20	39	302	13.2	368				
213	08/13/92	14:15	110 MW, Balanced Secondary Air Flows	110		45°/45°	100/100	3.95	965	23	5.00	19	298	13.2	369				
214	08/14/92	09:13	A Mill OOS, AS Found	101	A	45°/45°	100/100	3.93	888	25	4.80	152	270	12.9	377			10.8	
215	08/14/92	12:06	A Mill OOS, OFA Flow Biased to East	101	A	45°/45°	55/100	3.99	928	23	5.60	112	296	12.2	383			10.5	
216	08/14/92	14:10	A Mill OOS, OFA Dampers @ 40%	101	A	45°/45°	40/40	3.96	894	15	5.70	271	298	12.1	382				
217	08/14/92	16:30	A Mill OOS, OFA @ 100%, inners @ 45°-2	101	A	30°/45°	100/100	4.10	920	26	5.30	342	268	12.1	378				
218	08/14/92	18:30	All Mills, OFA @ 100%, inners @ 45°-2	101		30°/45°	100/100	3.97	859	23	4.90	54	239	12.9	378				
219	08/17/92	10:36	PSCC VWO Heat Rate Test	113		30°/45°	100/100	4.00	980	24	4.15	60	287	13.6	377	5.90	5.40		1891
220	08/18/92	08:45	OFA @ 100%, inners@45°-2, Outers@45°	100		30°/45°	100/100	4.04	871	24	4.85	74	246	13.4	368	4.85	5.25	9.1	1834
221	08/18/92	13:31	As 220 with Balanced Burner Secondaries	100		30°/45°	100/100	4.10	878	27	4.55	55	243	13.7	390	4.65	6.00	7.7	
222	08/18/92	15:38	As 221 with outers to 45°-2	100		30°/30°	100/100	4.02	869	30	4.70	36	271	13.5	400	4.75	6.10	5.1	
223	08/18/92	17:25	As 222 with Secondaries at normal position	100		30°/30°	100/100	4.00	886	27	5.15	38	279	13.0	406				
224	08/19/92	08:59	Repeat 223 next day	100		30°/30°	100/100	4.06	856	28	4.83	56	256	13.3	410	4.80	5.90	7.3	1829
225	08/19/92	11:04	Repeat 220	100		30°/45°	100/100	4.02	845	23	4.53	47	248	13.7	417	4.60	5.65	7.9	1874
226	08/19/92	14:33	OFA @ 100%, inners@45°-3, Outers@45°	100		22°/45°	100/100	4.02	840	24	4.70	88	244	13.6	419	4.60	5.65	7.7	1832
227	08/20/92	08:48	Repeat 226 next day	100		22°/45°	100/100	4.03	853	24	4.63	81	235	13.4	411	4.80	5.65	9.4	1797
228	08/20/92	11:02	inners to 45°	100		45°/45°	100/100	4.01	848	21	4.58	140	238	13.2	411	4.65	5.65	7.1	1808
229	08/21/92	08:43	C Mill OOS, innr@45°-2, otrs@45°,lowO2	100	C	30°/45°	100/100	3.24	823	27	4.35	215	261	14.6	420			10.3	1789
230	08/21/92	10:36	As 229 with normal O2	100	C	30°/45°	100/100	4.02	862	27	4.90	38	283	14.2	490			6.9	1834
231	08/24/92	10:23	OFA @ 100%, inners@45°-2, Outers@45°	100		30°/45°	100/100	3.99	841	25	4.75	253	235	13.9	538	4.90	6.65	8.2	1896
232	08/24/92	15:21	Repeat 231 (LOI Problems)	100		30°/45°	100/100	4.00	866	24	4.85	229	242	14.0	549			9.9	
233	08/25/92	07:55	100 MW, 100% OFA, 4.0% CR O2	100		30°/45°	100/100	3.96	865	24	4.97	121	240	14.1	550	4.95	6.95	4.7	1845
234	08/25/92	10:23	As 233 with W/E OFA Dampers @ 45/42%	100		30°/45°	45/42	3.85	886	16	5.43	122	276	13.6	532	5.25	7.20	3.4	1838
235	08/25/92	12:46	As 233 with W/E OFA Dampers @ 35/32%	100		30°/45°	35/32	4.14	911	12	5.50	56	298	13.4	490	5.45	7.35	3.9	1880
