INTEGRATED DRY NO_x/SO_2 EMISSIONS CONTROL SYSTEM

BASELINE TEST REPORT

(Test Period: November 11 - December 15, 1991)

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DISCLAIMER

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 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) urea injection 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 tested.

This report documents the first baseline test results conducted during the program. The baseline tests were conducted with the original burners and auxiliary equipment and represent the unmodified boiler emissions. The burner design of Arapahoe Unit 4 results in relatively high NO_x levels ranging from 740 to 850 ppm (corrected to 3% O_2, dry) over the load range. Excess air level was the primary factor influencing NO_x emissions. During normal boiler operations, there was a wide range in NO_x emissions, due to the variations of excess air, boiler load and other, secondary parameters. SO_2 emissions ranged from 350 to 600 ppm (corrected to 3% O_2, dry) and reflected variations in the coal sulfur content.

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ACFM	Actual Cubic Feet per Minute, gas flow
Btu	British Thermal Unit
B&W	Babcock & Wilcox
CEM	Continuous Emissions Monitor
CFM	Cubic Feet per Minute
CGA	Cylinder Gas Audit Test
DOE	U. S. Department of Energy
DRB-XCL™	B&W Low-NO_x Burner Design (dual register burner - axial control)
DSCF	Dry Standard Cubic Feet of Gas
DSCFM	Dry Standard Cubic Feet per Minute of Gas
EPRI	Electric Power Research Institute
HVT	High Velocity Thermocouple, suction pyrometry
LNB	Low-NO_x Burner
MMBtu	1,000,000 Btu
MMD	Mass Mean Diameter
MWe	MegaWatts (electrical)
MWg	MegaWatts (gross load)
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter under the 10 Micron Diameter Size

LIST OF DEFINITIONS

ppm	Parts Per Million
ppmc	Parts Per Million Corrected to 3% O_2 Level
PSCC	Public Service Company of Colorado
psi	Pounds per Square Inch
RATA	Relative Accuracy Test Audit
SCF	Standard Cubic Foot, measured at 1 atmosphere and 60°F

EXECUTIVE SUMMARY

1.0 INTRODUCTION

The Department of Energy (DOE) sponsored Integrated Dry NO_x/SO_2 Emissions Control System program is a DOE Clean Coal Technology III demonstration program being conducted by Public Service Company of Colorado (PSCC) at the Arapahoe Generating Station Unit 4. This utility boiler is a 100 MWe, down-fired unit and burns a low sulfur western coal. The project goal is to demonstrate 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) urea injection for additional NO_x removal; and 3) dry sorbent injection and duct humidification for SO_2 removal. It is anticipated the integrated system will achieve the NO_x and SO_2 reductions at costs lower than alternative methods and that the technologies will integrate synergistically to provide operational advantages not achievable with the individual processes. A final program objective will test the effectiveness of the integrated system with a high sulfur content coal.

This report documents the baseline tests conducted during the program. The baseline tests were conducted with the original burners and auxiliary equipment to establish the pre-modification boiler emissions levels. The baseline test results will be compared with the results of the tests conducted after the installation of low-NO_x burners and implementation of other NO_x and SO_2 emissions reduction techniques. The baseline program included parametric tests which systematically varied boiler operating conditions known to affect NO_x emissions. In addition, a long term monitoring period collected boiler emissions data for six days during normal boiler operation under system dispatch load control.

2.0 OBJECTIVES

The baseline testing was performed to establish boiler NO_x, SO_2, and other emissions representative of Arapahoe Unit 4 prior to the extensive emissions control modifications. The baseline test objectives were to:

- Establish baseline NO_x and SO_2 emissions levels from the boiler.
- Characterize the effect of boiler load, boiler operating O_2 level, number of mills in service and other boiler operating parameters on NO_x emissions.

- Establish other boiler operating variables, or constraints, such as minimum operating O_2, CO emissions, fly ash and bottom ash carbon levels, air in-leakage to the flue gas system, pulverized coal fineness, particulate emissions, particulate size distribution, furnace exit gas temperatures, and SO_3 levels.
- Determine that the boiler was in reasonable operating condition to prevent baseline characterization of the boiler emissions under unusual circumstances.
- Monitor emissions for an extended period of time under normal boiler operating conditions and with system dispatch load control.

3.0 DISCUSSION OF RESULTS

The primary focus of the parametric and long term load following tests was to establish the NO_x emissions and to a lesser extent the SO_2 emissions from the boiler. SO_2 emissions are largely affected by the fuel sulfur content in the coal, but were monitored during all phases of the testing. NO_x, on the other hand, is greatly influenced by various boiler operating parameters. These parameters were characterized during the parametric tests.

3.1 <u>NO_x Emissions</u>

The Arapahoe Unit 4 NO_x emissions were found to be relatively high compared to other boiler and burner designs. The parametric test results determined that boiler load and operating O_2 level were the most significant factors influencing the NO_x emissions, as indicated in Figure S-1. The full load data at the normal 4.0 to 4.5 percent O_2 operating levels exhibited boiler NO_x emissions of 850 ppmc (corrected to 3% O_2, dry gas condition) or 1.16 lb/MMBtu.

Boiler load was shown to have a significant influence on NO_x emissions, given a constant boiler O_2 level. NO_x emissions decreased by approximately 100 ppmc when the boiler load was reduced from 100 to 80 MWe and decreased by another 100 ppmc as the load was reduced to 60 MWe.

The effect of boiler operating O_2 level on NO_x emissions is indicated by the slope of the NO_x/O_2 data in Figure S-1. The average data at each load showed a characteristic slope of approximately 145 ppm $NO_x/\%O_2$, which indicates a high sensitivity of NO_x to O_2 level. Other boiler firing configurations with lower baseline NO_x levels exhibit a NO_x emission sensitivity to O_2

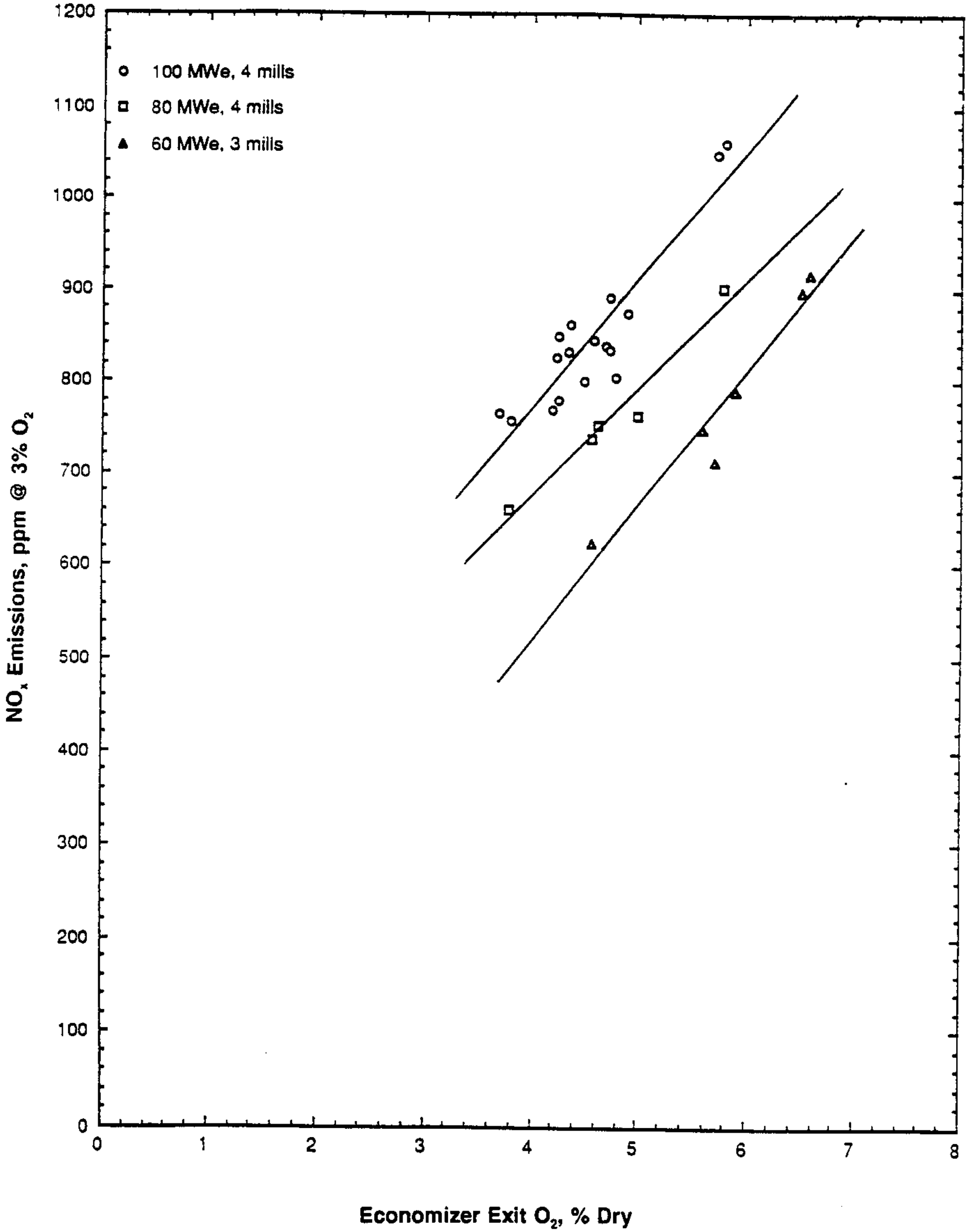

Figure S-1. Baseline NO_x Emissions as a Function of Economizer Exit O_2

level in the range of 30-100 ppm/%O_2. The Arapahoe Unit 4 data indicated that a relatively small change in boiler operating O_2 could be responsible for a large change in NO_x emissions.

Although both load and O_2 have a strong effect on NO_x emissions over the operating load range, the effects tend to counteract one another. The excess air, or O_2, typically increases with decreasing load on many utility boilers as a result of steam temperature, combustion, minimum air flow or other operational requirements. This was the case for Arapahoe Unit 4, which operated at an economizer exit O_2 level of 6.0% at 60 MWe. Higher O_2 levels at low load counteracted the reduced NO_x characteristic with decreasing load described previously. Figure S-2 shows NO_x and O_2 over the normal load range and shows a relatively flat NO_x versus load characteristic, due to these counteracting effects.

The results in Figure S-2 include NO_x versus load for both the parametric and long term test data. The parametric NO_x data (circle symbols) indicate that emissions did not decrease substantially below 80 MWe, due to the effect of increasing O_2 levels. The data gathered from the long term monitoring show that the average NO_x emissions (square symbols) at each load range agree very well with the parametric data and indicate similar trends with load. In addition, the long term NO_x data extend below the lowest parametric test load and show that the NO_x emissions increased to levels higher than the full load conditions. This effect was due to very high O_2 levels used during minimum load operation.

A second trend observed in the long term data was the wide range of NO_x emissions variation for a given load. The error bars in Figure S-2 indicate ±1 standard deviation of NO_x about the mean emission. These variations were highest at the lowest and highest load ranges. This wide range of NO_x emissions was the result of varying boiler O_2 levels, load, number of mills in service, and perhaps periods of transient boiler operation (parameters not controlled during the long term monitoring process).

3.2 SO_2 Emissions

SO_2 emissions were not affected by boiler operation and were dependent on the sulfur content in the fuel. Figure S-3 shows the SO_2 results during the long term monitoring tests, similar trends were seen during the parametric tests. The long term and parametric boiler SO_2 emissions

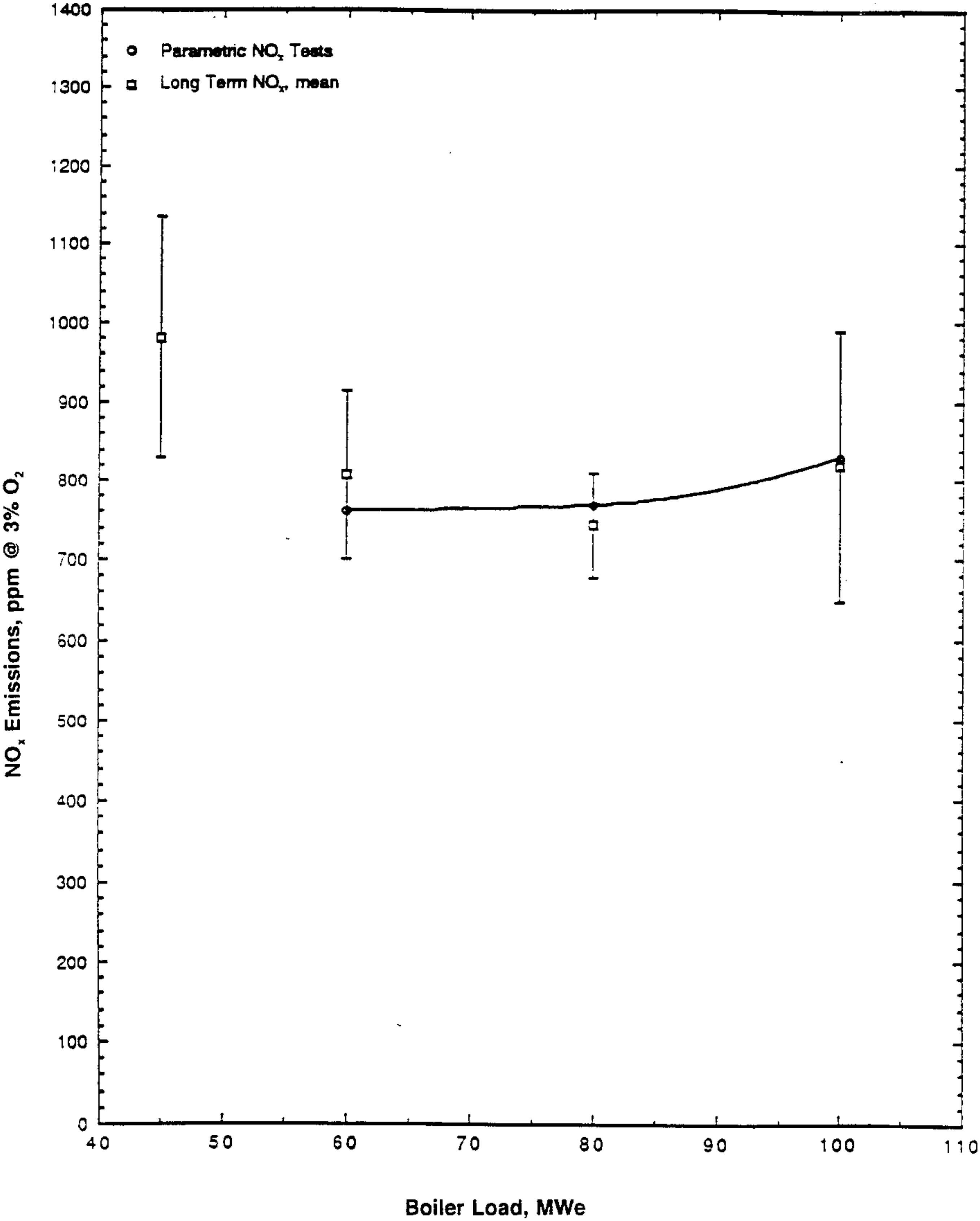

Figure S-2. NO_x versus Load for Long Term and Parametric Testing

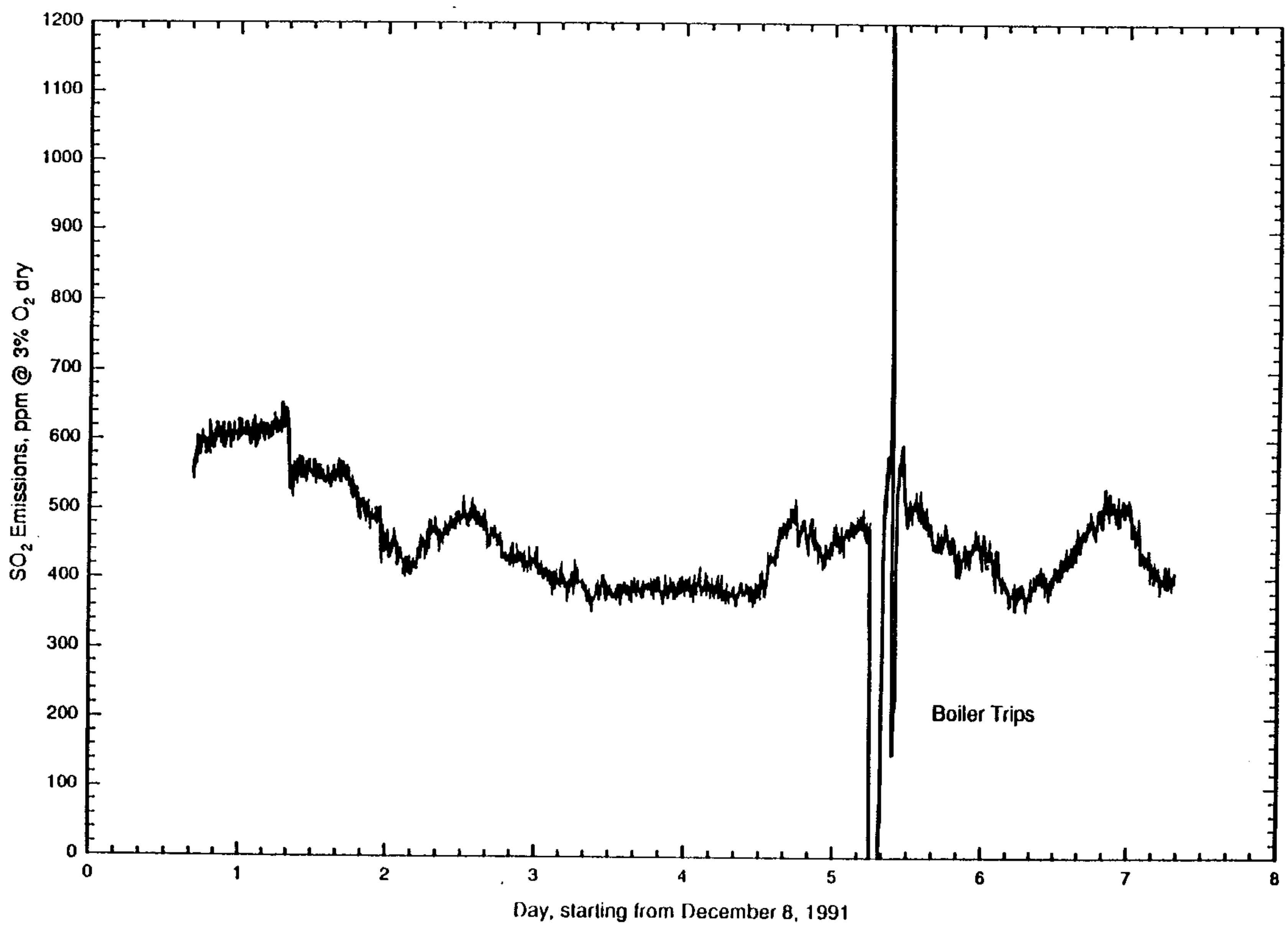

Figure S-3. SO_2 Emissions for the Long Term Monitoring Period, December 8 through 15, 1991 ranged from 350 to 600 ppmc (corrected to 3% O_2, dry, or 0.67 to 1.14 lb/MMBtu). The data show that the SO_2 levels were initially high at the start of the long term test and decreased over the next few days. The varying SO_2 levels were due to changes in the sulfur content of the coal. The plant's coal is supplied by two mine sources with different sulfur contents. The varying fuel sulfur was also confirmed by the coal sample analyses. Although the coal's sulfur content varied, the other coal properties did not vary enough to affect NO_x emissions to any measurable degree.

3.3 Other Emissions

Other measurements were also performed to evaluate boiler performance. Minimum economizer exit O_2 levels were found to be typically 3.5 to 4.0 percent and were limited by elevated CO and ash carbon levels. Under normal conditions, CO levels were below 50 ppm and fly ash carbon levels averaged 5 percent. Fly ash carbon levels increased with decreasing O_2 levels.

SO_3 measurements showed levels below 1 ppm and were consistent with the type of fuel burned in the boiler. Particulate emissions were also documented.

Distribution of the pulverized coal to the burner pipes was not uniform and may have adversely affected the minimum O_2 levels achieved by the boiler. This non-uniform coal distribution may also adversely affect the operation of the low-NO_x burners and should be further investigated as part of the start up for the new burners.

4.0 CONCLUSIONS

The following conclusions can be drawn for the baseline test results:

- Due to its burner design, NO_x emissions were relatively high for Arapahoe Unit 4 and ranged from 740 to 850 ppmc (1.01 to 1/16 lb/MMBtu) over the load range.
- Excess air level was the primary factor influencing NO_x emissions.
- A wide range of NO_x emissions resulted from normal boiler operation, due to the variations of O_2 and load.
- SO_2 emissions ranged from 350 to 600 ppmc (0.67 to 1.14 lb/MMBtu) and reflected variations in fuel sulfur content.
- Fuel distribution to the burners should be investigated with the start up of the low-NO_x burners.

1.0 INTRODUCTION

This report presents the results from the first test 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. This 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 significant reductions in SO_2 and NO_x emissions through the integration of existing and emerging technologies. The technologies to be integrated are: 1) a down-fired low-NO_x burner with overfire air; 2) urea injection for additional NO_x removal; and 3) dry sorbent injection and duct humidification for SO_2 removal. Figure 1-1 illustrates the technologies to be demonstrated and their relation to the boiler system.

During the demonstration program, these emissions control systems will be integrated and optimized to achieve up to 70 percent reductions in NO_x and SO_2. It is anticipated the emissions control system will achieve these reductions at costs lower than other currently available technologies. It is also anticipated that these technologies will integrate synergistically. Normally, 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 EPRI has shown that NH_3 can suppress the NO to NO_2 oxidation. In this 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 will be to test the effectiveness of the integrated system on a high sulfur content coal.

Because of 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 integrated system.
- Baseline combustion system/urea tests. Performance of urea injection with the original combustion system.
- Low-NO_x Burner (LNB)/ Overfire Air (OFA) tests.

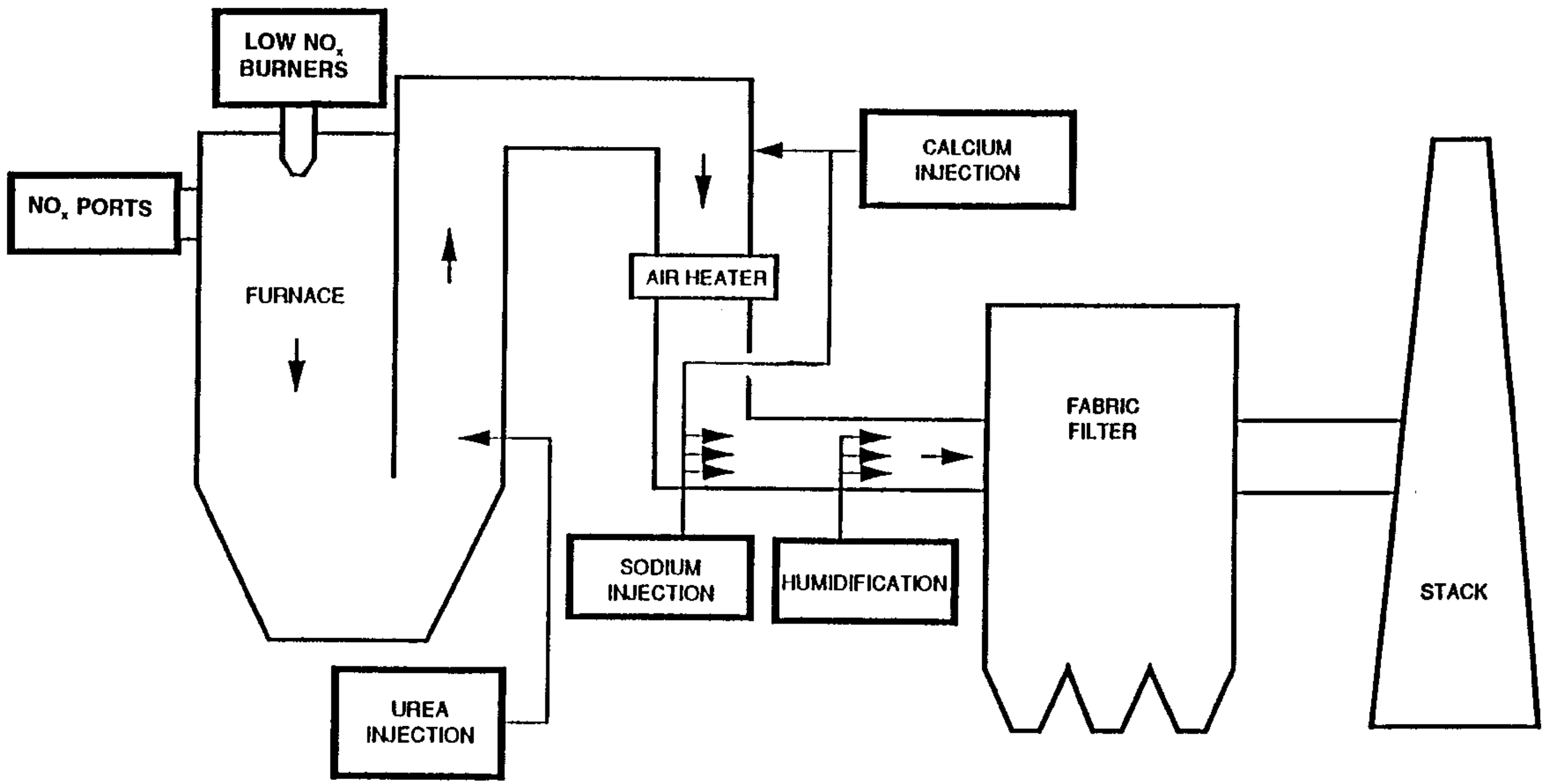

Figure 1-1. Arapahoe Unit 4 Integrated SO_2/NO_x Emission Control System

- LNB/OFA/Urea tests. NO_x reduction potential of the combined low-NO_x combustion system and urea injection.

- LNB/OFA/Sodium Injection. SO_2 removal performance of sodium-based sorbent.

- LNB/OFA/Sodium-Based Sorbent Injection/Urea. Integrated system performance.

- LNB/OFA/Calcium-Based Sorbent Injection. Duct injection, economizer injection with and without urea.

- High Sulfur Coal tests.

The baseline test results presented in this report were the initial performance tests of the boiler and were conducted with the original burners and auxiliary equipment. These test results will be utilized to compare with the future test results of the different NO_x and SO_2 emissions reduction technologies demonstrated during the program.

2.0 PROJECT DESCRIPTION

The following subsections will describe the demonstration program members, the key aspects of the demonstration program, the current burner and boiler system and the objectives of the baseline tests.

2.1 BACKGROUND

This project's goal is to demonstrate the removal of up to 70% of the NO_x and 70% of the SO_2 emissions from coal fired utility boilers. The project will establish an alternative emissions control technology integrating a combination of several processes, while minimizing capital expenditures and limiting waste production to dry solids that are handled with conventional ash removal equipment. These processes include low-NO_x burners and urea injection for NO_x control, sodium or calcium-based sorbent injection for SO_2 control, and flue gas humidification to enhance the reactivity of the SO_2 control compound.

The low-NO_x burners reduce NO_x formation by a combination coal/air combustion staging and the use of air ports. Urea injected downstream of the burners reacts chemically with NO_x to form nitrogen and water.

Sodium- and calcium-based reagents react with the SO_2 in the flue gas to form sulfites and sulfates, lowering the emissions of SO_2. Humidification of the flue gas increases the reactivity of the calcium reactants. The solid reacted sorbent is removed with the flyash in the existing fabric filter.

Sodium-based sorbent injection can convert nitrogen oxide (NO) to nitrogen dioxide (NO_2), which is one form of NO_x, and is visible in the stack plume under certain conditions. Ammonia, from the urea injection, reduces the NO_2 concentration by reacting with it. Thus, system integration will alleviate a potential undesirable side effect of SO_2 removal.

The demonstration program is directed at down-fired boilers, but the process can be utilized on other types of boilers. This project will be the first U.S. application of low-NO_x burners to a down-fired boiler.

The project objectives also include determining the cost effectiveness of the process and demonstrating that the process has no negative effects on normal boiler operation. The examination of negative effects includes the creation of any other unwanted releases of gaseous or solid emissions.

2.2 PROCESS DESCRIPTION

The Integrated Dry NO_x/SO_2 Emissions Control System is a multi-part process that uses low-NO_x burners, NO_x ports, and urea injection to control NO_x. Sodium-based sorbent injection or calcium-based sorbent injection, combined with in-duct humidification, is used for SO_2 removal.

B&W DRB-XCL™ Burner

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 bonded to the fuel molecules. Thermal NO_x forms when nitrogen in the combustion air dissociates and oxidizes at flame temperatures in excess of 2800°F.

The B&W DRB-XCL™ burner achieves increased NO_x reduction effectiveness by incorporating fuel staging along with air staging. Most low-NO_x burners reduce NO_x by the use of air staging. Air staging reduces the amount of combustion air during the early stages of combustion. Fuel staging involves the introduction of the fuel downstream of the flame under fuel-rich conditions, causing hydrocarbon radicals to be generated. These radicals reduce NO_x levels. This is accomplished by the coal nozzle/flame stabilizing ring design of the burner. In addition, combustion air is accurately measured and regulated to each burner to provide balanced air and fuel distribution for optimum NO_x reduction and combustion efficiency. Further, the burner assembly is equipped with adjustable burner vanes to provide swirl for flame stabilization and fuel/air mixing.

NO_x Ports

NO_x ports are used in conjunction with low-NO_x burners to increase the effectiveness of air staging. NO_x ports provide the final air necessary to ensure complete combustion. Conventional single jet NO_x 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 air swirl control.

The combined use of the low-NO_x burners and dual zone NO_x ports is expected to reduce NO_x emissions by up to 70%.

Urea Injection

NO_x reduction in utility boilers can also be accomplished by injecting urea into the furnace. The urea reacts with the NO_x and oxygen in the gases and forms nitrogen, carbon dioxide, and water. A urea injection system is capable of removing 40% to 50% of the remaining NO_x from the combustion process.

The optimum urea injection reaction temperature range is between 1700°F and 1900°F. At lower temperatures, side reactions can occur, resulting in the undesirable formation of ammonia. At higher temperatures, additional NO_x is formed. Chemical additives can be injected with the urea to widen the optimum temperature range and minimize the formation of ammonia.

The urea is generally injected into the boiler as an aqueous solution through atomizers. The atomizing medium can be either air or steam. The urea and any additive are stored as a liquid and pumped into the injection atomizers.

Dry Reagent SO_2 Removal System

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

Dry sodium-based reagent injection systems reduce SO_2 emissions; however, 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 tests have shown that ammonia slip from the urea injection system 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

In addition to selection of the proper injection point, the effectiveness of the calcium-based reagent in reducing SO_2 emissions can be increased by flue gas humidification. Flue gas conditioning by humidification involves injecting water into the flue gas stream 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 flow rate and increasing its 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% SO_2 removal is expected when calcium reagents are used in conjunction with flue gas humidification.

