30. 3041

INTEGRATED DRY NO_x/SO_2 EMISSIONS CONTROL SYSTEM

LOW-NO_x COMBUSTION SYSTEM SNCR TEST REPORT

(Test Period: January 11 to April 9, 1993)

DOE Contract Number DE-FC22-91PC90550

Prepared by

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

T. Hunt
Public Service Company of Colorado
Denver, CO

Prepared for

Public Service Company of Colorado
Denver, CO

November 1993

Final: June 1994

Patents Cleared by Chicago on JUN 30 1994

DISCLAIMER

This report was prepared by Fossil Energy Research Corp. pursuant to a cooperative agreement funded partially by the U. S. Department of Energy and neither Fossil Energy Research Corp., nor any of its subcontractors, nor the U. S. Department of Energy, nor any person acting on behalf of either:

(a) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

(b) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U. S. Department of Energy. The views and opinions of authors expressed herein do not necessarily state or reflect those of the U. S. Department of Energy.

30.3041

Public Service®

Public Service
Company of Colorado

5900 East 39th Avenue
Denver, CO 80207-1294

July 13, 1994

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

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

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

Gentlemen:

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

Please advise us if you have any questions.

Sincerely,

Terry Hunt, Project Engineer
Generation Engineering Services

Enclosure (2)

<u>With enclosure:</u>

cc: Mr. David L. Hunter (DOE)
Dr. C. Lowell Miller (DOE)
Mr. Howard Feibus (DOE)
Mr. Jeffrey Stallings (EPRI,2)
Mr. John Doyle (B&W)
Office of Technical Information Management (3)
Dr. S.N. Roger Rao (Burns and Roe Technical Group)
Mr. Steve Rohde (PSCC,2)
File CC-071G/D. Muggli
Mr. Dale Jones (Noell)
Mr. Jim Rooney (Coastal Chem)

ACKNOWLEDGEMENTS

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

ABSTRACT

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

This report documents the fourth phase of the test program, where the performance of the SNCR system, after the low-NO_x combustion system retrofit, was assessed. Previous to this phase of testing, a subsystem was added to the existing SNCR system which allowed on-line conversion of a urea solution to aqueous ammonium compounds. Both converted and unconverted urea were investigated as SNCR chemicals. Other parameters investigated included boiler load, the amount of chemical injected, as well as injection parameters (amount of mixing air, dilution water flow, and injector liquid orifice sizes).

Converted urea provided higher NO_x removals across the load range for a fixed level of NH_3 slip than urea. At full load with 10 ppm slip, NO_x removals of 44 and 47 percent could be obtained with urea and converted urea, respectively. However, the increased

removals with converted urea required higher chemical injection rates; thus, at loads of 80 MWe and higher, urea was the most efficient chemical. Byproduct N_2O emissions were lower for converted urea compared to urea.

Peak NO_x removals for urea injection with the retrofit low-NO_x combustion system were similar to those seen with the original burners, but the load at which the peak occurred increased from approximately 70 to 100 MWe. This shift was a result of a decrease in furnace exit gas temperature seen after the retrofit. On a normalized basis, both NH_3 and N_2O emissions with the retrofit combustion system were higher than those for the original burners, over the entire load range.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

Section **Page**

APPENDIX

Data Summary

LIST OF FIGURES

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF TABLES

LIST OF DEFINITIONS

AC	Alternating Current
B&W	Babcock & Wilcox
CEM	Continuous Emission Monitor
DCS	Distributed Control System
DOE	U. S. Department of Energy
DRB-XCL®	Dual Register Burner - Axially Controlled Low-NO_x
EDTA	Ethylenedinitro Tetracetic Acid
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FEGT	Furnace Exit Gas Temperature
FERCO	Fossil Energy Research Corp.
FGR	Flue Gas Recirculation
gpm	Gallons Per Minute
HVT	High Velocity Thermocouple, suction pyrometry
LCP	Local Control Panel
LNB	Low-NO_x Burner
MWe	MegaWatts (electrical)
nm	Nanometers
N/NO	Molar Ratio of Nitrogen Injected (in the SNCR Chemical) to the NO Present in the Flue Gas
OFA	OverFire Air
OOS	Out Of Service
PLC	Programmable Logic Control
ppm	Parts Per Million
ppmc	Parts Per Million Corrected to 3 percent O_2 level
PSCC	Public Service Company of Colorado
psig	Pounds per Square Inch Gauge
RATA	Relative Accuracy Test Audit
SCFM	Standard Cubic Feed per Minute, measured at 1 atmosphere and 60°F
SNCR	Selective Non-Catalytic NO_x Reduction

EXECUTIVE SUMMARY

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

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

- Baseline tests with the original combustion system (completed)
- Baseline tests with the original combustion system and SNCR (completed)
- Low-NO_x Burner (LNB)/Overfire Air (OFA) tests (completed)
- LNB/OFA/SNCR tests (completed, subject of this report)
- LNB/OFA/Calcium Injection tests
- LNB/OFA/Sodium Injection tests
- LNB/OFA/SNCR Dry Sorbent Injection tests (integrated system)
- High-Sulfur Coal tests with the integrated system
- Air Toxics Characterization

This report presents the results of the Selective Non-Catalytic Reduction tests performed after the combustion system retrofit on the Arapahoe Unit 4 boiler. Previous to this phase of testing, a subsystem was added to the existing SNCR injection system which allows on-line conversion of a urea solution to ammonium compounds. Both converted and unconverted urea were investigated as SNCR chemicals. At the conclusion of this report, the NO_x reduction performance of SNCR with the retrofit low-NO_x combustion system is compared to that for the original combustion system as documented during the second phase of the program.

The LNB/OFA/SNCR test program was conducted over a thirteen (13) week period from January 11, 1993, to April 9, 1993. During this time period, a parametric investigation of the effects of boiler load, chemical injection rate, and injection system parameters (mixing air and dilution water flow rates) was conducted for both converted and unconverted urea. Liquid injection nozzle diameters were optimized with urea injection before the parametric performance tests were conducted. The affect of operating the SNCR system with various mill out of service patterns was also assessed with urea injection.

The parameters found to have the greatest effect on process performance were boiler load and chemical injection rate (N/NO molar ratio). The effects of mixing air and dilution water flow rates were found to be small over the range of flows tested. Variations in boiler load showed the largest effect on system performance, due to the impact on the local flue gas temperatures in the area of chemical injection. SNCR is a highly temperature-dependent process with only a narrow window available for maximum NO_x removal.

As expected, increased SNCR chemical flow rates yielded higher NO_x removals, with the tradeoff of higher NH_3 emissions accompanying the increased removals. The results showed that NO_x removals were higher with urea than with converted urea for a given chemical injection rate, over nearly the entire boiler load range. NH_3 emissions were also found to be higher with urea. Therefore, for a given NH_3 emission limit, converted urea tended to provide higher NO_x removals than urea. As shown in Figure S-1, for a 10 ppm NH_3 emission limit NO_x removals of 19 to 47 percent were achievable with converted urea over the load range of 60 to 100 MWe, while urea injection resulted in removals of only 11 to 45 percent. However, over the load range of 80 to 100 MWe, urea was the most efficient chemical since the increased NO_x removals with converted urea required higher chemical feed rates.

Nitrous oxide (N_2O) emissions with converted urea were lower than with urea injection. With converted urea, the fraction of the NO_x reduced which was converted to N_2O ranged from 3 to 8 percent at a nominal N/NO molar ratio of 1.0, depending on load. With urea and a similar N/NO ratio, the conversion ranged from 29 to 35 percent.

Peak NO_x removals for urea injection with the retrofit low-NO_x combustion system were similar to those seen with the original burners, but the boiler load at which the peak occurred increased from approximately 70 to 100 MWe. This shift was a result of a decrease in furnace exit gas temperature seen after the retrofit. On a normalized basis, both NH_3 and N_2O emissions with the retrofit combustion system were higher than those for the original burners, over the entire load range. These increases are also attributed to reduced flue gas temperatures in the region of injection.

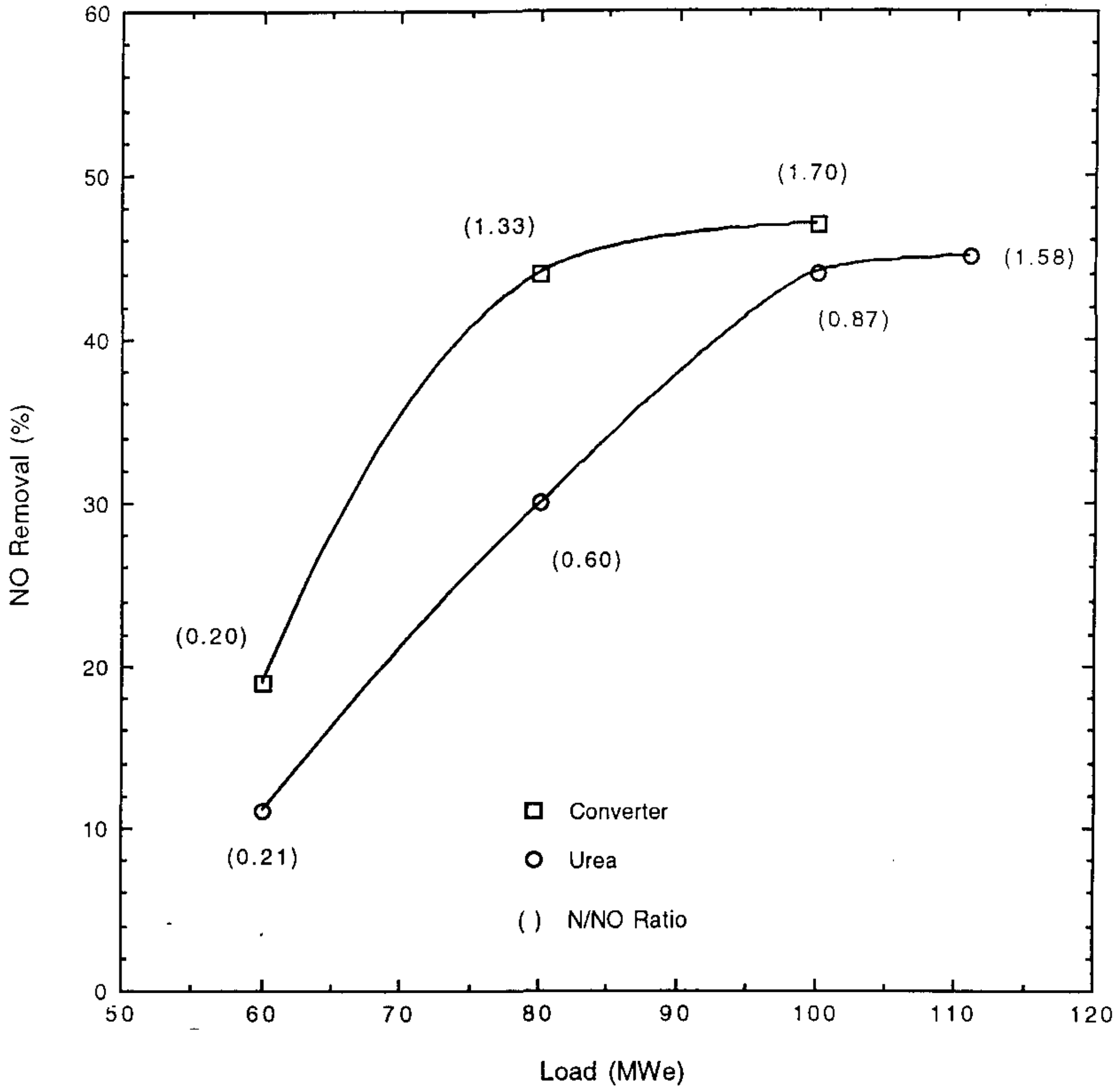


Figure S-1. Comparison of NO Removals for Urea and Converted Urea for a Fixed NH_3 Slip Level of 10 ppm

1

INTRODUCTION

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

During the demonstration program, these emissions control systems are being optimized and integrated with the goal of achieving up to 70 percent reductions in NO_x and SO_2. It is anticipated that 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. For example, an undesirable side effect of sodium-based sorbent injection for SO_2 control has been oxidation of NO to NO_2,resulting in plume colorization. Pilot-scale testing, sponsored by the Electric Power Research

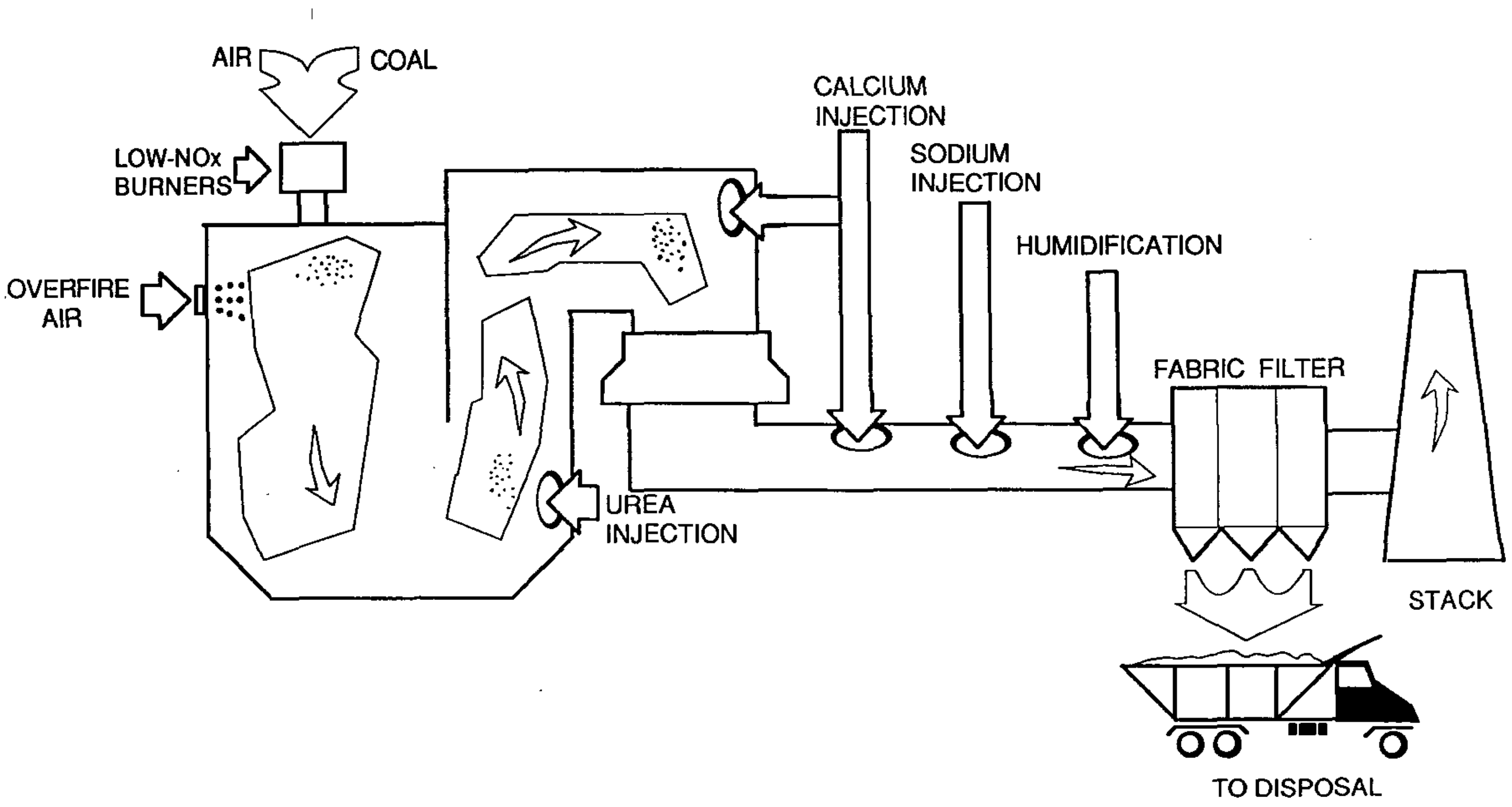


Figure 1-1. Arapahoe Unit 4 Integrated Dry NO_x/SO_2 Emissions Control System

Institute (EPRI), has shown that the presence of NH_3 can reduce the NO_2 emissions resulting from sodium-based dry sorbent injection. In the integrated system, the byproduct NH_3 emissions from the urea injection system will serve to minimize NO_2 formation. An additional objective of this program is to test the effectiveness of the integrated system on a high-sulfur coal.

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

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

In addition to investigation of NO_x and SO_2 emissions, the test program will also investigate air toxic emissions. Air toxic emission levels were obtained during the testing of the low-NO_x combustion system, and with urea injection. Two additional tests will be conducted during the calcium and sodium injection tests to determine the potential air toxics removal of these pollution control technologies. The air toxics test results will be documented in separate reports.

This report presents the results of the selective non-catalytic reduction tests performed after the combustion system retrofit on the Arapahoe Unit 4 boiler. Previous to this phase of testing, a subsystem was added to the existing SNCR injection system which allows on-line conversion of a urea solution to ammonium compounds. Both converted and unconverted urea were investigated as SNCR chemicals. At the conclusion of this report, the NO_x reduction performance of SNCR with the retrofit combustion system is compared to that for the original combustion system as documented during the second phase of the program.

2

PROJECT DESCRIPTION

The following subsections will describe the key aspects of the technologies being demonstrated, the project participants, and the boiler and the original combustion system. This will be followed by a description of the retrofit low-NO_x combustion system and a brief review of the results of the low-NO_x burner/overfire air tests. Finally, a review of the results of the Selective Non-Catalytic Reduction tests with the original combustion system will be presented.

2.1 Process Description

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

2.1.1 Low-NO_x Burners

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

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

2.1.2 Overfire Air

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

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

2.1.3 Selective Non-Catalytic Reduction

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

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

The SNCR chemical of primary interest for the present program is urea. The urea is generally injected into the boiler as a liquid solution through atomizers. The atomizing medium can be either air or steam, although air is used in the current installation. The

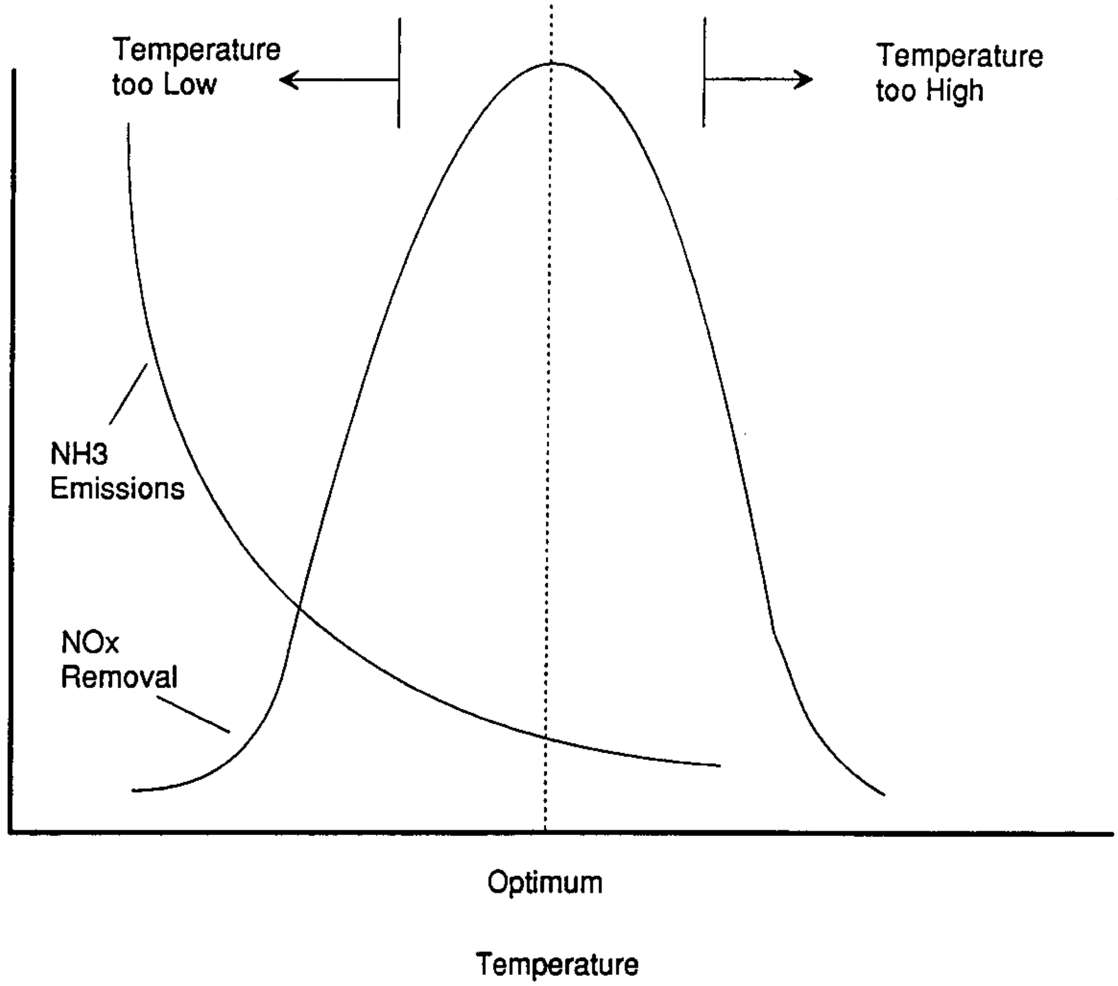


Figure 2-1. Conceptual Temperature Window for the SNCR Process

urea and any additives are stored as a liquid and pumped through the injection atomizers. At Arapahoe Unit 4, a system has also been installed to catalytically convert the urea solution to ammonium compounds.

2.1.4 Dry Reagent SO_2 Removal System

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

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

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

2.1.5 Humidification

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

2.2 Project Participants

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

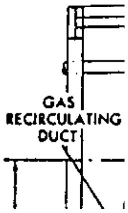
B&W was responsible for engineering, procurement, fabrication, installation, and shop testing of the low-NO_x burners, overfire air ports, humidification equipment, and associated controls. They are also assisting in the testing program, and will provide for commercialization of the technology. NOELL,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

2.3 Boiler and Original Combustion System Description

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

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

The original intertube burners were not comparable to a more common wall-fired burner. Each burner consisted of a rectangular coal/primary air duct which was split into 20 separate nozzles arranged in a four by five rectangle that injected the coal/air mixture evenly across the furnace roof. A secondary air windbox surrounded each burner and allowed air flow around each of the individual coal nozzles, resulting in a checkerboard


GAS
RECIRCULATING
DUCT

pattern of coal/primary air and secondary air streams. The burners had no provisions to control the rate of fuel and secondary air mixing.

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

2.4 Low-NO_x Combustion System Description

The low-NO_x combustion system retrofit at Arapahoe Unit 4 was comprised of work in three areas: the installation of the low-NO_x burners, the addition of an overfire air system, and modifications to the existing boiler control system. Each of these areas is discussed separately in the sections that follow.