236	08/25/92	15:01	As 233 with W/E OFA Dampers @ 55/58%	100		30°/45°	55/58	4.15	898	20	5.18	76	263	13.7	449	5.00	7.60	5.0	1882
237	08/26/92	09:06	80 MW, 100% OFA, 4.9% CR O2	80		30°/45°	100/100	4.91	686	23	5.70	65	219	13.2	423	5.55	7.45	5.5	1710
238	08/26/92	11:46	As 237 with W/E OFA Dampers @ 30/34%	80		30°/45°	30/34	4.86	724	10	6.38	22	275	12.7	415	6.20	7.75	2.8	1732
239	08/26/92	13:58	As 237 with W/E OFA Dampers @ 45/44%	80		30°/45°	45/44	4.91	697	16	6.05	94	247	12.8	415	5.65	7.65	4.5	1749
240	08/28/92	08:33	80 MW, 100% OFA, 5.7% CR O2	80		30°/45°	100/100	5.69	769	23	6.70	19	247	12.4	408	6.65	7.70	3.6	1669
241	08/28/92	10:40	As 240 with W/E OFA Dampers @ 40/42%	80		30°/45°	40/42	5.76	776	14	7.02	9	285	12.1	405	6.80	7.70	2.1	1716
242	08/28/92	14:27	As 240 with W/E OFA Dampers @ 25/29%	80		30°/45°	25/29	5.70	791	8	7.13	6	314	11.9	403	6.95	7.15	1.7	1760
243	08/28/92	16:36	As 242 with avg O2 reduced to same as 240	80		30°/45°	25/29	5.13	731	8	6.78	8	287	12.3	406	6.50	6.65	2.4	1755
244	08/29/92	08:09	60 MW, 100% OFA, 7.0% CR O2	60	C	30°/45°	100/100	6.94	629	25	7.98	11	304	11.4	412	7.90	8.20	2.1	1538
245	08/29/92	10:13	As 244 with W/E OFA Dampers @ 42/39%	60	C	30°/45°	42/39	6.99	657	16	8.33	14	310	11.2	423	8.25	8.40	3.0	1570
246	08/29/92	12:05	As 244 with W/E OFA Dampers @ 25/20%	60	C	30°/45°	25/20	6.94	679	9	8.50	9	337	11.2	476	8.45	8.60	2.2	1580

Arapahoe 4 Retrofit Burner Data Summary

Test	Date	Time	Description	Load MWe	Mills OOS	Burner Spin Vanes Inner/outer	OFA Dmprs % Open West/East	CR O2 % wet	Total Air kpph	OFA Flow %	O2 %	CO ppm	NOc ppm@ 3% O2	CO2 %	SO2c ppm@ 3% O2	Airhtr O2 %	Stack O2 %	LOI FERCo %	Acoustic FEGT °F
247	08/29/92	14:08	As 246 with avg O2 reduced to same as 244	60	C	30°/45°	25/20	6.42	646	9	8.05	10	308	11.4	512	7.90	8.25	2.2	1589
248	08/30/92	08:32	60 MW, 100% OFA, 6.2% CR O2	60	B	30°/45°	100/100	6.23	591	26	7.70	11	256	11.5	529	7.40	7.70	2.0	1620
249	08/30/92	10:15	As 248 with W/E OFA Dampers @ 42/39%	60	B	30°/45°	42/39	6.24	596	16	8.07	18	268	11.3	519	7.65	7.95	2.9	1585
250	08/30/92	12:05	As 248 with W/E OFA Dampers @ 16/15%	60	B	30°/45°	16/15	6.27	613	6	8.23	28	294	11.1	543	7.80	8.20	3.1	1596
251	08/30/92	13:51	As 250 with avg O2 reduced	60	B	30°/45°	16/15	6.12	589	5	7.95	38	284	11.4	553	7.65	7.95	3.4	1612
252	08/30/92	15:28	*As 250 with avg O2 reduced to same as 248*	60	B	30°/45°	16/15	5.91	573	5	7.62	57	269	11.7	553	7.35	7.70	3.5	1616
253	08/31/92	08:22	80 MW, 100% OFA, 4.7% CR O2, Rpt 237	80		30°/45°	100/100	4.71	714	23	5.75	51	220	13.2	552	5.55	6.10	3.5	1758
254	08/31/92	10:49	As 248 with Dmprs @ 31/29%, Rpt 238	80		30°/45°	31/29	4.82	732	10	6.28	23	271	12.7	555	6.05	6.70	1.6	1751