2.3 PROJECT PARTICIPANTS

PSCC is the Project Manager for the project, and is responsible for all aspects of project performance. PSCC will engineer the dry injection system and the modifications to the flyash system, provide the host site, train the operators, provide selected site construction services, provide start up services and maintenance, and assist in the testing program.

B&W is responsible for engineering, procurement, fabrication, installation, and shop testing of the low-NO_x burners, NO_x ports, humidification equipment, and associated controls. They will also assist in the testing program, and will provide for commercialization of the technology. Noell, Inc. is responsible for the engineering, procurement and fabrication of the urea system. Fossil Energy Research Corp. will conduct the testing program. Western Research Institute will characterize the waste materials and recommend disposal options. Colorado School of Mines will provide research in the areas of bench scale chemical kinetics for the NO_x formation reaction. Stone & Webster Engineering will assist PSCC with the engineering efforts. Cyprus Coal, Amax Coal, and Coastal Chemical, Inc. will supply the coal and urea for the project.

2.4 BOILER 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 constructed in the early 1950's and was designed to burn Colorado lignite or natural gas. The station currently burns a Colorado coal or natural gas. A side sectional view of the boiler is shown in Figure 2-1.

The furnace firing configuration is a down-fired system employing a single row of 12 burners located on the roof and arranged across the width of the furnace. A single division wall separates the furnace into east and west halves, each having six burners. The secondary air also enters the roof of the furnace and surrounds each burner. After passing through the burner, the combustion gas flows down the furnace and turns upward to flow through the convective sections on the boiler back pass. After reaching the burner level elevation, the flue gases pass through a horizontal duct and into the tubular air heater.

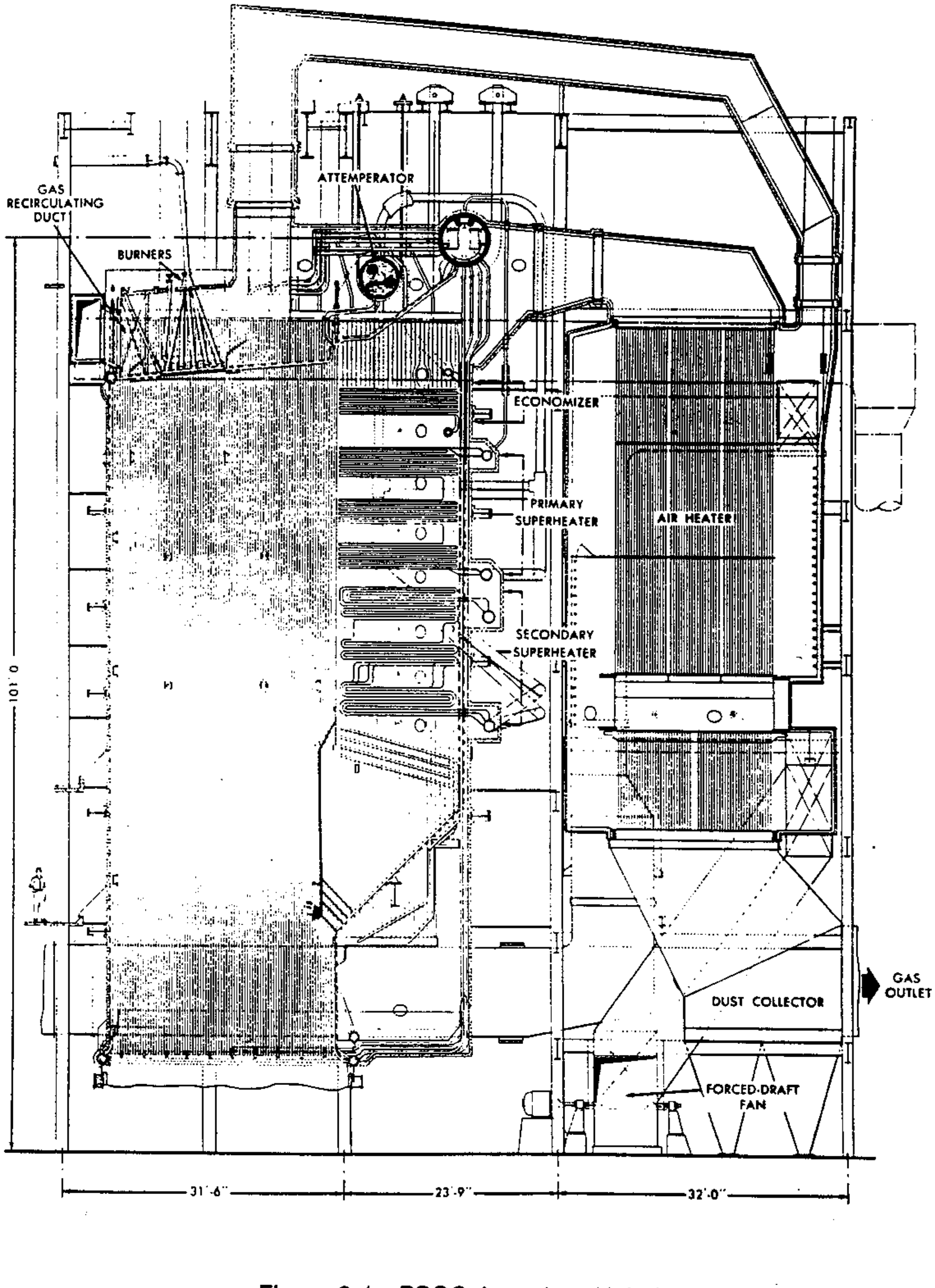

Figure 2-1. PSCC Arapahoe Unit 4

Each burner consists of a rectangular coal/primary air duct which fans out to form 20 separate nozzles upon entering the furnace. These nozzles are arranged in a four by five rectangular pattern on the furnace roof. The secondary air windbox surrounds the burner and allows air flow around each of the nozzles of a single burner. The result is a well mixed checkerboard pattern of coal/primary air and secondary air streams for each burner.

The burners are numbered one through twelve from west to east. Each of the four attrition mills supplies primary air and coal to three of the burners. The coal piping allows each mill to supply two burners in one furnace half and one in the other half. Figure 2-2 shows the burner firing configuration and mill coal distribution arrangement of the four mills. The secondary air ducts are positioned behind the burners and include a secondary air damper for each burner. When a single burner is removed from service, the secondary air flow is also stopped by closing the associated secondary air damper. The damper is manually controlled at the burner deck and is intended for on/off duty.

After passing through the tubular 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 gases into a common stack for Units 3 and 4.

2.5 BASELINE TESTS ON ARAPAHOE UNIT 4

The baseline tests on Arapahoe Unit 4 were performed to demonstrate and document the initial emissions of NO_x and SO_2, without any modifications to the boiler or burner systems. These tests will serve as the baseline or the basis for comparison to the emissions reduction technologies that will be implemented during the program. Emissions measurement and characterization of the unit operation are the key objectives of the baseline tests.

The baseline test program was performed during the time period from November 11 to December 15, 1991.

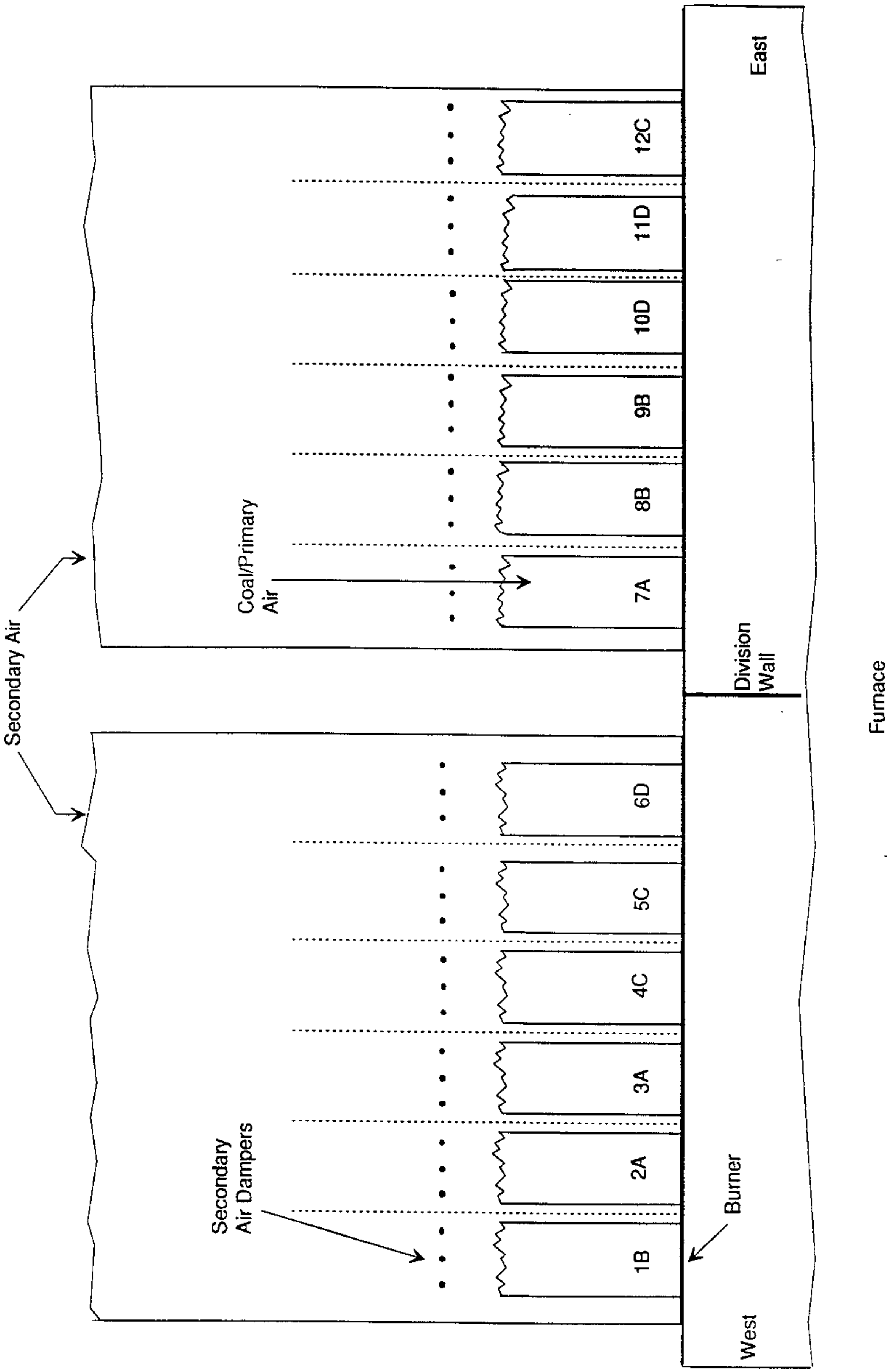

Figure 2-2. Burner Mill Arrangement

3.0 TEST MATRIX AND MEASUREMENT METHODS

The baseline test program included two phases, a parametric test program and a long term monitoring test program. The parametric testing included individual tests at various loads, excess air settings and other boiler operating parameters, such as the number of mills in service. Each parametric test was performed with specific boiler operating conditions which could be repeated or duplicated at a later time. During the long term emissions monitoring test phase, the unit was run under dispatch control and unit operation was not influenced by the tests crews. Under normal system dispatch operations, boiler load typically varied from 60 to 100 MWe. For test purposes, full load operation was defined as 100 MWe net, which was slightly less than the maximum attainable load which can be generated by the unit.

3.1 PARAMETRIC TESTS

The initial parametric testing utilized a predetermined test matrix of the boiler operating conditions of load, excess air and the number of mills or burners in service. These three parameters were considered to be the most important in terms of NO_x emissions and were also parameters that could be varied on a day-to-day basis, depending upon operator preferences or the limitations imposed by auxiliary equipment operation.

Parametric tests were conducted at net generation loads of 60, 80 and 100 MWe. Although constant load operation was not typical for the unit, except during minimum and full load operation, consistent unit operation was necessary to allow comparison with test data to be acquired during the later phases of the test program.

Excess air levels can significantly affect NO_x formation and were controlled during each parametric test. Excess air was evaluated by monitoring the economizer exit O_2 levels with a separately installed probe grid. Although the control room instrumentation included the economizer exit O_2 measurement, additional instrumentation was required to accurately monitor the O_2 as well as other gas species of NO_x, SO_2, CO and CO_2. Additional gas emission monitoring probes were installed at the air heater exit and the stack locations and were routinely monitored during the parametric tests. The specific locations of these probes are discussed in Section 3.3.

3.2 LONG TERM MONITORING TESTS

During long term monitoring, gas emission measurements were conducted while the unit operated in its normal day to day configuration. A six-day test period was set aside for the long term monitoring test phase. During this time period, the boiler was operated under normal dispatch control, with no interference or changes imposed by the test crews. A data logger was used to record the gaseous emissions data, as well as a load signal from the boiler. The load signal was the gross load (MWg), because it was the only available load indication which could be monitored without interfering with the boiler control system.

During this long term period, the gas analysis system was modified to permit unattended operation; however, instrument calibrations were performed manually. Instrument calibrations, data recovery and system check out were performed twice during each 24 hour period of this test phase. Only a single gas sample point was monitored during the long term testing. The stack location was chosen as the single gas sample station monitored for the long term testing. A probe installed in the Unit 4 ductwork was located just upstream of the common Unit 3 and 4 stack. The stack was considered a primary CEM sample location for the gaseous instrumentation system that will be installed for the later stages of the program; therefore, these data will allow direct comparison with future long term measurements.

3.3 GAS ANALYSIS INSTRUMENTATION

The gas analysis monitors and sampling system were installed in a mobile gas analysis laboratory, which was located on the west side of the boiler. The gas analysis instruments included:

- Teledyne Model 326 electrochemical O_2
- ThermoElectron Model 10 chemiluminescent NO/NO_x
- Horiba Model 2000 NDIR CO
- Horiba Model 2000 NDIR CO_2
- Western Research Model 721A NDUV SO_2

A grid of 12 probes in a six wide by two high array was installed in the existing six ports at the economizer exit test location. Individual sample probes were constructed of stainless steel tubing and included sintered stainless steel filters. Heat traced and insulated sample tubing transported a separate gas sample for each probe to the gas analysis laboratory. A schematic of the gas sample system is shown in Figure 3-1. The individual sample streams were dried and the flow rate measured to obtain accurate blends of sample from any desired combination of probes. Figure 3-2 shows the grid of these probes located at the economizer exit duct. Two probe depths were used; the short probes were located at one-fourth of the duct depth, while the long probes were located at three-fourths of the duct depth. The probe placement divided the duct into equal area sections for representative gas sampling from the economizer exit duct.

Additional gas sample probes were installed at the air heater exit and the stack locations. The alternate sample locations will provide additional gas emission measurement data, which will be necessary during the subsequent NO_x and SO_2 reduction tests. 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, respectively. Figure 3-3 shows the location of the probes at the air heater exit. These sample probes and tubing are 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. In addition to the grid at the air heater exit location, a single probe with a heated sample line was installed in order to accurately monitor the SO_2 and NO_2 emissions from the boiler. This sample stream was maintained at 250°F to prevent moisture condensation and loss of these gas sample species.

3.4 RELATIVE ACCURACY TEST AUDIT

TRC Environmental Consultants was contracted to perform a Relative Accuracy Test Audit (RATA) to verify the accuracy of the combustion gas analysis system. These field tests consisted of a cylinder gas audit (CGA) utilizing EPA Protocol 1 gases. This audit was performed for the following gaseous species: O_2, NO_x, SO_2, and CO. Two levels of gas concentration, which were similar to the levels measured at Arapahoe, were utilized. The cylinder gases were injected into the measurement system between the sample probe and the sample line, at the extraction point on the duct. Table 3-1 shows the results of the RATA test.

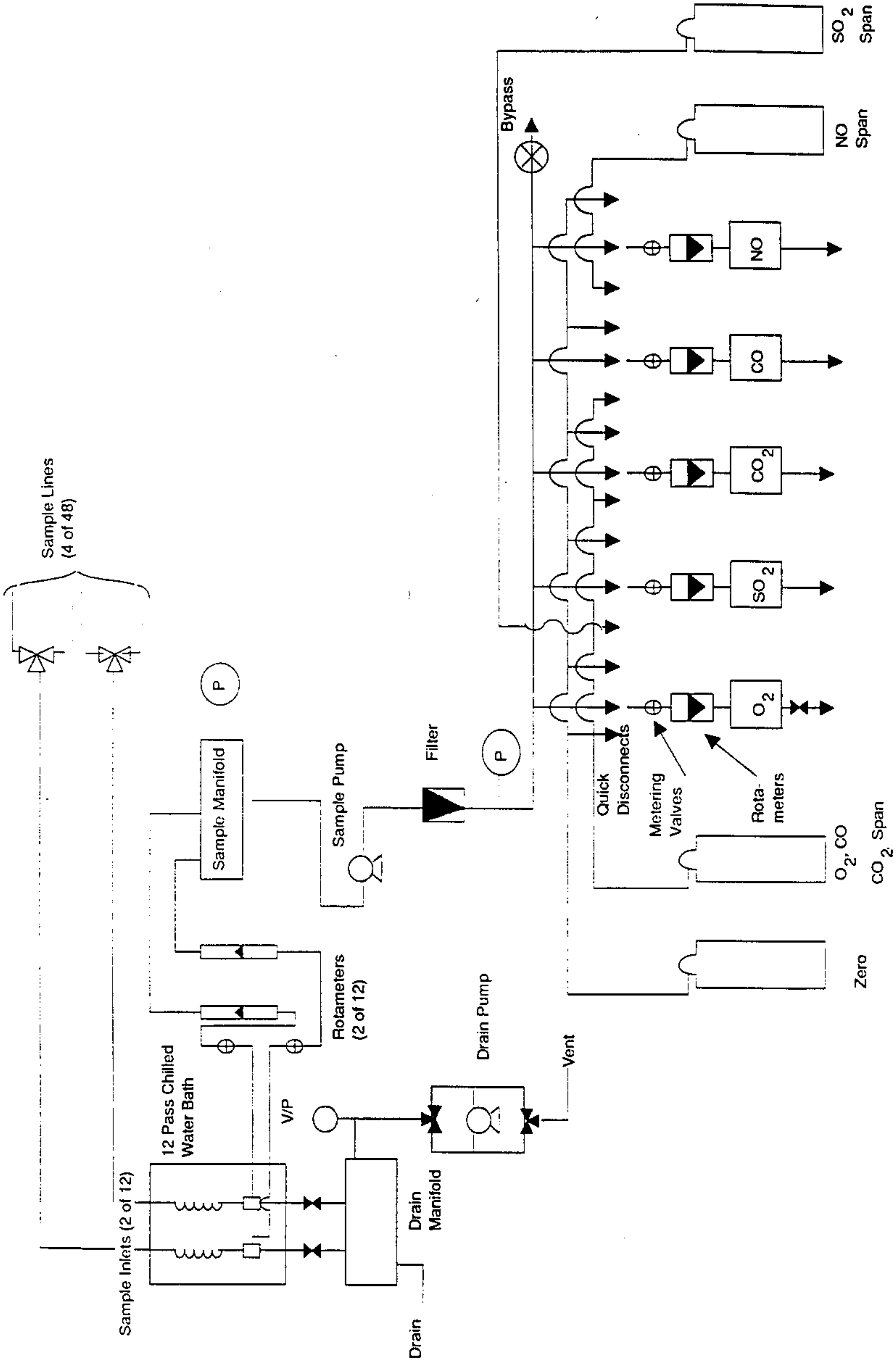

Figure 3-1. Gas Analysis System Schematic

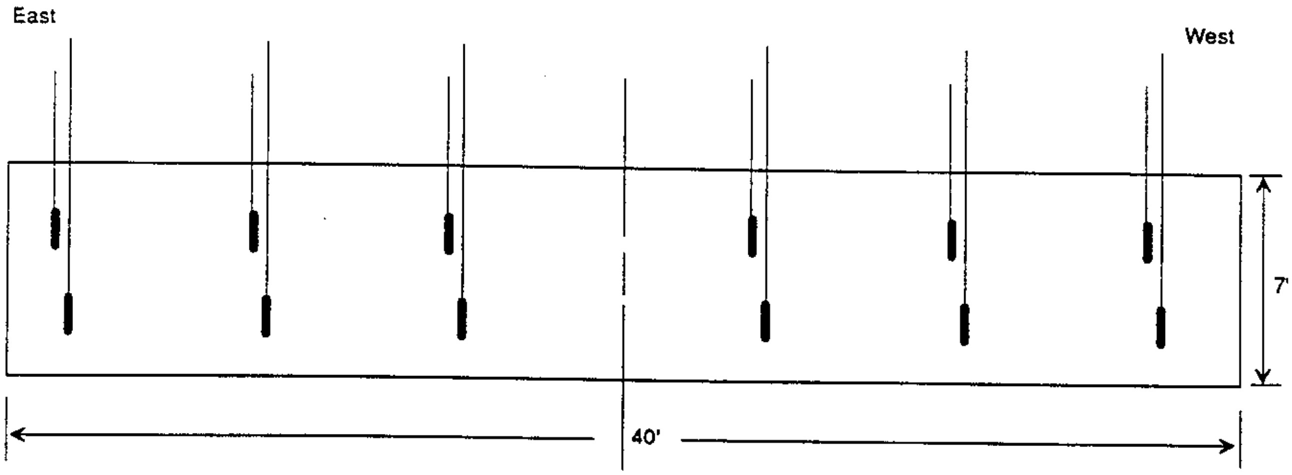

Figure 3-2. Economizer Exit Probe Locations

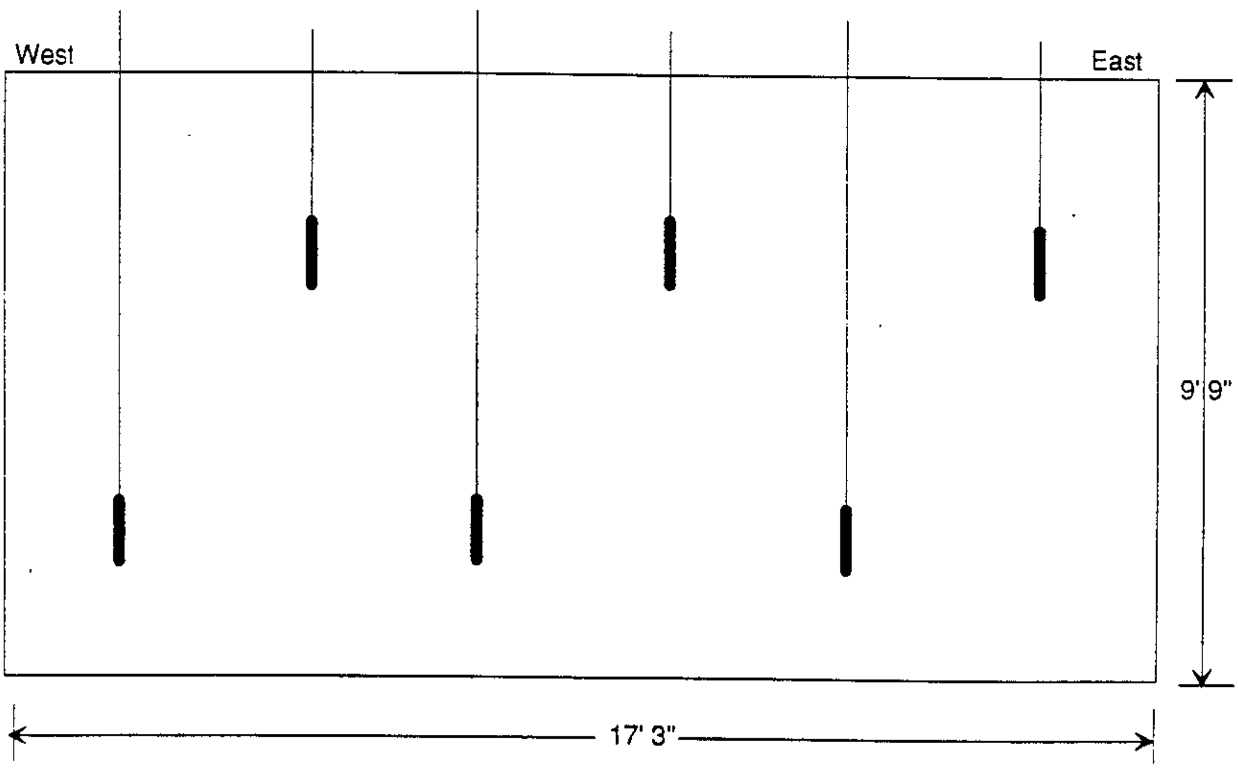

Figure 3-3. Air Heater Exit Probe Locations

Table 3-1

CEM CYLINDER GAS AUDIT

Parameter	Cylinder Value	Measurement Value	% Difference
Sulfur Dioxide, SO_2 (ppm)	250	246	1.46
	388	389	-0.26
Nitrogen Oxides, NO_x (ppm)	484	502	-3.59
	771	807	-4.46
Carbon Monoxide, CO (ppm)	450	489	-7.98
	744	821	-9.38
Oxygen, O_2 (%)	4.85	4.79	1.25
	7.72	7.79	-0.90

The results indicated that the difference between the reference gas and the FERCo instrument response was within the ±15 percent limits of the CGA test methodology (40 CFR 60 Appendix F). The O_2, NO_x, and SO_2 emissions showed good relative accuracy during these verification tests. In most cases, the gas measurement accuracy was within ±5 percent, with exception of the CO instrument. The eight to nine percent error of the CO instrument was within the 15 percent limit, but was higher than expected. Cross checks between different calibration gas bottles did not uncover a reason for the CO instrument discrepancy.

3.5 GAS INSTRUMENTATION OPERATION

The instruments utilized during the baseline test program were contained in a mobile gas analysis laboratory. The system is manually operated to permit calibration or sampling at the various sample points as required. The system was housed in an environmentally controlled enclosure to permit stable instrument temperature and minimal instrument calibration drift.

Instrument calibration could be performed on demand and was performed prior to every test. In cases where a single test extended longer than an hour or two, more frequent calibrations were performed. For the parametric tests, analyzer calibrations were performed at least every 2 hours during a long test. Frequent calibration allowed the detection and elimination of instrument drift problems. Cross checks were also performed to confirm that new calibration gas bottles were in agreement with older bottles in use.

4.0 COAL ANALYSIS RESULTS

Two types of coal samples were obtained during the baseline testing, the 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 were representative of an as-fired coal sample. Pulverized coal samples were obtained to determine the coal fineness and evaluate the operation of the mills.

4.1 AS-FIRED COAL COMPOSITION

As-fired or feeder coal samples were obtained on each test day. These samples were used to determine if significant changes in the fuel composition occurred during the tests. Selected samples were submitted for coal and ash analysis by an independent laboratory. Individual and average coal analysis results are presented in Table 4-1. In general, the individual analyses were consistent with each other, and indicated a fairly stable coal supply for the duration of the testing. The coal parameters which could affect the test results include the fuel heating value, fixed carbon or volatiles content or significant changes of the moisture content. However, the results indicate that these parameters remained relatively stable. The ash content varied by 2.5 percentage points among the three individual analyses. While the ash content variation may affect the ash collection system, it will not greatly affect NO_x or SO_2 emissions.

One coal parameter which varied during the baseline test was the fuel sulfur content, which directly affected the SO_2 emissions from the unit. The coal analyses indicated that the fuel sulfur content ranged from 0.43 to 0.58 percent, which was a variation of nearly 35 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. As will be shown in later sections, significant SO_2 emission variations were found during the parametric and long term monitoring phases of the baseline test program.

4.2 FINENESS MEASUREMENTS

A single set of pulverized coal fineness samples was taken from each of the 12 individual burner pipes. Samples from the three pipes from a given mill were then composited for fineness analysis. The mill samples were sieved with 50, 100 and 200 mesh screens and plotted on a Rosin-Rammler graph. The fineness results for each mill are shown in Figure 4-1.