2.4.1 Low-NO_x Burners

To reduce the NO_x emissions formed during the combustion process, B&W DRB-XCL^R burners were retrofit to the Arapahoe Unit 4 boiler. Figure 2-4 shows a simplified schematic of the burner. The burner has two main design features which limit the formation of NO_x. First is the addition of a sliding air damper. In many older burner designs, a single register is used to control both total secondary air flow to the burner and also the swirl (i.e., the rate of fuel/air mixing). The use of the sliding damper separates the functions and allows the secondary air flow to be controlled independently of the swirl. The burner includes a circular pitot tube array which provides a relative indication of the secondary air flow to each burner. The second feature is the addition of dual spin vane registers. The most important variable in controlling the formation of NO_x is the rate at

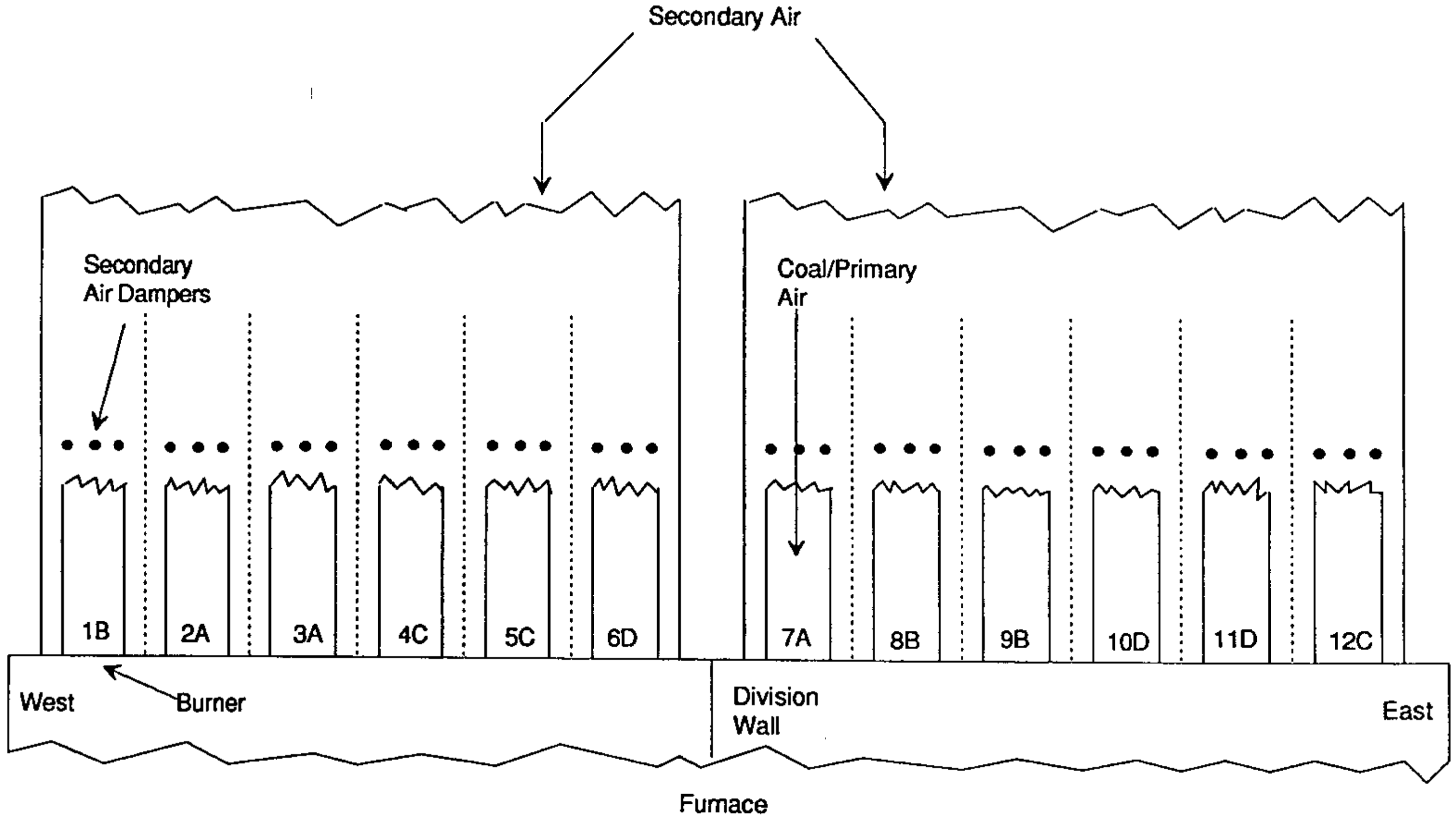


Figure 2-3. Original Burner-Mill Arrangement - Looking to the North (Note: the letter next to each burner designates one of the four pulverizers)

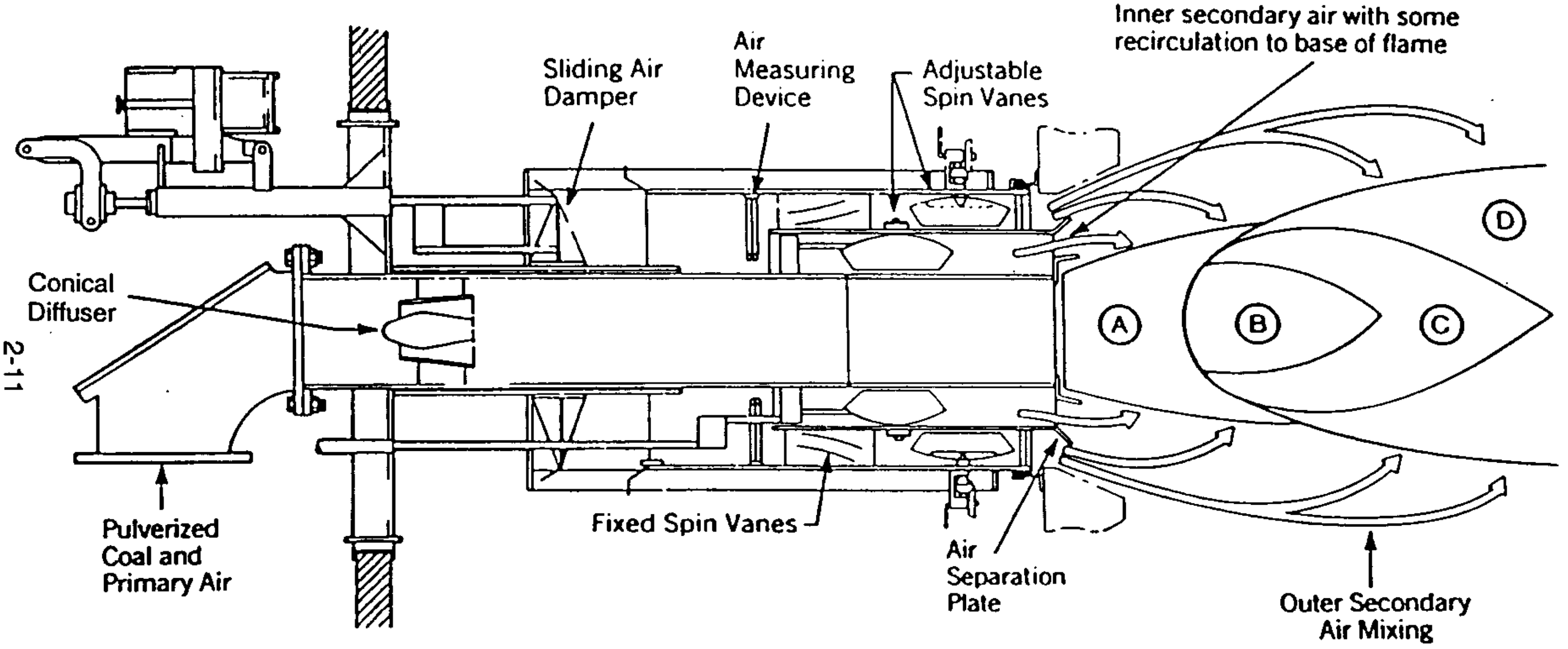


Figure 2-4. B&W DRB-XCL™ Low-NO_x Burner

which oxygen is mixed with the fuel. The dual spin vane registers provide a great amount of control over the amount of swirl imparted to the secondary air, and thus the rate of fuel/air mixing in the near-burner region.

An electric linear actuator is used to adjust the sliding damper which controls the total secondary air to each burner. The control system allows for three disc positions: cool, light and normal. The cool position is used while a burner is out of service and provides a minimum amount of cooling air so that the burner metal temperatures do not exceed the design limit of 1300°F. The light position is used to provide slightly more air while the gas ignitors are firing. The normal position is used while the burners are fired with either coal or natural gas. Limit switches in the actuator are used to adjust the three disk positions. The adjustment of these limit switches allows the secondary air to be individually adjusted at each burner, if burner-to-burner imbalances occur.

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

The burners were placed in 4 rows of 3 burners as shown in Figure 2-5. The boiler has a full division wall that separates the furnace into two approximately square sections. A major problem encountered during the retrofit was the limited space available for burner placement. The outer edge of the burners on each side of the division wall are located within a few inches of each other.

The secondary air duct originally entered the windbox at the rear (south side) of the furnace roof as shown in Figure 2-2. Since the new burners required significantly more

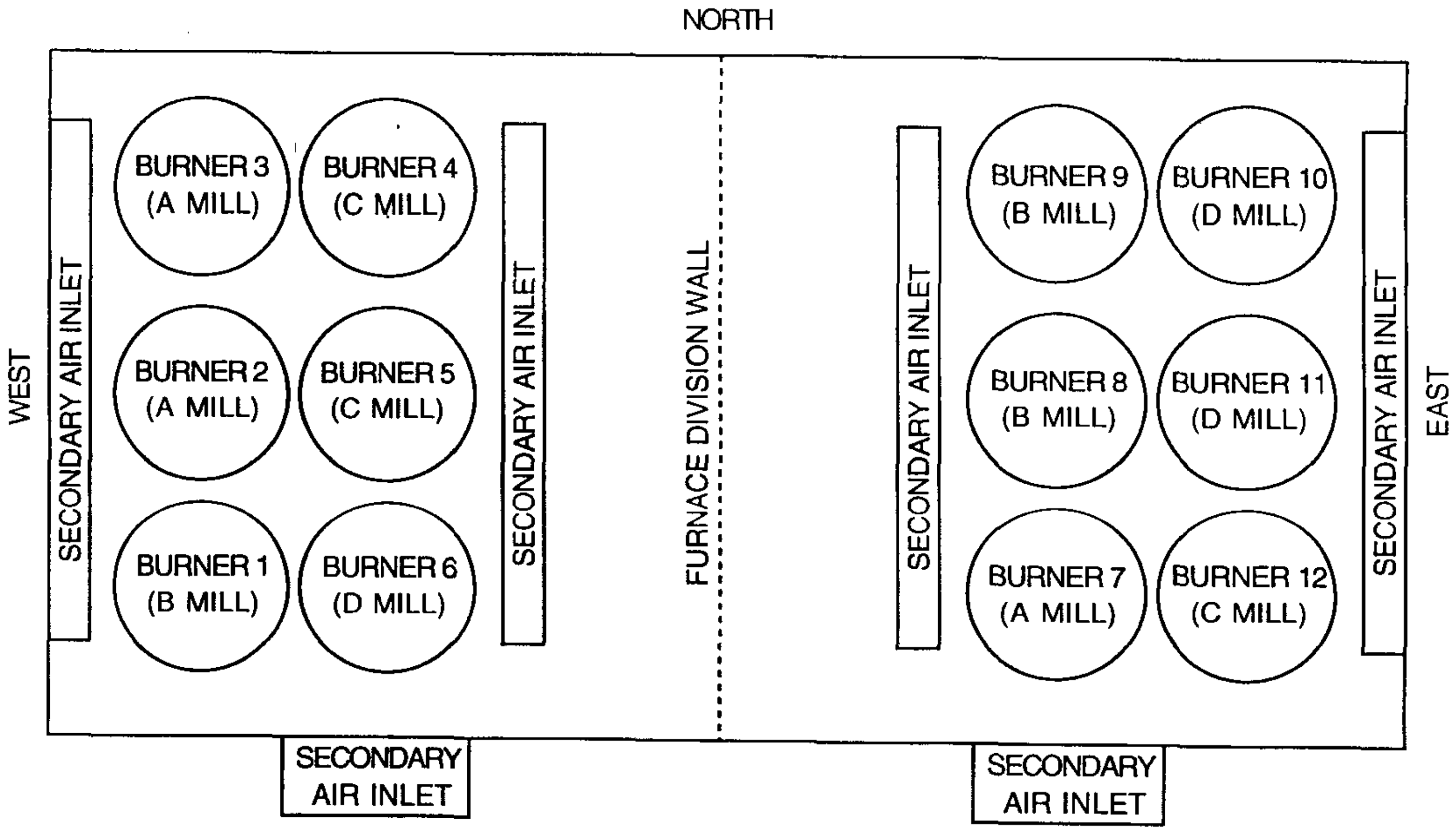


Figure 2-5. Plan View of Burner Arrangement after Retrofit

roof area than the intertube burners, and there were now four burners where the secondary air duct was originally located, providing sufficient secondary air to the windbox became a challenge. The majority of the air is introduced through four "pant-leg" ducts as shown in Figure 2-6. The Arapahoe 4 boiler was originally designed to use flue gas recirculation (FGR) for steam temperature control. However, the system was no longer in use, so two abandoned FGR ducts which entered the front (south) wall of the windbox were used to provide the balance of the secondary air.

The retrofit also included new gas burners, gas ignitors and flame scanners. Arapahoe Unit 4 was originally designed with the ability to fire 100 percent natural gas. While coal is used as the main fuel, natural gas is used on occasion to provide load when pulverizers or other equipment are out of service. The capability to fire 100 percent natural gas was maintained by the use of a gas ring header located at the tip of each burner. No modifications were made to the original Riley pulverizers, although new variable speed feeder drives were added to provide more consistent coal feed.

2.4.2 Overfire Air System

An overfire air system (or in this case, an "underfire" air system due to the down-fired configuration) was also retrofit to the Arapahoe Unit 4 boiler. Three B&W Dual-Zone NO_x Ports were added to the east and west sides of the furnace approximately 20 feet below the boiler roof. A numerical modeling study was performed by B&W in order to determine the optimum size and location for the ports. These ports were designed to inject up to 25 percent of the total secondary air through the furnace sidewalls.

Conventional single-jet overfire air ports are not capable of providing adequate mixing across the entire furnace. The B&W Dual Zone NO_x Ports, however, incorporate a central zone which produces an air jet with sufficient axial momentum to reach across to the division wall and a separate outer zone that diverts and disperses air in the region near the wall. This two-stage injection provides faster mixing and more equal distribution of

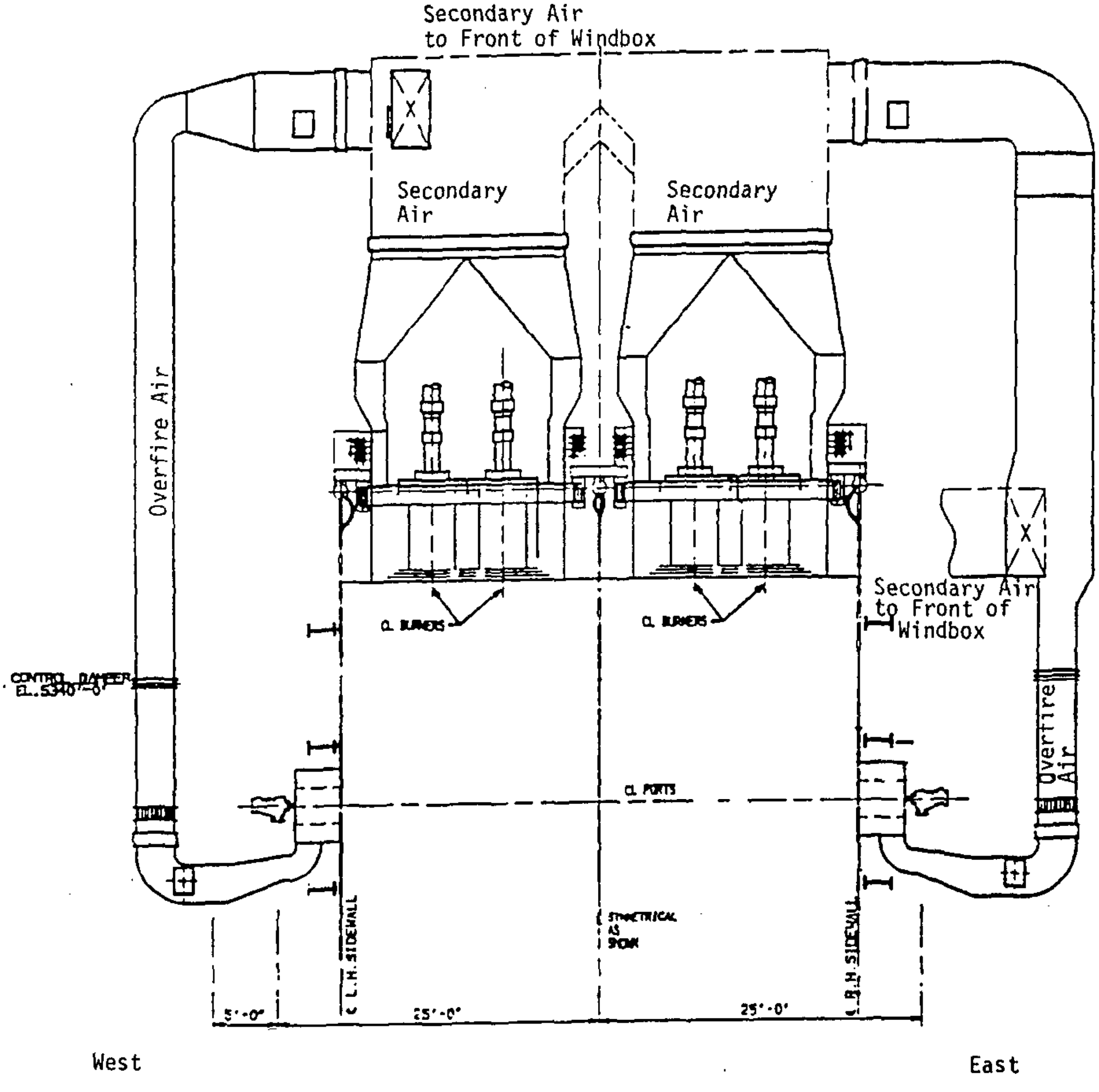


Figure 2-6. Front Sectional of View of Upper Furnace - Looking North

air into the furnace. A schematic of the NO_x port is shown in Figure 2-7. The central zone has a manual air control disk for flow control, and the outer zone incorporates manually adjustable spin vanes for swirl control. Two circular pitot tube arrays provide a relative air flow measurement between the inner and outer flow areas of each port.

The overfire air ports are located on each side of the furnace in a small windbox, as shown in Figure 2-8. New ductwork was added that directs secondary air from the boiler roof to the sidewalls as shown in Figure 2-6. Each of the ducts that supply the overfire air windboxes contains an opposed blade louver damper to control air flow, and a pitot tube grid with a flow straightener to measure total overfire air flow to each side of the furnace. As two sootblowers were originally located on each side of the furnace at the location chosen for the overfire air ports, the retrofit also entailed lengthening (in order to accommodate the depth of the new windboxes) and a slight relocation of these sootblowers.

2.4.3 Control System Modifications

Arapahoe Unit 4 was originally controlled with a Bailey pneumatic control system. The boiler had limited control for burner management and was operated manually. Due to the complexity of the retrofit, a new distributed control system (DCS) was necessary to control the boiler and other pollution control equipment added as part of the Integrated Dry NO_x/SO_2 Emissions Control system. The new burner management system includes both infrared and ultraviolet flame scanners as well as automated controls for most boiler functions. The ignitors and main gas systems were modified for automatic control of all vent and main fuel valves so that the boiler may now be safely started from the control room. The DCS also allows better control of the equipment so that a more efficient control of fuel and air may be maintained during the rapid load swings that occur during load following under automatic control.