255	08/31/92	12:41	As 254 with O2 Bias at -0.25%	80		30°/45°	31/29	4.50	712	10	6.00	30	256	13.1	554	5.70	6.40	1.9	1776
256	08/31/92	15:23	As 254 with O2 Bias at -0.70%	80		30°/45°	31/29	4.03	709	10	5.82	75	251	13.1	557	5.60	6.20	2.0	1794
257	09/01/92	08:21	100 MW, 100% OFA, 4.5% CR O2	100		30°/45°	100/100	4.43	893	24	5.47	20	261	13.4	557	5.25	5.90	2.6	1912
258	09/01/92	10:16	As 257 with OFA Dampers @ 50/50%	100		30°/45°	50/50	4.51	905	18	5.63	23	282	13.3	553	5.65	6.25	2.6	1917
259	09/01/92	12:18	As 257 with OFA Dampers @ 35/35%	100		30°/45°	35/35	4.49	931	12	5.90	12	314	13.0	557	5.80	6.30	2.4	1914
260	09/02/92	08:42	100 MW, 100% OFA, 3.5% CR O2	100		30°/45°	100/100	3.52	822	23	4.27	212	221	14.4	525	4.20	4.75	8.0	1915
261	09/02/92	11:14	As 260 with OFA Dampers @ 50/50%	100		30°/45°	50/50	3.55	865	18	4.95	251	257	13.7	496	4.20	4.95	5.9	1901
262	09/02/92	13:18	As 260 with Dmprs @ 43/44%, Aborted	105		30°/45°	43/44	3.28	906	16	4.90	285	281	14.2	453			7.6	1887
263	09/02/92	14:49	As 260 with OFA Dampers @ 43/44%	100		30°/45°	43/44	3.36	854	15	4.90	246	275	13.7	436	4.50	4.80	6.7	
264	09/03/92	08:55	100 MW, 100% OFA, 5.0% CR O2	100		30°/45°	100/100	4.88	878	24	5.60	27	275	13.2	416	5.50	6.00	5.8	1859
265	09/03/92	10:49	As 264 with OFA Dampers @ 49/50%	100		30°/45°	49/50	5.05	924	18	5.93	21	312	12.9	411	5.85	6.15	5.2	1833
266	09/03/92	15:25	As 264 with OFA Dampers @ 33/35%	100		30°/45°	33/35	4.88	957	12	6.50	12	364	12.5	411	6.15	6.60	4.3	1802
267	09/03/92	08:08	80 MW, 100% OFA, 5.7% CR O2	80		30°/45°	100/100	5.71	757	23	6.48	20	257	12.4	407			3.6	1685
268	09/03/92	10:18	As 267 with OFA Dampers @ 42/40%	80		30°/45°	42/40	5.80	792	14	7.10	9	306	11.9	410	6.85	7.20	2.5	1718
269	09/03/92	12:01	As 267 with OFA Dampers @ 26/28%	80		30°/45°	26/28	5.76	804	8	7.15	3	333	11.7	407	6.90	7.30	1.8	1738
270	09/17/92	09:02	100MW, Dmprs @ 50/50%, 4.0% CR O2	100		30°/45°	50/50	4.13	891	18	5.55	139	293	13.2	409	5.20	5.35	6.7	1825
271	09/17/92	11:22	As 270 w/ Nox Port Spin Vanes Wide Open	100		30°/45°	48/50	4.39	897	18	5.55	25	311	13.4	407	5.45	5.40	4.9	1848
272	09/17/92	14:39	As 270 w/ Nox Port Spin Vanes Closed	100		30°/45°	55/61	4.10	909	18	5.58	16	323	13.4	405	5.35	5.40	5.2	1810
273	09/18/92	08:49	100MW, 18% OFA, 4.0% CR O2, Rpt 270	100		30°/45°	49/46	4.00	868	18	5.35	170	282	13.6	416	4.90	5.40	5.9	1826
274	09/18/92	11:03	As 273 w/ Nox Port Spin Vanes Closed	100		30°/45°	58/56	4.18	871	18	5.35	27	288	13.7	415	5.15	5.60	3.9	1812
275	09/18/92	14:10	As 274 w/ NOx Port Centers Balanced	100		30°/45°	59/57	3.96	895	18	5.50	48	304	13.4	407	5.10	5.70	5.7	1791
276	09/18/92	16:25	Quick Repeat of 274	100		30°/45°	57/57	4.18	869	18	5.35	20	293	13.5	406				