Table 4-1

PSCC ARAPAHOE UNIT 4 BASELINE COAL ANALYSIS

Test Number	2	21	35	
Date	11/11/91	11/19/91	12/4/91	Averages
Proximate Analysis				
%Moisture	10.11	11.53	11.34	10.99
%Ash	10.39	7.75	8.98	9.04
%Volatile	35.02	35.28	34.98	35.09
%Fixed Carbon	44.48	45.44	44.70	44.87
Total	100.00	100.00	100.00	100.00
HHV, Btu/lb	11106	11076	11108	11097
FC/V	1.27	1.29	1.28	1.28
Prox Analysis, MAF				
%Volatile	44.05	43.71	43.90	43.89
%Fixed Carbon	55.95	56.29	56.10	56.11
HHV, Btu/lb	13970	13722	13941	13877
Ultimate Analysis				
%Carbon	61.98	61.94	62.07	62.00
%Hydrogen	4.46	4.31	4.32	4.36
%Nitrogen	1.37	1.53	1.53	1.48
%Chlorine	0.04	0.00	0.00	0.01
%Sulfur	0.46	0.58	0.43	0.49
%Oxygen	11.23	12.36	11.33	11.64
%Ash	10.39	7.75	8.98	9.04
%Moisture	10.11	11.53	11.34	10.99
Total	100.04	100.00	100.00	100.01
Ult Analysis, MAF				
%Carbon	77.95	76.73	77.90	77.53
%Hydrogen	5.61	5.34	5.42	5.46
%Nitrogen	1.72	1.90	1.92	1.85
%Chlorine	0.05	0.00	0.00	0.02
%Sulfur	0.58	0.72	0.54	0.61
%Oxygen	14.12	15.31	14.22	14.55
Hardgrove Grind		42	44	43
%Moisture		2.84	2.38	2.61

Table 4-1 (continued)

PSCC ARAPAHOE UNIT 4 BASELINE COAL ANALYSIS

Test Number	2	21	35	
Date	11/11/91	11/19/91	12/4/91	Averages
Fusion Temp Reducing, °F				
Initial	2510	2412	2464	2462
Softening	2591	2475	2527	2531
Hemispherical	2640	2529	2574	2581
Fluid	2700	2624	2680	2668
Fusion Temp Oxidizing, °F				
Initial	2540	2507	2549	2532
Softening	2667	2567	2586	2607
Hemispherical	2700	2634	2654	2663
Fluid	2700	2700	2700	2700
Ash Analysis, %				
SiO_2	59.29	52.34	56.99	56.21
Al_2O_3	23.62	26.15	24.41	24.73
Fe_2O_3	4.02	3.68	3.18	3.63
CaO	4.18	6.32	5.00	5.17
MgO	1.33	1.35	1.61	1.43
Na_2O	1.04	0.52	1.27	0.94
K_2O	1.01	0.71	1.00	0.91
TiO_2	0.74	0.77	0.75	0.75
MnO_2	0.07	0.07	0.07	0.07
P_2O_5	0.72	1.64	0.97	1.11
SO_3	2.95	4.63	3.23	3.60
StO*	0.24	0.41	0.28	0.31
BaO*	0.29	0.39	0.48	0.39
LiO				
Undetermined	0.50	1.02	0.76	0.76
Total	100.00	100.00	100.00	100.00
Base/Acid Ratio	0.1384	0.1587	0.1468	0.148
Silica Ratio	86.152	82.179	85.34	84.557
T_{250}	2900	2845	2900	2882
Fouling Index	1.04	0.52	1.27	0.94
Slagging Index	2548	2435	2502	2495

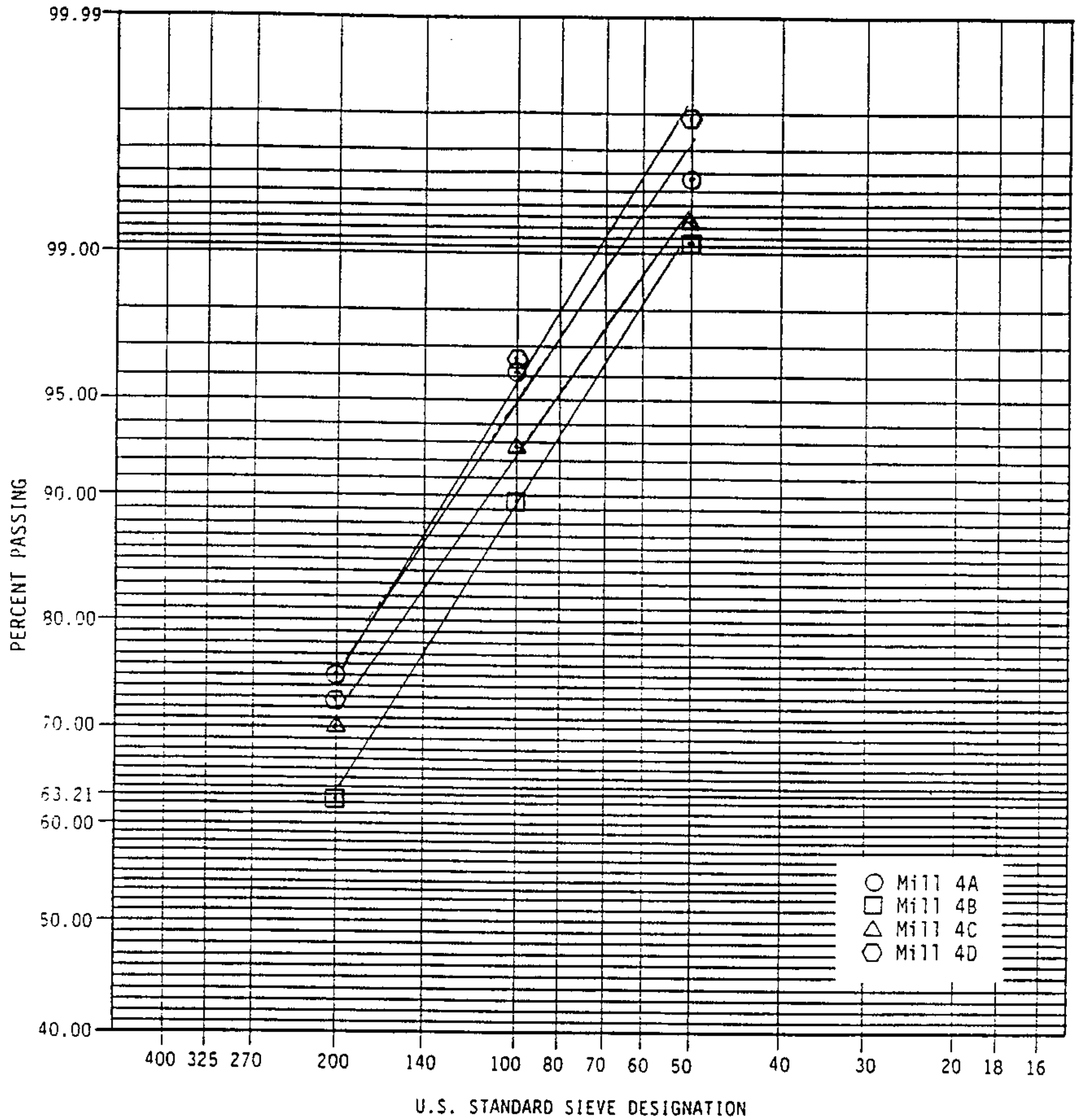

Figure 4-1. Mill Fineness Results

Although the data show some variation, the Unit 4 attrition mills appear to grind the coal to an acceptable fineness. All mills allowed a grind of less than one percent retained on the 50 mesh screen (better than 99 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. All mills, with the exception of mill 4B, yielded a fineness greater than 70 percent passing through a 200 mesh screen. The 4B mill results were 62 percent through 200 mesh, significantly lower than the others. The reason for this reduced performance was not clear, although plant personnel indicated that mill 4B was considered to be one of the mills in need of an overhaul. The condition of mill 4B may be responsible for its decreased performance relative to the other mills.

Midway through the baseline testing, mill 4D was removed from service and its hammers replaced. However, this was not expected to significantly change the overall performance of this mill, since 4D showed good performance prior to the hammer replacement.

4.3 BURNER BALANCE

The 12 pulverized coal burner pipe samples were individually weighed prior to compositing and sieving of the four mill fineness samples. Since the samples from each pipe were collected for a set period of time and flow rate, these individual sample weights provided an approximate coal flow distribution among the burner pipes of a single mill. Using this approximation, the relative coal flow to the burners was estimated and is shown in Figure 4-2. The arrangement of the burner pipes corresponds to the west to east orientation of the burners along the top of the furnace.

The ideal case shown in Figure 4-2 assumes an equal coal fraction of 8.33 percent per burner pipe (12 burner pipes or 1/12 of the total flow per pipe). Since the total coal flows through the individual mills were not necessarily equal, the results were calculated with the assumption that each mill had 25 percent of the flow and the sample weights were used to determine the relative split for the mill. In actual operation, the relative coal split for the four mills could vary on a day-to-day, 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. The feeder system on

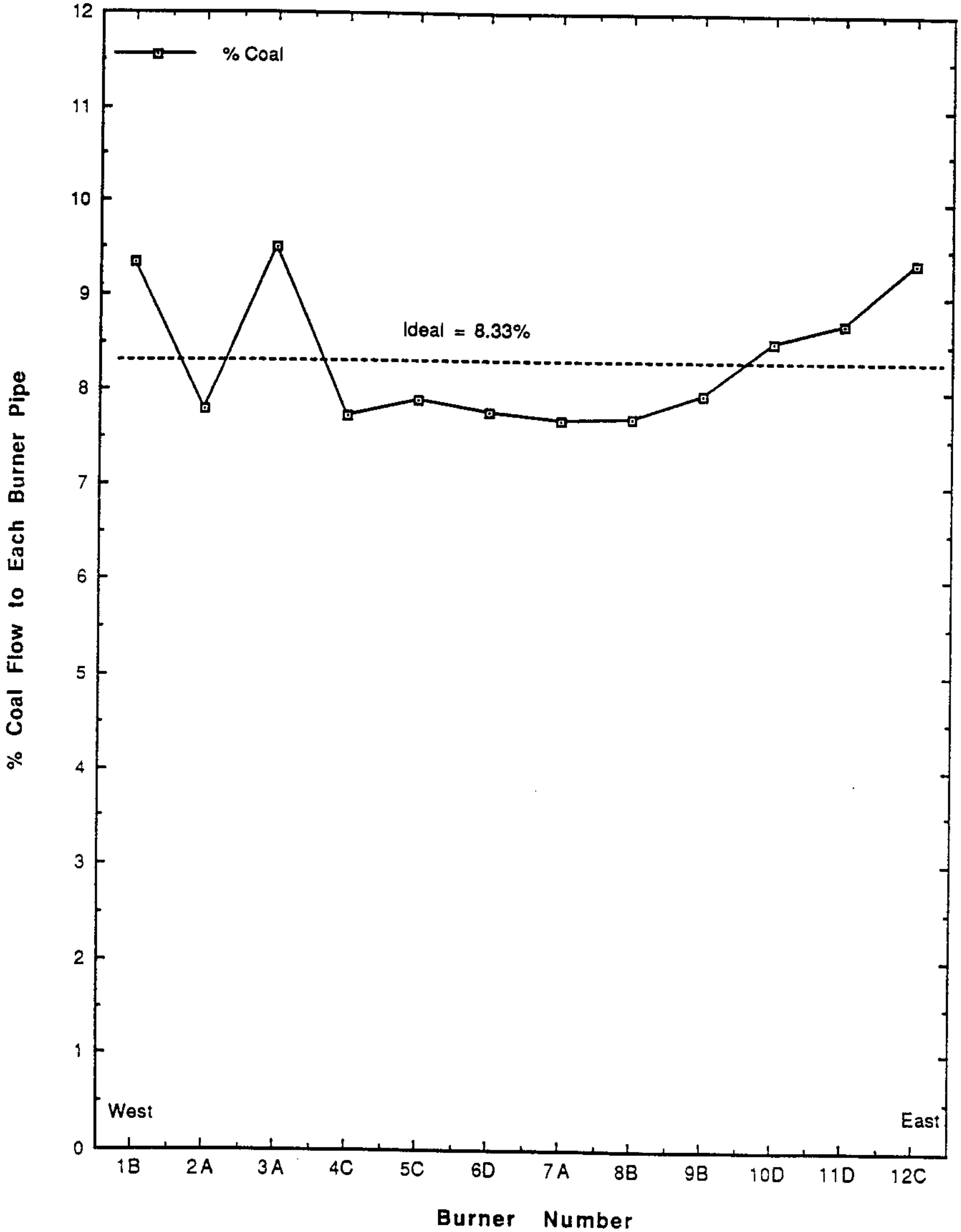

Figure 4-2. Burner Pipe Coal Distribution.

Arapahoe Unit 4 does not include gravimetric feeders; therefore, the relative feeder flows cannot be easily determined or controlled.

In any case, the individual burner pipe coal flow estimates indicated that there were significant variations among the three pipes of every mill. As can be seen in Figure 4-2, burner pipes 1B, 3A and 12C were particularly high relative to the ideal coal flow rate, while the 10D and 11D burners of Mill 4D were also high and happened to be located adjacent to one another. The net effect of the pipe loading data and the location of the burners is that most of the coal was delivered to the walls of the furnace and less to the center of the furnace.

This suspected coal flow imbalance can have a significant effect on the combustion process and NO_x emissions as well. Additional details on the combustion effects will be given during the discussion of the boiler gaseous emissions in a following section. However a significant coal flow imbalance can cause excessive carbon losses and/or a limitation to the minimum air flows which can be sustained within the limit of acceptable carbon losses. Since the data indicted that the coal flow was concentrated along the sidewalls of the boiler, carbon burnout problems would be expected in these areas. Conversely, the region near the center of the furnace would have less coal and a greater availability of air, which could lead to locally high NO_x emissions.

5.0 PARAMETRIC NO_x EMISSIONS RESULTS

Table 5-1 summarizes the parametric tests performed during the baseline test series. The summary indicates the primary boiler variables such as load, steam flow, control room O_2 levels and mill patterns. Additional data on the economizer exit average O_2, NO_x, CO, CO_2, and SO_2 emissions are also shown. In addition, the average O_2 levels at the air heater exit and the stack location are included. Finally, the summary includes the average carbon content for the fly ash, bottom ash and baghouse ash samples that were collected.

The difference between NO and NO_x emissions was monitored on most tests; however, the difference was not significant within the limits of detection. NO_2 emissions, if any, were at the level of less than 10 to 20 ppm and the NO_x versus NO levels were not generally distinguishable from each other. For the purposes of this report, NO and NO_x emissions are used interchangeably.

Primary test conditions for the parametric tests were boiler load, excess air (economizer exit O_2) and mill patterns. These test parameters represent the primary factors influencing the NO_x emissions for this unit. Three loads of 100, 80 and 60 MWe net were tested. All load values cited in this parametric test section are the unit net MWe. Economizer exit O_2 levels varied above and below the typical or "normal" settings. However, the absolute level depended upon the load and, to some extent, the preferences of the control room operator.

5.1 EFFECT OF LOAD UPON NO_x EMISSIONS

Figure 5-1 summarizes the parametric NO_x data with a cross plot between average economizer exit O_2 and NO_x for the three loads tested. The full load data (100 MWe) are represented by the circle symbols in the figure, while the 80 and 60 MWe data are represented by the squares and triangles, respectively. The unshaded or open symbols represent data with the normal number of mills, which were 4 mills in service for the 100 and 80 MWe data and 3 mills in service (one mill out of service) for the 60 MWe data. The data shown in Figure 5-1 indicate that for a given economizer exit O_2 condition, NO_x emissions increased with increasing load. Typical full load NO_x emissions were 850 ppmc (parts per million corrected to 3 percent O_2 concentration, dry) at

Table 5-1. Summary of Parametric Baseline Tests

Test No.	Date & Time	Control Room Data: Load	O2	Opacity	Mills	Steam Flow	Gaseous Emissions: O2 Econ Out	CO	NOxc	CO2	SO2c	O2 AHO	O2 Stack	Ash Carbon: Fly Ash	Bottom Ash	Bag House
		MWe	% wet	%	OOS	e4pph	%	ppm	ppm@3%	%	ppm@3%	%	%	%	%	%
1	11/11/91 09:35	104	3.15	2.0		840	3.70	78	766	13.50	379	3.30	3.65			
2	11/11/91 14:44	104	3.40	2.0		830	4.37	38	862	13.00	384	4.30	4.40	5.02		
3	11/11/91 17:04	104	4.55	2.0		840	5.80	34	1061	11.70	367	5.80	5.90			
4	11/12/91 13:32	100	3.30	2.0		880	4.90	41	874	12.90	394	4.80	5.05			
5	11/12/91 15:27	100	2.25	2.0		880	4.20	210	769	13.60	412	4.15	4.35	8.15		
6	11/13/91 14:25	100	3.30	2.0		870	4.23	44	825	14.60	388	4.10	4.55			
7	11/13/91 16:24	99	3.40	2.0		865	4.25	47	849	14.52	394	4.25	4.70			
8	11/14/91 09:08	101	3.35	2.3		870	4.73	40	834	14.20	380	4.20	4.65	6.85		
9	11/14/91 16:37	100	3.30	2.0		870	4.78	60	804	14.23	399	4.30	4.65			
10	11/15/91 09:37	99	3.50	3.0		865	4.25	60	780	14.60	370	4.15	4.45			
11	11/16/91 08:11	81	3.90	3.0		682	4.63	38	752	14.27	395	4.55	4.70	3.86	0.30	
12	11/16/91 13:00	79	2.90	2.5		683	3.78	112	659	15.08	394	3.70	4.00	5.97	0.55	
13	11/16/91 15:45	80	5.10	3.0		685	5.78	37	901	13.20	381	5.70	5.75			
14	11/17/91 08:05	59	4.90	2.5	B	455	5.58	43	749	13.35	382	5.50	5.70	2.99		
15	11/17/91 10:43	58	3.60	2.0	B	450	4.56	85	624	14.28	394	4.35	4.75	6.39		
16	11/17/91 12:49	58	6.10	2.5	B	445	6.58	38	916	12.38	380	6.55	6.78			
17	11/17/91 14:28	58	5.70	2.5	C	450	6.50	37	898	12.50	380	6.22	6.50			
18	11/17/91 16:09	58	5.10	2.5	C	445	5.88	37	790	13.13	402	5.80	5.97			
19	11/19/91 08:16	100	3.40	3.0	A	870	4.40	70	938	14.60	585	4.00				
20	11/19/91 09:00	100	3.50		A	870	4.60	1000	722	14.20	571	4.30	5.01			
21	11/19/91 11:30	99	3.50	2.5	A	865	4.40	75	976	14.45	542	4.30	4.65			
22	11/19/91 13:13	99	3.50	2.0	B	870	4.23	95	925	14.65	537	4.10	4.30			
23	11/19/91 14:55	100	3.10	2.0	C	870	4.18	50	895	14.78	523	3.95	4.45			
24	11/19/91 16:32	100	3.30	2.0	D	870	4.20	75	891	14.80	508					
25	11/19/91 17:30	100	3.50			865	4.35	50	832	14.60	483					
26	11/19/91 22:50	80	4.40	3.0		672	5.00	35	762	13.95	457	4.90	5.55			
27	11/20/91 00:24	79	4.40	3.0	A	675	5.25	43	840	13.68	440	5.15	5.70			
28	11/20/91 02:00	80	4.80	2.5	B	680	5.15	43	824	13.75	468	5.05	5.55			
29	11/20/91 03:48	80	4.40	2.5	C	680	4.95	38	815	14.03	414					
30	11/20/91 05:03	79	4.30	2.5	D	680	4.88	40	814	14.05	415					
31	11/21/91 08:45	101	2.80	2.5		885	3.80	105	756	15.00	390	3.62	3.85	10.94	6.86	
32	11/21/91 11:41	101	4.10	2.0		890	4.73	37	891	14.15	391	4.75	4.85	4.35	3.46	
33	11/21/91 14:43	100	5.10	2.0		900	5.72	35	1049	13.20	379	5.60	5.85	2.58		
34	12/03/91 09:00	99	3.93	2.3		877	4.50	57	800	14.40	416	4.40	4.58	5.38	0.76	5.25
35	12/04/91 09:00	100	3.98	2.0		882	4.70	43	839	14.20	411	4.55	5.13	3.51	1.13	6.30
36	12/05/91 09:00	100	3.85	2.0		875	4.58	43	845	14.30	488	4.33	4.83	5.28	0.53	6.38
37	12/07/91 08:30	79	3.87	2.0		680	4.57	41	737	14.30	570	4.40	4.70	2.55	0.11	2.82
38	12/08/91 09:00	61	4.73	2.3	C	500	5.69	35	712	13.30	570	5.50	5.75	1.20		2.56

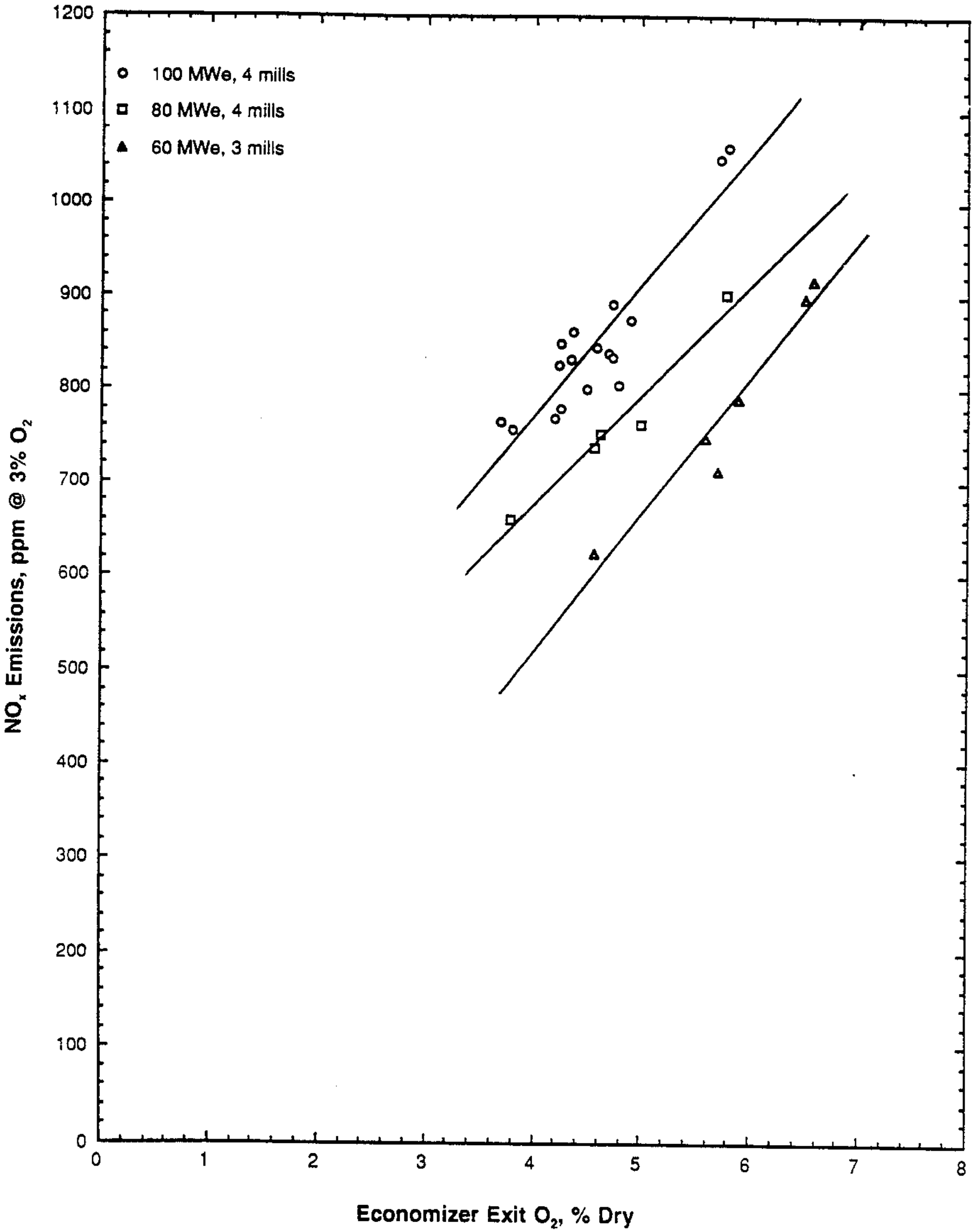

Figure 5-1. Baseline NO_x Emissions as a Function of Economizer Exit O_2

O_2 levels of approximately 4.5 percent. At 80 MWe, the typical emissions were reduced to 780 ppmc.

During normal operation, the O_2 level was typically increased as the load decreased in order to maintain adequate steam temperatures. For instance, as the load decreased to 60 MWe, the O_2 level typically increased from 4.5 to 5.8% during normal operation. The combination of reduced load and higher O_2 levels counteracted one another to produce NO_x emissions of 760 ppmc, which were similar to the NO_x emissions at 80 MWe.

The typical NO_x emissions at normal O_2 levels are replotted in Figure 5-2 as a function of boiler load. The highest NO_x emissions occurred at full load conditions and decreased with decreasing load. Below 80 MWe, NO_x emissions decreased slightly, due to the counteracting effects of increasing O_2 level and reduced heat release rate. The normal or typical O_2 levels are also included in Figure 5-2 and show that O_2 levels increase with decreasing load. Since the O_2/NO_x relationship of Unit 4 was relatively steep, higher O_2 prevented significant NO_x reductions with decreasing load. With normal O_2 levels, NO_x emissions ranged from nominally 760 to 850 ppmc over the load range of 60 to 100 MWe (1.04 to 1.16 lb/MMBtu).

These average NO_x levels should be used with caution, since these represent values which could be significantly varied by small changes in operating O_2 level. The variation of NO_x emissions under typical Unit 4 operation will be further examined in the long term monitoring tests.

5.2 EFFECT OF O_2 LEVEL ON NO_X EMISSIONS

As indicated in the previous subsection, the boiler excess air level had a significant effect on NO_x emissions. Data in Figure 5-1 indicate that the effects of excess air, or operating O_2 level, are significant and as important as the boiler load on the NO_x emissions. The curves for the three boiler loads have similar NO_x/O_2 slopes. The typical O_2 influence was approximately 145 ppm NO_x/percent O_2, which indicates a very strong dependance upon O_2. For full load operation, the variation of O_2 results in 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 optional parameter affecting NO_x on this unit.

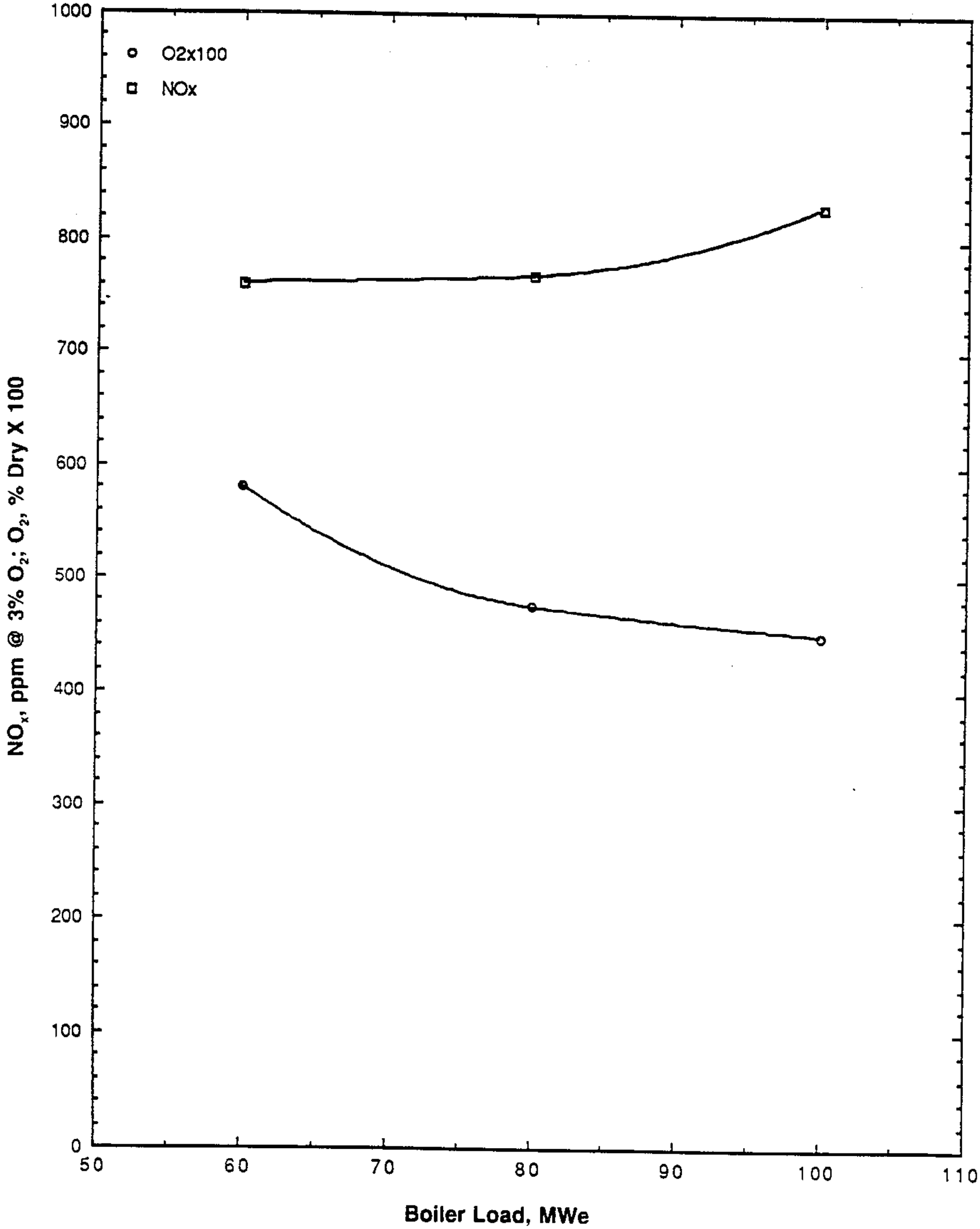

Figure 5-2. NO_x and O_2 Levels versus Load with Typical Boiler Operation

The large influence of operating O_2 was considered a characteristic of this burner and boiler design. A similarly high dependance upon operating O_2 has been experienced in other field test evaluations of boilers with high baseline NO_x emissions. Note that the variation of NO_x for a constant load was as much as 300 ppm, as the O_2 changed by 2.0 percentage points. This NO_x effect was as high or higher than the NO_x emission variation with a 60 to 100 MWe load change at a constant O_2 level. As a result, excess air or operating O_2 level was the dominant factor affecting NO_x emissions for Arapahoe Unit 4.

5.3 EFFECT OF MILL PATTERN UPON NO_x EMISSIONS

The full load and 80 MWe tests described above were performed with all four mills in service; however, the mill capacity permits one mill to be off line while maintaining full load. Full load, three mill operation can be required under conditions where a mill is removed from service for maintenance or mill/feeder failure conditions. Since combustion within the furnace could be directly affected by the loss of a mill, NO_x emissions could also be altered by the three mill operation. Tests were performed to briefly examine NO_x emissions with different three mill patterns at operating loads of 80 and 100 MWe. Each of the four mills was removed from service and the emissions recorded under both load conditions. Only a single economizer exit O_2 level was tested for each mill configuration, in order to limit the baseline test time requirements.

Figure 5-3 shows the previous four mill tests at 80 and 100 MWe, as well as the additional three mill NO_x data. The three mill data are signified by the shaded symbols in Figure 5-3. At 100 MWe, the three mill NO_x emissions were found to be approximately 100 ppmc higher than an average of the four mill data at an equivalent O_2 level. The cluster of the three mill NO_x emission data points, which represents operation with the different mills removed from service, indicates that the influence of the particular mill removed from service was not a significant factor. Although the effect of the different mills may have a secondary effect upon NO_x emissions, additional data points would be required to accurately determine the significance of this parameter. Note that the range of NO_x emissions for these tests was equal to or lower than the normal variations of the baseline tests with all four mills in service.

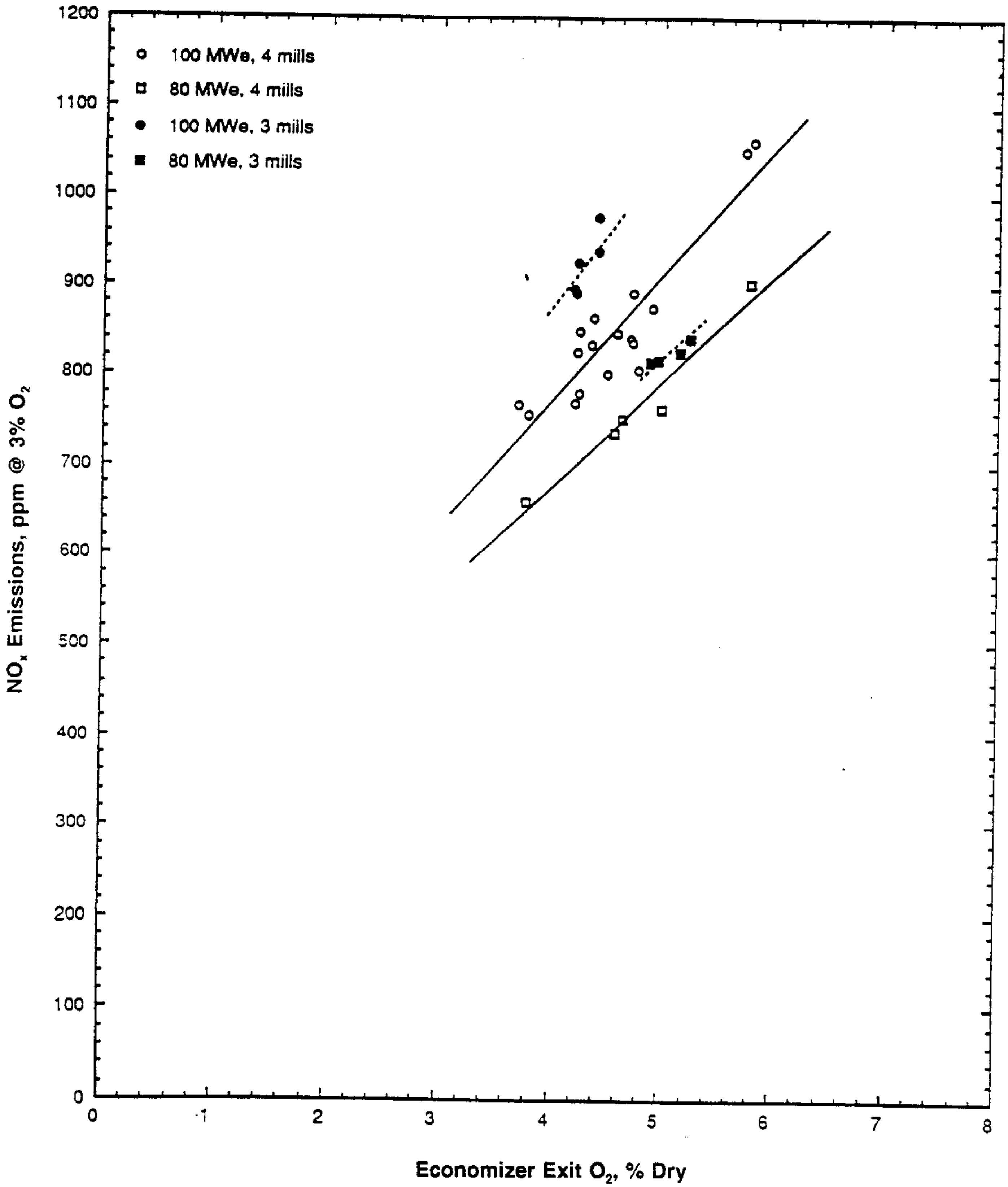

Figure 5-3. Baseline NO_x Emissions Comparison between Three and Four Mill Operation.