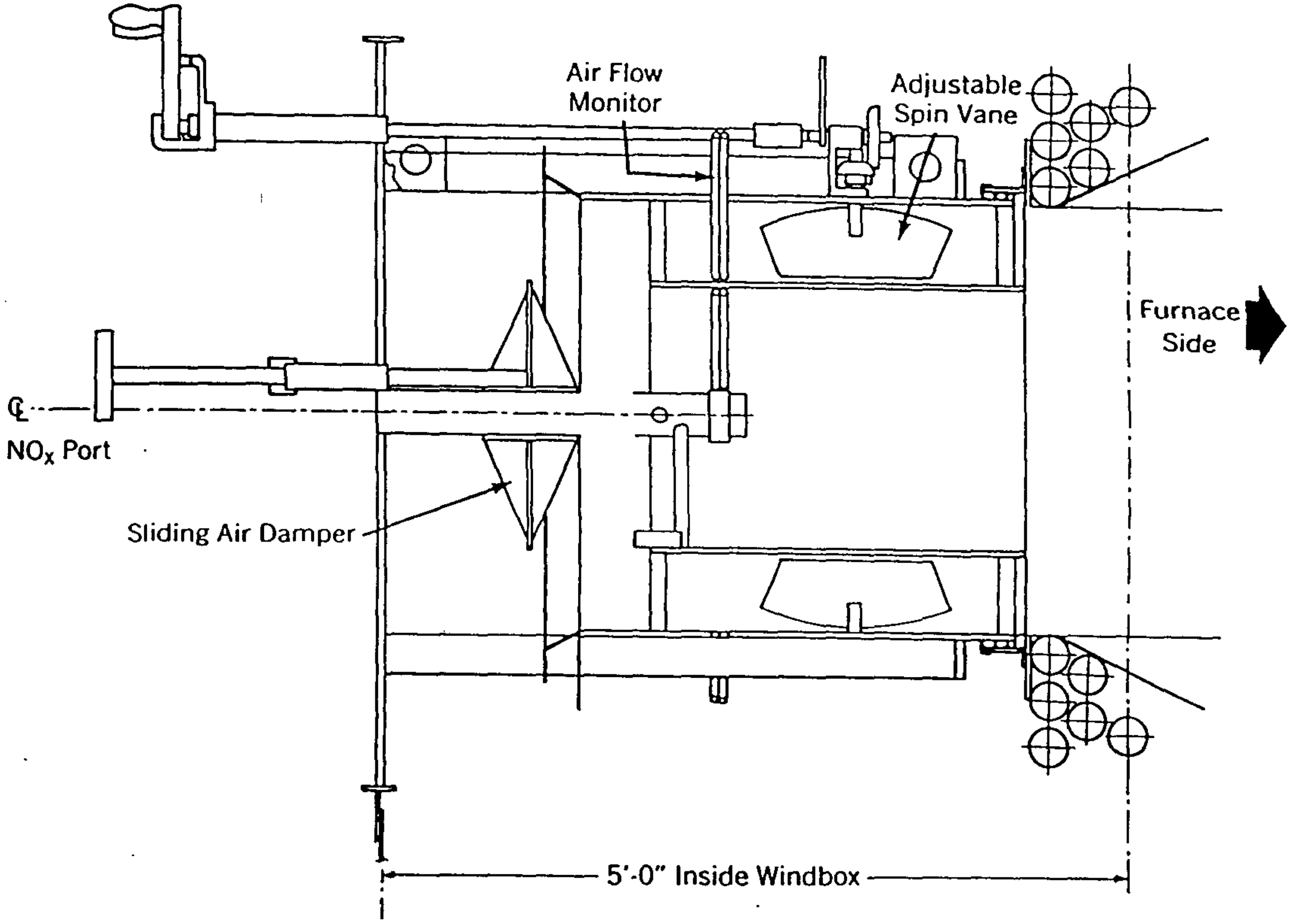


Figure 2-7. B&W Dual Zone NO$_x$ Port

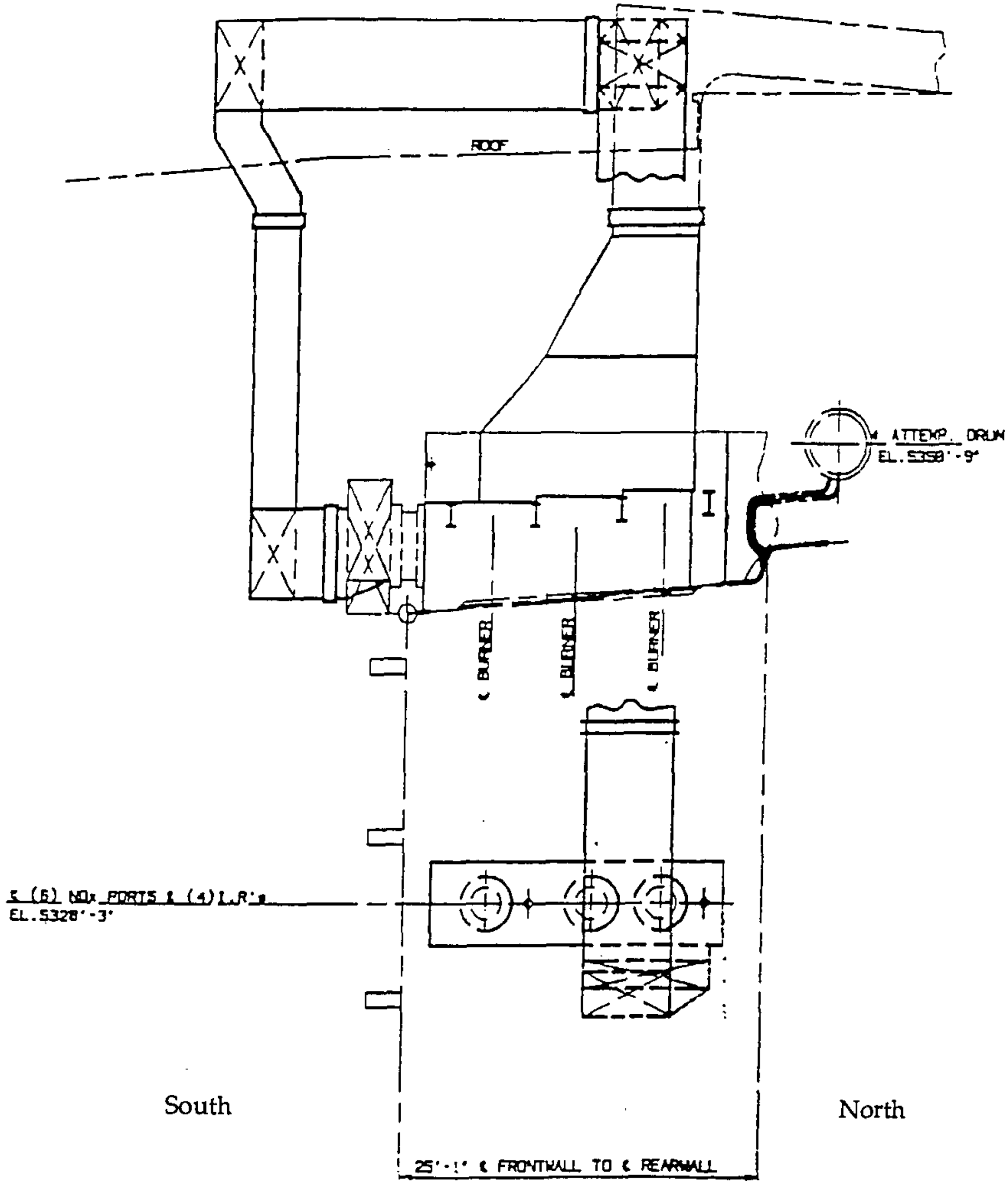


Figure 2-8. Side Sectional View of Upper Furnace - Looking West

2.5 Low-NO_x Burner/Overfire Air Test Results

This section presents a brief summary of the results of the low-NO_x burner/overfire air tests performed after the combustion system retrofit on the Arapahoe Unit 4 boiler. During these tests, the performance of the new combustion system was compared to that of the original system, as documented during the baseline test program. Complete documentation of the baseline and LNB/OFA tests is contained in separate reports(1,2).

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

NO_x emissions with the retrofit combustion system were 63 to 69 percent lower than those for the original combustion system, depending on boiler load (Figure 2-9). These results were obtained under baseloaded conditions with maximum overfire air (corresponding to 24 percent of the total secondary air flow at full load). OFA port cooling requirements precluded reducing the overfire air flow to zero at this particular installation, thereby limiting the minimum overfire air condition to 15 percent of the total secondary air. Increasing the overfire air flow from 15 to 25 percent resulted in only a 5 to 10 percent increase in NO_x removal. This suggests that the majority of the NO_x removal was due to the low-NO_x burners, and not the overfire air system. However, it must be realized

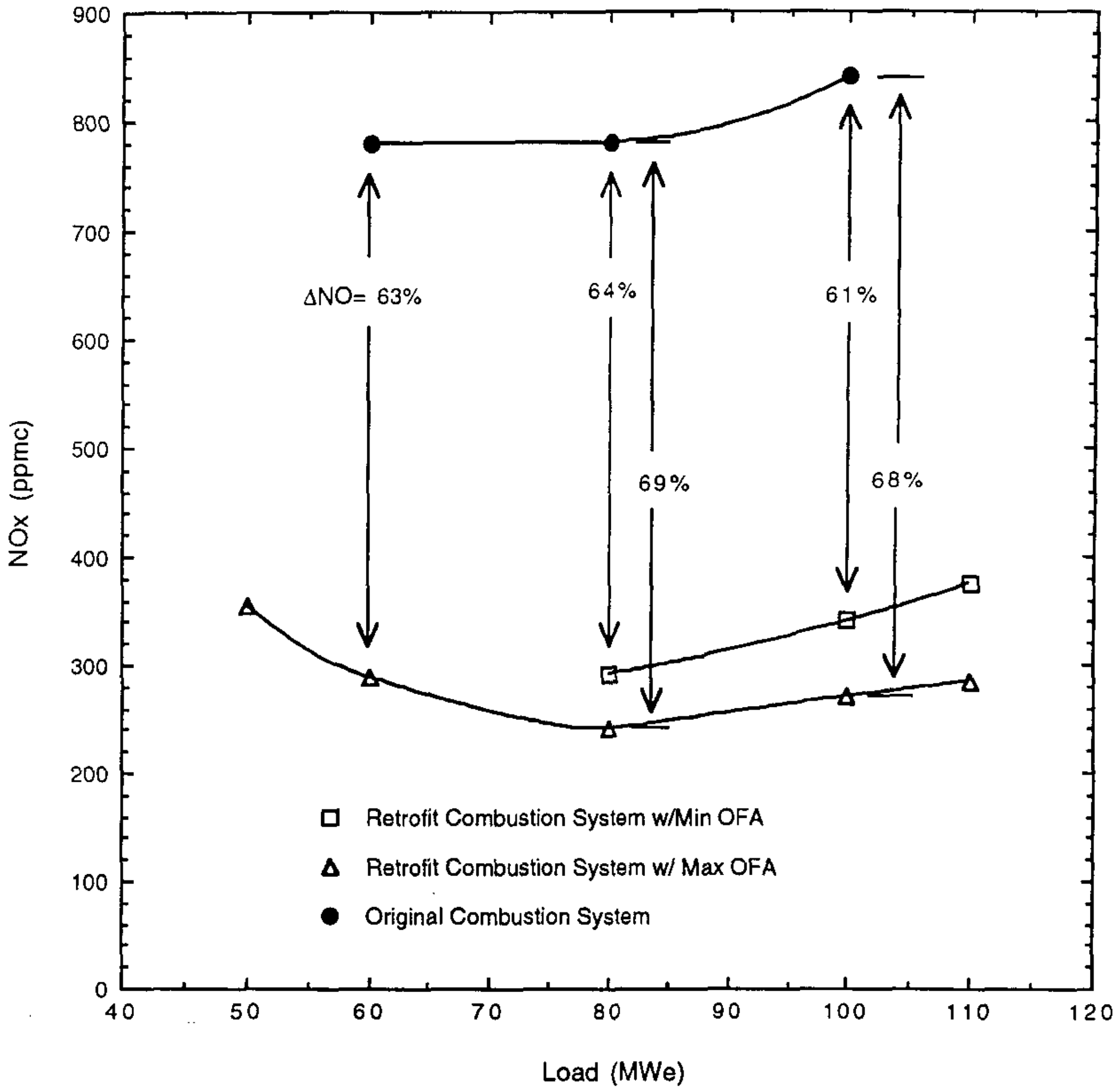


Figure 2-9. NO_x Emissions as a Function of Boiler Load for the Original and Retrofit Combustion Systems

that it was not possible to completely separate the relative roles of the burners and overfire air system at this particular installation due to the inability to reduce the overfire air flow to zero.

For this retrofit, significant reductions in CO emissions and flyash carbon levels were seen with increasing overfire air flow rates. This was contrary to what was expected, and is attributed to increased overfire air penetration to the center of the furnace and increased mixing at the higher flow rates. Overall CO emissions and flyash carbon levels did not increase during baseloaded operation as a result of the combustion system retrofit.

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

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

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

2.6 Baseline SNCR Test Results

This section presents a brief summary of the results of the baseline SNCR tests with the original combustion system on the Arapahoe Unit 4 boiler. Complete documentation of the baseline SNCR tests is contained in a separate report(3). The objectives of these tests were twofold. First, to start up and check out the functional performance of the SNCR hardware. Second, to provide a preliminary characterization of the SNCR process performance with the original combustion system. This characterization would then serve as a basis of comparison of the combined LNB/OFA/SNCR system to the use of SNCR alone.

The baseline SNCR test program was conducted over a five (5) week period from February 4, 1992, to March 6, 1992. The short time period did not allow a complete optimization of the injection system. In fact, a detailed optimization was not necessarily warranted, as the combustion modifications scheduled for April and May, 1992, were expected to impact operation of the boiler, and therefore change the optimal SNCR operating parameters. A limited parametric investigation of the effects of boiler load, chemical injection rate, and injection system parameters (i.e., injection location, mixing air and dilution water flow rates, and injection nozzle orifice sizes) was accomplished during the five-week period. The injection system parameters were optimized while utilizing urea as the SNCR chemical. The effects of boiler load and chemical injection rate were then assessed for both urea and aqueous ammonia (NH_4OH) injection.

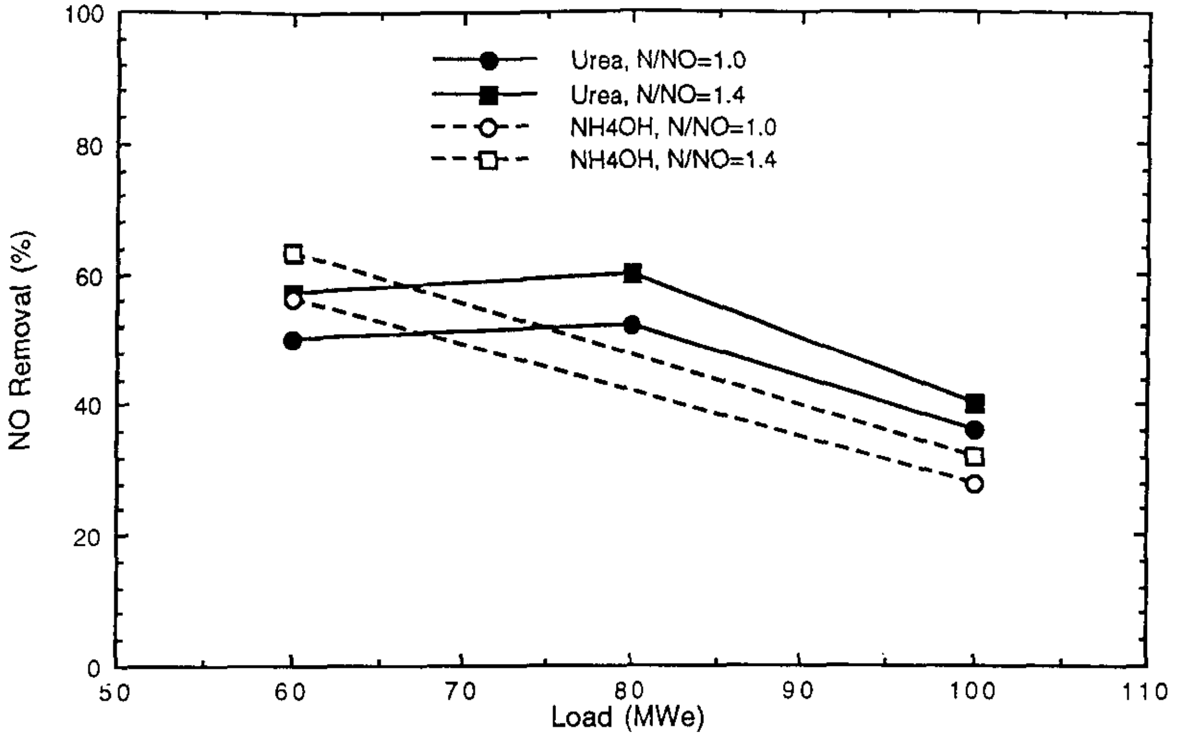
The parameters found to have the greatest effect on process performance were boiler load, chemical injection rate (N/NO molar ratio), and mixing air and dilution water flow rates. The effects of mixing air and liquid orifice sizes were found to be minimal. Although mixing air flow rate had only a slight effect on NO_x removal, large increases in NH_3 emissions resulted from decreased mixing air flow rates. Variations in boiler load and dilution water flow showed the largest effects on system performance, due to their impact on the local flue gas temperatures in the area of chemical injection. SNCR is a highly temperature dependent process with only a narrow window available for maximum NO_x removal.

As expected, increased SNCR chemical flow rates yielded higher NO_x removals, with the tradeoff of higher NH_3 emissions accompanying the increased removals. The results (Figure 2-10a) showed that NO_x removals were higher with urea than with NH_4OH for a given chemical injection rate, over nearly the entire boiler load range. NH_3 emissions were also found to be higher with urea (Figure 2-10b). Therefore, for a given NH_3 emission limit, NH_4OH injection tended to provide higher NO_x removals than urea. As shown in Figure 2-11, for a 10 ppm NH_3 emission limit NO_x removals of 26 to 36 percent were achievable with NH_4OH over the load range of 60 to 100 MWe, while urea injection resulted in removals of only 16 to 36 percent. However, over the load range of 65 to 100 MWe, urea was the most efficient chemical since the increased NO_x removals with NH_4OH required higher chemical feed rates.

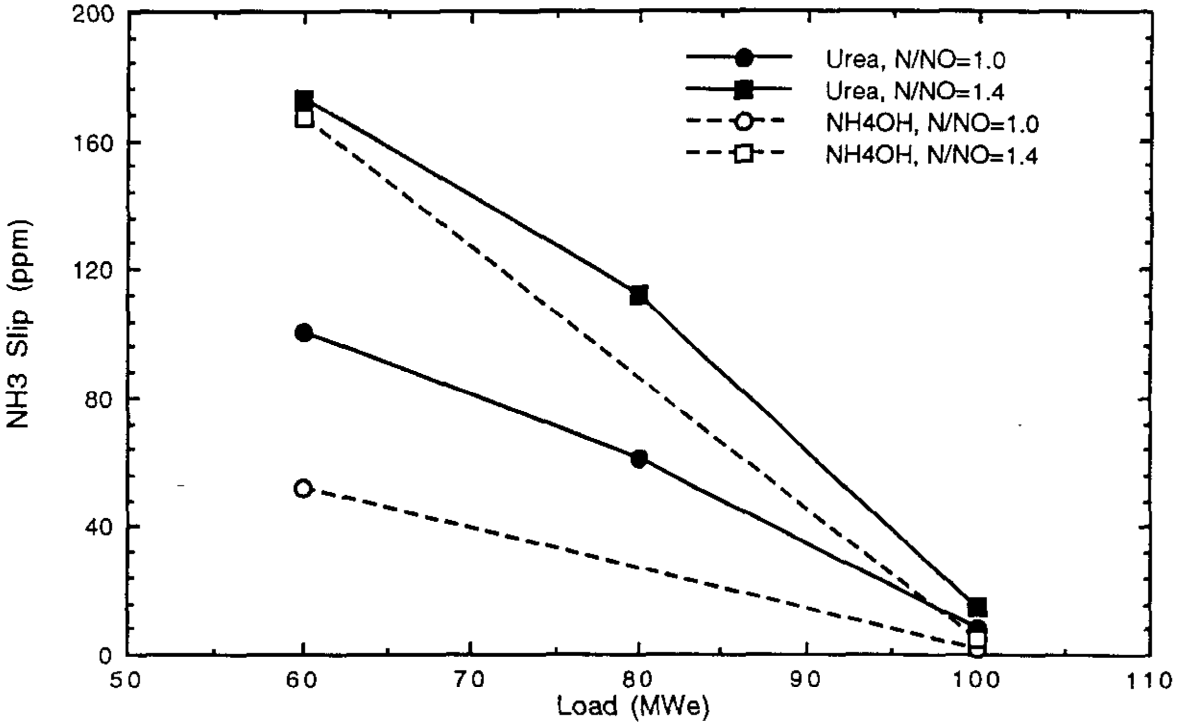
Consistent with previous studies, nitrous oxide (N_2O) emissions with NH_4OH injection were lower than with urea injection. With NH_4OH, the fraction of the NO_x reduced which was converted to N_2O was less than 2 percent at a nominal N/NO molar ratio of 1.0, irrespective of load. With urea and a similar N/NO ratio, the conversion ranged from 9 to 15 percent at 100 and 60 MWe, respectively.

In addition to byproduct emission of NH_3 and N_2O, it was also found that the SNCR process increased CO emissions. The increase in CO emissions with NH_4OH injection was found to be lower than that for urea injection. With NH_4OH, the increase in CO emissions was on the order of 8 ppm at a nominal N/NO molar ratio of 1.0, irrespective of load. With urea and a similar N/NO ratio, the increase in CO emissions ranged from 10 to 40 ppm at 100 and 60 MWe, respectively.

The above comparisons of the performance of urea and NH_4OH are for injection through the same set of injectors, and for the same set of injection conditions (mixing air and dilution water flow rates). The conclusions may not apply to a system that has been independently optimized for the two different SNCR chemicals.



a) NO Removal



b) NH_3 Emissions

Figure 2-10. SNCR Performance with Original Combustion System (Initial NO_x Level Approximately 850 ppmc)

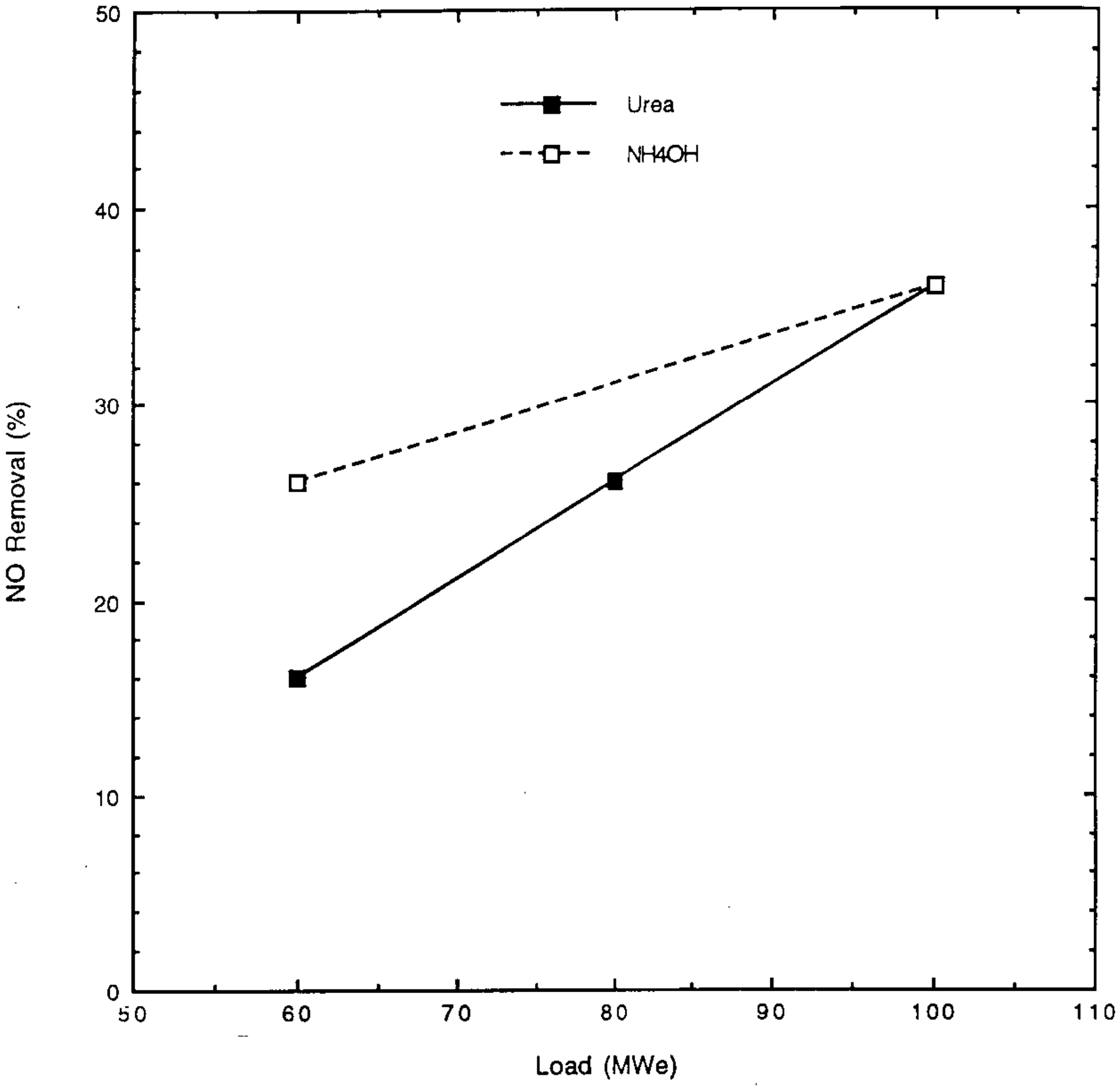


Figure 2-11. Comparison of NO Removals for Urea and NH_4OH for a Fixed NH_3 Slip Level of 10 ppm with the Original Combustion System

before the start of the baseline SNCR tests. The measurements were made in order to locate the temperature regions where urea injection was believed to be most effective (1650 to 1950°F). While it was expected that the combustion modifications would alter the temperature distribution within the boiler, it was believed that the change would be minimal (on the order of only 25°F). Acoustic and suction pyrometry (HVT) techniques were used simultaneously to obtain the gas temperature measurements. The results of these measurements are briefly summarized below, and complete documentation of the temperature measurement tests is contained in a separate report[(6)]. Figure 3-4 shows the parts used for the temperature measurements. Since the acoustic temperature measurement technique requires a clear line of sight across the furnace at the measurement location, the first available location with acceptable access for the instrument was through a pair of ports just downstream of the first set of screen tubes (Location G in Figure 3-4).