277	09/19/92	08:19	100MW, Port Vanes Closed ,Centers Open, Max OFA (19%), 4.0% CR O2, 45/45	100		45/45	98/100	4.10	885	19	5.45	80	289	13.9	409			5.2	1836
278	09/19/92	10:01	As 277 with inners/outers @ 45-2n/45	100		30°/45°	70/70	4.20	888	20	5.38	23	287	13.8	410			3.8	1847
279	09/19/92	11:57	As 277 with inners/outers @ 45-3n/45	100		30°/45°	60/65	4.19	885	19	5.43	19	295	13.8	405			4.0	1843
280	09/19/92	14:57	As 277 with inners & outers @ 45-2n	100		30°/30°	48/49	4.04	905	19	5.60	31	298	13.5	402			5.2	1811
281	09/20/92	08:12	Repeat 277	100		45°/45°	100/100	4.03	896	19	5.48	50	303	13.8	411			4.6	1837
282	09/20/92	09:39	As 281 with inners/outers @ 45-1n/45	100		37°/45°	100/100	4.27	889	20	5.38	37	297	13.8	409			4.4	1857
283	09/20/92	11:00	As 281 with inners/outers @ 45-2n/45	100		30°/45°	65/80	4.18	895	19	5.50	19	306	13.6	407			4.7	1860
284	09/20/92	14:19	A 283 with NOx Port Centers Balanced	100		30°/45°	80/100	3.57	901	19	5.53	164	305	13.5	403			4.4	1890
285	09/21/92	08:30	110MW, Max OFA, 3.0% CR O2	110		30°/45°	100/100	3.01	920	18	4.85	198	291	14.0	420	4.45	4.75	6.4	1899
286	09/21/92	10:35	110MW, Max OFA, 4.0% CR O2	110		30°/45°	100/100	3.97	970	21	5.65	36	336	13.3	419	5.55	5.60	4.2	1921
287	09/21/92	13:42	110MW, Max OFA, 4.8% CR O2	110		30°/45°	100/100	4.78	990	21	5.97	20	343	12.9	413	5.95	6.10	4.4	1900
288	09/21/92	15:14	Rpt 285, Abort Half-Way Through	110		30°/45°	100/100	3.03	927	21	4.93	390	307	13.3	398			9.8	1862
289	09/22/92	08:34	110MW, Min OFA, 3.7% CR O2	110		30°/45°	25/17	3.69	1011	8	5.90	123	377	13.6	412	5.65	5.95	5.7	1881
290	09/22/92	10:34	110MW, Min OFA, 4.0% CR O2	110		30°/45°	21/19	3.96	1015	8	5.95	128	377	13.6	409	5.85	5.95	6.2	1881
291	09/22/92	14:17	As 290 w/ Mills Biased to Balance CR O2	110		30°/45°	21/19	3.91	975	8	5.70	220	353	13.6	405	5.40			

Arapahoe 4 Retrofit Burner Data Summary

Test	Date & Time		Description	Load MWe	Mills OOS	Burner Spin Vanes Inner/outer	OFA Dmprs % Open West/East	CR O2 % wet	Total Air kpph	OFA Flow %	O2 %	CO ppm	NOc ppm@ 3% O2	CO2 %	SO2c ppm@ 3% O2	Airhtr O2 %	Stack O2 %	LOI FERCo %	Acoustic FEGT °F
292	09/23/92	10:50	110MW, 15% OFA, 4.0% CR O2	110		30°/45°	39/42	3.82	1018	15	6.12	73	375	13.1	393	5.90	6.10	6.7	1831
293	09/23/92	13:34	As 292 w/ Mills Biased to Balance CR O2	110		30°/45°	39/42	3.85	1002	14	5.85	182	364	13.2	392	5.60	5.80	9.2	1843
294	09/24/92	08:22	110MW, 21% OFA, 3.8% CR O2	110		30°/45°	100/100	3.81	981	21	5.43	80	338	14.5	407	5.05	5.45	5.8	1866
295	09/24/92	12:05	As 294 w/ Mills Biased to Balance CR O2	110		30°/45°	100/100	3.71	931	21	5.33	49	336	14.6	404			7.2	1876
296	09/25/92	08:13	110MW, 21% OFA, 3.8% CR O2, Rpt 294	110		30°/45°	100/100	3.73	975	21	5.30	37	339	14.1	423			6.1	1840