A locally higher burner zone combustion intensity is the probable reason for the higher NO_x emissions with three mill operation. With only three mills, the combustion intensity for the nine operating burners rises as a result of the 33 percent increase in coal and air flows. Confining the flames in a smaller area will raise local flame temperatures and intensify mixing patterns, which can increase NO_x emissions.

The effects of three mill operation at 80 MWe, while similar to the full load data, were lower in magnitude. Three mill operation resulted in NO_x emissions only marginally higher (20-60 ppmc) than the average 80 MWe, four mill data. There was some uncertainty in these 80 MWe results, due to lower NO_x emissions for a reference four mill test performed on the same day. The four mill emission test was lower than the average of all other 80 Mwe data and indicated that the difference between three and four mill emissions were higher than the averages shown in Figure 5-3. In any case, the differences were not as significant for 80 MWe as compared to the 100 MWe results.

Operation of the Unit at 60 MWe was usually performed with three mills in service (typically either the 4B or 4C mill is pulled off line). Figure 5-1 previously showed all data at 60 MWe with either mill 4B or 4C off line. No significant change in the NO_x emissions could be noted between the removal of either of these two mills. Since 60 MWe tests were considered lower priority than higher load settings, other mill combinations were not included in the test matrix.

5.4 EMISSION PROFILES AT THE ECONOMIZER EXIT DUCT

The O_2 and NO_x data discussed previously were the average values measured from the 12 point sampling grid at the economizer exit. In addition to the composite samples, individual probes were sampled to determine emission profiles within the duct. This allowed the performance of combustion diagnostics and the ability to detect any significant fuel/air imbalances in the unit.

The O_2 levels from the control room instrumentation could be significantly different from the grid values. The control room O_2 monitors were four conventional in situ Zirconia cell probes. The four control room monitors are installed across the duct width just upstream of the economizer exit grid. The control room O_2 probe placement was weighted towards the center of the duct.

This is commonly the region of lowest O_2 on typical utility boiler applications, due to the existence of air infiltration along the boiler or furnace side walls.

Figure 5-4 shows a typical profile for the gaseous emissions measured with the economizer exit probe grid of 12 individual probes. Each location within the duct is signified by its approximate location on the graph; east to west along the width and top to bottom along the duct depth. The orientation of the 12 burners corresponded with the width of the duct from the west side to the east side. The grid measurements indicated high O_2 levels for the probes located at the A and F locations on the extreme east and west sides of the furnace. The higher O_2 levels long the sides of the duct may indicate air in-leakage into the flue gas stream. Location of significant duct or boiler air leaks was not uncovered for the unit. However, the balance draft design of the unit will permit air infiltration at any point between the measurement section and the location of the burners. The higher O_2 levels at the side walls may be the cumulative effect of infiltration from small leaks rather than a result of a major duct problem. Another possible explanation may be associated with the air flows at the burner zone. The high O_2 may be the result of combustion air that does not mix well with the pulverized coal flames, due to the burner location near the side walls or perhaps a windbox to furnace air leak. This unused combustion air may flow along the side walls, become entrained with the flue gas and will be detected by the economizer exit probe grid.

As a result of this O_2 pattern, the average economizer exit grid O_2 measurements were higher than the control room indications. Control room monitor locations roughly corresponded to B through E of the duct width locations, which were the probes with the lowest O_2 levels. As a result, the control room monitors were always significantly lower than the average grid O_2 levels. Another factor to consider when comparing the control room and mobile laboratory O_2 levels is that the control room monitor measures O_2 on a wet basis, while the mobile laboratory readings are on a dry gas basis. Thus, the control room instruments will read about 8% lower than the mobile laboratory results for a comparable sample.

NO_x emissions (corrected to 3% O_2) are also included in the lower plot in Figure 5-4. In general, the reverse trend of the O_2 plot can be seen for the NO_x emissions; higher corrected emissions

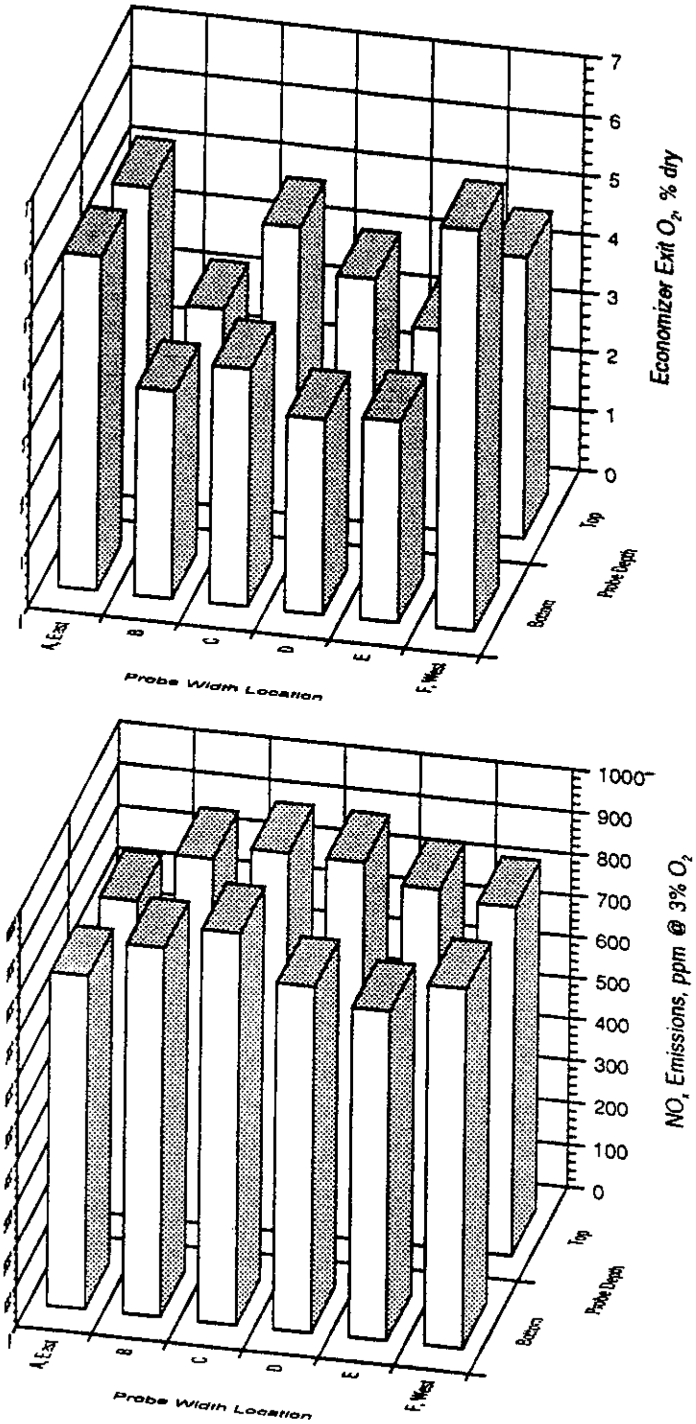

Figure 5-4. Economizer Exit O_2 and NO_x Profiles

exist in the center of the furnace, while lower levels are seen along the side walls. Although the lower NO_x levels at the side walls appear to contradict the high O_2 levels at the same locations, this was attributed to the coal distribution to the burners and not to the effects of the air infiltration (higher O_2 levels). The profile of the coal distribution indicated that the coal was biased toward the furnace side walls and away from the center of the furnace. With an even distribution of air to the burners, this will allow higher NO_x emissions at the center of the furnace, where the flames are operating more fuel lean or with higher air levels. At the sidewalls, the burner O_2 levels will be lower as a result of the higher coal flows, yielding lower NO_x formation. This is essentially the profile of the NO_x emissions seen in Figure 5-4. The O_2 profile apparently contradicts the coal distribution data as a result of possible air infiltration or leakage effects. The location of a potential air leak is probably downstream of the flame zone and does not affect NO_x formation characteristics near the burners. Therefore the air inleakage will simply dilute the flue gases, and raise the O_2 levels along the sidewalls, but will not be a factor in the NO_x emission profile.

A comparison between the control room and the average economizer exit O_2 levels was made to permit correlation of the typical control room data with the results presented in this report. This relationship is shown in Figure 5-5, which includes all data from the parametric baseline tests. This average control room data were recorded from the screen display of the plant's data logging computer system, which averaged the outputs from the four O_2 probes in the economizer exit duct. The average economizer exit O_2 levels measured in the mobile laboratory with the 12 point grid were nominally one percent O_2 higher than the control room indicators. 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 O_2 difference will be due to the nonuniform O_2 distribution and the placement of the in situ monitors.

The relationship between the control room monitors was fairly consistent during the baseline tests, although the test-by-test values can be affected by changing unit operation. For example, the number of mills in service could affect the economizer exit O_2 distribution and thereby affect the O_2 difference. Variations such as these may be responsible for some of the data scatter in Figure 5-5. This relationship between O_2 levels may also vary with time, if the suspected imbalance of the coal or the air infiltration patterns should change radically.

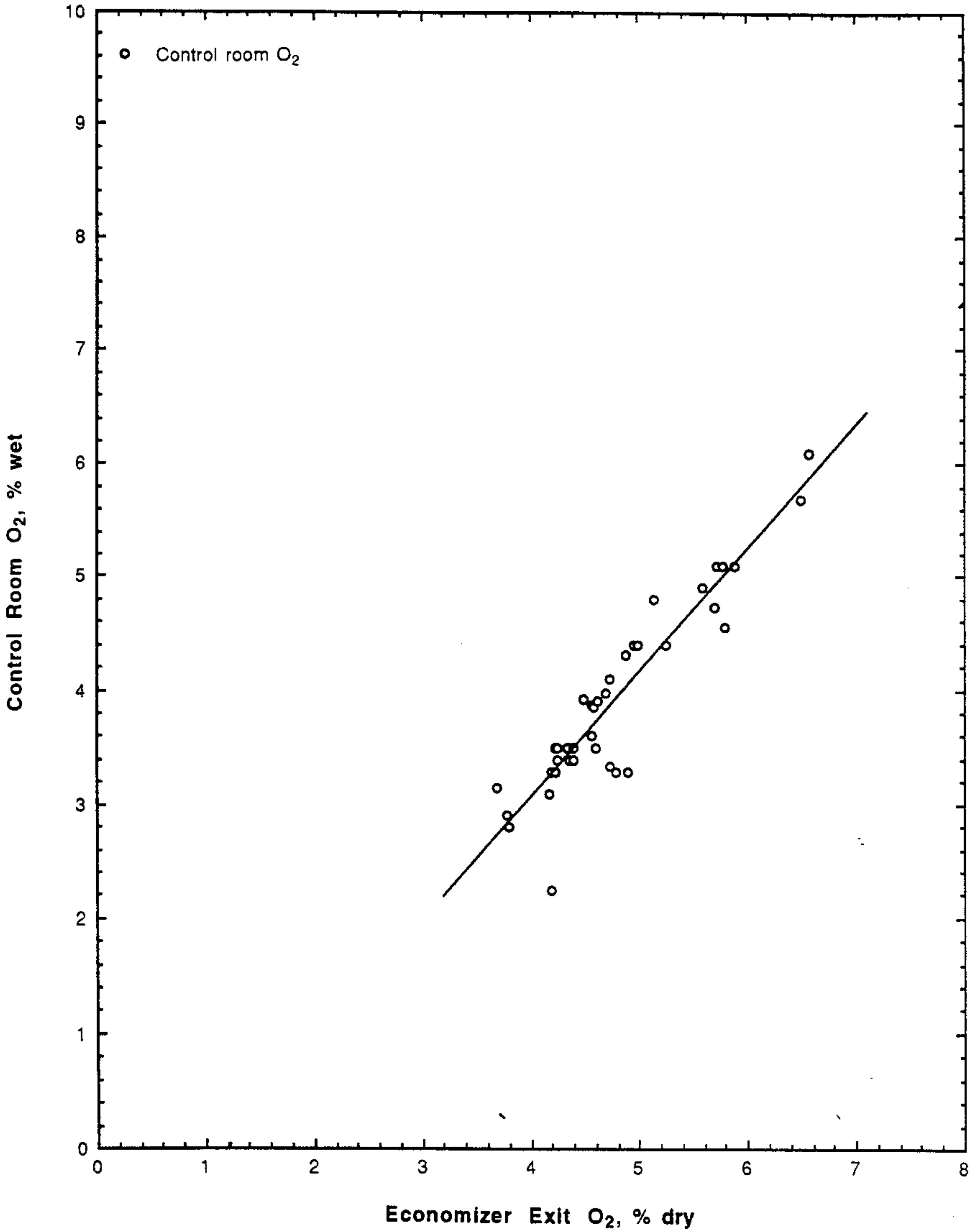

Figure 5-5. Comparison between the Control Room O_2 and the Economizer Exit O_2 Measurements

5.5 O_2 PROFILES ALONG THE FLUE GAS FLOW PATH

In addition to the economizer exit grid location, air heater exit and stack gas samples were acquired from the unit during the parametric testing. At the air heater exit, a less extensive grid of six probes was installed to evaluate the air heater leakage and to serve as a cross check of the unit emissions. A single "stack" probe was installed in the flue gas duct immediately before entering the Units 3 and 4 common stack. The stack probe was located well downstream of the baghouse and the induced draft fans, so that a single probe was considered to be sufficient to obtain a representative sample at this location. The stack location was considered important for comparing the baseline emissions with the data to be collected later in the program when a new Continuous Emissions Monitor (CEM) is to be installed and used for the retrofit test program. The stack location was also the primary test point for the long term monitoring baseline tests.

Figure 5-6 compares the O_2 levels at the air heater exit and stack locations with the economizer exit levels for all baseline tests. In both cases, data correlations were generally very good, indicating that the O_2 levels or the dilution along the gas stream flow path were reasonably consistent for the unit. The data comparison between the air heater exit and the economizer exit was very close, indicating a minimal amount of leakage across the air heater, consistent with the tubular design of the air heater.

As seen in Figure 5-6, for a few cases, the O_2 level measured at the air heater exit is slightly lower than the O_2 level measured at the economizer exit. This is likely due to the fewer number of probes used at the air heater exit and the greater difficulty in obtaining a representative sample. Since the air heater exit probe grid had fewer probes, some areas along the furnace side walls may not have been as well represented as the more extensive economizer exit grid. The net result would be a lower O_2 level indication for the air heater exit.

The data plot between the economizer exit and the stack location indicated higher O_2 levels at the stack. The typical difference was of the order of 0.3 percent O_2, which again was relatively low. The typical inleakage from the economizer exit to the stack was only 2 percent.

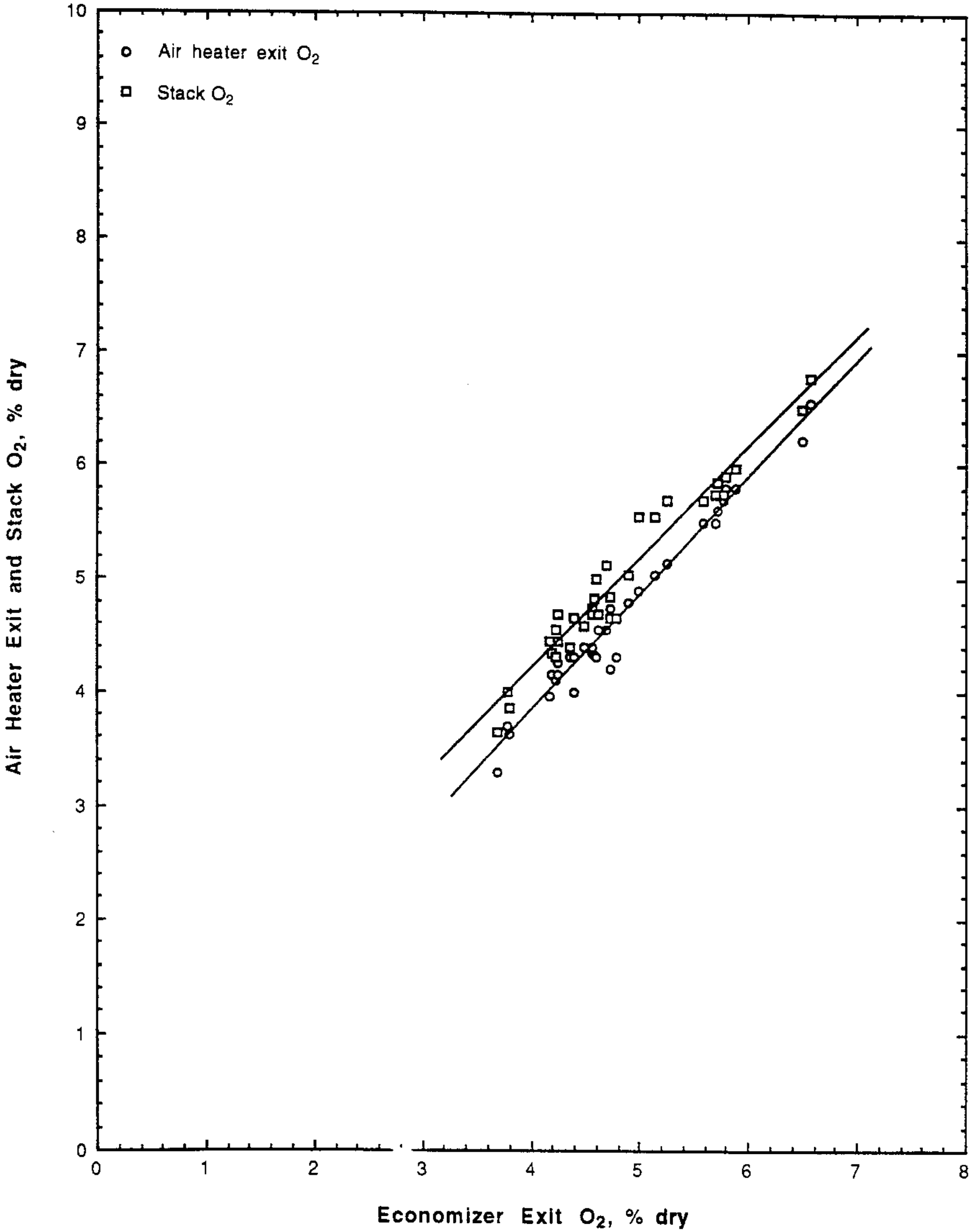

Figure 5-6. Comparison between the Air Heater Exit and Stack O_2 Levels with the Economizer Exit

An additional data comparison between the economizer exit O_2 and CO_2 levels is shown in Figure 5-7. These data show a very good correlation between the two gas species, as would be expected for combustion flue gas products. The correlation indicted that the errors resulting from the instrument calibration drift were low.

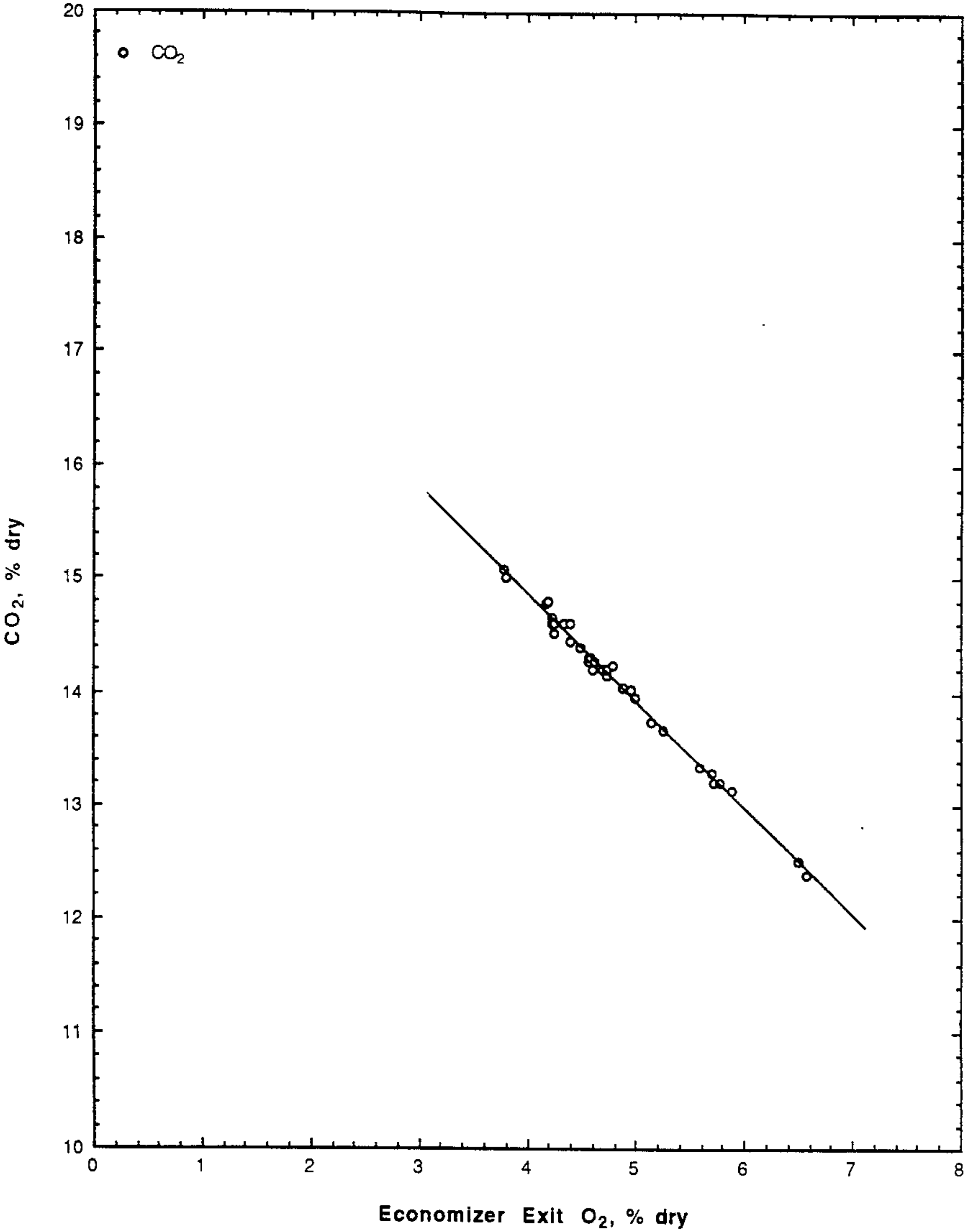

Figure 5-7. Comparison between Economizer Exit O_2 and CO_2 Measurements

6.0 SO_2 AND SO_3 GASEOUS EMISSIONS

SO_2 and SO_3 emissions are largely a function of the coal's fuel sulfur content. Since the Arapahoe Generating Station utilized a relatively low sulfur western coal, low SO_2/SO_3 emissions were expected.

6.1 SO_2 EMISSIONS

SO_2 emissions can frequently be determined directly from the fuel sulfur content on a one to one basis. In the case of the Unit 4 baseline tests, the SO_2 emission measurement was utilized to monitor potential fuel supply variations which may affect the combustion tests. The coal supply at Arapahoe alternated between two Colorado mine sources. Aside from the sulfur content, the coals were considered to be very similar. The two coals have sulfur contents which were relatively low; however, the sulfur contents differed from each other.

Some variations of the SO_2 emissions were noted during the course of the baseline testing. Figure 6-1 shows the average SO_2 emissions for each baseline test presented on a corrected and dry gas basis. The range of the emissions was somewhat wide, considering that the typical emission was approximately 400 ppmc (0.76 lb/MMBtu), but ranged from nominally 350 to nearly 600 ppmc for some tests (0.67 to 1.14 lb/MMBtu). The variations have been attributed to the coal supply from the two mine sources. The second coal, with a higher sulfur content, was responsible for the emissions in the range of 550 to 600 ppmc. There was no correlation with unit load, as expected, since the conversion of fuel sulfur to SO_2 is very close to 100 percent and is not affected by load or excess air levels.

A second SO_2 emission graph is shown in Figure 6-2, which simply shows the average emission as a function of test number. The test number corresponds approximately to calendar time, although the duration of some tests could be over an entire day, while others could be as short as one hour. SO_2 emissions were consistent until Test 19, at which point a substantial increase was noted. Although the increase in SO_2 indicated a change in fuel sulfur content and thus fuel properties, no major effects on NO_x emissions or other combustion characteristics were noted during this time frame. Although this fuel change might have a second order effect on NO_x

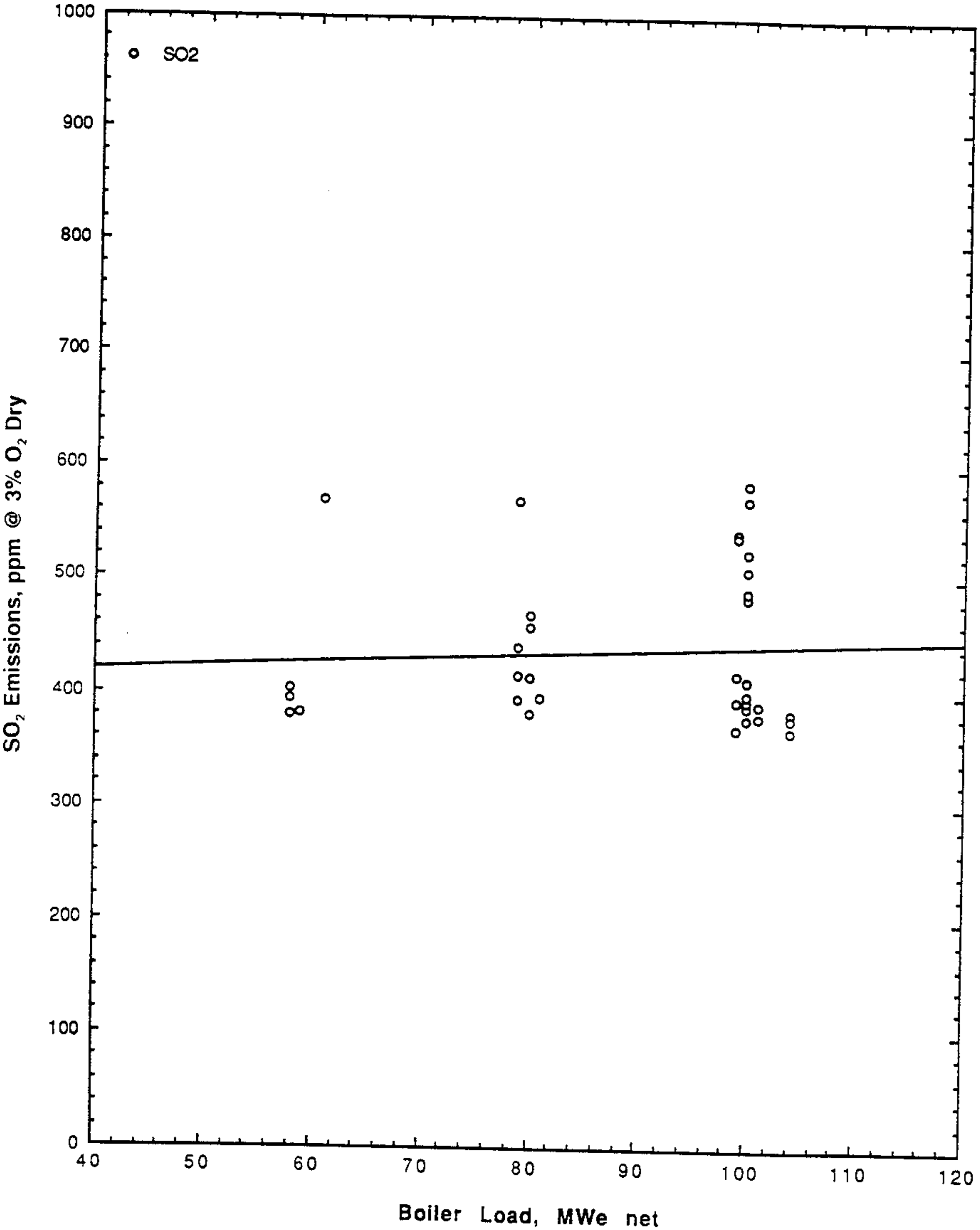

Figure 6-1. Baseline SO_2 Emissions

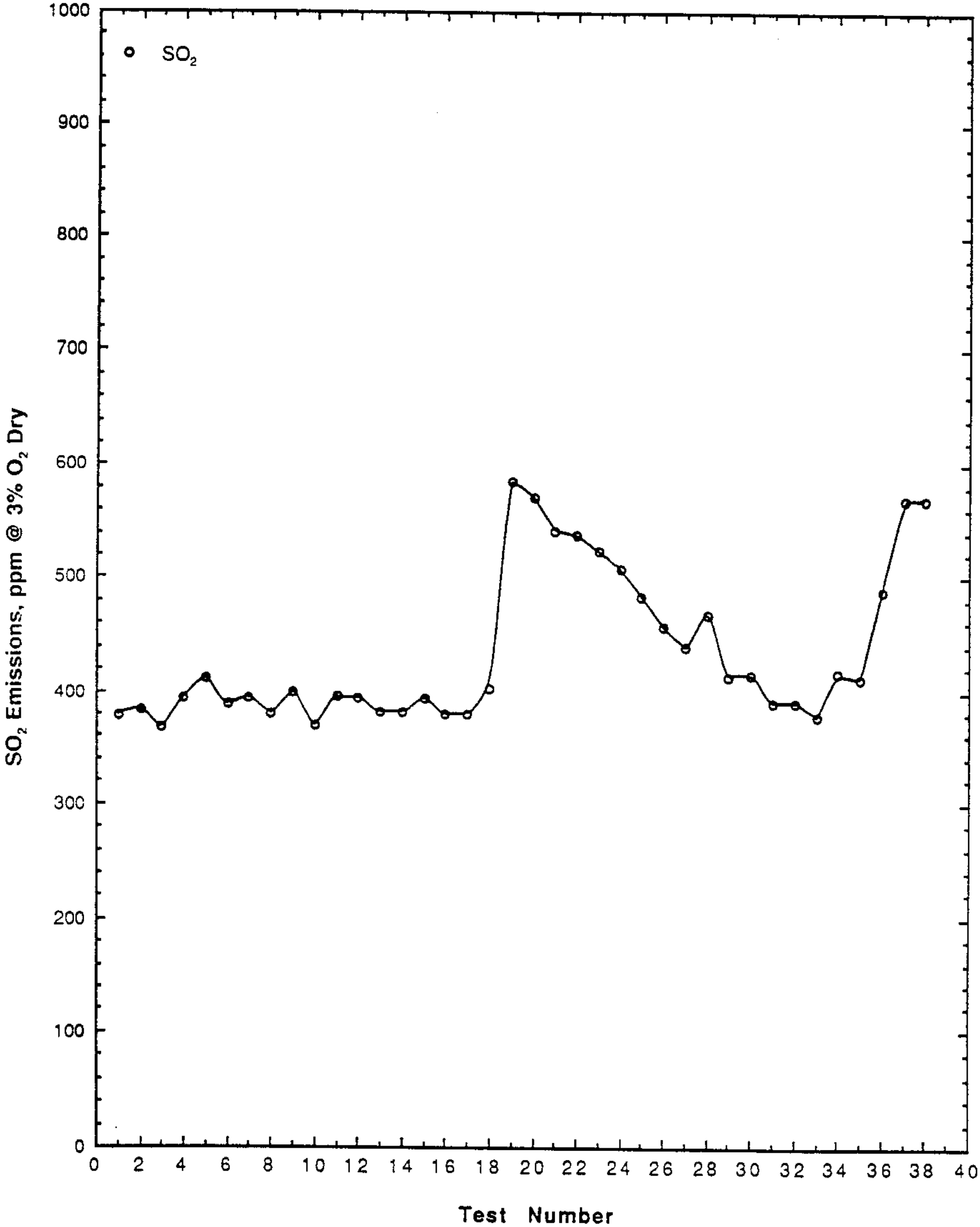

Figure 6-2. SO_2 Emissions for Consecutive Tests

emissions and may have contributed to some of the data scatter of the NO_x versus O_2 relationships, a dramatic change similar to SO_2 was not observed. In addition to the SO_2 emissions, similar variations were previously noted for the limited coal analyses that were performed. Variations of 33 percent were seen for the coal sulfur analyses, while the SO_2 emissions varied by as much as 50 percent. Only a limited number of coal analyses can be performed while the SO_2 emissions can be monitored on a continuous basis.