The results of the HVT and acoustic temperature tests made during April 1991 are summarized in Table 3-1. The table shows the average HVT value for each location which is computed from the mean values recorded at each traverse point. The high and low temperatures recorded during each HVT traverse are also indicated, and the averages of the acoustic measurements are shown for each of the three locations where measurements were possible.

Although the table shows that the temperature at each position is a function of load, it also shows an overall temperature distribution which is similar for each load condition. The average temperatures as a function of load are plotted in Figure 3-5 for selected port locations. From this distribution, a generalization regarding the flow field may be inferred. Namely, the upward turn from the furnace exit through the first set of screen tubes forces most of the gas along the back (north) wall of the unit as it enters the convective section. The relatively cool temperatures measured at Port D are likely the result of a recirculation zone which is set up as the gases flow around the wall separating the furnace and convective sides of the unit. In fact, one-tenth scale flow visualization studies (discussed later in this section) confirm the existence of a recirculation zone at this location.

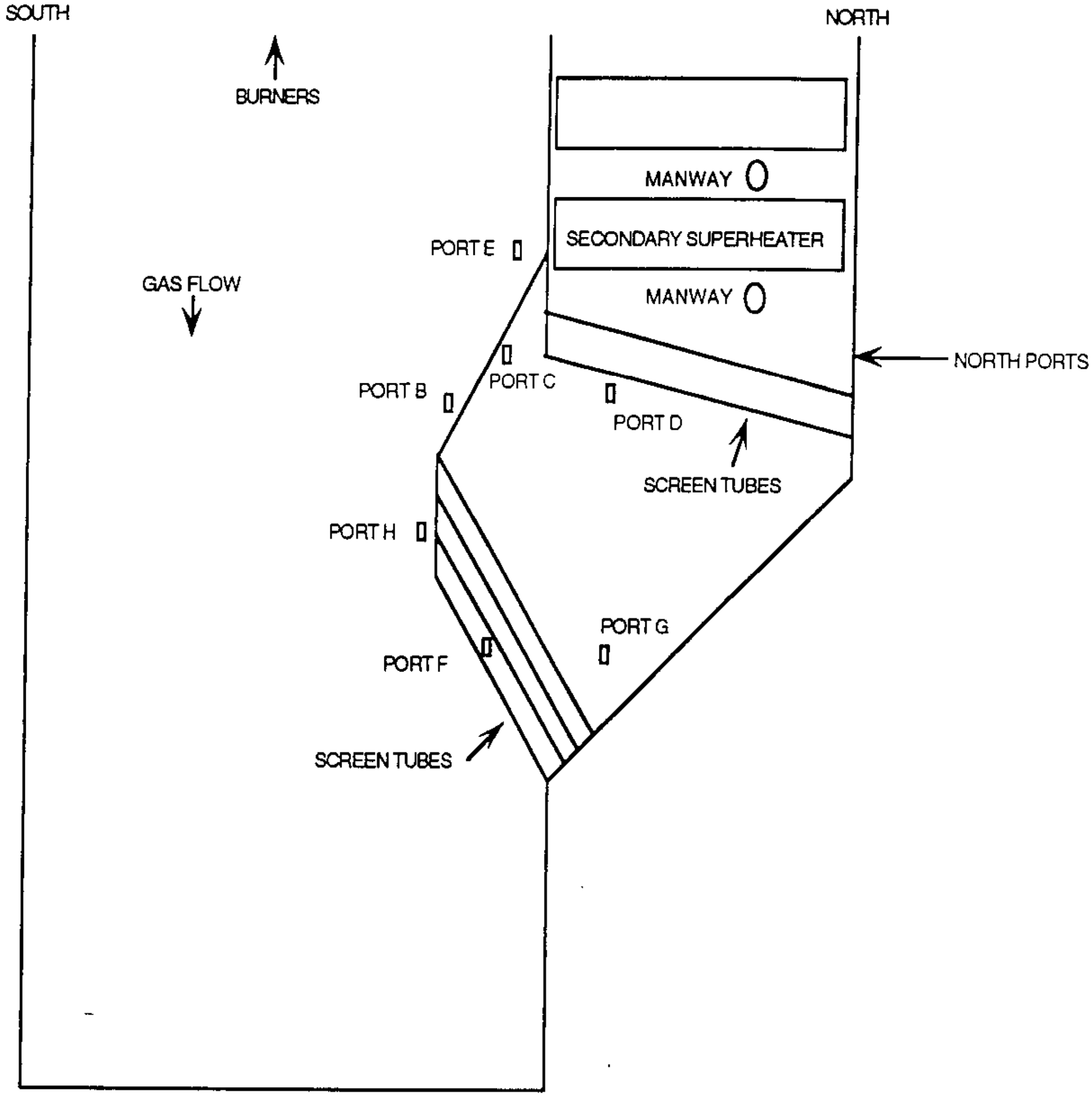


Figure 3-4. Port Locations for Temperature Measurements (view looking from east)

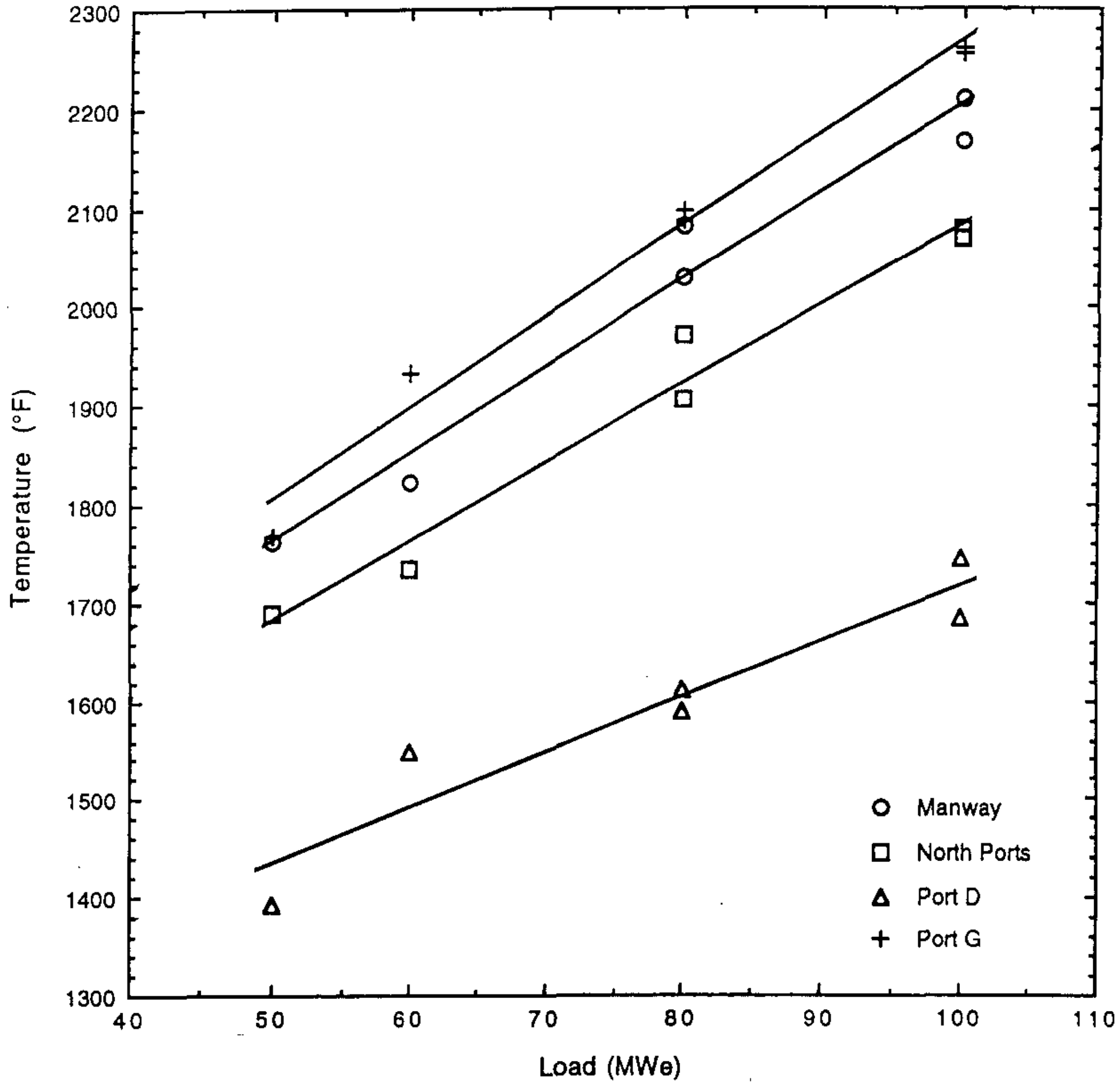


Figure 3-5. Effect of Load on Flue Gas Temperature at Selected Locations in the Furnace (Measurements Performed April 15 to 19, 1991)

Table 3-1

Flue Gas Temperature Measurement Results (April 15 to 19, 1991)

Boiler Operating Condition	Measurement Type	Port H (West Side)	Port F (West Side)	Port G (West Side)	Port D (West Side)	North Ports (Manway)
100 MWe, All Mills	HVT Avg. (F)	2451	2346	None	1750	2079
	HVT Range (F)	2380-2535	2290-2425	None	1570-1871	1817-2231
	Acoustic (F)*	None	None	2256	1744	2167
100 MWe, B Mill OOS	HVT Avg. (F)	2568	2346	2260	None	2069
	HVT Range (F)	2505-2630	2220-2490	2185-2320	None	1817-2245
	Acoustic (F)*	None	None	2302	1685	2209
80 MWe, All Mills	HVT Avg. (F)	2401	2239	None	1618	1905
	HVT Range (F)	2350-2430	2100-2300	None	1462-1754	1655-2083
	Acoustic (F)*	None	None	2087	1588	2028
80 MWe, B Mill OOS	HVT Avg. (F)	2263	2000	None	None	1971
	HVT Range (F)	2250-2270	1943-2040	None	None	1756-2175
	Acoustic (F)*	None	None	2097	1612	2081
60 MWe, B Mill OOS	HVT Avg. (F)	2288	1982	1720	1513	1735
	HVT Range (F)	2190-2360	1833-2095	1669-1728	1416-1612	1551-1945
	Acoustic (F)*	None	None	1934	1549	1822
50 MWe, B and C Mills OOS	HVG Avg. (F)	1908	1630	1487	1447	1690
	HVT Range (F)	1900-1930	1545-1705	1430-1533	1326-1531	1513-1810
	Acoustic (F)*	None	None	1767	1393	1762

*Acoustic measurements are a line-of-site average across the boiler.

The data discussed above are average data obtained at each of the port locations. The performance of the SNCR system can also be impacted by spatial temperature variations that might occur at each of the measuring planes. This can be the result of a number of factors, including the division wall in the furnace or the number of mills in service. The extent of this variation is shown in Figure 3-6, which shows the average west-to-east temperature profiles at the north port location for three and four mill operation at 100 MWe. As can be seen, the temperature variations along the east-west direction can be in excess of 300°F. Lower temperature regions were measured near the outer walls of the furnace and near the center of the furnace, downstream of the furnace division wall.

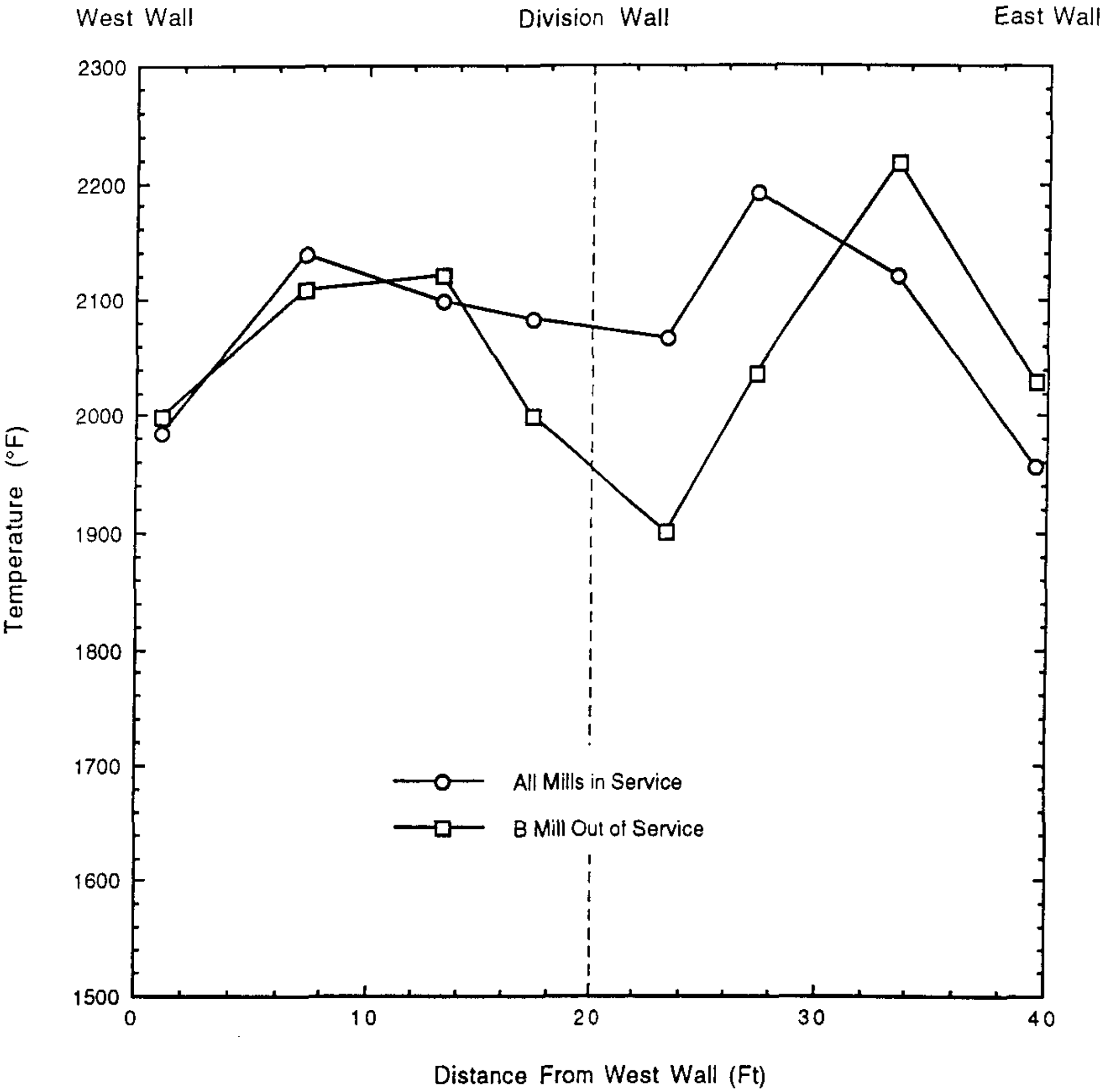


Figure 3-6. Average North Port Temperature Profiles at 100 MWe (Measurements Performed April 15 to 19, 1991)

Table 3-1 also indicates that, in the areas probed, the most promising location for urea injection is the area downstream of the second set of screen tubes (near the north ports), where the average HVT temperatures range from 1690 to 2080°F over the load range.

3.2.2 Cold Flow Modeling

In addition to temperature, the degree of chemical mixing with the bulk flue gas is critically important to the SNCR process. Maldistributed chemical injection results in lower overall NO_x reduction and higher ammonia slip. With the appropriate temperature regions identified by the temperature measurements, the next step in the design process by NOELL, Inc. was design of the injector system. This was accomplished with cold flow modeling techniques incorporating both flow visualization and tracer gas measurements to quantify and optimize a "mixing" parameter. A 1:10 scale cold flow model of the Arapahoe Unit 4 furnace and convective section was used for this part of the design procedure. Bulk flow characteristics were examined, as well as several injection scenarios, using flow visualization and tracer gas measurements. Injection configurations were optimized using a tracer gas technique to quantify the mixing between the injected chemical and the bulk flue gas. The results of these tests are briefly summarized below, and complete documentation of the cold flow modeling effort is contained in a separate report(7).

Approach. The flue gas temperature measurements indicated that the general vicinity of the north ports provided access to the necessary urea injection temperatures over the load range. The north ports were easily accessible (46 inches above a walkway) and represented a good location for wall mounted injectors. On the basis of this information, a scenario using two rows of wall injectors was developed. The injectors would be installed, running across the north wall of the convective section at roughly the same elevation as the north ports. One row of injectors would be installed at the exact same elevation as the north ports, pointed slightly upward, essentially parallel to the screen tubes (see Figure 3-7). Another row would be placed lower, below the screen tubes, pointed slightly downward, essentially parallel to the connective section bottom. With this

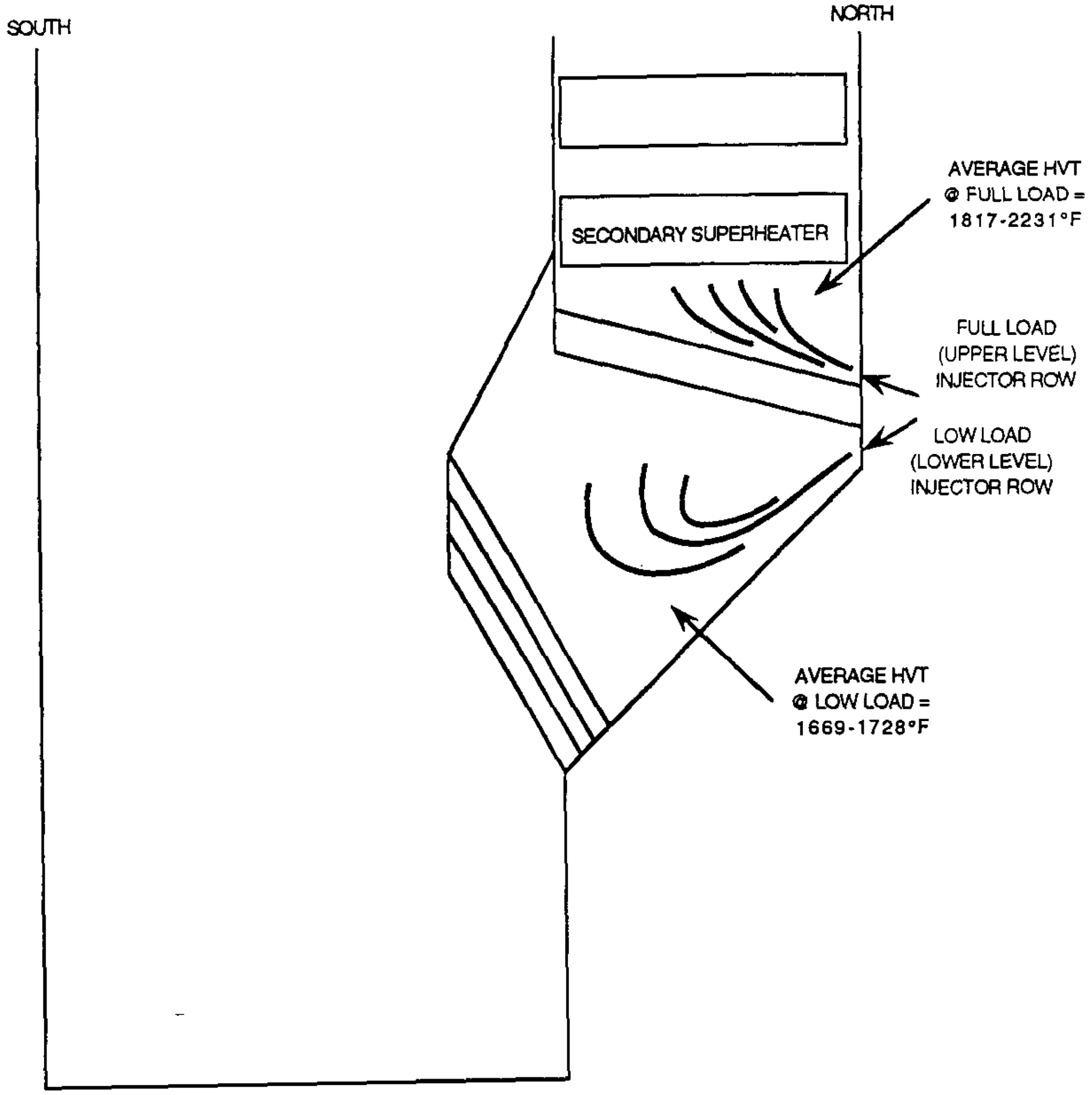


Figure 3-7. Injector Placement Scenario Based on Flue Gas Temperature Measurements

injector configuration, a load following procedure was developed. The upper injector level would be used at high loads where the cavity temperature was appropriate for efficient NO_x removal, and as load was reduced and temperature dropped below the optimum, the lower (i.e., hotter) level of injectors would be used. It was also anticipated that the downward oriented injectors would inject the chemical in a direction counter flow to the bulk gas flow, resulting in enhanced mixing and longer residence times. This scenario served as the basis for the cold flow modeling test procedure.

Methodology. Geometric and dynamic similarity between the full-scale boiler and the 1:10 scale model were maintained for the cold flow testing. Model Reynolds numbers were kept well above 15000 to simulate the gross turbulent mixing of the full-scale system. In examining the interaction of the injection flow with the bulk flow, equivalent full-scale and model momentum ratios were maintained.