297	09/25/92	09:42	As 296 w/ 10% OFA Bias to East, 20% OFA	110		30°/45°	100/60	3.81	961	20	5.33	27	338	13.9	417			5.7	1840
298	09/25/92	11:17	As 296 w/ 20% OFA Bias to East, 19% OFA	110		30°/45°	100/50	3.73	974	19	5.40	24	352	13.7	409			5.6	1853
299	09/25/92	13:04	As 298 (19% OFA) w/ E&W OFA Balanced	110		30°/45°	58/62	3.80	991	19	5.38	32	337	13.9	415			6.0	1844
300	09/28/92	10:58	100MW, 20% OFA, 3.85% CR O2	100		30°/45°	100/100	3.77	862	20	5.23	110	283	14.0	417	5.05	5.20	5.5	1759
301	09/28/92	12:48	100MW, 20% OFA, 4.4% CR O2	100		30°/45°	100/100	4.37	882	21	5.78	25	309	13.4	414	5.35	5.75	3.4	1785
302	09/28/92	14:24	100MW, 20% OFA, 4.9% CR O2	100		30°/45°	100/100	4.90	934	21	6.35	11	333	12.9	407	6.10	6.25	2.7	1793
303	09/29/92	10:03	HVT Tests, 111MW, 21% OFA, 4.0% CR O2	111		30°/45°	100/100	3.94	958	21	5.45	75	322	14.2	419				1838
304	09/30/92	08:43	100MW, 10% OFA, 3.8% CR O2	100		30°/45°	30/24	3.81	888	10	5.65	140	320	13.8	419	5.45	5.75	6.5	1804
305	09/30/92	10:21	100MW, 10% OFA, 4.4% CR O2	100		30°/45°	30/30	4.41	897	10	6.25	44	349	13.1	416	6.00	6.15	4.0	1831
306	09/30/92	11:38	100MW, 10% OFA, 5.0% CR O2	100		30°/45°	30/30	4.89	946	10	6.70	12	376	12.8	411	6.35	6.80	3.9	1829
307	09/30/92	13:34	100MW, 15% OFA, 5.0% CR O2	100		30°/45°	44/47	4.93	911	15	6.58	18	352	13.0	413	6.35	6.45	4.0	1809
308	09/30/92	15:00	100MW, 15% OFA, 4.4% CR O2	100		30°/45°	44/47	4.39	888	15	6.13	32	333	13.5	414	6.00	6.15	4.5	1813
309	09/30/92	16:18	100MW, 15% OFA, 3.8% CR O2	100		30°/45°	44/47	3.84	853	15	5.48	145	310	13.8	405	5.40	5.70	5.2	1834
310	10/01/92	09:38	100MW, 24% OFA, 4.9% CR O2, Old Ports	100		30°/45°	100/100	4.95	883	24	5.50	33	289	13.7	409	5.45	5.60	6.7	1807
311	10/01/92	11:31	100MW, 24% OFA, 4.4% CR O2, Old Ports	100		30°/45°	100/100	4.45	856	24	5.00	53	268	14.0	410	5.10	5.25	5.2	1840
312	10/01/92	13:37	100MW, 24% OFA, 4.0% CR O2, Old Ports	100		30°/45°	100/100	4.04	831	23	4.38	220	246	14.4	404	4.45	4.75	6.0	1859
313	10/01/92	15:25	100MW, 20% OFA, 4.0% CR O2, New Ports	100		30°/45°	100/100	4.02	830	21	4.85	65	280	14.2	408				
314	10/01/92	15:51	100MW, 20% OFA, 4.4% CR O2, New Ports	100		30°/45°	100/100	4.40	846	20	5.20	35	298	13.9	407				
315	10/02/92	09:01	100MW, 15% OFA, 4.9% CR O2, Old Ports	100		30°/45°	42/37	4.84	935	15	6.13	135	321	12.9	403	5.65	5.85	8.0	
316	10/02/92	11:03	100MW, 15% OFA, 5.6% CR O2, Old Ports	100		30°/45°	41/41	5.55	968	15	6.63	47	339	12.5	401	6.30	6.65	4.1	
317	10/02/92	12:33	100MW, 20% OFA, 6.0% CR O2, Old Ports	100		30°/45°	52/58	6.01	958	20	6.48	17	323	12.7	401	6.40	6.60	3.8	
318	10/02/92	13:58	100MW, 20% OFA, 4.9% CR O2, Old Ports	100		30°/45°	52/58	4.99	883	19	5.38	103	279	13.5	400	5.25	5.40	5.9	