Shortly before Test 19 was performed, the coal from the second mine, with higher fuel sulfur content, was probably being burned. The SO_2 emission data from Tests 19 through 30 were conducted over a two day period during a series of short term tests. During this time, the SO_2 emissions decreased from 600 to 400 ppmc, which indicated a shift back from a higher sulfur to a lower sulfur coal. Later in the baseline testing (Test 36), the fuel sulfur increased to the higher level.

These day-to-day and hour-to-hour variations of fuel sulfur and thus SO_2 levels will have to be factored into the test procedures used later in the program to characterize SO_2 removal with dry sodium or calcium sorbent injection.

6.2 SO_3 EMISSIONS

During the combustion process, some of the fuel sulfur can form SO_3 and additional SO_3 can be formed by SO_2 oxidation during the residence time in the flue gas flow path. In utility boiler operation, SO_3 levels can play an important role in the corrosion of low temperature equipment and formation of corrosive deposits. In coal fired systems, SO_3 can also be absorbed into the fly ash, which can mitigate some of the detrimental effects of SO_3. For a western coal fired utility boiler, the alkaline nature of the ash will tend to promote SO_3 absorption and therefore low levels of SO_3 may be expected.

SO_3 was determined at the economizer exit with the wet chemical controlled condensation technique. Tests were performed at three loads with normal excess air levels and boiler conditions. The data are presented in Table 6-1.

The measurements at all load conditions are at, or near, the measurement accuracy of the sampling and analytical technique. In any case, all measured levels were low, less than 1 ppm. The data suggest that SO_3 emissions may increase with decreasing load and/or increasing excess air levels; however, this may be difficult to establish with certainty as a result of the low concentrations.

Table 6-1

BASELINE SO_3 EMISSIONS

Test	Load (MWe)	O_2 (%)	Mills	SO_3 (ppm)	SO_3 (ppm @ 3%)
10	99	4.25	4	0.1	0.1
35	100	4.70	4	0.1	0.1
37	79	4.57	4	0.5	0.6
38	61	5.69	3	0.7	0.8

7.0 PARTICULATE AND ASH CARBON EMISSION RESULTS

The following subsections present the results for the particulate measurements and the products of incomplete combustion. CO emissions and ash carbon levels are the combustibles of most importance in utility boilers. Solid samples collected for ash carbon analysis included fly ash, bottom ash and solid samples from the baghouse hoppers.

Particulate emissions measurements were performed at the air heater exit (baghouse inlet) and the stack (baghouse exit) at full load conditions. Particulate sizing measurements were made at the baghouse inlet, as well as PM_{10} measurements at the baghouse exit.

7.1 CO AND OPACITY

Ash carbon and CO levels are two factors affecting the carbon burnout and therefore the boiler efficiency. CO emissions were monitored with the continuous analyzer for every test and the data were previously included with the data summary in Table 5-1. Typical emissions ranged from 30 to 60 ppm at normal boiler operating conditions. Higher CO levels were found for low excess air conditions or when a particular mill or secondary air damper setting resulted in localized regions of incomplete combustion in the furnace. These localized regions of low excess air were responsible for increased CO emissions and will be the limiting factor controlling the lowest O_2 level at which the boiler could be operated. These localized regions of low O_2 are most likely due to the non-uniform coal flow to the individual burners.

Figure 7-1 shows average CO emissions as a function of economizer exit O_2 level for all load settings. The average curve shows the general trend of increasing CO with lower excess air levels. The two data points which were significantly higher than the typical emission were for tests with unusual secondary air or feeder coal flow biasing test conditions. Brief tests were performed with secondary air damper adjustments, which were intended to compensate for the non-uniform coal distribution to the burners. These tests were unsuccessful and resulted in elevated CO emissions at normal O_2 levels. Overall, CO emissions remained relatively consistent under normal operating conditions.

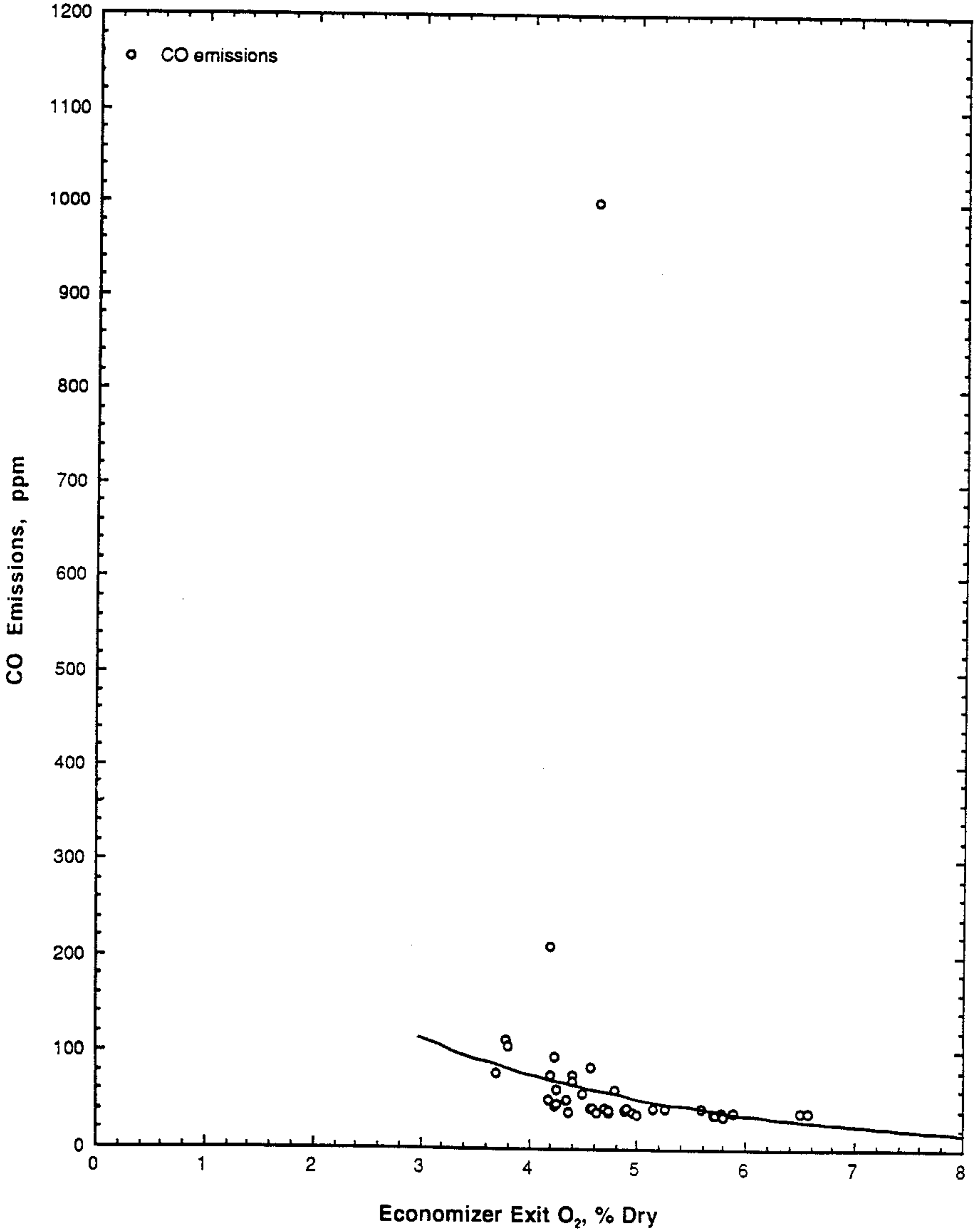

Figure 7-1. Baseline CO Emissions During Each Test at All Load Conditions.

Control room opacity readings were recorded for each test of the baseline series. The opacity monitor was located upstream of the stack probe location, in the baghouse exit duct between the ID fans and the common stack. Because of the baghouse performance, the outlet opacity was relatively consistent under all operating conditions. Figure 7-2 shows the opacity measurements for all test and load conditions. Opacity remained between 2 and 3 percent at all times. Opacity was also observed to remain at these levels during the reverse gas cleaning cycle, which is controlled by the average baghouse pressure drop. Significant changes in opacity could not be detected during cleaning cycles, at different baghouse pressure drop conditions or with high combustibles (CO emissions) operation.

7.2 FLY ASH CARBON MEASUREMENTS

Ash carbon levels were performed for specific tests at all loads. Fly ash carbon sampling was performed by extracting a high volume sample from the air heater exit ports. The carbon analysis was performed by an independent laboratory using a Perkin Elmer elemental analyzer. This analysis method is carbon specific and was considered superior to the Loss On Ignition (LOI) weight loss method.

Figure 7-3 shows the fly ash carbon content versus O_2 level for operating loads of 100, 80 and 60 MWe. These results indicate that the carbon content of the fly ash ranged from 1 to 11 percent. The majority of these tests were obtained under normal boiler operating conditions. The data clearly indicate that the carbon in the ash increased with decreasing O_2 levels. No obvious trend in fly ash carbon content is seen with load, although 100 MWe loads tend to have somewhat higher carbon contents than 80 MWe operation. The curve fit shown in Figure 7-3 represents the average for the 100 MWe data with four mills in service. Note that the data scatter for the 100 MWe case showed significant variation of the ash carbon levels, even with very similar operating conditions. This is not unexpected for ash carbon measurements, since results can be affected by minor variations of test conditions, coal or coal fineness variations and burner operation.

Data at reduced loads were basically similar to the full load data. The ash carbon measurements at 80 MWe were slightly lower than the average of the full load data, although overlap of the data

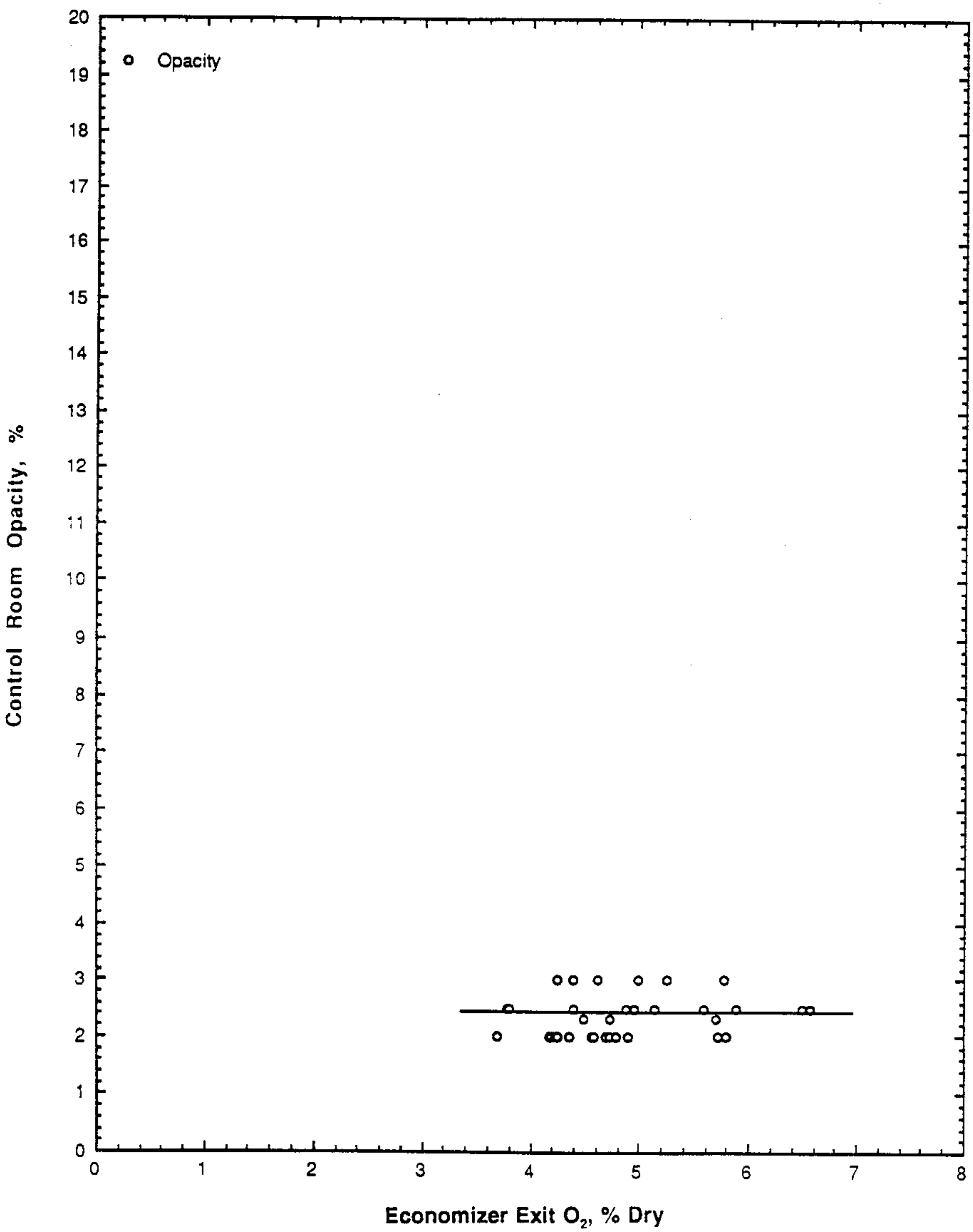

Figure 7-2. Control Room Opacity Measurements for All Tests.

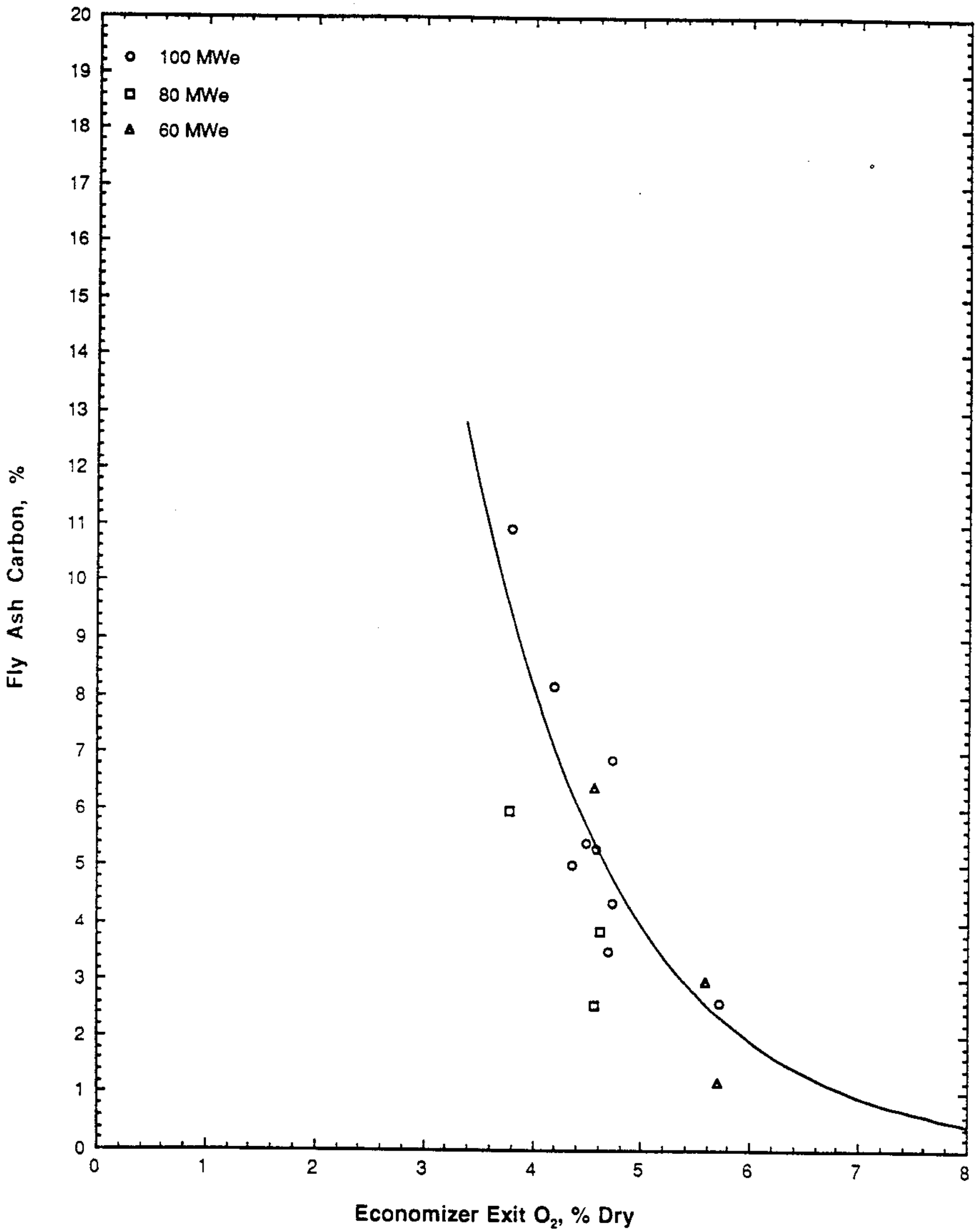

Figure 7-3. Fly Ash Carbon Content versus Economizer Exit O_2 at Various Loads

can be seen. The slightly lower ash carbon results were likely the result of lower coal throughput in the four operating mills, as compared to full load data. Since each mill's coal loading was reduced by a fifth, improved fineness may be anticipated, and carbon burnout may be enhanced. The longer residence times in the furnace at 80 MWe may also contribute to a lower carbon content. At 60 MWe, the ash carbon levels appear to be very similar to the full load average data.

As discussed above, the changes in carbon content with load were small. The levels presented here are representative of the boiler operation at the time of the baseline tests. This may change with improvements to the boiler operation, or mill operation, specifically the coal distribution to the burners. The data for the coal distribution has been previously discussed, and was found to bias the coal flow to the sides of the furnace. These conditions can have a detrimental effect upon ash carbon levels, since there will be a greater propensity to have burnout problems for the "fuel rich" burners. The net effect will be to shift the ash carbon versus excess air curves to the right on Figure 7-3, as compared to an equal burner coal flow test condition.

7.3 BOTTOM ASH AND BAGHOUSE ASH SAMPLES

Additional ash samples were acquired from the furnace bottom ash removal system and from the baghouse ash hoppers. These data are superimposed over the fly ash carbon data in Figure 7-4. The bottom ash samples were acquired during or immediately after a specific test, in order to obtain a sample that may be representative of the test conditions. Bottom ash samples were more difficult to obtain with any certainty and assign to a specific test condition. Unit 4 uses a wet bottom ash removal system which does not allow direct sampling from the unit. Therefore, the validity of these samples was less precise than the fly ash sampling techniques. Baghouse hopper samples also suffer from this problem, since it is difficult to know if a collected sample is entirely representative of ash deposited on the bags during a particular test period. Baghouse ash samples were obtained from the bottom of the ash hopper. Immediately before the start of a test, the hoppers were evacuated to remove the ash accumulated before test conditions were established. Samples were obtained from every other hopper (6 of 12) on both the west and east sides of the baghouse. The 6 hopper samples were composited to form a single ash sample and later analyzed.

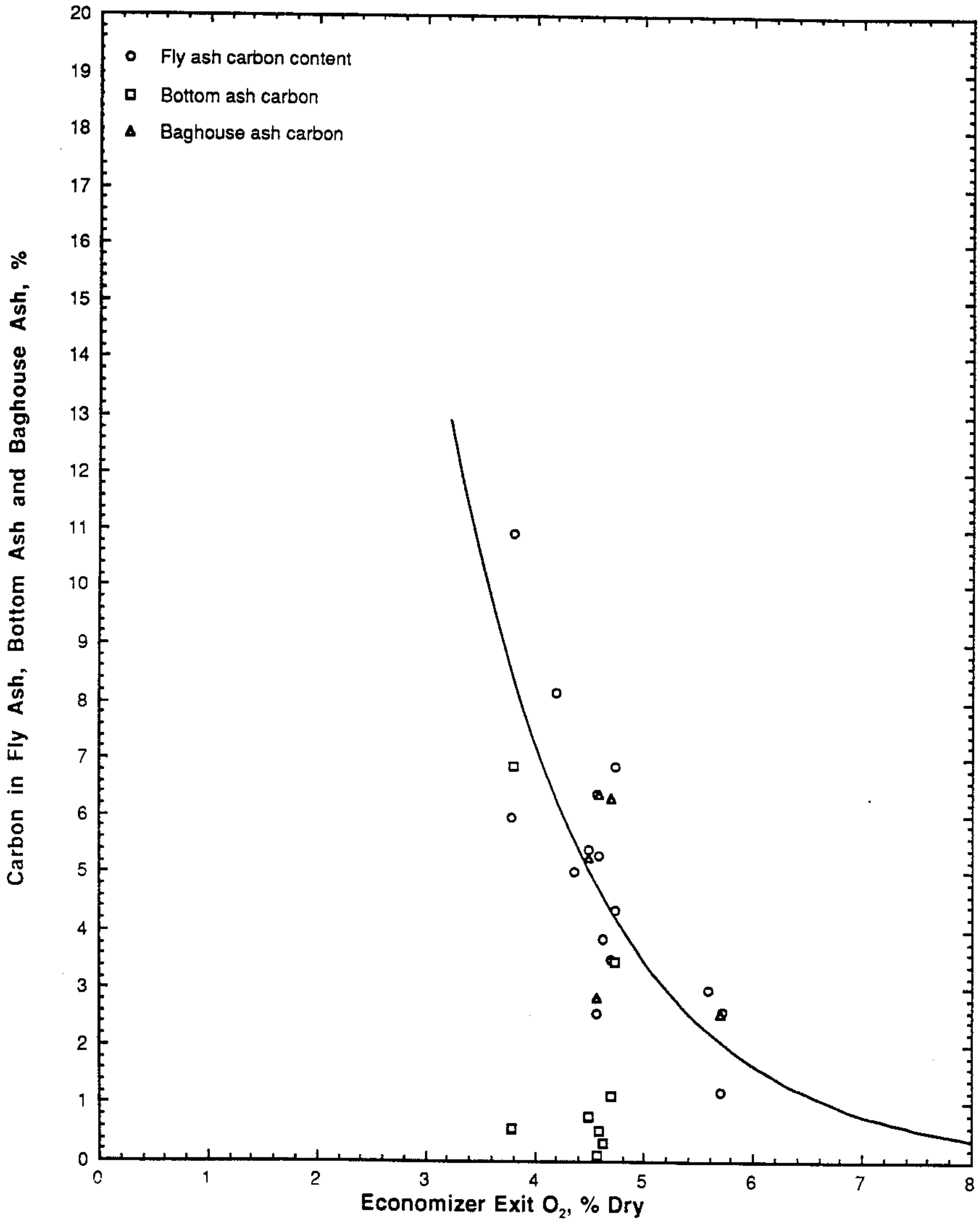

Figure 7-4. Comparison among Fly Ash, Bottom Ash and Baghouse Ash Carbon Content

The carbon content of the bottom ash samples was generally lower than the comparable fly ash samples. Overall, the carbon in the bottom ash was at or below the 1 percent carbon level; therefore, the bottom ash samples can be characterized as being lower than the flyash carbon.

The baghouse ash samples should be equivalent to the fly ash samples; however, there is greater uncertainty concerning when the samples were acquired, relative to the test periods. The data in Figure 7-4 show similar trends for the baghouse and fly ash samples. A one-to-one comparison between the fly ash, bottom ash and baghouse ash carbon levels for individual tests was shown in Table 5-1.

7.4 PARTICULATE MASS MEASUREMENTS

Particulate mass and distribution measurements were performed on limited basis at full load and normal excess air conditions. EPA Method 17, in stack filtration, was used for particulate mass loading determination at both the inlet and outlet of the baghouse. The average inlet and outlet mass loading results are tabulated in Table 7-1. The average inlet loading was 2.1 gr/DSCF. The average outlet emissions from the baghouse were 1.5 lb/hr at full load operation (or 0.0007 gr/DSCF). Based upon these measurements, the collection efficiency of the baghouse was over 99.96 percent.

Review of this outlet mass loading by PSCC indicated that the baghouse outlet loadings were lower than expected for this unit. Although a review of these measurements did not uncover any significant discrepancy, the emissions for EPA Method 5 sampling had been previously determined to be closer to 9 to 10 lb/hr (approximately 0.0035 gr/DSCF) at full load. Although different test methods were utilized for the current test program, no conceivable difference between Methods 5 and 17 will account for the discrepancy. Additional testing may be performed during the next test phase to resolve this question of the baghouse exit emissions.

7.5 PARTICULATE SIZE DISTRIBUTION RESULTS

The particulate size distributions were measured by two different methods. A cascade impactor was used to measure the particle size distribution at the inlet to the baghouse. EPA Method 201A was used to determine the PM_{10} emissions at the outlet of the baghouse.

Table 7-1

AVERAGE MASS LOADING RESULTS AT FULL LOAD

Parameter	Baghouse Inlet	Baghouse Outlet
Flow Rate (ACFM)	414,733	445,394
Flow Rate (SCFM, dry)	219,500	247,230
Temperature (°F)	263	258
Moisture (%)	8.3	6.5
Concentration (gr/SCF, dry)	2.1	0.0007
Emissions (lb/hr)	3,935	1.5

A University of Washington Mark V cascade impactor with a precutter was used for the inlet size samples. The impactors had a maximum aerodynamic cut point of 9.3 microns and the measured cumulative mass above this cut point was approximately 30 percent. The data above the maximum cut point has been extrapolated with a standard impactor cubic spline fit. The results of this technique indicated that the particle mass mean diameter (MMD) was 12 microns. These results are tabulated in Table 7-2 and the cumulative particle size distribution curve is shown in Figure 7-5.

The baghouse exit PM_{10} measurement determines the particulate matter (PM) emissions which are attributable to particles equal to or less than an aerodynamic diameter of 10 microns. The mass below 10 microns was determined from a combination of a 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 were recovered from the impinger washes by drying the collected water and weighing the residue. These additional condensible emissions were added to the sub-10 micron solid emissions determined by a University of Washington impactor and the mass emission measurements.