With respect to flow visualization, two techniques were used. The bulk flow patterns were obtained by seeding the main burner flow with neutrally buoyant bubbles. For the higher velocity jets, smoke was used for flow visualization.

In order to provide a basis for quantifying and comparing the degree of mixing achieved with each injection system configuration, the injection air was seeded with a tracer gas. Sixty-point sample and velocity traverses were conducted over the entire cross-sectional area of the convective section. The location at which these traverses were conducted was dependent upon the injection level, and the locations of the planes of measurement are shown in Figure 3-8. The measured concentrations were converted into a contour map to visually assess the uniformity of mixing achieved with a given injector configuration. In effect, however, this was only marginally more quantitative than flow visualization. A method was developed to better quantify mixing between different injection configurations, as well as to directly compare the measurements by negating any differences in overall tracer gas concentration or velocity distribution. This method normalizes the tracer gas measurements and accounts for a non-uniform velocity field in

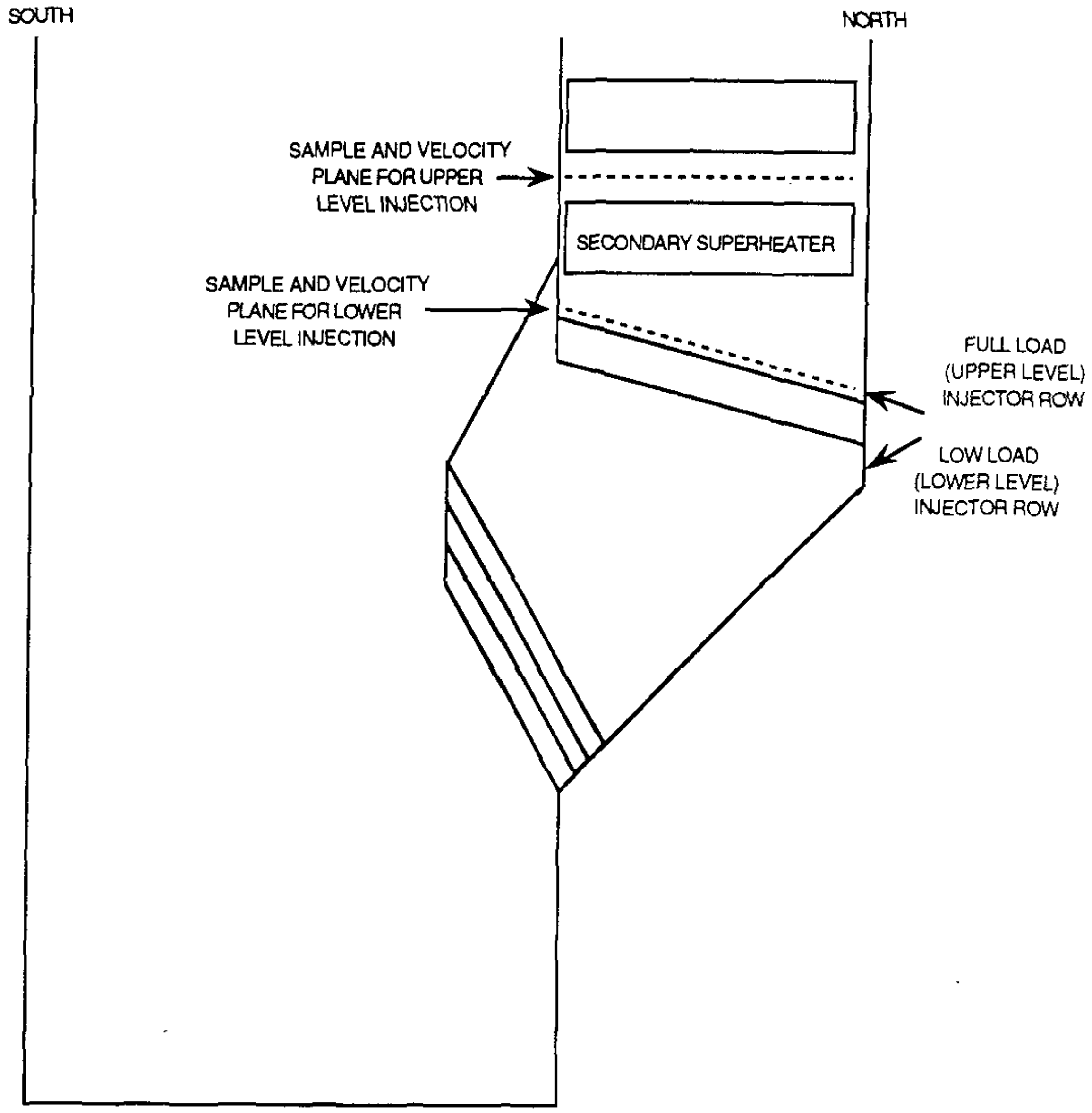


Figure 3-8. Sample and Velocity Traverse Planes for Tracer Gas Measurements

the overall mixing determination. The method is based on the assumption that if the flowfield was perfectly mixed, each sample point in the 60-point grid would exhibit a normalized value of one, and the standard deviation would be zero. At the other extreme, if the flowfield was totally unmixed and all of the tracer gas was measured within a single sample cell, a normalized value of 60 would be obtained in one cell, while all other sample cells exhibited a value of zero. The standard deviation of this latter case is a maximum. Intermediate levels of mixing will possess standard deviations of the normalized tracer gas concentration between these two extreme values. Each standard deviation value represents a certain mixing percentage, with zero standard deviation representing 100 percent mixed, and the maximum standard deviation representing zero percent mixed. This method for quantifying the degree of mixing was used to optimize the following parameters for the upper and lower injector rows (or "levels"):

- number of injectors
- injector angle
- injector diameter
- amount of mixing air.

Results. A synopsis of the overall model bulk flow patterns is shown in Figure 3-9. At the convective section entrance, the flow encountered a 50 percent reduction in cross-sectional area as well as an immediate 180° upward turn. This resulted in a high velocity region running up against the north wall, and a large recirculation zone extending nearly halfway across the convective section. The flowfield entering the first convective tube bank was clearly non-uniform.

The design injection air flow rate was nominally two percent of the total boiler flow at full load. Previous design experience had shown this flow rate to provide high levels of mixing while not being excessive from the standpoint of compressor power costs. At full scale, the velocity at the injection nozzle is kept sonic. Thus, the evaluation of different injection configurations began by keeping the injection air flow and the injector nozzle velocity constant (thereby setting the momentum ratio constant) and varying the number of injectors. As the number of injectors changed, the jet diameter was also changed to

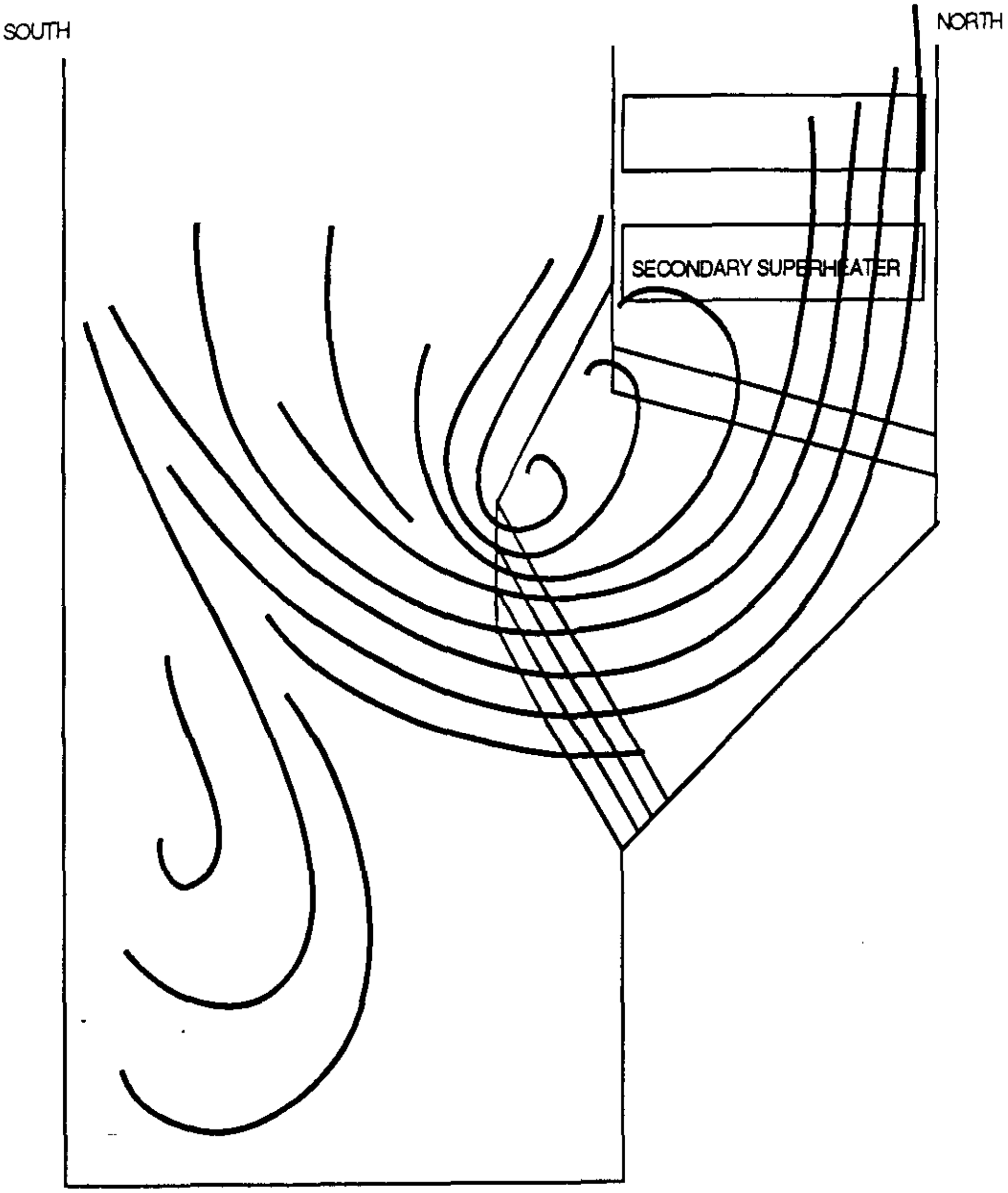


Figure 3-9. Overall Bulk Flow Patterns

maintain constant injection air flow. Optimizing the number of injectors involved the testing of four different scenarios: 8, 10, 12 and 20 jets. These tests were performed at the full load test condition with the upper level of injectors aimed +15° (upward) from horizontal. The results of the mixing tests are shown in Figure 3-10. As the number of jets varied, there were trade-offs between jet penetration and lateral dispersion in the east-west direction. Figure 3-10 shows that ten jets provided the highest mixing of the four cases at 71 percent. In this case, the ten jets penetrated to the middle of the plane and mixed very well laterally. Although the eight jet configuration resulted in increased penetration, the decrease in lateral mixing resulted in reduced mixing. At the other extreme, the lateral dispersion with twenty jets was good, but it was accompanied by a large decrease in penetration. These results are directly applicable to the lower injection level as well, since the variations in the lateral flowfield (east to west) was minimal as the bulk flows through the model were changed from the high load condition to the low load condition.

After it was determined that 10 injectors was the optimum number, the injector angles were optimized for both levels. At the upper level, the angle was varied from -15° to +15° from horizontal with essentially no change in the mixing. As the angle was increased above +15°, the mixing degraded. Angles below -15° were not tested, since jet penetration into the upper screen tube bank was not desirable. At the lower injection level, tests were run pointing the jets directly horizontal (0°), and also directly counterflow to the bulk gas flow (-45°). Mixing was relatively poor at 59 percent with the jets aimed horizontally, but increased dramatically to 85 percent when the jets were aimed in the counterflow direction.

3.2.3 System Design Summary

The main conclusions reached as a result of the flue gas temperature measurement and cold flow modeling efforts are summarized below.

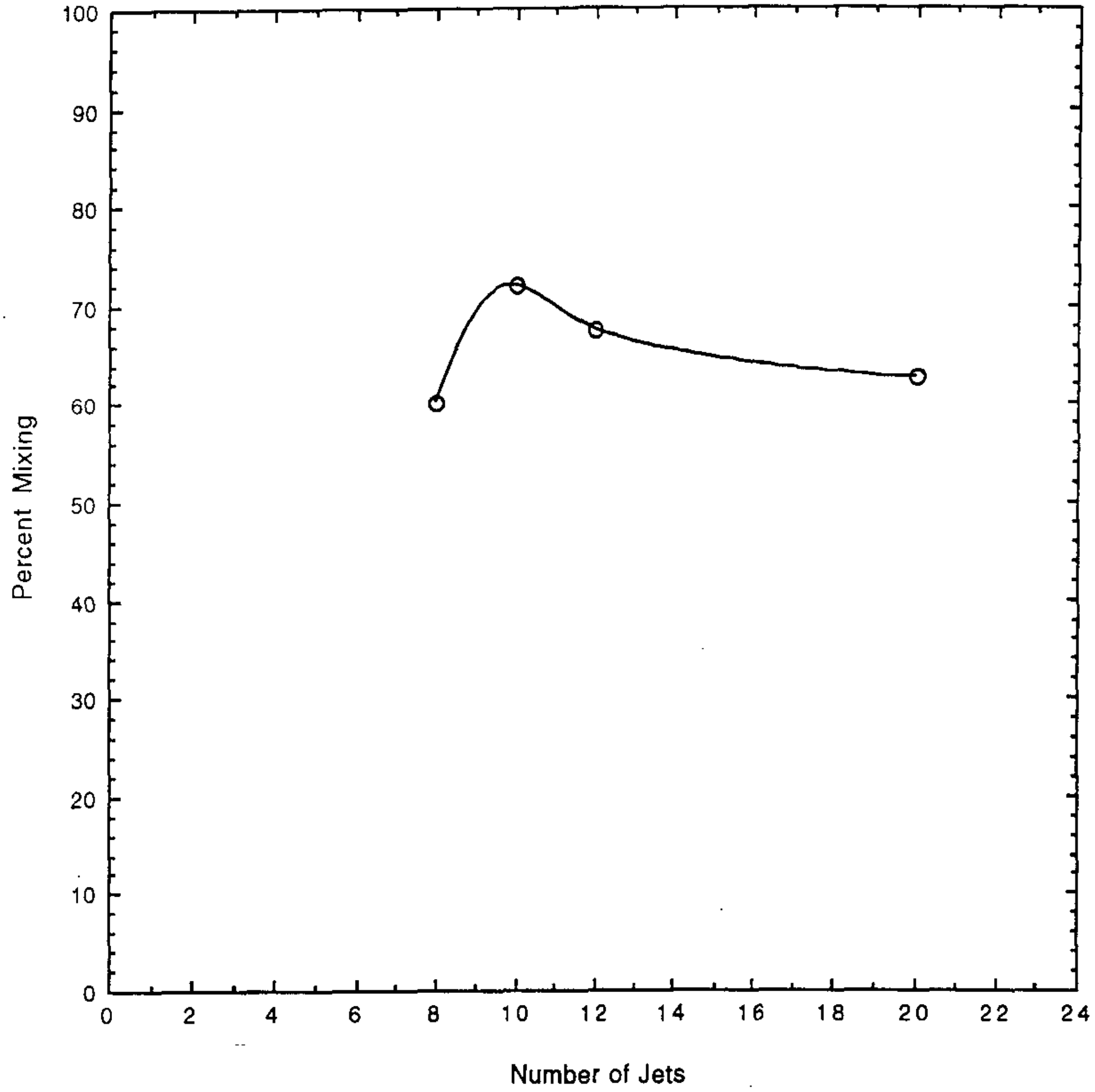


Figure 3-10. Effect of Number of Jets for Upper Level Injectors Angled +15° from Horizontal

- Flue gas temperature measurements showed that the general vicinity of the north ports provided the necessary chemical injection temperatures. The results also indicated that two different levels of injectors were required to optimize the SNCR process over the load range. At full load an upper level would be used, while at reduced loads a lower level would be necessary. This arrangement allows chemical injection into the proper temperature zone over the load range.

- Cold flow modeling showed that at full load with the upper level injectors at approximately elevation 5306 feet (relative to sea level), mixing was optimal using the following injection configuration:

  -- number of evenly spaced injectors = 10;
  -- injector diameter = 1.61 inches full scale;
  -- injector angle = 15° ± 5° from horizontal.

- Cold flow modeling showed that at reduced load, with the lower level injectors at approximately elevation 5302 feet, mixing was optimal using the following configuration:

  -- number of evenly spaced injectors = 10;
  -- injector diameter = 1.08 inches full scale;
  -- injector angle = -45°± 5° from horizontal (directly counterflow).

3.3 System Description

The NOELL, Inc., SNCR injection system is designed to achieve a high degree of mixing between the flue gases and the reducing reagent in short residence times. Figure 3-11 shows a simplified flow diagram of the system as implemented at Arapahoe Unit 4. The system may be separated into four simple subsystems; urea recirculation, injection, ammonia conversion, and atomization.

The urea recirculation loop handles the storage and heating of the base urea chemical. Urea is received in a 65 percent (by weight) liquid solution and is stored in one of two 20,000 gallon tanks. A 65 percent solution must be maintained above 115°F to prevent crystallization of the urea. At Arapahoe Unit 4, the solution temperature was maintained by circulating with one of two 200 gpm recirculation pumps through an electric heater.

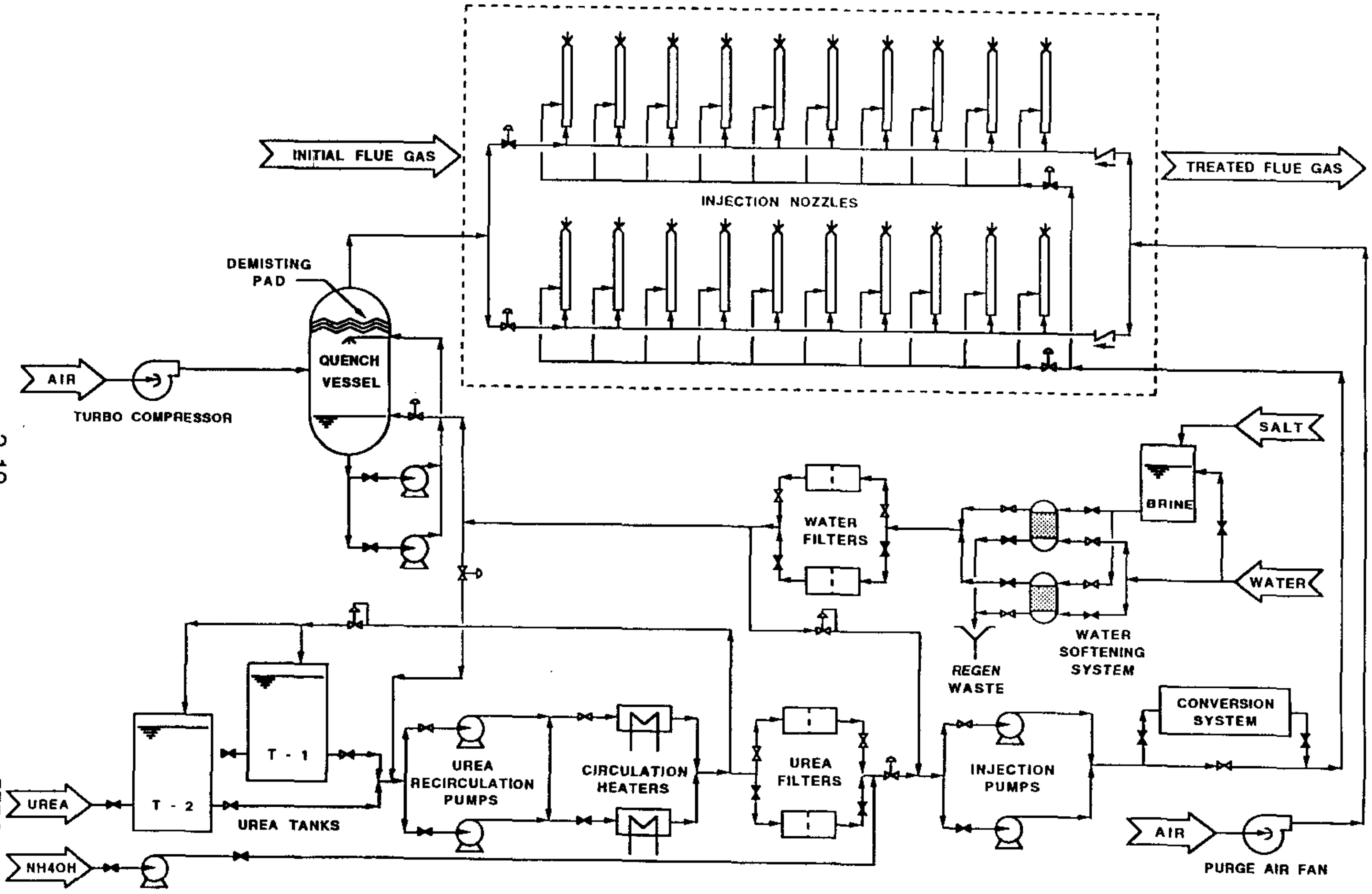


Figure 3-11. Arapahoe Unit 4 SNCR System Flow Diagram

During the baseline SNCR testing, it was found that maintaining this concentrated urea solution at the elevated temperature could cause some ammonia vaporization in the storage tank and a slight ammonia odor would be noticed on some days. This problem was solved by diluting the urea, after delivery to approximately a 37.5 percent concentration. Urea at this concentration reduces the crystallization point to below 14°F as shown in Figure 3-12. Storing the dilute solution has eliminated any ammonia vaporization and, in addition, saves the energy required to constantly recirculate and heat the solution.

In the injection system, a small slipstream of the urea from the recirculation loop is filtered, mixed with softened water to further dilute the urea, and is then pumped at high pressure (100 to 1000 psig) to the atomizers. The liquid transfer lines are insulated and heat traced to 50°F to prevent crystallization of the urea. The system at Arapahoe Unit 4 uses one of two positive displacement pumps driven by AC variable speed drives. The variable speed drives allow the total liquid flow to be varied from 2.0 to 10.5 gpm. The ability to vary the total flow allows some control over the effective flue gas injection temperature. When the flue gas in the injection area is at or below the optimum temperature for effective NO_x removal (recall Figure 2-1), low flows are desirable so that the flue gas temperature is not significantly reduced by the evaporation of excess water. When the flue gas temperatures are higher than the optimum, larger flows allow some gas temperature cooling by evaporating the water before the urea begins reacting with the NO_x.