319	10/02/92	15:17	100MW, 20% OFA, 5.2% CR O2, Old Ports	100		30°/45°	52/58	5.21	923	20	6.00	36	304	13.1	400	5.85	6.10	4.4	
320	10/02/92	16:37	Recheck Test # 318	100		30°/45°	52/58	4.98	913	19	5.90	45	302	13.1	398				
321	10/03/92	09:24	100MW,24%OFA,4.9%CRO2,Old,Rpt#310	100		30°/45°	100/100	4.90	854	24	4.95	89	270	13.9	406	5.05	5.20	6.6	
322	10/03/92	10:49	100MW, 24% OFA, 4.9% CRO2, Wide Open	100		30°/45°	100/100	4.98	868	25	5.10	18	292	13.7	404	5.15	5.50	4.7	
323	10/03/92	12:17	100MW, 24% OFA, 4.4% CRO2, Wide Open	100		30°/45°	100/100	4.43	849	24	4.68	37	271	14.1	408	4.55	4.80	5.2	
324	10/03/92	13:28	100MW, 24% OFA, 3.8% CRO2, Wide Open	100		30°/45°	100/100	3.79	793	24	4.03	115	249	14.7	402	3.95	4.20	6.7	
325	10/04/92	08:33	60MW, B Mill OOS, 28% OFA, 7.6% CRO2	60	B	30°/45°	100/100	7.55	633	28	8.53	7	323	10.9	388	8.25	8.50	1.7	1564
326	10/04/92	09:48	60MW, B Mill OOS, 28% OFA, 7.0% CRO2	60	B	30°/45°	100/100	7.00	600	28	8.05	10	300	11.3	391	7.75	8.05	1.8	
327	10/04/92	11:04	60MW, B Mill OOS, 28% OFA, 6.5% CRO2	60	B	30°/45°	100/100	6.47	585	27	7.73	13	289	11.6	390	7.50	7.60	2.8	
328	10/04/92	12:42	60MW, C Mill OOS, 28% OFA, 7.6% CRO2	60	C	30°/45°	100/100	7.57	613	27	8.08	11	305	11.3	383	7.95	8.15	2.2	
329	10/04/92	13:54	60MW, C Mill OOS, 28% OFA, 7.0% CRO2	60	C	30°/45°	100/100	6.98	587	26	7.68	15	292	11.6	385	7.50	7.75	3.1	
330	10/04/92	15:05	60MW, C Mill OOS, 28% OFA, 6.5% CRO2	60	C	30°/45°	100/100	6.49	557	26	7.20	21	277	12.0	384	6.95	7.25	3.2	
331	10/05/92	08:05	80MW, 25% OFA, 6.2% CRO2	80		30°/45°	100/100	6.14	767	25	7.08	6	303	12.4	392	6.80	6.95	2.4	
332	10/05/92	09:16	80MW, 25% OFA, 5.5% CRO2	80		30°/45°	100/100	5.52	731	25	6.45	5	287	12.7	386				
333	10/05/92	09:50	80MW, 25% OFA, 5.0% CRO2	80		30°/45°	100/100	5.14	696	24	6.10	7	272	13.1	389				
334	10/05/92	10:25	80MW, 25% OFA, 4.5% CRO2	80		30°/45°	100/100	4.49	648	24	5.43	21	240	13.8	395	5.15	5.30	3.3	
335	10/05/92	12:08	80MW, 15% OFA, 4.5% CRO2	80		30°/45°	42/38	4.43	672	15	5.70	180	262	13.4	390	5.45	5.65	4.2	
336	10/05/92	13:32	80MW, 15% OFA, 5.0% CRO2	80		30°/45°	42/38	5.06	692	15	6.15	97	282	13.0	387	6.05	6.10	3.0	
337	10/06/92	08:51	100MW, 20% OFA, 3.8% CRO2	100		30°/45°	59/55	3.79	840	20	4.75	237	270	14.3	409	4.70	4.90	8.3	

Arapahoe 4 Retrofit Burner Data Summary

Test	Date	Time	Description	Load MWe	Mills OOS	Burner Spin Vanes Inner/outer	OFA Dmprs % Open West/East	CR O2 % wet	Total Air kpph	OFA Flow %	O2 %	CO ppm	NOc ppm@ 3% O2	CO2 %	SO2c ppm@ 3% O2	Airhtr O2 %	Stack O2 %	LOI FERCo %	Acoustic FEGT °F
338	10/06/92	10:12	100MW, 20% OFA, 4.4% CRO2	100		30°/45°	59/55	4.32	862	20	5.25	109	288	13.8	411	4.90	5.10	4.5	