The PM_{10} results are tabulated in Table 7-3 and indicate that the PM_{10} baghouse exit emissions were higher than the mass loadings as determined by the Method 17 analysis. The exit PM_{10} emissions of 9.5 lb/hr were approximately six times the exit mass loading levels. This difference

Table 7-2

AVERAGE BAGHOUSE INLET PARTICLE SIZE DISTRIBUTION

Aerodynamic Diameter	Cumulative Weight (%)	dM/dLOG(D_{50},mg/SCFM,dry)
0.20 (microns)	0.4	25.7
0.25	0.4	21.0
0.40	0.5	5.7
0.50	0.5	17.9
0.75	0.7	59.5
1.00	0.8	111.0
1.50	1.5	322.5
2.00	2.3	419.0
2.50	3.0	482.4
4.00	5.6	1296.3
5.00	8.6	2388.1
7.50	19.9	5350.9
10.0	36.2	12020.9
15.0	72.8	10967.7
20.0	90.6	5946.2
25.0	97.2	2546.2
40.0	100.0	48.9
50.0	100.0	0.4

Table 7-3

AVERAGE BAGHOUSE EXIT PM_{10} RESULTS

Parameter	Average Value
Flow Rate (SCFM, dry)	254,864
Temperature (°F)	261
PM_{10} Concentration (gr/SCF, dry)	0.0043
Emissions (lb/hr)	9.5

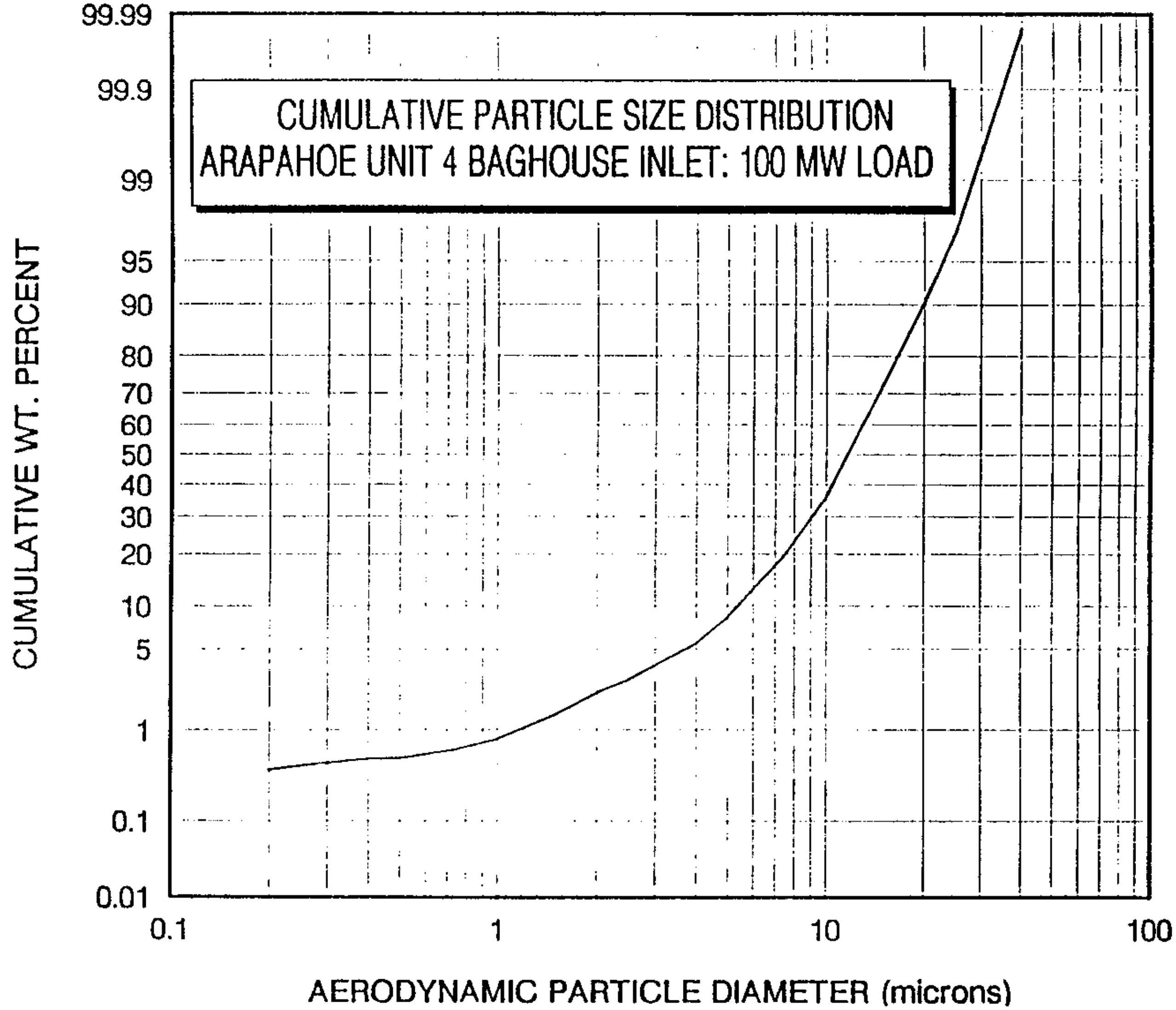

Figure 7-5. Baghouse Inlet Particulate Size Distribbution.

is likely due to the condensible emissions that are included in the PM_{10} methodology. The ice bath and water impingers can increase mass emissions as a result of the capture and subsequent weighing of sulfate compounds in the flue gas. Based upon 400 ppm SO_2 emission and the measured gas flow rates, if all of the SO_2 were converted to sulfate and subsequently condensed in the impinger train, an emission of over 1,400 lb/hr can be calculated. Therefore, only a small fraction of the SO_2 will account for the increase resulting from condensible emissions. The very low SO_3 and NO_2 emissions from the boiler may be sufficient to account for the condensible mass, and these gas species are even more likely to be condensed within the impingers.

8.0 FURNACE EXIT GAS TEMPERATURE MEASUREMENT RESULTS

During the course of the baseline test series, furnace exit gas temperature measurements were made in order to provide a reference point for comparison with the retrofit low-NO_x burners following their installation. The data were also of interest for the urea injection test phase of the program. Temperature data were gathered using both suction pyrometry (high velocity thermocouple, HVT) and acoustic pyrometry. The results of each technique are discussed separately in the following sections.

8.1 SUCTION PYROMETRY RESULTS

The suction pyrometry (HVT) measurements were made at a point just upstream of the first set of screen tubes (Port H in Figure 8-1). The HVT probe was of a standard water-cooled design, utilizing a single radiation shield and a type R thermocouple. Restricted access to the sample port on the east side of the unit limited the overall probe length to 14 feet, resulting in a maximum insertion depth of 12 feet from each side. The boiler is approximately 40 feet wide; thus approximately 40 percent of the gas flow along the centerline of the unit was unreachable. Data were taken at 3, 6, 9 and 12 foot depths, with a repeat of the 3 foot point as the probe was withdrawn.

HVT measurements were made at three different load points (100, 80 and 60 MWe). The average temperatures from the west and east traverses from port H, as well as the combined average for each operating condition are shown in Table 8-1. In each case, the average temperature on the east side of the unit was higher than on the west side. The extreme difference seen at the 60 MWe condition (Test 38) was primarily due to the mill out-of-service pattern. Visual observations both at the furnace exit and at the entrance to the second set of screen tubes (Port B in Figure 8-1) confirmed that there was more flame carryover on the east side, even during the four mills-in-service test conditions (Tests 35 - 37). It should also be noted that, although the two 100 MWe tests were run on separate days, and there were differences between the west and east averages, the combined average temperatures for each test were equal.

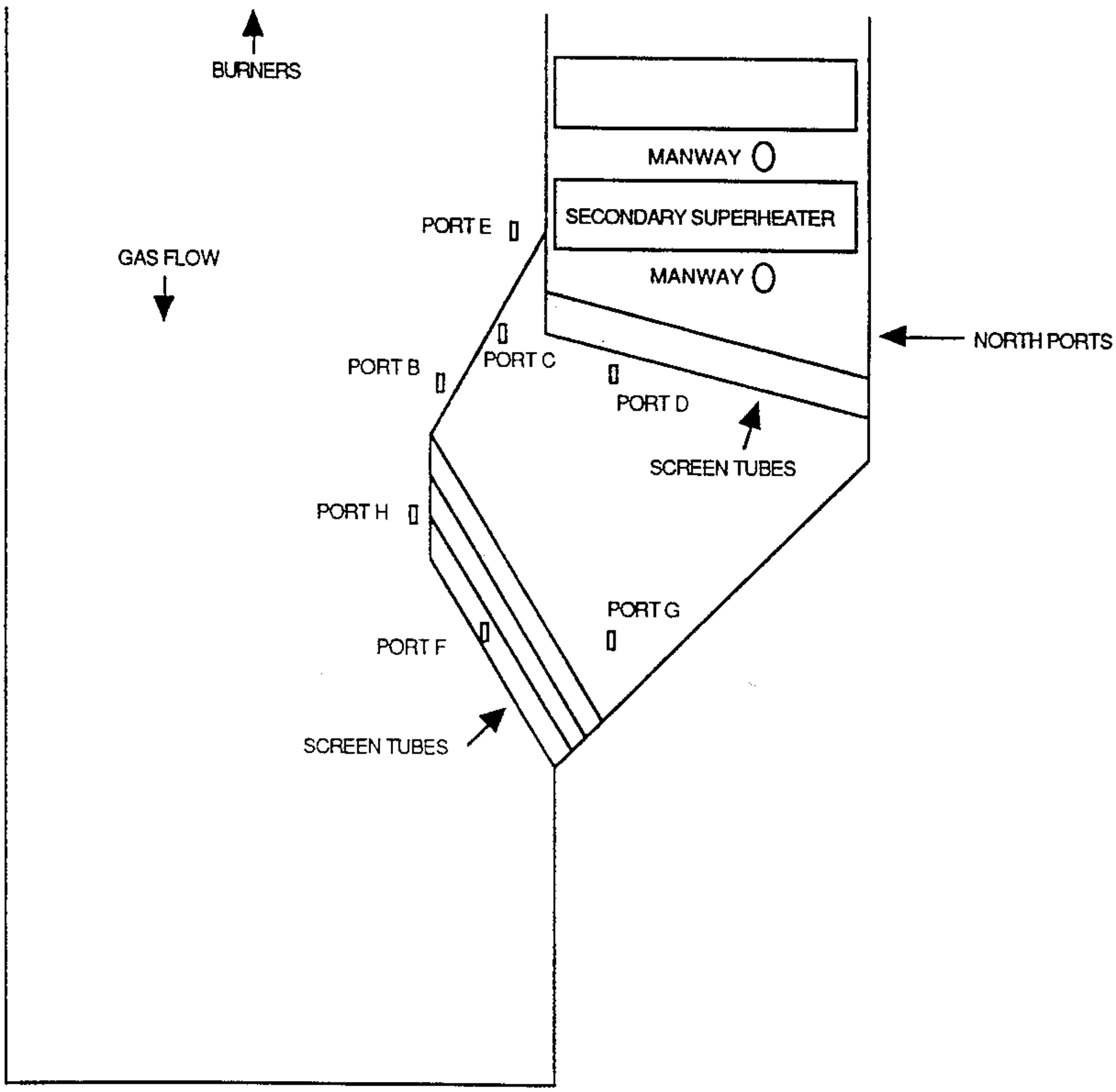

Figure 8-1. Temperature Sample Port Locations

Table 8.1

HVT FURNACE EXIT GAS TEMPERATURE RESULTS (PORT H)*

Test Number	Net Load (MWe)	Mills Out-of-Service	Average Temperature (°F)		
			West	East	Combined
35	100	None	2367	2443	2405
36	100	None	2391	2414	2402
37	80	None	2319	2348	2333
38	60	C	2075	2248	2161

Table 8.2

ACOUSTIC AND HVT TEMPERATURE RESULTS (PORT G)*

Test Number	Net Load (MWe)	Mills Out-of-Service	Average Temperature (°F)	
			Acoustic	West HVT
34	100	None	2020	N/A
35	100	None	2047	1997
36	100	None	2052	N/A
37	80	None	1940	1924
38	60	C	1721	1693

* See Figure 8-1 for port locations.

8.2 ACOUSTIC PYROMETRY RESULTS

In addition to the HVT temperature measurements, temperatures were also measured in the furnace using a CODEL™ acoustic pyrometry system. The acoustic pyrometer sends a sound pulse across the furnace; the transit time for the pulse is measured and thus the average speed of sound can be determined. The average temperature along the path is then determined from the average sound speed. The acoustic temperature measurement technique required a clear line-of-sight across the unit at the measurement location. Since the boiler has a division wall running the length of the furnace, measurements were not possible at the port used for the HVT measurements (Port H). The first available location with acceptable access for the acoustic instrument was Port G (Figure 8-1). In order to provide verification of the acoustic measurements, an HVT traverse was made through Port G on the west side for each test condition (structural steel and a stairway precluded HVT access to the east port).

The results of the acoustic and HVT measurements are shown in Table 8-2. The acoustic pyrometer was configured to provide a line-of-sight average temperature once a minute. Data were collected over a four- to five-hour period for each test condition. Thus, the temperatures shown in Table 8-2 represented the average of between 250 and 300 individual measurements. In each case, the acoustic average temperatures were higher than the HVT averages for the west side. This was consistent with the results obtained at Port H (Table 8-1), where the west temperatures were lower than the combined averages, due to the west-east temperature imbalance.

8.3 TUBE METAL TEMPERATURES

In addition to these gas temperature measurements, secondary superheat tube metal temperatures were monitored during the parametric tests. These tube metal thermocouples were located on the back side of the boiler and 20 tube temperatures were monitored on a multipoint chart recorder. Tube metal temperatures were monitored to detect abnormally high temperatures that can be produced by very low O_2 operation or unusual burner or mill firing patterns. Excessive metal temperatures have been noted in previous tests performed on Arapahoe Unit 4. During the baseline tests, these tube metal temperatures did not exhibit excessively high levels; therefore, the tube temperatures did not limit boiler or test operations.

9.0 LONG TERM MONITORING TEST RESULTS

The last week of baseline testing was reserved for a long term monitoring test series which extended over 6 days, 24 hours per day. During this time period, boiler emissions were monitored continuously, while the unit was operated under normal conditions. Therefore, the data collected during this time are considered representative of normal Unit 4 operations, for the particular loading requirements during this period.

9.1 LONG TERM TEST OPERATIONS

During this long term test period a single point sample was used for this monitoring effort. While the multi-point grid installed at the economizer exit was appropriate for the parametric tests, maintaining sufficient and balanced flow from every point would be difficult for extended periods and unattended operation. The single point sampling point was located downstream of the baghouse just upstream of the stack.

Several reasons justified the stack location for the long term monitoring test. A single representative sample point will be easier to monitor than the extensive economizer exit probe grid. The stack port was located well downstream of any equipment which would alter the flue gas concentrations and would permit a well mixed and representative sample to be obtained with a minimum number of probes. The parametric baseline tests included the measurement and comparison of the average gas concentrations at the economizer exit and the stack locations; therefore, the long term monitoring data could be cross correlated with the parametric test results. In addition, the stack sample point will likely be the primary sample station for the CEM instrumentation which will be installed with the low-NO_x burners; therefore, the data will be directly comparable for future monitoring periods.

Modifications to the sample drier were made to enable the condensate drain to be emptied on a continuous basis without operator attention. Instrument calibrations were done manually twice per day. Probe purging and system check out were also performed daily.

Parametric data measurement was performed with laboratory chart recorders and manual data recording. For the long term test, a data logger was installed to record the outputs from the gaseous instrumentation. The data logger was set up to scan or monitor the gas emission outputs every ten seconds and store a five minute average of these scans. Therefore, the data recovered were a continuous record of five minute averages, recorded over the duration of the test. In addition to the O_2, NO_x, SO_2, CO_2, and CO analysis, a control room load signal was included on the data logger to monitor the unit operation. The strip chart recorders were also retained for the long term tests. A net MWe signal could not be obtained without disrupting the system control signals in the control room; however, a gross MWe indicator could be obtained. The gross load was recorded in the same fashion as the gaseous instrumentation. Additional information of the unit operation was available from the control room data sheets, which the operators routinely record on an hourly basis.

9.2 SO_2 EMISSIONS

A continuous record from the data logger SO_2 emissions is shown in Figure 9-1 for the long term test period. As can be seen from the graph, the long term monitoring test started on the afternoon of the first day (December 8, 1991) and extended into the morning of the seventh test day (December 15, 1991). This plot represents the five minute average data points for the entire six day period.

The SO_2 emissions ranged from 380 to 620 ppm corrected to three percent O_2, which was very similar to the range exhibited for the individual parametric tests. An average emission was approximately 470 ppmc for the six day period. As with the parametric data, these SO_2 emissions reflected the changes of the fuel sulfur content of the coal and indicated that the coal composition was varying during the test. Since the SO_2 emissions are relatively unaffected by the unit operation, these results indicate fuel variations exhibited during the test.

The sharp SO_2 emission spikes shown during the morning of day five were the result of a boiler outage and not a variation of the coal. During this time period, the boiler was off line for approximately five hours and tripped twice. The unit was brought back on line and load reestablished late in the morning. Electrical power to the gas analysis instrumentation was also lost for two to three hours during this period, which added to the loss of measurement. Some of the data variability, or spikes, were caused by the second unit trip and the variation of O_2 levels, which influenced these corrected emissions.

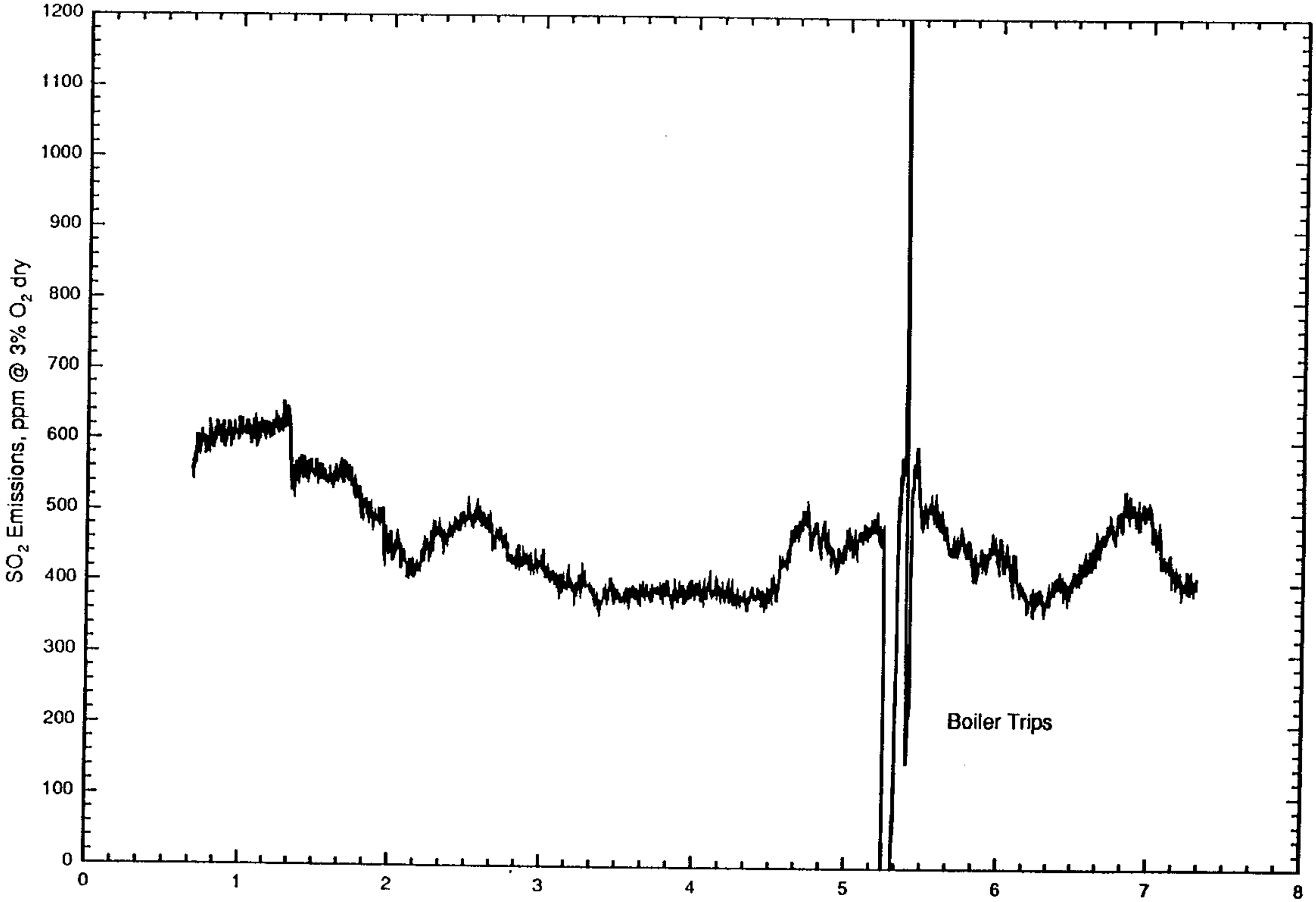

Figure 9-1. SO_2 Emissions for the Long Tem Monitoring Period, December 8 through 15, 1991.

9.3 NO_x EMISSIONS

Unlike SO_2 emissions, the NO_x levels will be significantly altered by the unit operating characteristics. The parametric data have indicated that the emissions will be greatly affected by the excess air levels, boiler load and to a lesser extent, the operating mill or burner patterns. Since Arapahoe Unit 4 was being controlled by dispatch during this period and followed system load demands, a wide variation of NO_x emissions was anticipated. Figures 9-2a through 9-2h show the variation of the NO_x emissions, O_2 levels and the gross boiler load (shown as MWg) for the six day test. Each graph represents a single day of the test period, so that hour-by-hour variations for these three parameters can be examined. It should also be noted that to a certain degree these trend plots will be dependent upon the seasonal conditions. Thus, these data are indicative of the system demand for this particular test period.

A few general trends can be noted from the data. Unit 4 is obviously a cycling unit and rarely remains at a constant load setting during the day. Typical loads cycle between 70 and 90 MWe during a majority of the day. The parametric test measurements indicated that the gross load was only 2 to 4 MWe higher than the net load, so that a relatively small correction would be applied to the gross load indication to conform to the previous net load values. Peak load conditions typically occurred during the morning and evening hours, although the duration at or above 100 MWe varied on a day-to-day basis. Even during these peak load conditions, the load was not constant, but remained variable in response to system load demands. Only rarely was the load blocked at a maximum condition of 110 MWe gross.

Minimum load operation was also variable and the unit was rarely parked at a minimum operating condition. Minimum load was between 40 and 50 MWe gross. Only on the last test day was the load parked at 47 MWe and remained constant during the early morning hours. In most cases, short term variations of 3 to 4 MWe were evident.

Examination of the load and O_2 trends shows that there generally was an inverse relationship between these two parameters. As the load increased, the O_2 levels would generally decrease, within limits. This effect is not unusual, since excess air levels are frequently increased at low load operation. The reason for higher excess air levels at reduced load is to increase the

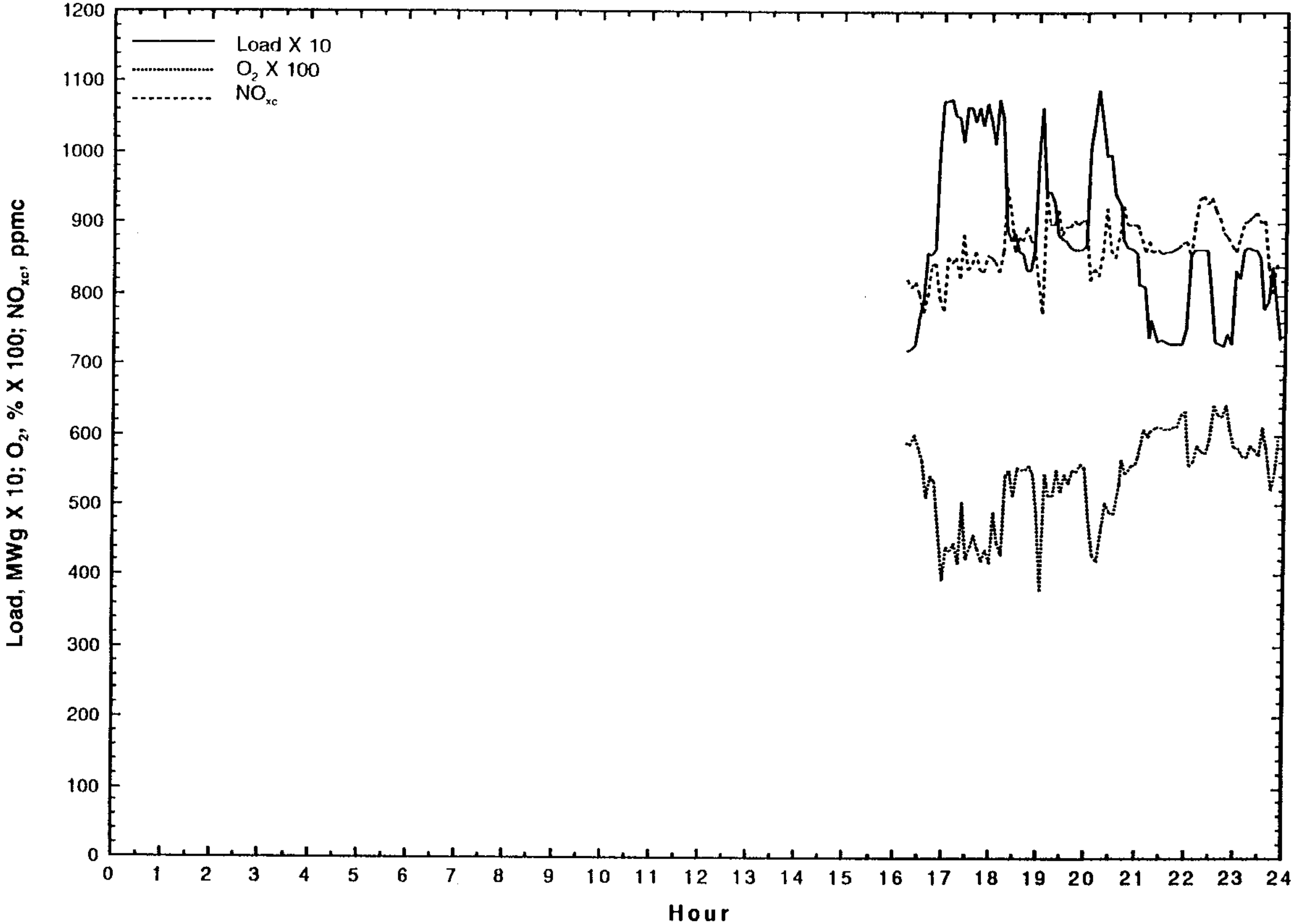

Figure 9-2a. Load, Stack O_2 and NO_x Emissions for Day 1 - Sunday, December 8, 1991

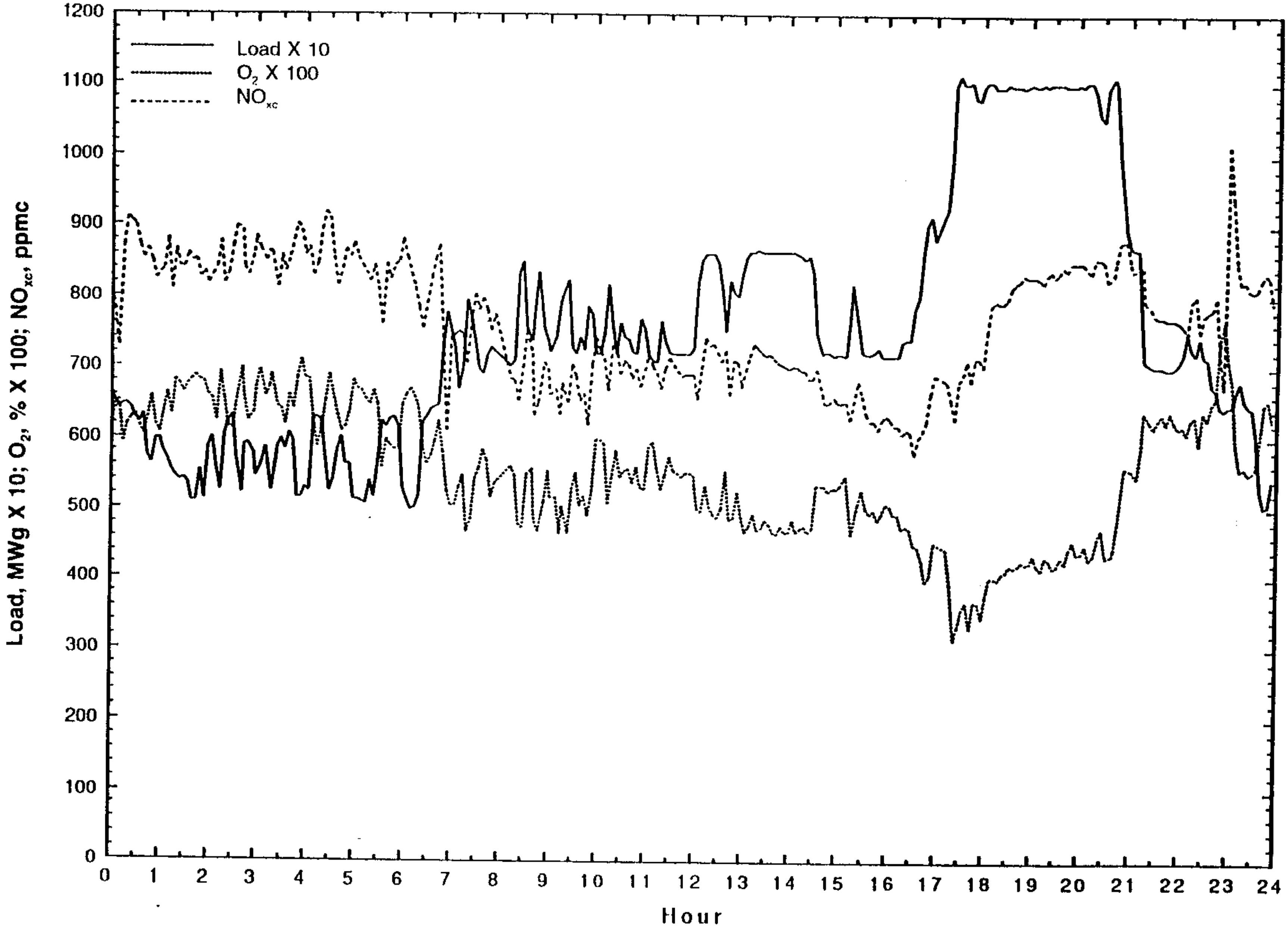

Figure 9-2b. Load, Stack O_2 and NO_x Emissions for Day 2 - Monday, December 9, 1991

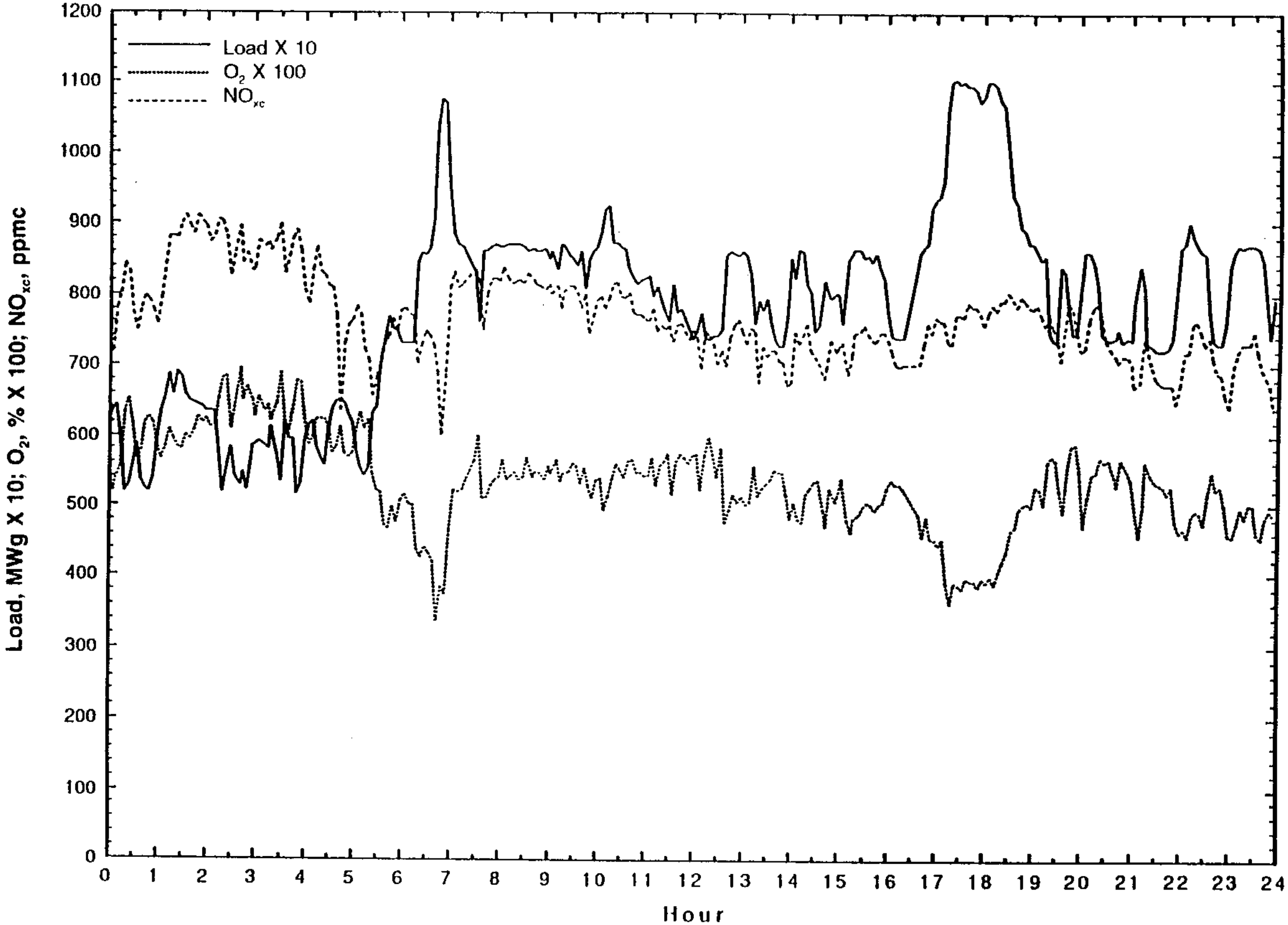

Figure 9-2c. Load, Stack O_2 and NO_x Emissions for Day 3 - Tuesday, December 10, 1991