The ammonia converter is a new system that was added after the original SNCR test program was conducted with the original burners. It was found that at low flue gas temperatures at low loads, urea was not very effective for NO_x removal. A short test showed that aqueous ammonia reacted both faster and at a lower temperature in the boiler, and was also more effectively utilized at lower temperatures than urea. Although ammonia was more effective, it remained desirable to store urea due to safety concerns. NOELL, Inc., suggested an on-line conversion system that would convert the urea into

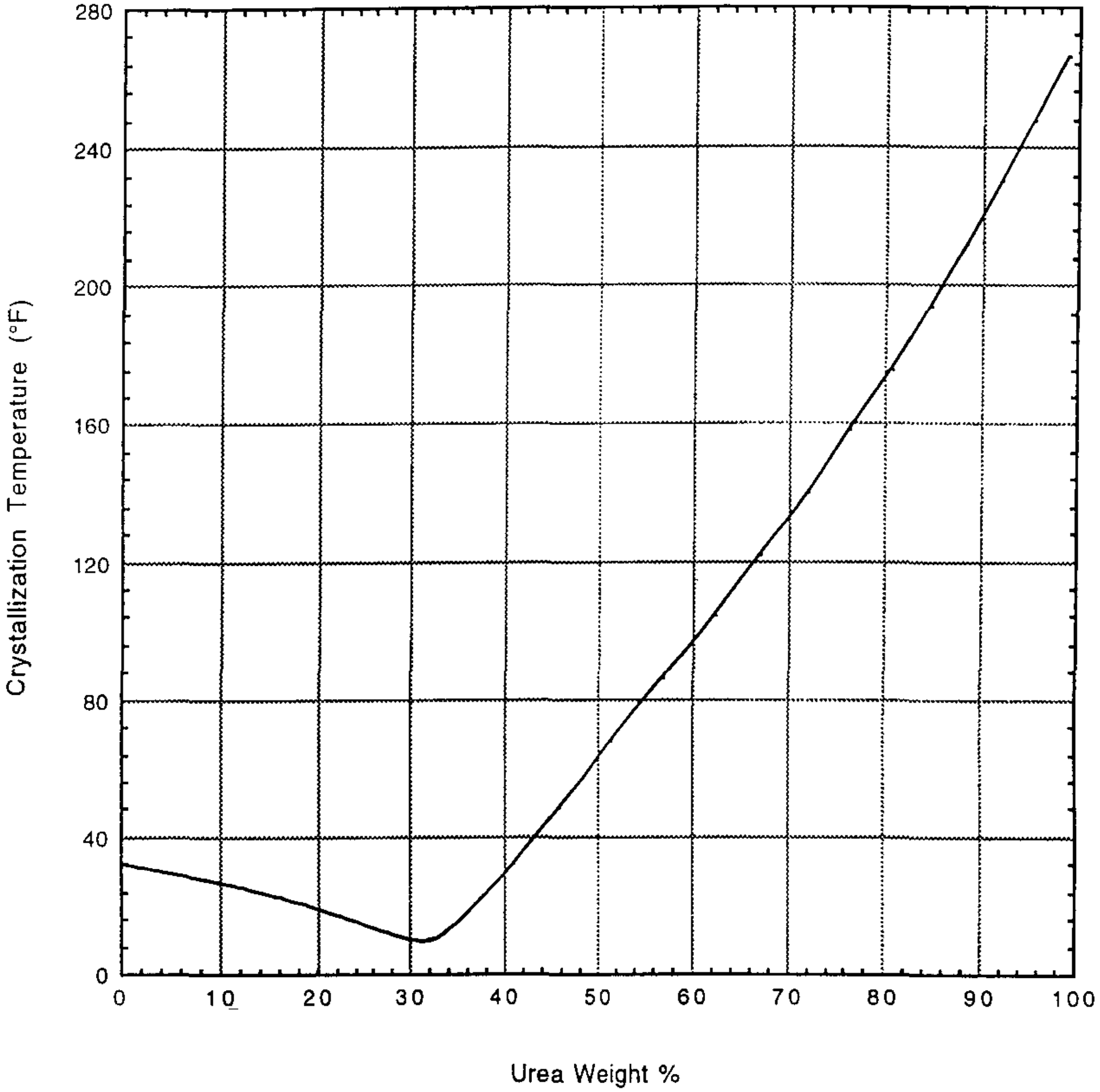


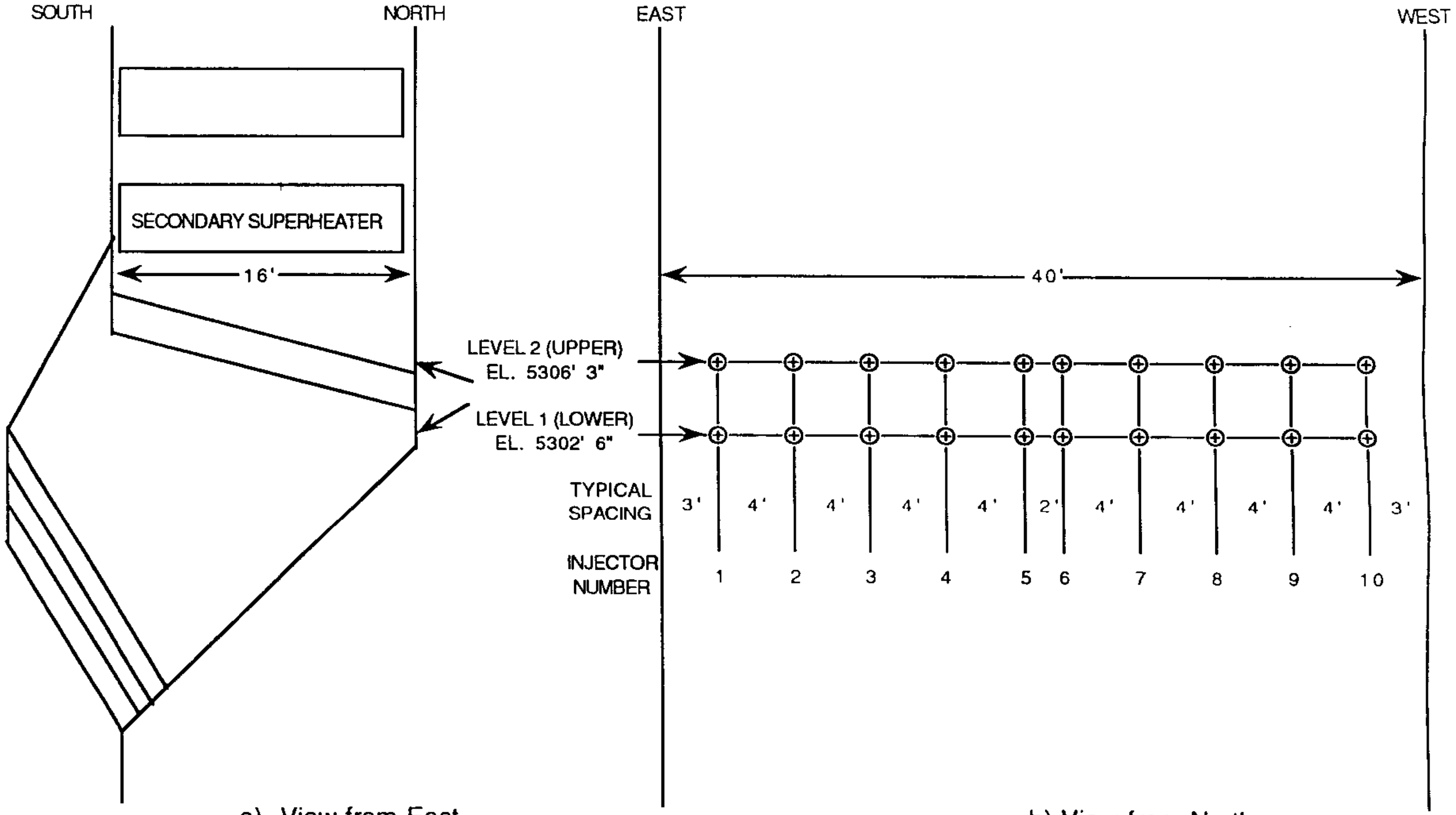
Figure 3-12. Crystallization Point of Aqueous Urea Solutions as a Function of Concentration

ammonia compounds. This system first heats the urea and then passes the urea over a proprietary catalyst that causes the urea to convert to ammonia based compounds. The system can be bypassed so that either urea or ammonia compounds may be injected as selected by the control operator.

The SNCR system at Arapahoe Unit 4 uses NOELL, Inc.'s proprietary dual-fluid injection nozzles to distribute the urea or ammonia compounds evenly into the boiler. A centrifugal compressor is used to supply a large volume (up to 9000 scfm) of medium pressure (4 to 12 psig) air to the injection nozzles to help atomize the solution and rapidly mix the chemical with the flue gas. The volume of air supplied is controlled by variable inlet guide vanes and a variable diffuser assembly, which automatically delivers a preset discharge pressure. Upon exiting the compressor, the air passes through a quench vessel which cools the hot compressed air by recirculating, spraying, and evaporating water. The quench skid has redundant pumps for water recirculation, and the water level within the quench vessel is maintained automatically by a switch operated solenoid valve.

Two rows of ten wall-mounted injection nozzles were installed on the Arapahoe Unit 4 boiler; one at elevation 5302'6" and one at elevation 5306'3", which placed the two levels immediately upstream and downstream of the second set of screen tubes, as shown in Figure 3-13. The injection angle for the lower level of nozzles (Level 1) is oriented 45° down from horizontal, and the angle of the upper level nozzles (Level 2) is 15° above horizontal.

The purpose of two levels of injectors was to have some means of temperature control for the urea injection system. The upper nozzles were expected to operate in the range of 80 to 100 MWe. As the load was further reduced and flue gas temperatures decrease, the lower level would be used. During the initial test program, it was found that either the flue gas was too cold or the residence times too low over the entire load range for effective NO_x reduction at the upper level. Therefore, all further testing was completed with the Level 1 injectors.



a) View from East

b) View from North

Figure 3-13. Arapahoe Unit 4 SNCR Injection Nozzle Location

Purge air is used to keep the level of injection lances not in service cool and free of ash build up. The air is supplied by a purge air fan which draws ambient air through a filter and silencer. The air is fed through the air lines not in use, up to the air header on the level not injecting urea, and then through the nozzles.

The urea injection system is controlled by a programmable logic controller (PLC). The PLC is operated using an IBM compatible computer and controls all the functions of the system (equipment on/off, valves open/close, etc.), except for three local control systems in local control panels (LCPs); the centrifugal compressor, the circulation heaters and the water softening skid. These LCPs control the equipment and receive the main commands and transmit the key information to and from the PLC. Some of the valves need manual pre-selection for redundant equipment, i.e., urea recirculation pump, quench pump, or filter inlet and outlet valves.

From the local computer, the SNCR system can be either manually set, or operated under automatic control. Under automatic control operation, the urea flow rate is set by a feed forward control function using a boiler load signal. The system also utilizes feedback control to trim the urea flow rate by ±30 percent. The feedback control loop can use either a stack NO_x signal or a stack NH_3 signal.

4

MEASUREMENT METHODS

The evaluation of the performance of the selective non-catalytic reduction system required the documentation of gaseous emissions, NH_3 slip levels, and furnace exit gas temperatures, as well as boiler operational performance parameters. This section summarizes the measurement methods that were utilized during the LNB/OFA/SNCR test phase of the program.

4.1 Gas Analysis Instrumentation

The gas analysis instrumentation utilized during the current phase of testing was different from that used during the baseline SNCR tests performed during February and March of 1992. Complete documentation of the earlier system is contained in a separate report(3). An Altech 180 continuous emission monitoring (CEM) system was purchased as part of the Integrated Dry NO_x/SO_2 Emissions Control System and installed during the low-NO_x combustion system retrofit. The CEM system utilizes a Perkin Elmer MCS 100 infrared gas analyzer which is capable of continuously analyzing eight gas species simultaneously, using either gas filter correlation or single beam dual wavelength techniques.

The analyzer cycles through and measures all eight gas species in approximately 22 seconds. In that time, two readings are made for each gas species to be measured. The first reading is a reference value at a known wavelength and gas concentration (either 0 or 100 percent), and the second is a measured reading to determine the quantity of the desired species in the sample stream. Table 4-1 provides a listing of the full scale range, measurement technique, and interfering species for each of the gases measured.

Table 4-1. Gas Species Measured by Perkin Elmer MCS 100 Analyzer

Measured Species	Range	Measurement Technique	Interfering Species
NO	0-500 ppm	Gas Filter Correlation	H_2O
CO	0-400 ppm	Gas Filter Correlation	H_2O
SO_2	0-400 ppm	Single Beam Dual Wavelength	NH_3, H_2O
NO_2	0-100 ppm	Single Beam Dual Wavelength	NH_3, SO_2, H_2O
CO_2	0-20 volume %	Single Beam Dual Wavelength	H_2O
H_2O	0-15 volume %	Single Beam Dual Wavelength	None
N_2O	0-100 ppm	Single Beam Dual Wavelength	CO, CO_2, H_2O
NH_3	0-50 ppm	Gas Filter Correlation	CO_2, H_2O

Using the gas filter correlation technique, the system takes a reference reading at a known wavelength and a known concentration of gas, usually 100 percent. The system then takes another reading at the same wavelength for the sample gas and records the energy absorbed by the sample. The relative difference in energy is then representative of the concentration in the sample gas.

Likewise in the single beam dual wavelength method, a reference reading is taken at a wavelength where the desired species does not absorb energy (zero percent reference). The system then takes a measured reading at a wavelength where the desired species is known to absorb energy. The relative difference in energy is again representative of the concentration of the species in the sample stream.

Once the ratio of reference to measure energy is calculated, the energy level is corrected to account for interferences via reference tables for each specific gas. After correction for interferences, the data is zero adjusted, converted to the appropriate units, calibration corrected, and output for display and recording.

Since O_2 is not infrared active, the CEM system also contains an Ametek O_2 analyzer. The sample cell is a zirconium oxide closed end tube with electrodes of porous platinum coated onto the inside and outside of the tube. The cell produces a millivolt signal proportional to the relative difference of O_2 inside and outside of the cell. The millivolt signal is converted to percent O_2, scaled (0 to 25 percent), and then displayed and recorded.

All CEM analyzer and sampling system functions, including a daily automatic calibration sequence, are controlled by the MCS 100 Programmable Logic Controller (PLC). The measured gas concentration data is displayed on a dedicated 486-based computer, which also provides data logging, manipulation and reporting capabilities.

A Relative Accuracy Test Audit (RATA) was performed on March 5, 1993, in order to verify the accuracy of the CEM system. The audit was performed by TRC Environmental Corp. in accordance with the requirements established in 40 CFR, Part 60, Appendices A and F. Complete documentation of the audit is contained in a separate report(8), and the results are summarized in Table 4-2.

Table 4-2

CEM RATA Results

Parameter	Relative Accuracy (%)
CO_2 (%, wet)	2.64
Moisture (%)	7.86
O_2 (%, wet)	17.81
NO (ppm, wet)	1.53
NO (lb/MMBtu, wet*)	5.93
NO (ppm, dry)	1.02

* *Calculated on an O_2 basis*

Acceptance criteria for RATA evaluation of component instruments of the CEM is 20 percent. Based upon the results, all individual parameters were found to be within the acceptance criteria.

4.2 Gas Sampling System

As shown in Table 4-1, the MCS 100 was configured to measure NH_3. This capability imposes special requirements upon the design of the CEM sampling system. In order to maintain the integrity of the sample, the entire sampling system (probe, sample line, pump, flowmeter, and sample cell) must be maintained at 230°C (445°F). Due to these heat tracing requirements, the CEM system was configured to sample from only two different single-point locations. One at the exit of the air preheater in the duct leading to the fabric filter, and one downstream of the fabric filter and induced draft fans, in the duct leading to the common stack for Units 3 and 4.

In order to obtain a representative composite gas sample, as well as provide the ability to look at discrete areas of the flue gas flow, Fossil Energy Research Corp. provided a sample gas conditioning system which would allow sampling from additional unheated sample probes. Although the MCS 100 is utilized as the gas analysis instrumentation, the measurement of NH_3 at the additional sampling locations is not possible due to the lack of high temperature heat tracing. A schematic of the sample gas conditioning system is shown in Figure 4-1. The system can accommodate up to 24 individual sample lines. Up to 12 of these can be composited together and then analyzed. Each of the individual sample streams is dried in a refrigerated dryer where the gas is cooled and the moisture is dropped out in a trap. Each stream then passes through a metering valve and rotameter, after which all the streams are blended together in a manifold and directed to a pair of sample pumps. The rotameters are used to balance the individual flows in order to provide an accurate composite blend. Downstream of the pumps, a portion of the composited sample is diverted to a final pass through the condenser (where the increased pressure aids in the removal of any remaining moisture), through a final particulate filter, and then to the Altech CEM for analysis.

The location of the unheated sample probes during the current phase of testing was identical to that for the baseline SNCR tests, namely: 12 at the exit of the economizer,

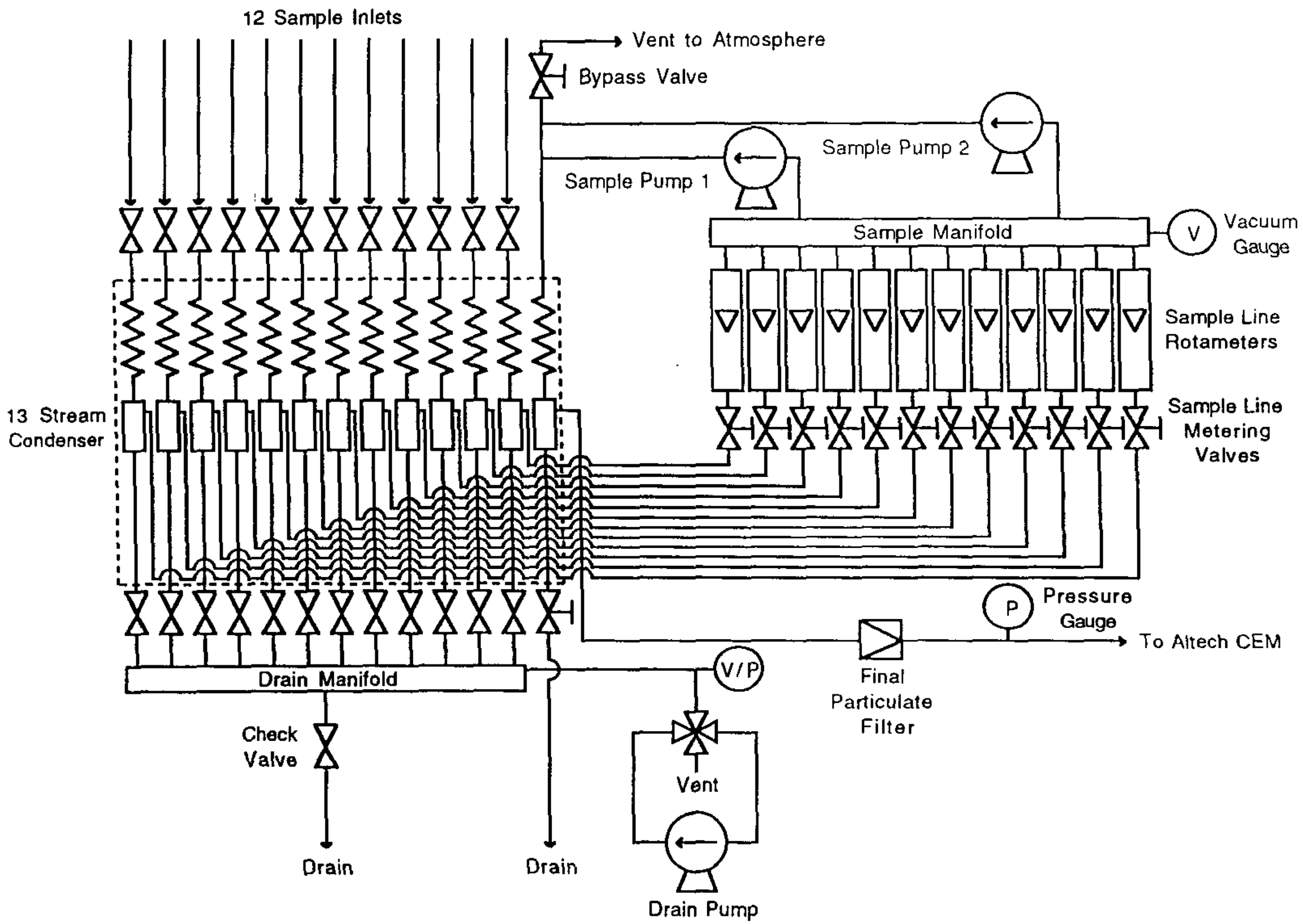


Figure 4-1. Sample Gas Conditioning System

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

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

The importance of the position of the 12-point grid relative to the four PSCC probes was realized during the baseline burner tests when it was found that the average O_2 measured from the grid was nominally one percent higher than the average indicated in the control room. This difference was attributed to the inability of the four PSCC probes to detect the elevated O_2 levels along the east and west sides of the duct which result from both air in-leakage and overfire air that didn't penetrate to the center of the furnace. A comparison between the control room and average economizer exit O_2 levels was made during the low-NO_x combustion system tests in order to determine if the retrofit had any effect on the difference between the two. This comparison also permitted correlation of

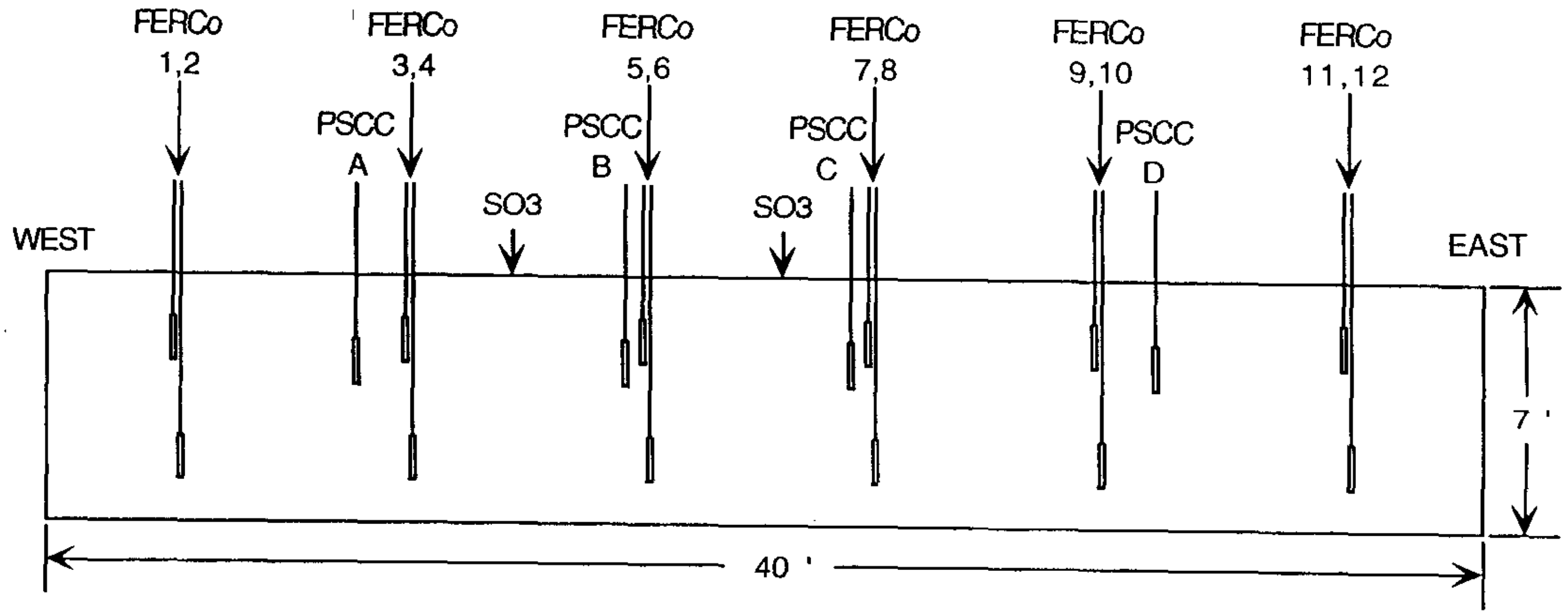


Figure 4-2. Economizer Exit Sampling Locations

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

Additional gas sample probes were installed at the air heater exit and the stack (fabric filter outlet duct) locations. Whereas, the 12-point economizer exit sampling grid would be utilized for detailed point-by-point measurements, the air heater exit and stack sampling probes would be used only to obtain general duct averages at these locations, and will be necessary during the NO_x and SO_2 reduction tests. Therefore, only a limited number of probes were utilized at these test locations; six at the air heater exit and a single probe at the stack location. Figure 4-4 shows the location of the probes at the air heater exit. These sample probes and tubing were similar to the installation at the economizer exit. The staggered probes were installed at one-fourth and three-fourths duct depths, similar to the economizer exit. The figure also shows the location of the heated probe for the CEM system at the exit of the air heater. This probe is not in the same plane as the six-point grid, but approximately 3 feet upstream.. At the stack sampling location, the heated probe for the CEM system is approximately 20 feet upstream of the unheated probe installed during the baseline burner tests. Only a single probe is used for both the CEM and the unheated probe locations since both are downstream of the fabric filter and induced draft fans where little stratification of the flue gas stream is expected. Figure 4-5 shows the installation of the unheated probe in the fabric filter outlet duct.