339	10/06/92	11:32	100MW, 20% OFA, 5.0% CRO2	100		30°/45°	59/55	4.89	865	22	5.78	40	306	13.3	408	5.80	5.90	3.1	
340	10/06/92	13:18	100MW, 15% OFA, 5.0% CRO2	100		30°/45°	39/35	4.99	898	15	6.35	21	351	12.7	408	6.15	6.50	3.0	
341	10/06/92	14:44	100MW, 15% OFA, 4.4% CRO2	100		30°/45°	39/35	4.45	852	15	5.75	69	324	13.3	402	5.35	5.65	5.5	
342	10/06/92	16:02	100MW, 15% OFA, 3.8% CRO2	100		30°/45°	39/35	3.79	832	15	5.28	132	303	13.5	405	5.10	5.45	4.9	
343	10/07/92	09:10	100MW, C Mill OOS, 28% OFA, 5.0% CRO2	100	C	30°/45°	100/100	4.95	923	28	6.23	128	308	12.8	408	6.00	6.25	11.4	
344	10/07/92	10:48	100MW, C Mill OOS, 28% OFA, 4.5% CRO2	100	C	30°/45°	100/100	4.46	898	27	5.45	293	281	13.4	405	5.60	5.90	13.7	
345	10/07/92	13:09	100MW, C Mill OOS, 28% OFA, 6.1% CRO2	100	C	30°/45°	100/100	6.19	990	27	7.18	78	340	12.2	403	7.05	7.45	9.5	
346	10/13/92	07:55	110MW, 24% OFA, 4.2% CRO2	110		30°/45°	100/100	4.17	970	24	5.25	22	304	14.0	537	4.85	5.25	4.0	
347	10/13/92	09:53	110MW, 24% OFA, 3.5% CRO2	110		30°/45°	100/100	3.46	924	25	4.58	56	278	14.5	536	4.45	4.65	5.2	
348	10/13/92	11:23	110MW, 24% OFA, 2.8% CRO2	110		30°/45°	100/100	2.86	893	24	3.98	111	249	14.9	530	3.85	4.05	7.8	
349	10/13/92	13:53	110MW, 15% OFA, 3.5% CRO2	110		30°/45°	40/40	3.48	1001	15	5.30	99	332	13.7	501	7.00		6.2	
350	10/13/92	15:08	110MW, 15% OFA, 4.2% CRO2	110		30°/45°	40/40	4.17	1008	15	6.03	46	357	13.1	505	5.65	5.90	4.7	
351	10/14/92	07:58	80MW, C Mill OOS, 27% OFA, 5.9% CR O2	80	C	30°/45°	100/100	5.93	779	27	7.38	17	332	12.0	421	7.30	7.60	4.5	
352	10/14/92	09:06	80MW, C Mill OOS, 27% OFA, 4.9% CR O2	80	C	30°/45°	100/100	4.99	707	27	6.23	39	287	12.9	416	6.05	6.30	7.3	
353	10/14/92	10:33	80MW, C Mill OOS, 27% OFA, 4.4% CR O2	80	C	30°/45°	100/100	4.47	688	27	5.80	88	266	13.3	417	5.55	5.85	8.4	
354	10/14/92	12:04	80MW, B Mill OOS, 27% OFA, 4.4% CR O2	80	B	30°/45°	100/100	4.40	702	27	6.00	62	259	13.2	419	5.90	6.10	8.0	
355	10/14/92	13:12	80MW, B Mill OOS, 27% OFA, 4.9% CR O2	80	B	30°/45°	100/100	4.90	731	28	6.40	40	274	12.9	416	6.30	6.40	6.2	
356	10/14/92	15:03	80MW, B Mill OOS, 27% OFA, 5.7% CR O2	80	B	30°/45°	100/100	5.73	778	27	7.05	31	298	12.1	409	7.00	7.15	5.5	
357	10/15/92	08:03	80MW, D Mill OOS, 27% OFA, 5.8% CR O2	80	D	30°/45°	100/100	5.77	791	27	7.38	24	325	12.3	411	7.25	7.35	5.8	
358	10/15/92	09:33	80MW, D Mill OOS, 27% OFA, 4.7% CR O2	80	D	30°/45°	100/100	4.64	732	27	6.30	78	274	13.2	410	6.15	6.25	8.2	
359	10/15/92	10:48	80MW, D Mill OOS, 27% OFA, 6.3% CR O2	80	D	30°/45°	100/100	6.26	813	27	7.60	27	333	12.1	411	7.45	7.60	6.2	
360	10/15/92	12:23	80MW, A Mill OOS, 27% OFA, 6.3% CR O2	80	A	30°/45°	100/100	6.26	778	27	7.08	13	335	12.5	411	6.95	7.25	4.5	