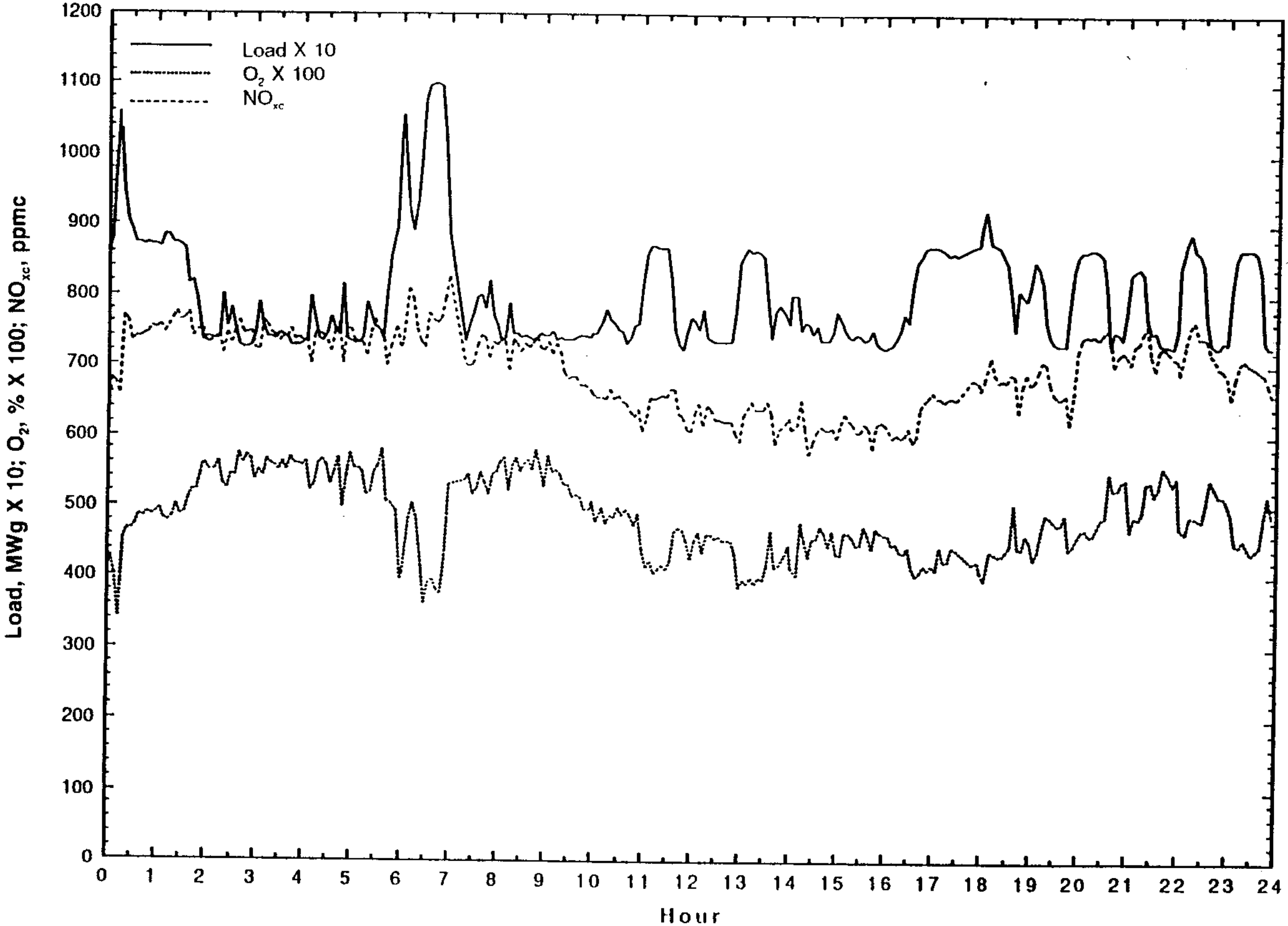

Figure 9-2d. Load, Stack O_2 and NO_x Emissions for Day 4 - Wednesday, December 11, 1991

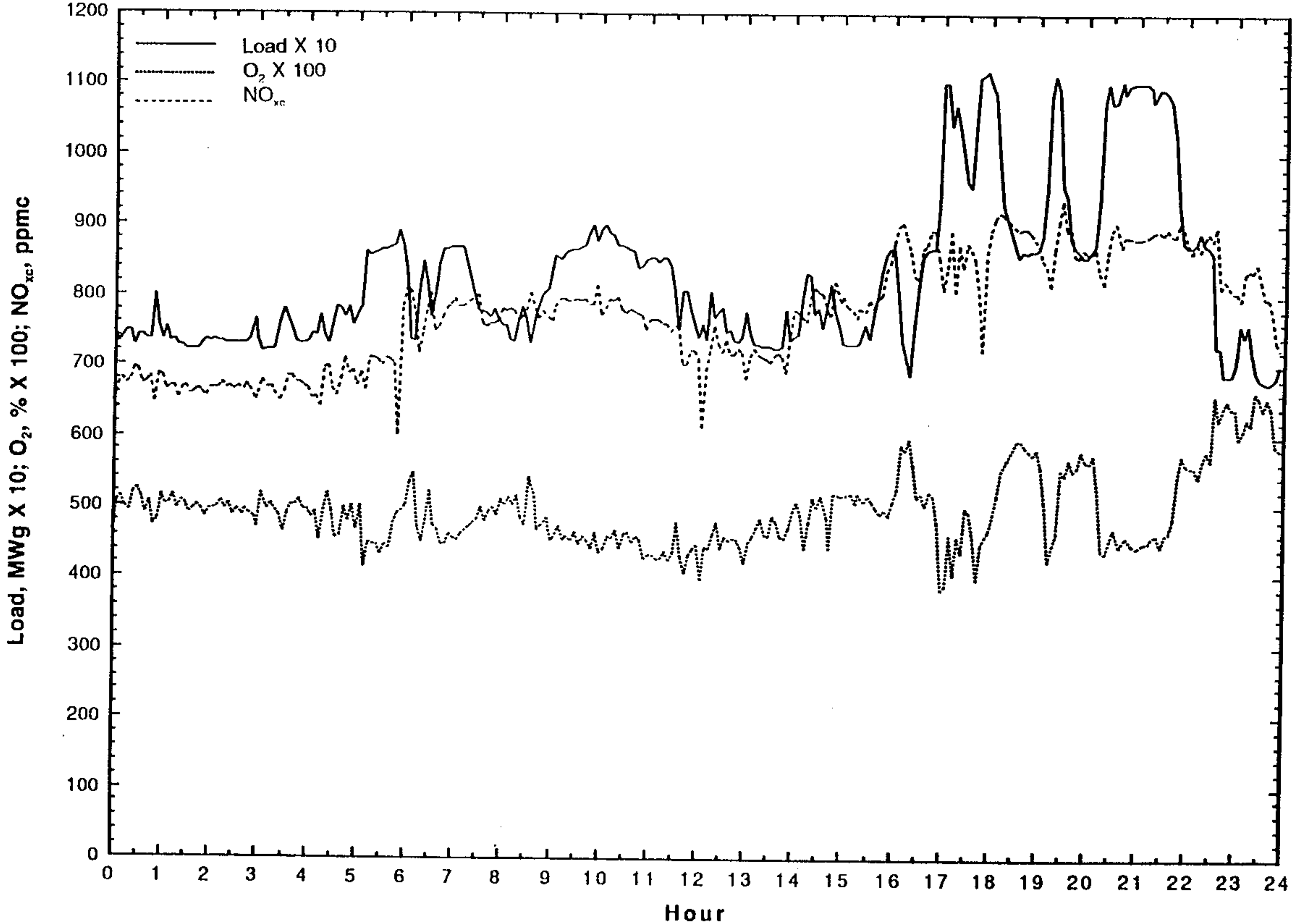

Figure 9-2e. Load, Stack O_2 and NO_x Emissions for Day 5 - Thursday, December 12, 1991

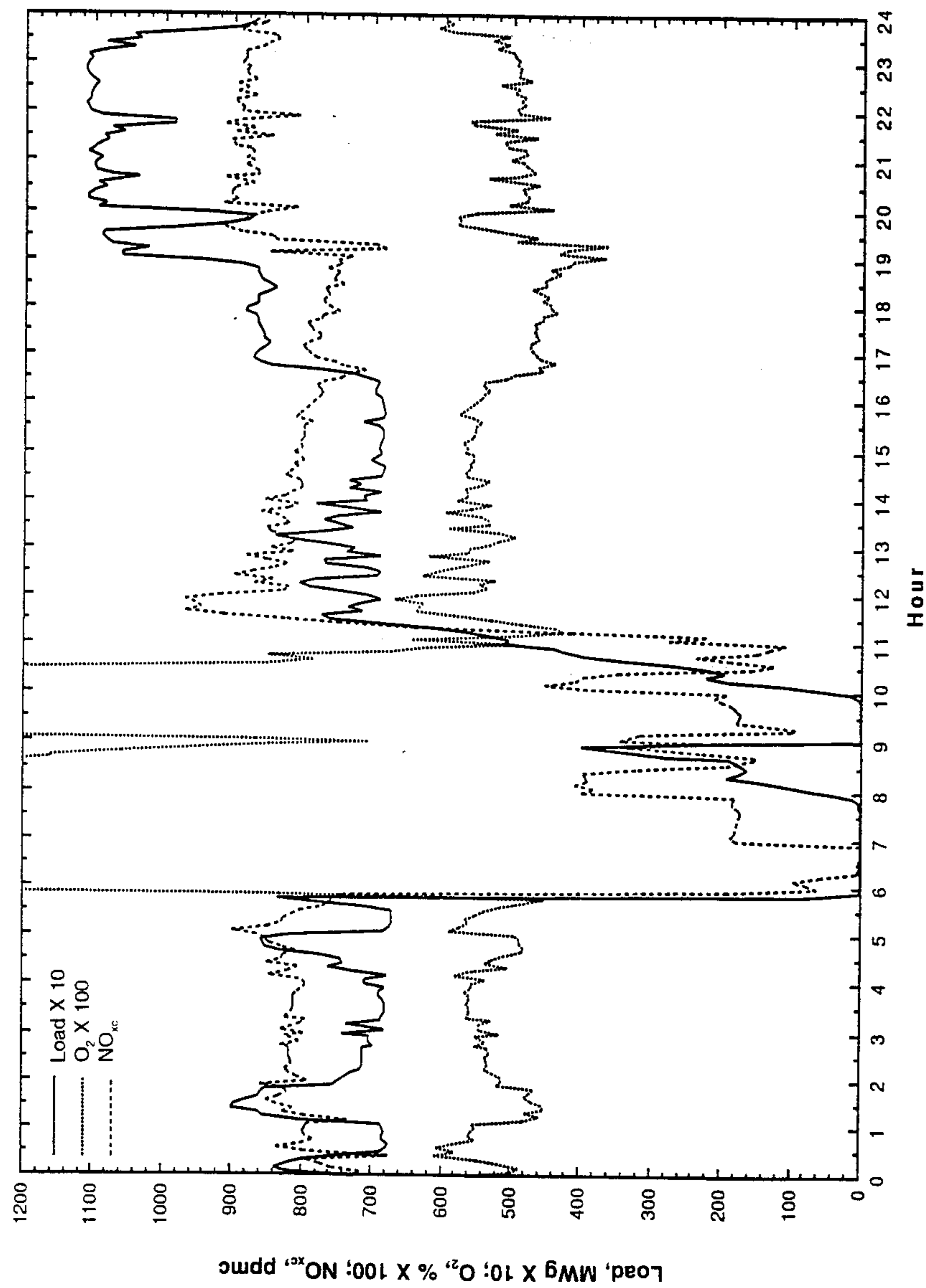

Figure 9-2f. Load, Stack O_2 and NO_x Emissions for Day 6 - Friday, December 13, 1991

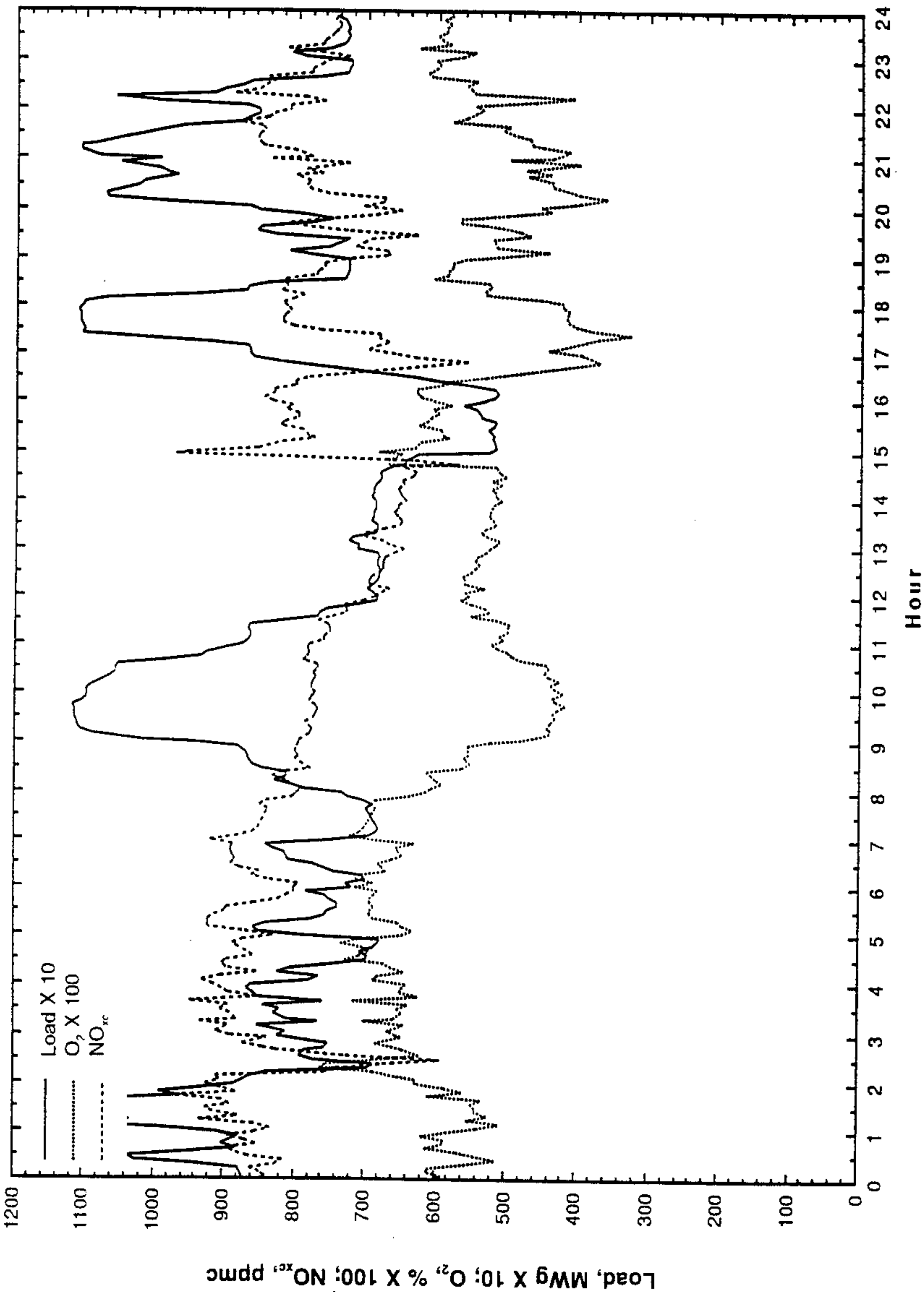

Figure 9-2g. Load, Stack O_2 and NO_x Emissions for Day 7 - Saturday, December 14, 1991

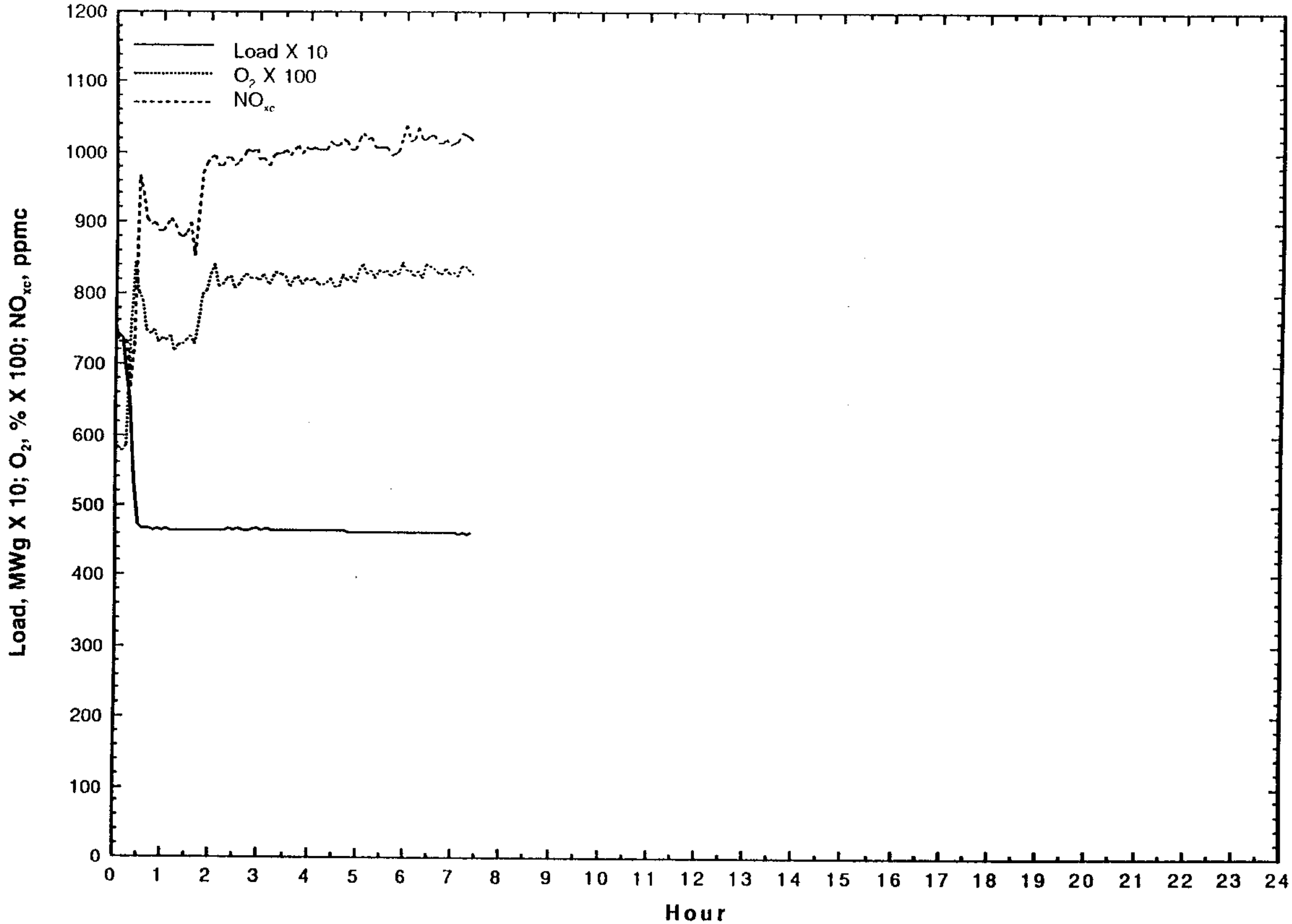

Figure 9-2h. Load, Stack O_2 and NO_x Emissions for Day 8 - Sunday, December 15, 1991

convective heat transfer (higher mass flow of the flue gas) and maintain the required steam temperatures.

As was seen in the parametric tests, this unit design results in NO_x emissions being very dependent on O_2 levels. Likewise, the effect of load was partially counteracted by changes in the O_2 level, since high load conditions tended to raise NO_x, yet reduced O_2 operation at high load decreased NO_x. As a result of these counteracting effects, the variations of NO_x were not extensive over the load range. Corrected NO_x emissions typically ranged from 600 to 900 ppmc, which were very similar to the levels determined from the parametric testing.

The highest NO_x emissions did not always coincide with high load, but could also occur at reduced loads when the system was operated at a high O_2 level. Figure 9-3 is a cross plot of all NO_x data with the boiler load for the long term monitoring period. Several observations can be made from this plot. The load did not have a first order effect upon NO_x emissions over the range from 50 to 100 MWe. While an indistinct trend, or range of emissions, can be noticed with boiler load, a wide range of emissions at any given load prevents characterizing the load effect with any certainty. At the minimum load of 45 MWe, NO_x emissions were typically higher than at full load. The high NO_x emissions were the result of the very high O_2 levels that were implemented at low load. The relatively low-NO_x data scatter below 50 MWe was due to the boiler outage and start up conditions and would not be considered characteristic of normal operation.

The density of the individual data points gives an indication of the amount of time that the boiler operated as a specific load. The points show that the boiler operated primarily in the range of 65 to 85 MWe gross, with additional time at maximum load (110 MWe) and at minimum load (45 to 50 MWe). The light scatter of data below 700 ppmc NO_x and less than 50 MWe load were the data collected during transient operation (boiler trip and start up conditions) and should not be included with any data analysis.

The wide range of emissions at any given load was primarily due to O_2 and perhaps the secondary effects of different mill operating patterns. Figure 9-4 is a cross plot between the load

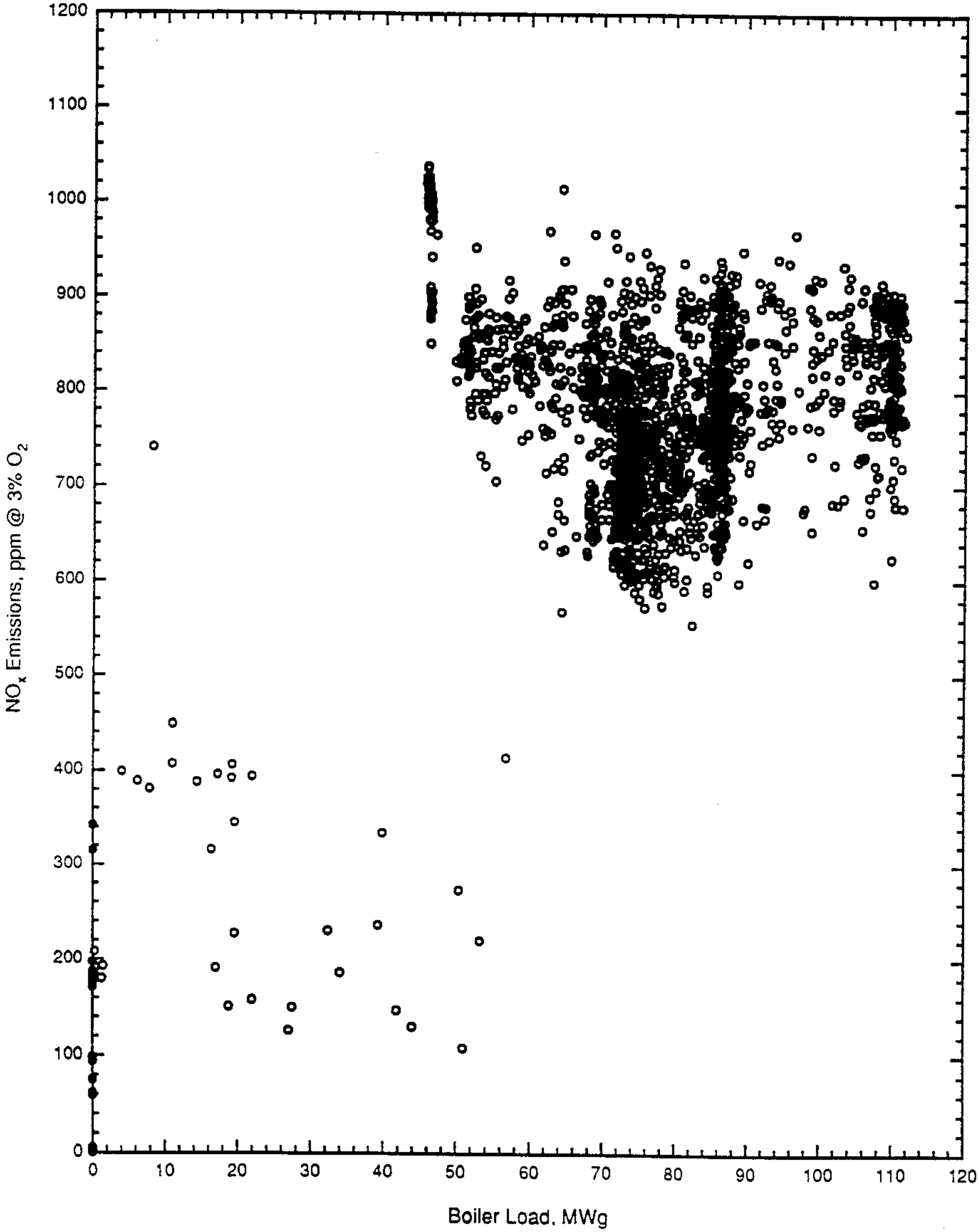

Figure 9-3. Cross Plot Between NO_x Emissions and Boiler Load During Long Term Monitoring.

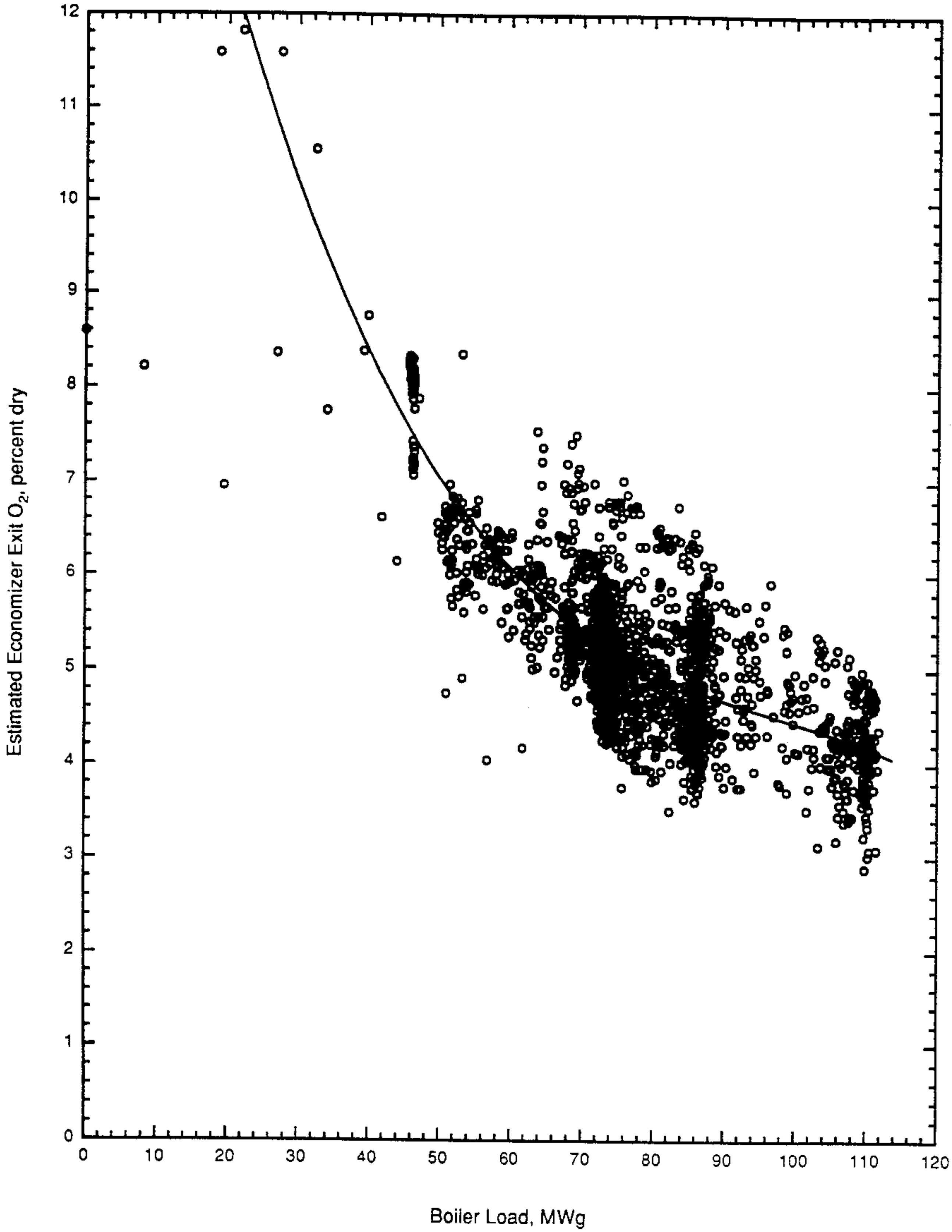

Figure 9-4. Cross Plot Between Estimated Economizer Exit O_2 and Boiler Load.

and the economizer exit O_2, which was estimated from the measured stack O_2 with the relationships determined during the parametric tests. This estimated economizer exit O_2 was used in all correlations in this section to allow comparison with the parametric test operating conditions. The curve indicated the trend of increasing O_2 with lower load, but also showed the wide range of O_2 at any given load. This range of O_2 levels will directly influence NO_x emissions and was the primary reason for the wide range of emissions at any given load setting. Since the operation of the boiler was at each operator's discretion, a range of O_2 levels may be expected. One operator may be concerned with reducing excess air levels to maintain high boiler efficiency, while others may place greater importance upon maintaining steam temperatures and will raise the O_2.