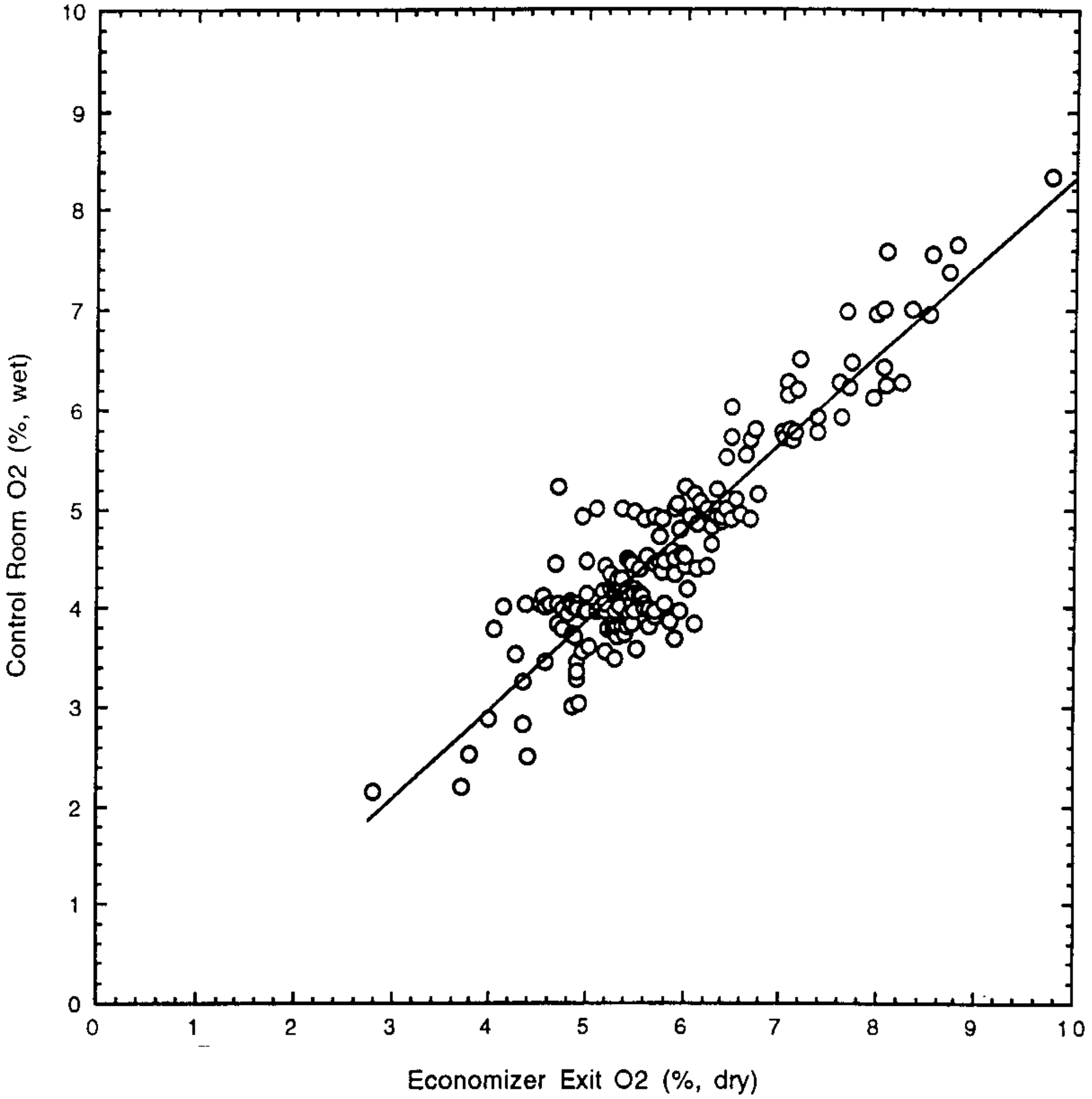


Figure 4-3. Comparison between Control Room O_2 and Economizer Exit Grid O_2 Measurements

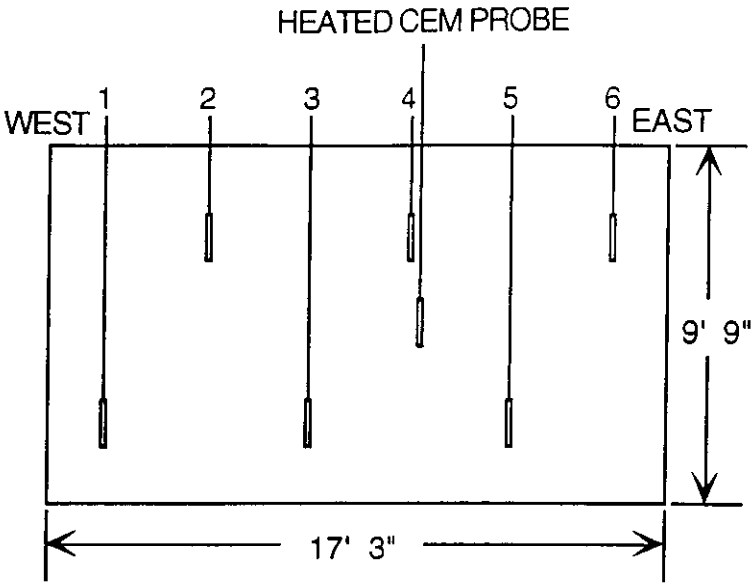


Figure 4-4. Air Heater Exit Sampling Locations

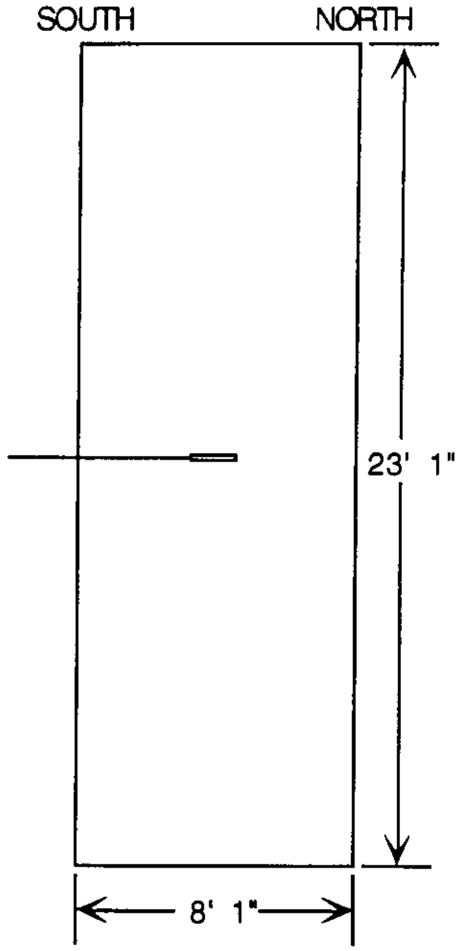


Figure 4-5. Fabric Filter Outlet Duct Sampling Location

4.3 NH_3 Measurements

The measurement of NH_3 emissions is an important aspect of quantifying the performance of a SNCR system. Traditionally, batch or wet chemical sampling techniques have been used for this purpose. However, the time delay between the collection of the sample and the delivery of the results, due to the required laboratory analysis, is less than optimal when trying to optimize process performance in a field test situation. Recently, a number of continuous ammonia analyzers have become available, which could provide the on-line performance desirable for a field test program. However, these analyzers are considered to be in a developmental and proving stage, due to difficulties in obtaining and preserving valid gas samples, especially in sulfur-laden environments.

Wet chemical NH_3 analysis was the primary measurement used during the current test program. Although an EPA method is not available for NH_3 measurement, the method described below has been utilized by Fossil Energy Research Corp. and others during numerous test programs and has been proven sufficiently accurate. Flue gas samples are withdrawn from the duct through a stainless steel probe, and are then passed through three impingers as shown in Figure 4-6. The first two impingers contain 0.02N sulfuric acid (H_2SO_4) and the final impinger is dry. Nominally two cubic feet of flue gas is passed through the impinger train during each test at a rate of approximately 0.2 ft^3/min. Total sample times were nominally 10 to 12 minutes for each test. At the conclusion of each test, the sample probe, teflon line, and sampling train glassware are washed with dilute H_2SO_4 into the bottle containing the impinger solution. The sample solution is then analyzed for ammonia.

During the baseline SNCR tests, the sample solutions were analyzed with a specific ion electrode. Although this type of analysis is a standard technique and is considered quite accurate, it is very temperature-sensitive in that it is most important that the standard and sample solutions be at the same temperature when analyzed. The time required to assure thermal equilibrium can lead to a substantial time delay between the collection of the sample and the delivery of the results. In order to provide a more rapid turn around

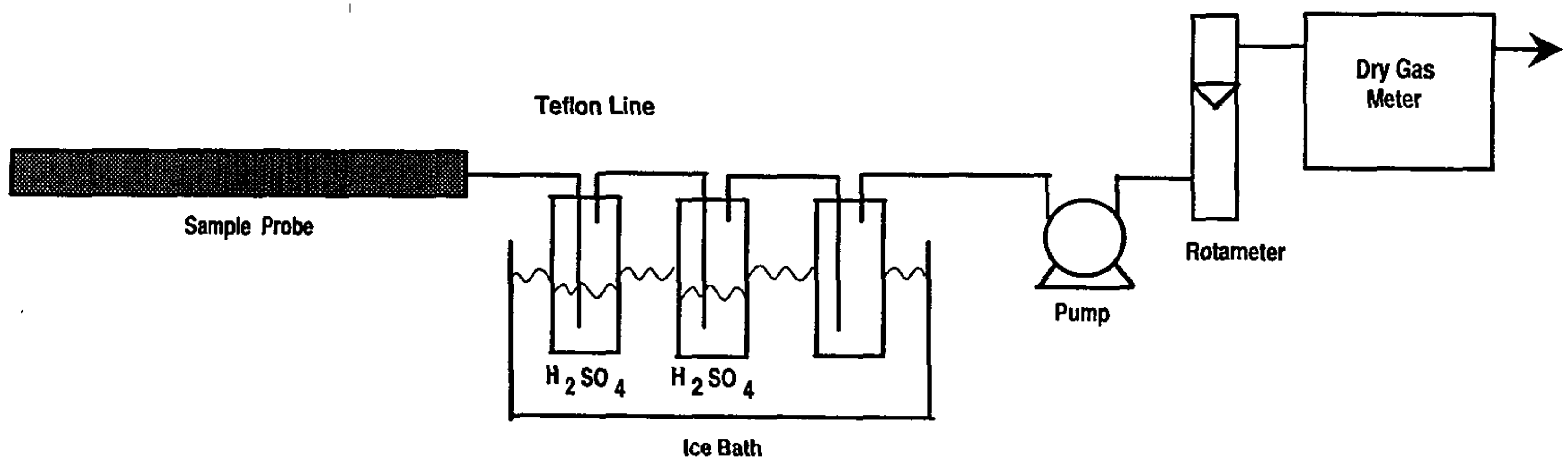


Figure 4-6. NH_3 Sample Train Schematic

of NH_3 data during the LNB/OFA/SNCR tests, the sample solutions were analyzed on-site using the Direct Nesslerization Method. In this method, the Nessler reagent and a stabilizing agent (EDTA) are added to the sample solution and mixed thoroughly. After the reaction is complete (a minimum of ten minutes is required), the light absorbance of the sample is determined photometrically at 425 nm. The reading is compared to the absorbance of standard solutions to determine the ammonia concentration in the sample. Using this method, an NH_3 emission value could be obtained in a manner of minutes after the completion of a test.

The rapid turnaround of NH_3 emission data was used to quickly diagnose and guide the test program during the optimization of the SNCR injection system. However, a portion of each sample solution was also later analyzed with a specific ion electrode since this analysis is considered the standard technique. Figure 4-7 shows a crossplot of the NH_3 data from the two different analyses. The results show a reasonable correlation between the two, but a significant amount of scatter is also apparent. All wet chemical NH_3 emission values discussed in the remainder of this report are from the specific ion analyses.

The majority of the wet chemical ammonia samples were obtained from a set of six ports located in the air heater exit duct (just upstream of the ports used for the continuous gas analysis samples shown in Figure 4-4). A more limited number of samples was obtained downstream of the fabric filter. Unless noted otherwise, the ammonia values represented in the results section are composite samples obtained along the centerline of the duct at the air heater exit.

With the availability of the on-site analysis equipment, it was not uncommon to have the results of the Nessler analysis before the boiler and injection system were stabilized at the next test condition. This was a great advantage in addressing an NH_3 sampling problem which was discovered at the low-load operating condition. Near the end of the initial day of testing at the 60 MWe, it was found that the NH_3 emission results were not

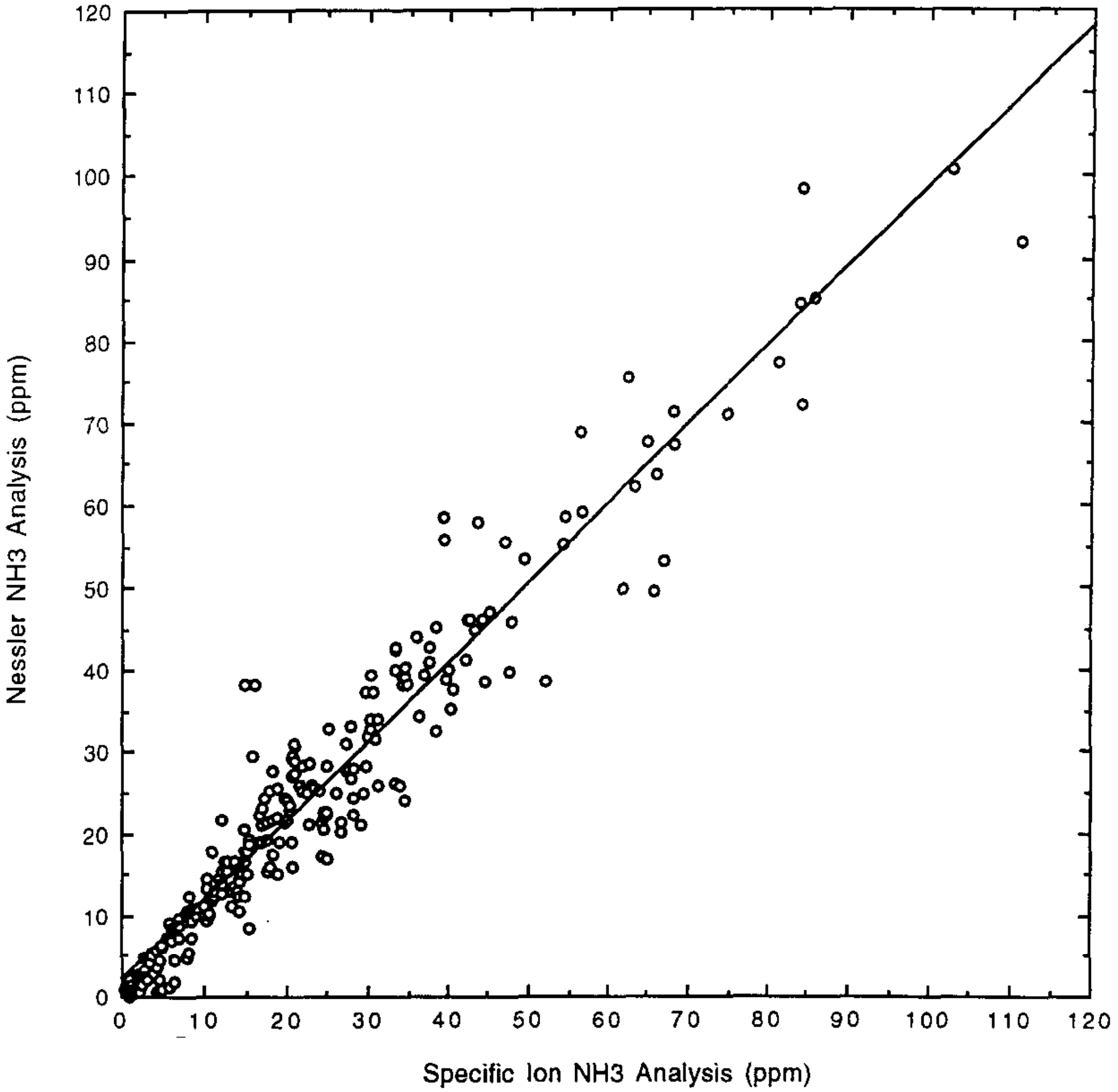


Figure 4-7. Crossplot of Nessler and Specific Ion NH_3 Analyses Results

responding as expected to changes in the N/NO ratio. A repeat of the first test condition of the day showed that although the NO removals at the beginning and end of the day were in agreement, the measured NH_3 emissions were over three times higher at the end of the day. A significant amount of testing had been previously completed at boiler loads of 80, 100 and 100 MWe, and a lack of repeatability of this magnitude had never occurred before. It was hypothesized that at 60 MWe, flue gas temperatures were low enough to allow adsorption and desorption of NH_3 by flyash deposits in the duct. This behavior was seen during the baseline SNCR tests(3), where NH_3 measurements at the stack indicated that the ash in the baghouse provided a substantial capacity for the adsorption and desorption of NH_3. Tests performed during the earlier phase of testing showed that with the ash in the baghouse free of NH_3, it would take up to three hours for NH_3 emissions measured at the exit of the baghouse to equal that measured at the inlet.

During the current phase of testing, a test was conducted at the low-load condition, where a constant N/NO ratio was maintained for nearly three hours. This test was run after the SNCR system had been shut down for approximately 18 hours. The results (Figure 4-8) show that a substantial amount of time (on the order of one hour) was necessary for the NH_3 emissions measured at the air heater exit to stabilize, even though the NO removal measured at the same location was stable after only a few minutes. As stated above, this type of behavior was not seen at boiler loads greater than 60 MWe, and for all tests performed at these loads, waiting 15 to 20 minutes after starting a test (i.e., changing an injection parameter) before starting the NH_3 sampling procedure was more than sufficient to assure consistent and repeatable results. However, all subsequent tests at 60 MWe were run with a minimum waiting period of one hour, in order to allow the NH_3 emissions to stabilize. No further repeatability problems with the wet chemical technique were encountered after the adoption of this test protocol.

Although the wet chemical technique was the primary measurement method for NH_3 during the current test program, the CEM NH_3 measurements at the air heater exit and stack sampling points were also recorded on a test-by-test basis, thus providing an

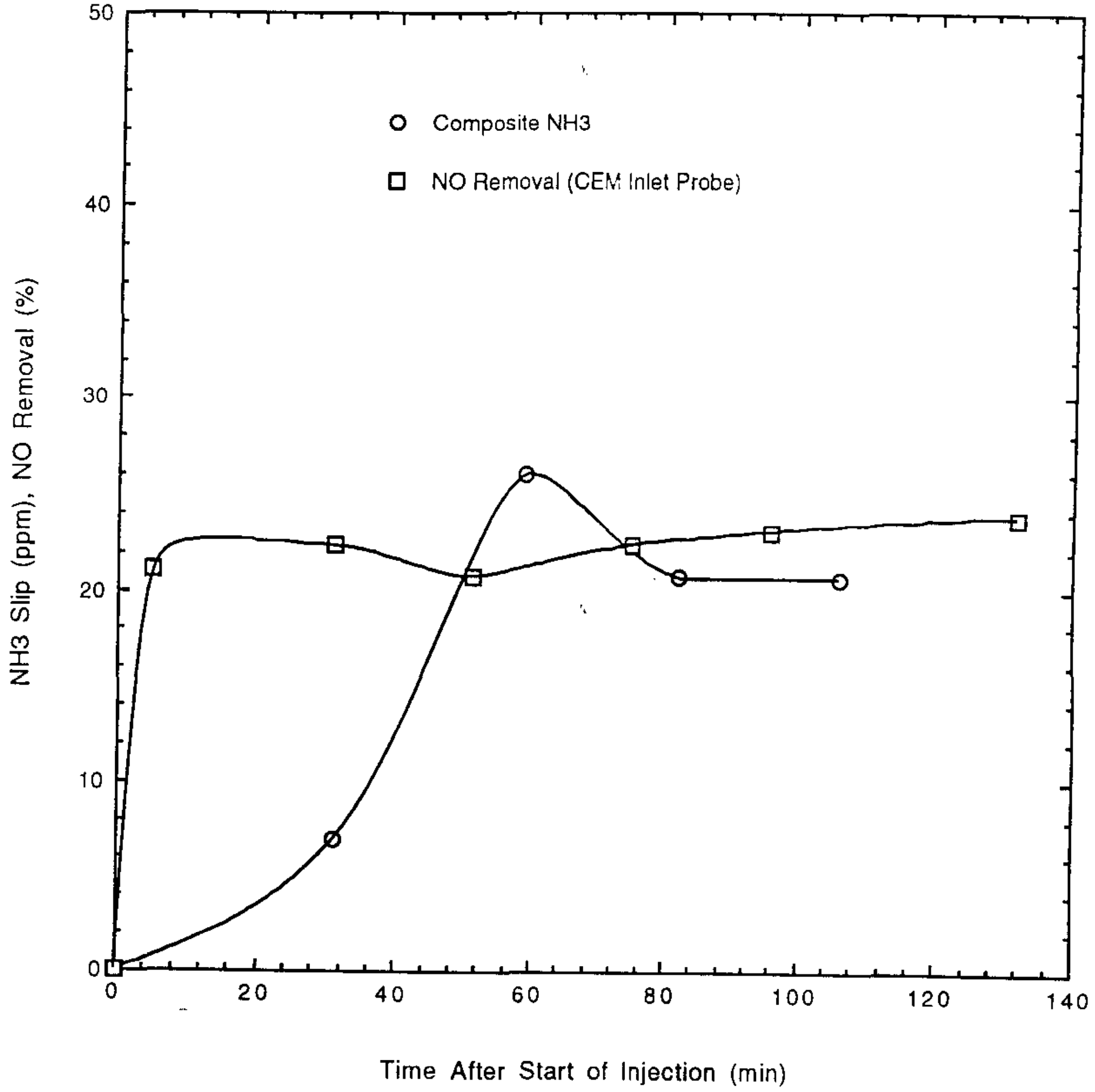


Figure 4-8. NH_3 Emissions and NO Removal at Air Heater Exit (Test Number 548)

opportunity to compare the performance of the continuous instrument to the standard technique. The vast majority of the wet chemical measurements made at the air heater exit were collected in the manner described above (i.e., composite samples across the width of the duct). However, individual samples were often collected through each of the six sampling ports (recall Figure 4-4), in order to assess the distribution of NH_3 across the duct. These measurements showed that the NH_3 profile was far from uniform, and therefore, the single CEM sampling point would not provide an accurate assessment of the average NH_3 concentration at this location. In order to provide the most reasonable comparison, the CEM data at this location was compared to the individual measurements made through the Number 4 port (again, see Figure 4-4). The results (Figure 4-9) show good agreement between the two methods, considering that there was a small difference in the sampling locations.