361	10/15/92	13:32	80MW, A Mill OOS, 27% OFA, 5.8% CR O2	80	A	30°/45°	100/100	5.79	762	26	6.75	16	317	12.7	408	6.60	6.80	5.0	
362	10/15/92	14:46	80MW, A Mill OOS, 27% OFA, 5.2% CR O2	80	A	30°/45°	100/100	5.18	723	26	6.35	28	300	13.0	405	6.15	6.50	6.2	
363	10/16/92	07:48	100MW, B Mill OOS, 28%OFA, 5.0% CRO2	100	B	30°/45°	100/100	4.98	924	28	6.43	43	350	13.3	409	6.40	6.60	8.6	
364	10/16/92	09:13	100MW, B Mill OOS, 28%OFA, 4.4% CRO2	100	B	30°/45°	100/100	4.34	885	28	5.90	79	332	13.5	406	5.75	5.90	9.7	
365	10/16/92	10:59	100MW, B Mill OOS, 28%OFA, 3.6% CRO2	100	B	30°/45°	100/100	3.61	851	27	5.03	212	299	14.1	398	5.05	5.15	12.4	
366	10/20/92	11:26	100MW, GAS FIRE, 26% OFA, 2.1% CRO2	100		30°/45°	100/100	2.13	777	26	2.80	166	197	10.4	0				
367	10/20/92	12:18	100MW, GAS FIRE, 26% OFA, 3.4% CRO2	100		30°/45°	100/100	3.46	854	26	4.90	35	336	9.5	0				
368	10/20/92	13:06	100MW, GAS FIRE, 26% OFA, 2.6% CRO2	100		30°/45°	100/100	2.52	793	26	3.80	53	231	10.1	0				
369	10/20/92	13:33	100MW, GAS FIRE, 8% OFA, 2.6% CRO2	100		30°/45°	30/30	2.50	821	8	4.40	15	795	9.8	0				
370	10/21/92	09:11	TRC Tests, 100MW, 24% OFA, 3.7% CRO2	100		30°/45°	100/100	3.70	830	24	4.87	35	253	14.4	402				1886
371	10/22/92	08:12	TRC Tests, 100MW, 24% OFA, 3.7% CRO2	100		30°/45°	100/100	3.73	839	24	4.84	94	251	14.7	417		5.10		1882
372	10/22/92	13:47	TRC Tests, 100MW, 24% OFA, 4.2% CRO2	100		30°/45°	100/100	4.18	855	24	5.30	78	268	14.2	407		5.25		1854
373	10/23/92	07:56	TRC Tests, 100MW, 24% OFA, 4.3% CRO2	100		30°/45°	100/100	4.29	852	24	5.34	66	270	14.2	402		5.80		
374	10/24/92	08:04	50MW, A&DMillsOOS, 32%OFA,8.4%CRO2	50	A&D	30°/45°	100/100	8.33	592	32	9.75	25	355	10.6	408	9.80	9.60	5.9	1430
375	10/24/92	09:56	60MW, A&DMillsOOS, 31%OFA,7.6%CRO2	60	A&D	30°/45°	100/100	7.67	658	31	8.80	26	360	11.3	405	10.00	8.70	5.4	1500
376	10/25/92	07:17	HVT Tests, 60MW, 26% OFA, 7.3% CRO2	60	C	30°/45°	100/100	7.37	646	26	8.70	8	312	11.1	527				
377	10/25/92	12:04	HVT Tests, 80MW, 24% OFA, 5.2% CRO2	80		30°/45°	100/100	5.10	728	24	6.55	12	262		542				
378	10/26/92	09:18	TRC Tests, 100MW, 15% OFA, 4.5% CRO2	100		30°/45°	40/40	4.54	917	15	5.99	31	310	13.8	573		5.75		1846
379	10/27/92	08:40	TRC Tests, 100MW, 15% OFA, 4.6% CRO2	100		30°/45°	40/40	4.55	900	15	5.89	21	303	14.0	466		5.95		1822
380	10/29/92	08:22	100MW GAS FIRE, 8% OFA, 3.0% CRO2	100		30°/45°	25/15	2.82	795	8	4.35	5	663	9.3	0	7.60	7.10		
381	10/29/92	09:36	100MW GAS FIRE, 8% OFA, 2.2% CRO2	100		30°/45°	25/15	2.19	774	9	3.70	35	565	9.6	4	7.00	6.60		
382	10/29/92	10:03	100MW GAS FIRE, 8% OFA, 3.5% CRO2	100		30°/45°	25/15	3.54	839	9	5.20	2	743	8.8	3				
383	10/29/92	11:01	100MW GAS FIRE, 20% OFA, 3.8% CRO2	100		30°/45°	?/?	3.82	811	20	4.70	27	436	9.1	4				