CO emissions were not included in the trend plots for the long term monitoring, but are shown in Figure 9-5 as a function of the estimated economizer exit O_2. In general, the CO emissions remained below 100 ppm for all loads. The density of the data points indicates that the region of 50 ppm was a common emission from the boiler. A slight trend of increasing CO as the O_2 decreased can also be noted, which would be expected under carefully controlled testing conditions. The scattering of data points shows that the CO emissions could increase significantly with otherwise adequate O_2 levels. These data points can be attributed to operating conditions different from the parametric test conditions, but can be experienced with normal boiler operation. Rapid boiler load variations can lead to temporary fuel or air flow excursions, which can affect CO emissions. Adding or removing a mill from service will lead to transient boiler conditions that can cause spikes of CO emissions at normal overall excess air levels. Another condition which could result in higher than normal CO emissions is a large imbalance in the feeder coal flows to the operating mills, which would force certain mills to operate with high fuel flows, resulting in a propensity to form local areas of high CO emissions. High CO can occur when a mill is removed from service, but the secondary air dampers are not fully closed. This will divert a portion of the combustion air from the operating burners, which will tend to starve them of air and increase CO emissions.

Figures 9-6a through 9-6d present the NO_x and CO emissions versus the estimated economizer exit O_2 levels for selected load ranges. These data sets allow additional trends to be determined within each selected load range. Average NO_x versus O_2 curve fits have been included and can

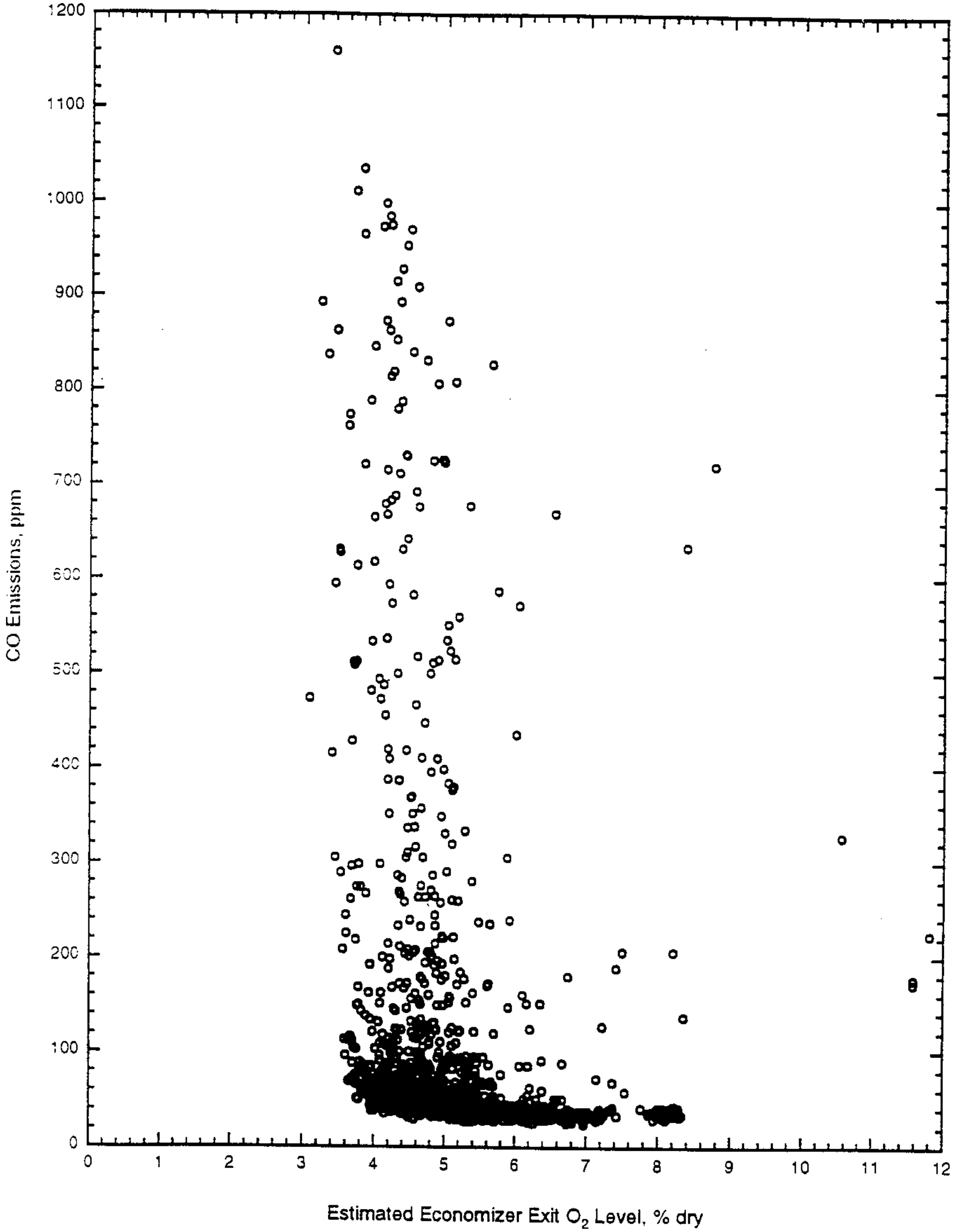

Figure 9-5. Cross Plot Between CO Emissions and Estimated Economizer Exit O_2 Level for All Loads.

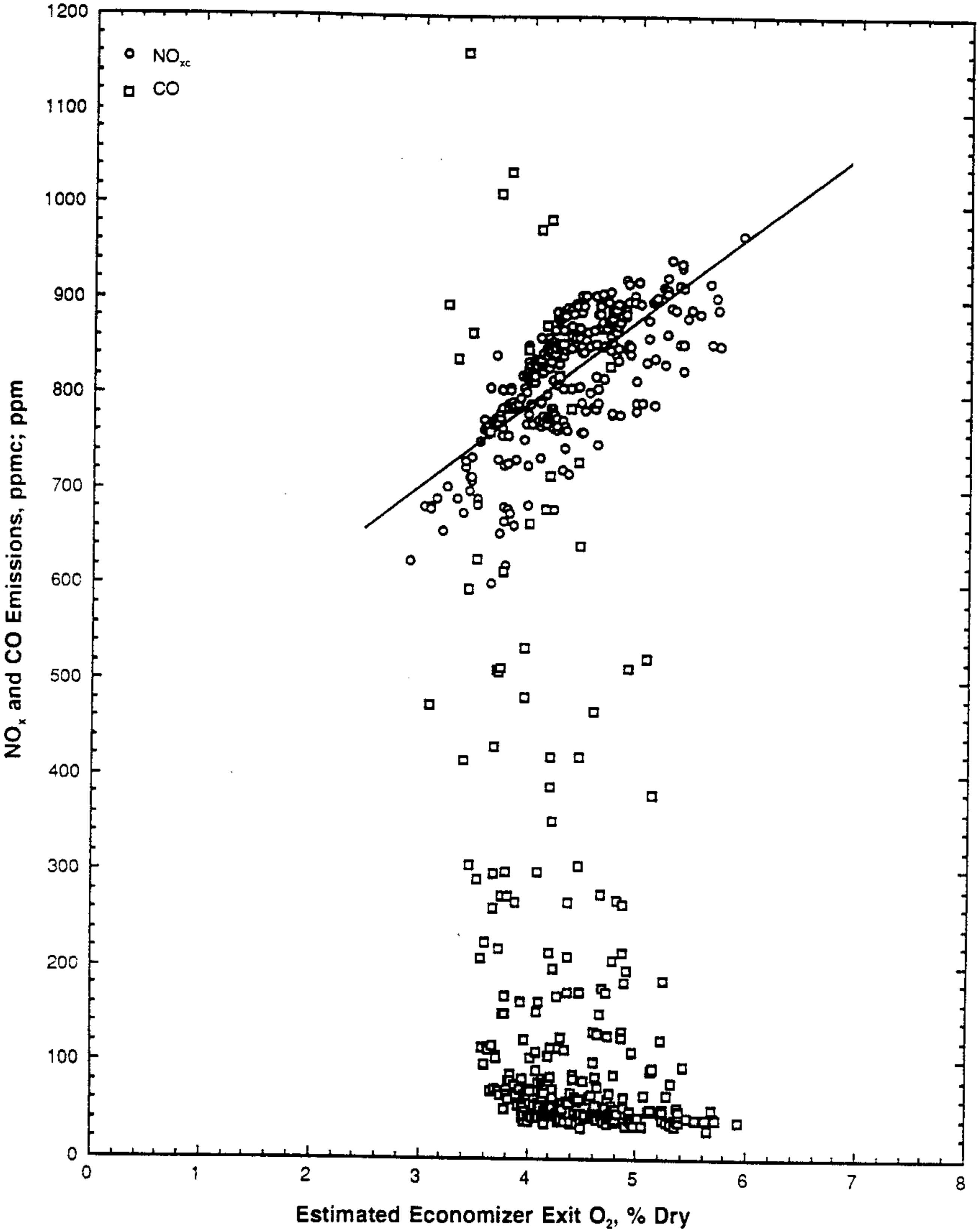

Figure 9-6a. NO$_x$ and CO Emissions during the Long Term Monitoring for 90 and 100 MWg Boiler Loads

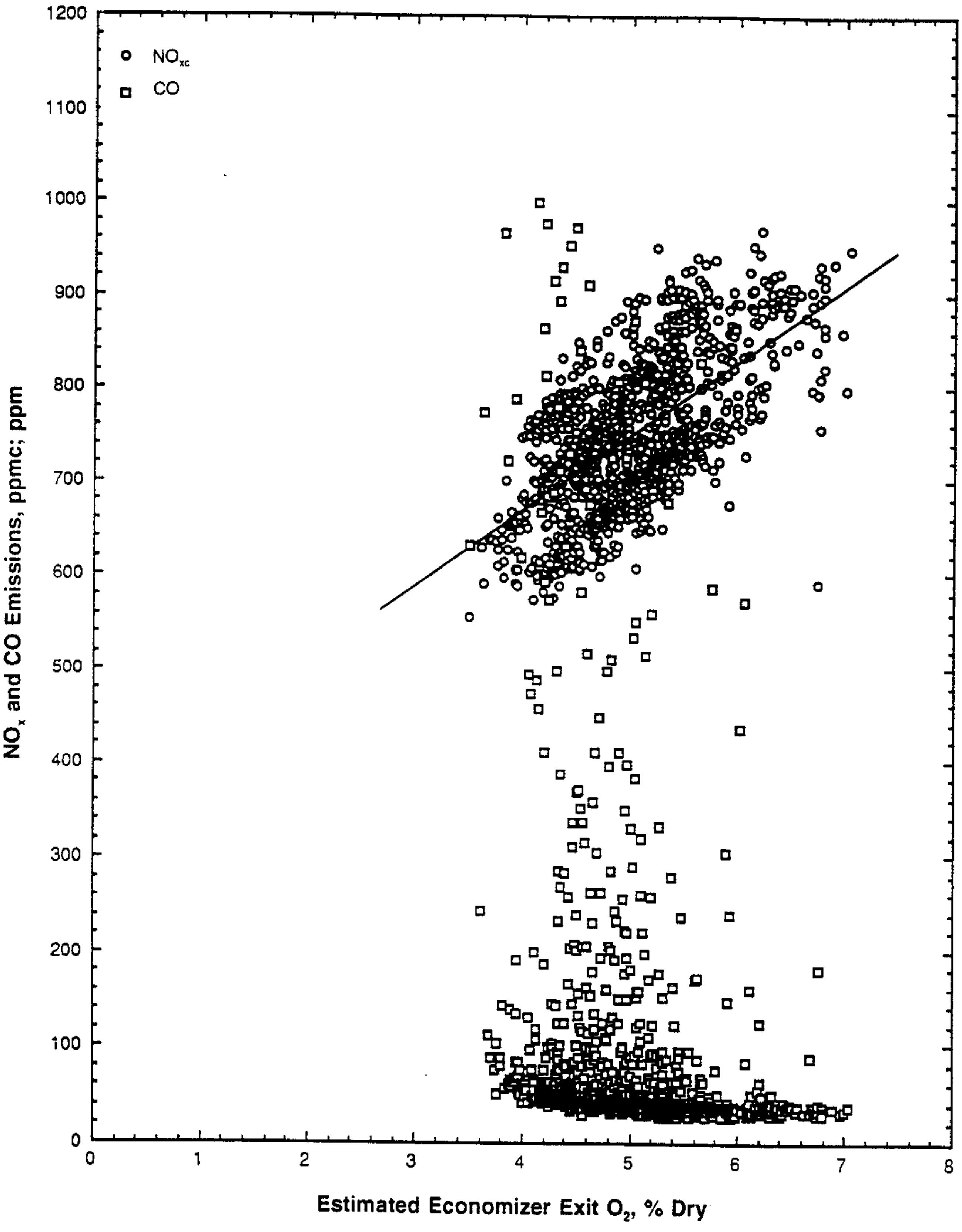

Figure 9-6b. NO$_x$ and CO Emissions during the Long Term Monitoring for 70 and 90 MWg Boiler Loads

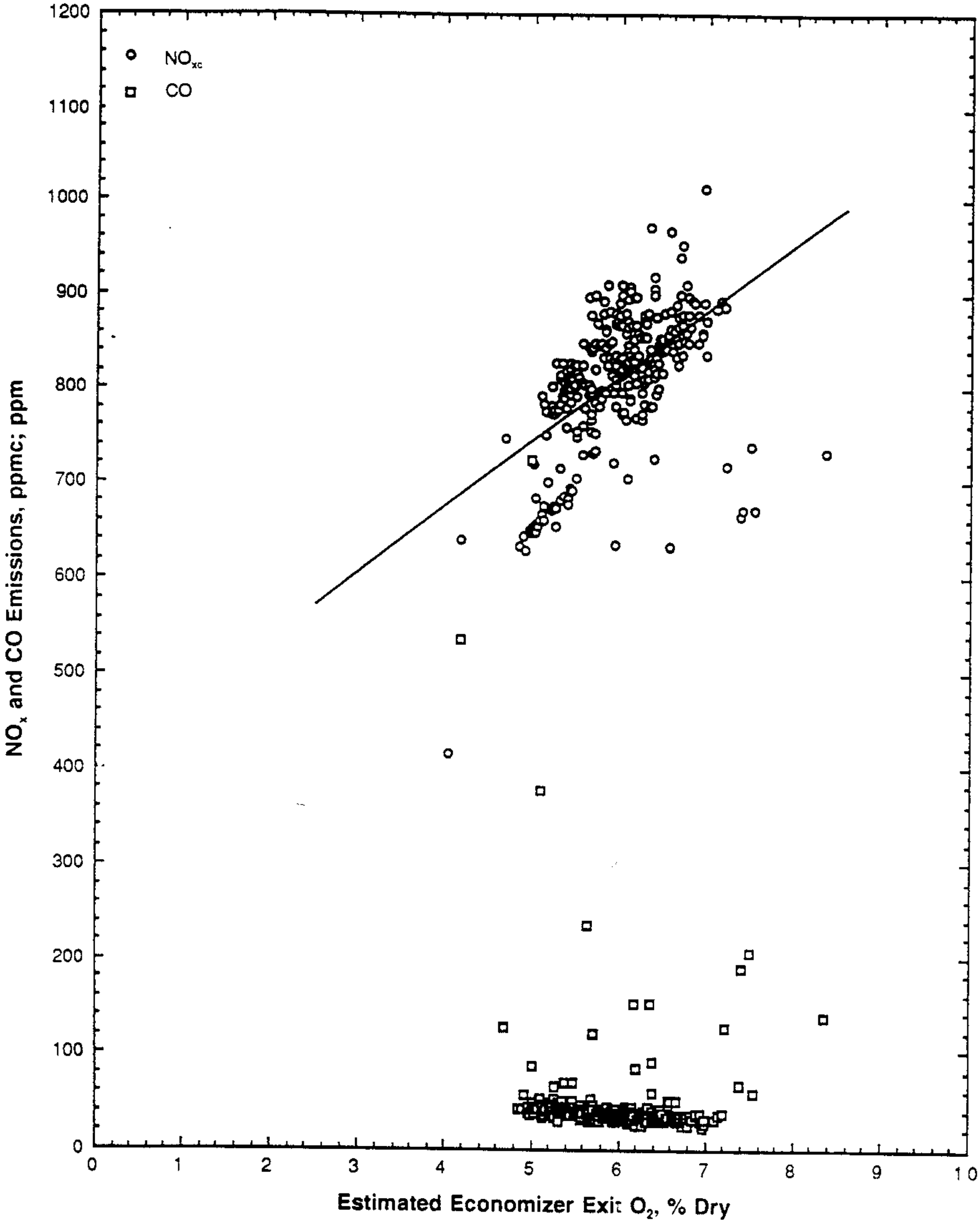

Figure 9-6c. NO_x and CO Emissions during the Long Term Monitoring for 50 to 70 MWg Boiler Loads

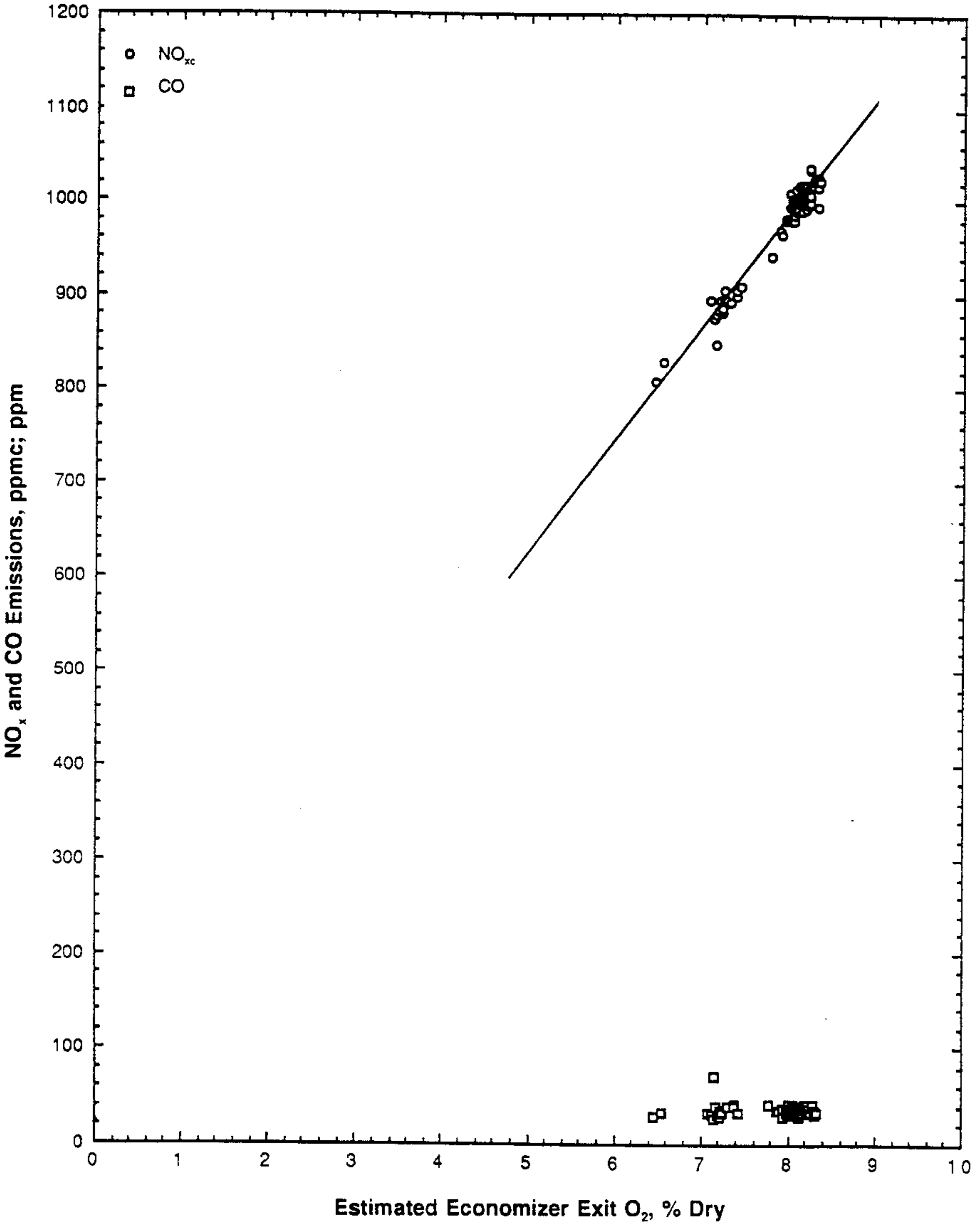

Figure 9-6d. NO$_x$ and CO Emissions during the Long Term Monitoring for 40 to 50 MWg Boiler Loads

be compared to the parametric tests. For a specific load range, a trend of increasing load with increasing O_2 was observed, although a significant range of NO_x emissions was also evident. Overall, the different graphs show that the NO_x decreased with load (on average) but the high O_2 at the minimum load reversed the trend. As expected, reducing boiler load decreased NO_x emissions for a constant O_2 level.

NO_x data for each load range during the long term tests were analyzed to determine the mean and standard deviation of the individual data points. Table 9-1 shows the statistical evaluation, while Figure 9-7 compares these results to the parametric test results obtained earlier. The long term data are represented in the figure by the average values, with a band extending to ± 1 standard deviation around the average. The average NO_x emissions from the parametric tests are also presented in the figure and compare well with the long term data. The two averages agree within approximately 40 ppmc throughout the load range from 60 to 100 MWe. The long term data also show that the NO_x variations were highest at extremely high and low loads, while the emissions were more consistent at 80 MWe.

The most significant difference between parametric and long term NO_x data appeared at a 60 MWe load. The parametric data indicated a slight NO_x decrease from 80 MWe, while the average long term data showed an increase in NO_x. The difference is probably attributable to the "normal" O_2 chosen for 60 MWe parametric tests and the mean O_2 obtained during the long term operation. A relatively small difference in O_2 level would easily account for these NO_x differences and perhaps indicates that the unit operated with higher than expected O_2 at low load. The very high NO_x emissions at minimum load is also clearly indicated by the figure.

The last data plot, Figure 9-8, shows the relationship between the CO_2 and O_2 measurements. This relationship is very similar to the parametric baseline data presented earlier. The relatively tight grouping of the data again indicates that instrument calibration drift was not likely to be a significant problem during the long term monitoring period.

Table 9-1

STATISTICAL NO_x EVALUATION OF LONG TERM DATA

Load Range (MWe)	40-50	50-70	70-90	90-110
Number of Points	86	302	1130	297
NO_x Average (ppmc)	981	807	774	820
NO_x (ppmc) Standard Deviation	152	108	65	170

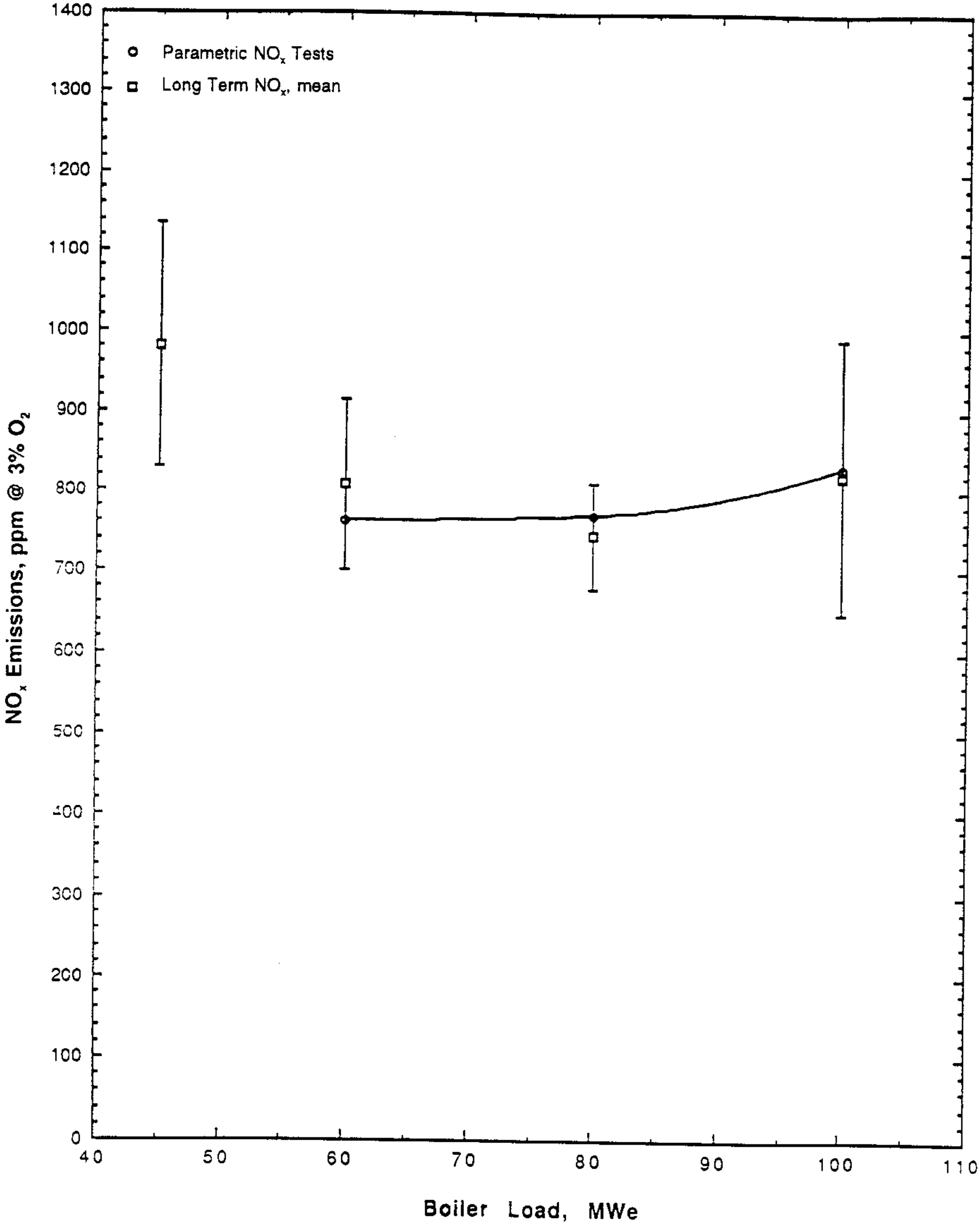

Figure 9-7. NO_x versus Load for Long Term and Parametric Tests

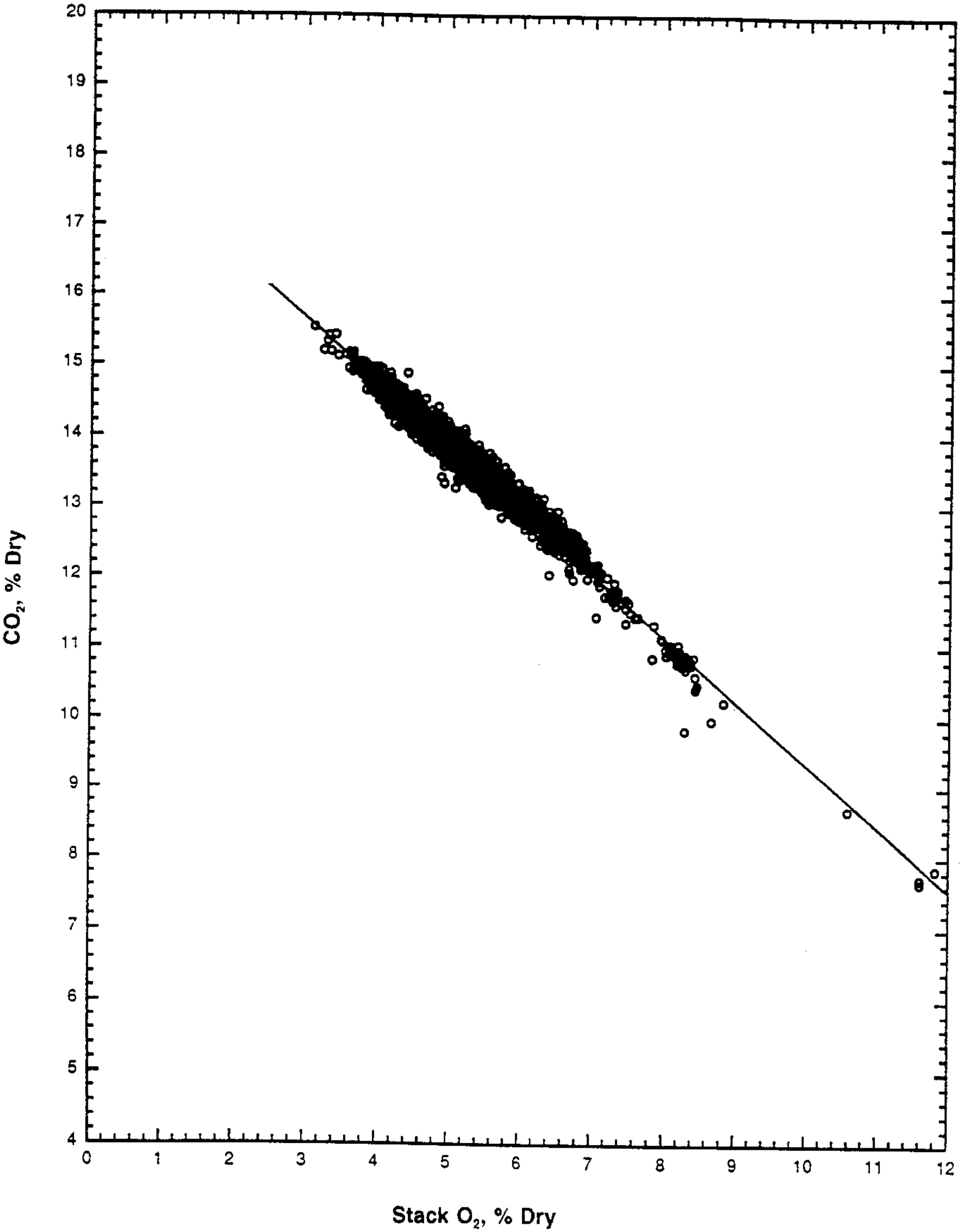

Figure 9-8. Cross Plot between O_2 and CO_2 Levels

10.0 CONCLUSIONS AND OBSERVATIONS

The following conclusions and observations can be made from the baseline tests.

NO_x Emissions

- NO_x emissions were relatively high from Arapahoe Unit 4, primarily due to its burner design, with average NO_x levels ranging from 740 to 850 ppm over the load range.
- Excess air level was the primary factor influencing NO_x emissions with a slope of approximately 145 ppm $NO_x/\%O_2$ at full load.
- A very wide range of emissions was documented for normal boiler operation, due to the variation of O_2 and load.

SO_2 Emissions

- Typical SO_2 emissions ranged from 350 to 600 ppmc, reflecting varying fuel sulfur content. SO_3 emissions remained low (below 1 ppm).
- The variation of SO_2 may have an impact upon the structuring of future SO_2 reduction tests.

Boiler Operation

- Minimum O_2 levels were approximately 3.5 to 4.0% as measured from the economizer exit grid (economizer exit grid O_2 measurements were nominally 1% higher than the control room O_2 readings). Operation at or below these levels would result in elevated CO and combustible emissions.
- Fly ash carbon levels ranged from 1 to 11% and were typically 5%.
- Lower minimum O_2 levels may be possible with better coal distribution to the burners, which would extend the O_2 range without significantly impacting combustible emissions. Coal flow balancing among the pipes should be considered as part of the start up of the low-NO_x burner system.