In order to check for accuracy of the CEM NH_3 measurements at the stack, a limited number of wet chemical NH_3 samples were also collected at this location. Although the wet chemical samples were made at a point in the duct approximately 20 feet downstream of the CEM stack probe, both were far enough downstream of the baghouse and induced draft fans that stratification of the flow was much less of a concern than at the air heater exit. The results (Figure 4-10) show good agreement between the two methods, although the CEM measurements are approximately 15 percent lower than the wet chemical results. This apparent bias is primarily due to the 5 ppm difference between the CEM and wet chemical results for the one high NH_3 slip data point in the figure, and the fact that there are only nine data points in the entire set. If the high slip point is removed from the data set, the correspondence between the two methods is nearly one-to-one. It is therefore reasonable to assume that if the number of data points was to increase, the effect of the one point would decrease, and the correlation between the two methods would be better.

Overall, the performance of the CEM in regard to the measurement of NH_3 emissions was found to be quite good. As the test program progressed, and more experience with

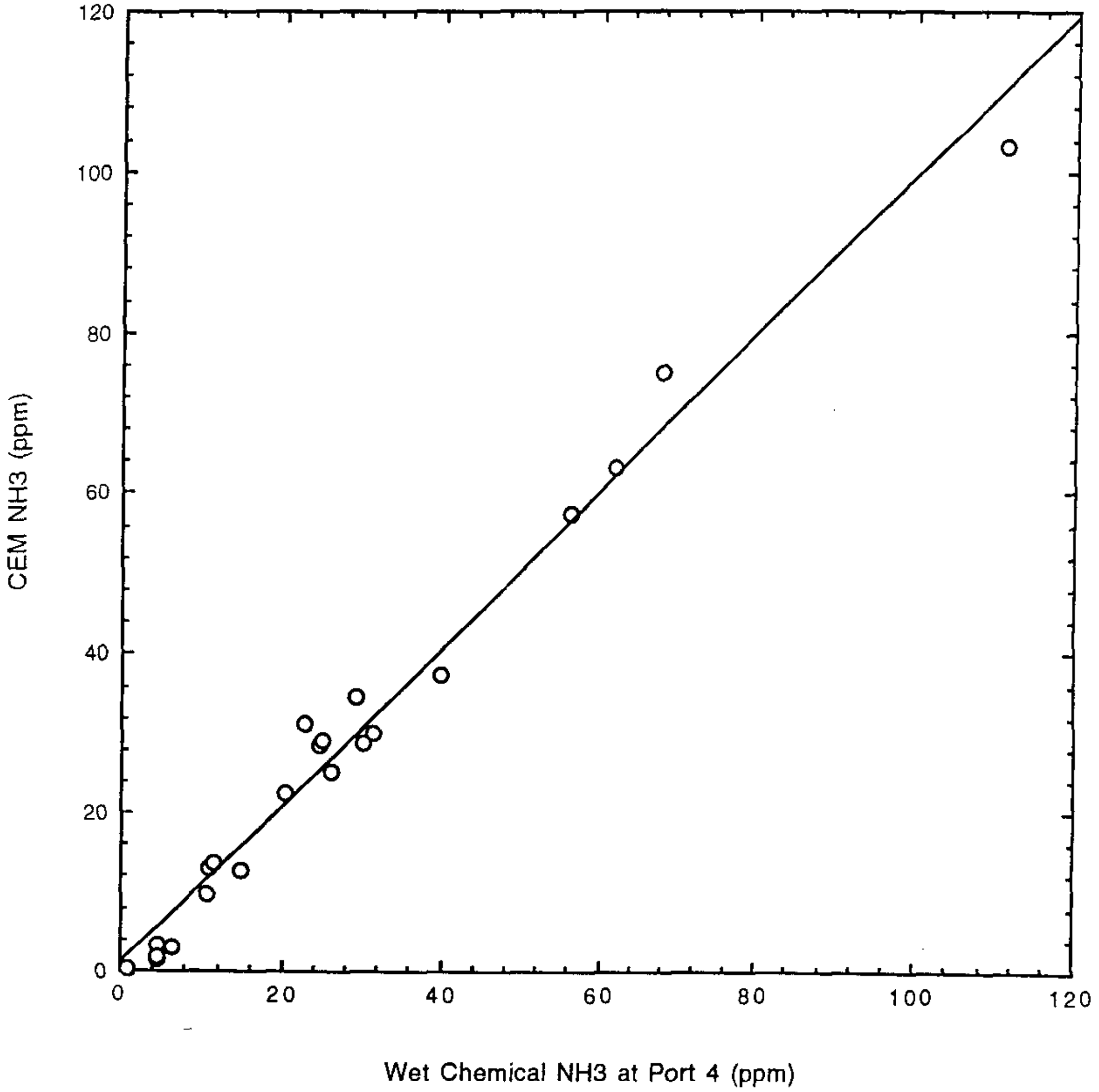


Figure 4-9. Comparison between CEM and Wet Chemical NH_3 Analyses at Air Heater Exit

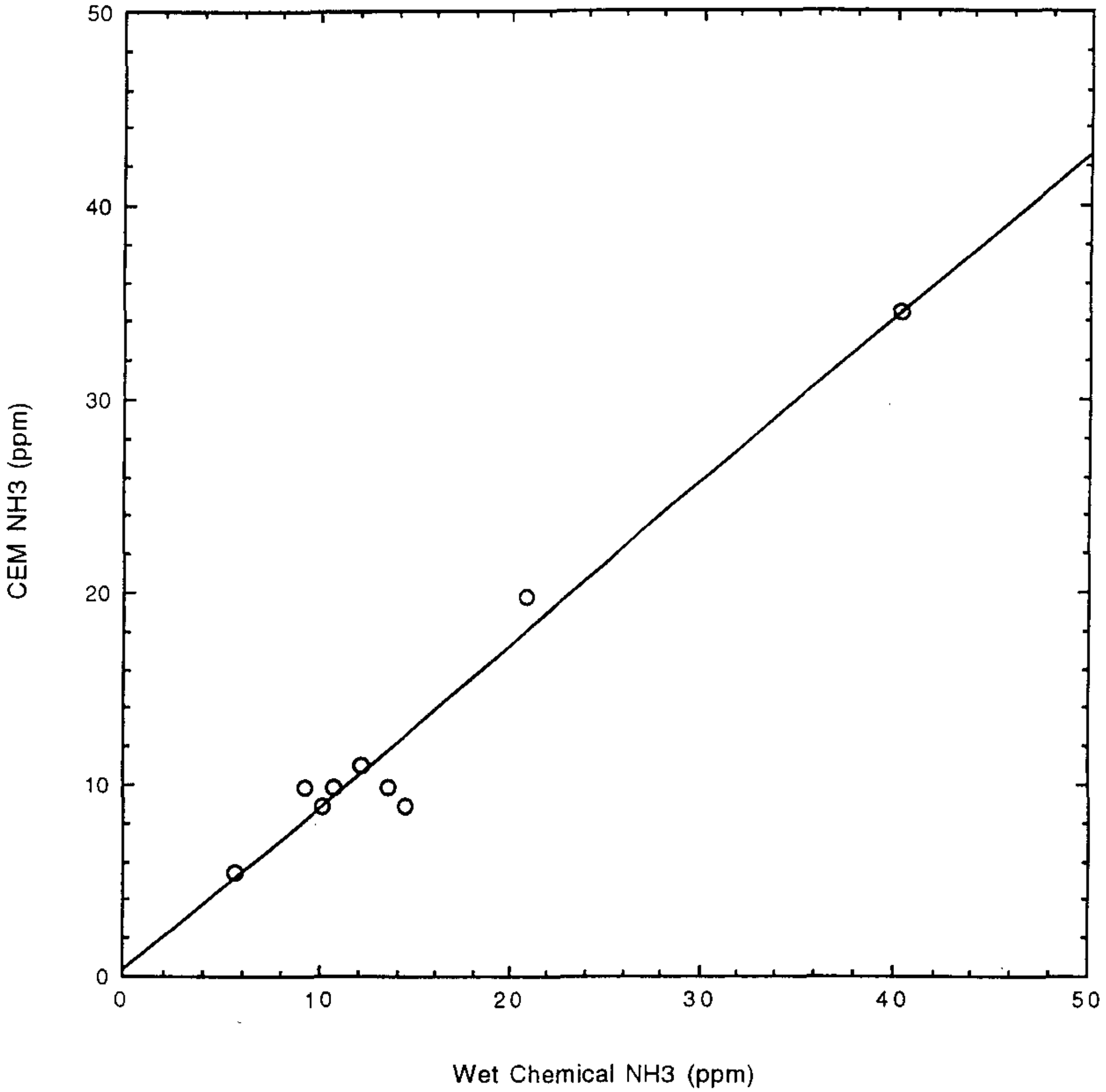


Figure 4-10. Comparison between CEM and Wet Chemical NH_3 Analyses at Stack

the instrument was gained, the monitor was used more frequently as a quick indication of trends in NH_3 slip at the air heater exit. However, it could never be used as an absolute measurement due to the stratification of the flue gas at this location. At the stack location, the CEM was believed to be accurate enough to provide a valid indication of NH_3 slip.

4.4 Furnace Exit Gas Temperature Measurements

During the course of the current test series, furnace exit gas temperature (FEGT) measurements were made in order to provide a comparison with those recorded after the combustion system retrofit during the LNB/OFA tests. The temperature measurements were made using an acoustic pyrometer.

An acoustic pyrometry system, manufactured by Combustion Developments Ltd. of England, was utilized to provide a continuous assessment of the furnace exit gas temperatures. The acoustic pyrometer sends a sound pulse across the furnace; the transit time for the pulse is measured and, thus, the mean speed of sound across the furnace is determined. The average temperature along the path can then be determined from the speed of the sound pulse. The acoustic temperature measurement technique requires a clear line of sight across the furnace at the measurement location. Since the boiler has a division wall running the length of the furnace, the first available location with acceptable access for the acoustic instrument was through a pair of ports just downstream of the first set of screen tubes (Location G in Figure 3-4).

5

RESULTS

The results section has been divided into the following subsections:

5.1 Flue Gas Temperature Measurements

As the performance of the SNCR system is highly dependent on the flue gas temperature at the injection location, this subsection will provide a review of the temperature measurements made in the vicinity of the injection location both before and after the low-NO_x combustion system retrofit.

5.2 System Optimization Tests

Before conducting the parametric performance tests with urea and converted urea, a short series of tests was conducted with the goal of providing an even flue gas composition across the furnace at the injection location, as well as minimizing the effect of any areas which exhibit uncharacteristically high NH_3 slip levels. The results of these activities, which included biasing the coal mills and varying the diameter of the liquid injection nozzles, are presented in this subsection.

5.3 Urea Injection Test Results

The results of the parametric performance tests with urea are presented.

5.4 Converted Urea Test Results

The results of the parametric performance tests with converted urea are presented.

Before presenting the test results, it is of value to discuss the impacts that the various SNCR injection parameters can have on the process. In some cases, these effects are coupled and may have offsetting impacts on the overall SNCR process. Changing an injection system parameter can 1) change the overall level of mixing of the chemical with the combustion products, 2) change drop size and thus evaporation times, 3) change local temperatures, and 4) change the location in the furnace where the chemical mixes with the combustion products. The general effect of these various changes are summarized in Table 5-1.

As is apparent from Table 5-1, changing an injection parameter can impact the process in a number of ways. For instance, increasing the mixing air flow rate, while potentially increasing the mixing, will also provide localized cooling of the combustion products. Thus, depending upon the local temperatures, increasing the mixing air flow rate may or may not have an overall beneficial effect on the SNCR process performance.

Table 5-1

General Effects of Injection System Parameters

Increasing	Jet Penetration	Overall Mixing	Drop Size	Local Temperature
Mixing Air Pressure(1)	+	+	-	-
Dilution Water Flow	+	0	-	-
Air Orifice Size(2)	-	-	+	0
Liquid Orifice Size(3)	+	0	+	0

(1) Same air orifice size increases air flow rate
(2) Same air flow rate decreases injection velocity
(3) Same liquid flow decreases atomization

Localized cooling of the flue gas occurs when the air/liquid mixture is injected due to 1) the energy required to heat the mixing air, 2) the energy required to vaporize the liquid and 3) the energy required to heat the vaporized liquid to the local combustion product temperature. Table 5-2 summarizes the nominal cooling effects for the range of injection system parameters investigated during the current series of tests. The local cooling effect can range from 34 to 66°F at full load conditions depending on the injection system parameters. The cooling effect can be higher at lower boiler operating loads.

Table 5-2

Summary of Local Combustion Gas Cooling by the SNCR Injection Jets

	Injection Parameters		
Load (MWe)	P_{Air} (psig)	Q_{Liq} (gpm)	Calculated Localized Cooling, ΔT (°F)
100	12	6	66
100	12	4	60
100	12	2	54
100	8	6	50
100	4	6	34

Before the results are presented, it is also worthwhile to discuss how the tests were actually run and, in particular, how the chemical injection rate and NO removals were defined. The relative chemical feed rate for a particular test is indicated by the N/NO molar ratio (i.e., the molar ratio of the amount of nitrogen injected to the amount of NO in the untreated flue gas). Before each test, a target N/NO ratio was decided upon, and a baseline NO level measured at the economizer exit. From these two values, a chemical feed rate was calculated and the injection pump speed and urea control valve settings determined. At the conclusion of the test, the N/NO ratio was calculated from the average urea flow and baseline NO level. Since the urea flow may vary slightly over the duration of a test, and the baseline NO level may vary over the course of the day (baseline NO levels were not checked after each individual test, but periodically throughout each day), the calculated N/NO ratio was often slightly different than the target value. Throughout the text of this report, the target (or nominal) N/NO ratios will be utilized in the discussion of test conditions (i.e., a nominal N/NO ratio of 1.0 will indicate a calculated N/NO ratio in the region of 0.9 to 1.1).

From the preceding discussion, it is apparent that the N/NO ratio for each test was based on the boiler NO emission level existing after the low-NO_x combustion system retrofit. The amount of NO removal for each test was also calculated relative to this post-retrofit baseline. Although an individual test may result in a calculated NO removal of 40 percent, it must be realized that this is in addition to the 63 to 69 percent achieved with the low-NO_x combustion system (recall Figure 2-9). For this example, the overall NO removal due to the cumulative effect of the low-NO_x combustion system and SNCR would be approximately 80 percent.

Finally, recall that during the early part of the baseline SNCR test program, it was found that the flue gas temperature at the upper (second) injection level was too cold for effective NO_x removal even at full load. All subsequent testing was conducted with the lower (first) level of injectors and, therefore, all of the results presented in this report are for Level 1 injection only unless otherwise noted.

5.1 Flue Gas Temperature Measurements

Flue gas temperatures have been measured during five separate test campaigns at Arapahoe Unit 4. The first temperature measurements were made in April of 1991 to support the design of the SNCR injection system(6). Subsequent temperature measurements have been made during the baseline tests with the original combustion system(1), the baseline SNCR testing(3), retrofit low-NO_x combustion system testing(2), and during the current phase of testing with the SNCR system and low-NO_x combustion system.

Figure 5-1 summarizes the flue gas temperature measurements made at the furnace exit (Port G, see Figure 3-4) using the acoustic pyrometer. Acoustic temperature measurements made during the baseline burner and baseline SNCR tests showed that the furnace exit gas temperatures were significantly lower than those measured in April 1991 in support of the SNCR system design phase. The data collected during the baseline burner and baseline SNCR tests agree well with each other, but are on the order of 150 to 200°F lower than those measured in April 1991. Although no definitive explanation can be put forth, possible reasons for the difference in temperatures were discussed in References 1 and 3.

As seen in Figure 5-1, temperature measurements made following the low-NO_x burner retrofit, and more recently during the current SNCR testing, indicate a decrease in furnace

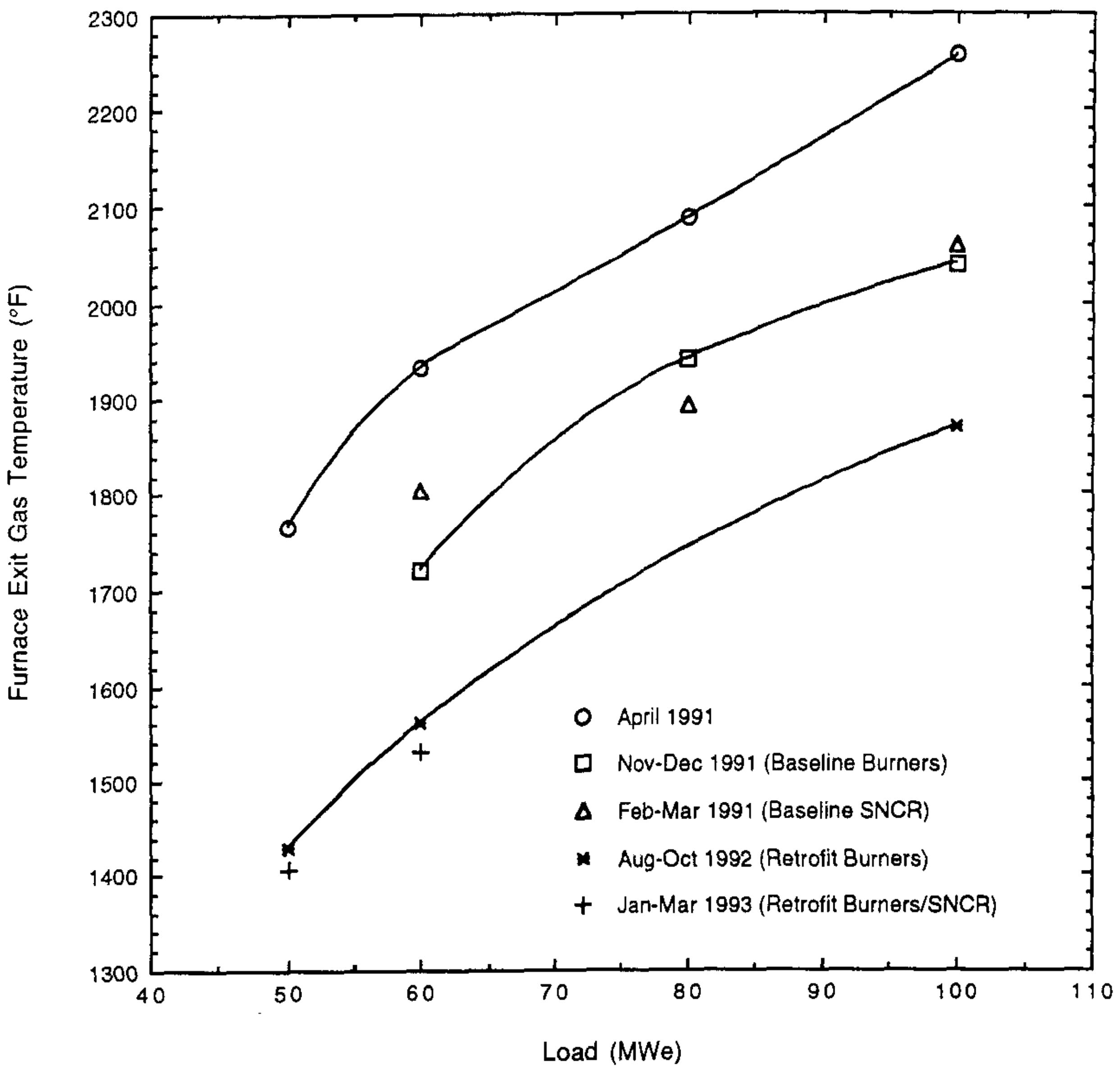


Figure 5-1. Historical Variation of Furnace Exit Gas Temperature as a Function of Boiler Load

exit gas temperatures of 180 to 240°F (relative to the measurements made during the baseline burner and baseline SNCR testing).

After the combustion system retrofit, suction pyrometry (HVT) temperature traverses were also made through the eight ports along the north side of the boiler downstream of the second set of screen tubes (recall Figure 3-4). These measurements were made to assess the effect of the retrofit on the flue gas temperatures in the immediate vicinity of the SNCR injection location. Measurements at 2, 4, 6, and 8-foot depths were made through each of the eight ports, resulting in a 32-point grid. Figure 5-2 shows the average of the 32 temperature measurements as a function of boiler load, and compares the results to those found measured prior to the retrofit. The data show a post-retrofit decrease in temperature on the order of 250°F across the load range. Figure 5-3 shows the average post-retrofit temperature profiles at the north port location for boiler loads of 60, 80, and 110 MWe. In this figure, each point represents the average of the four measurements made through a particular port. Excluding the points near the outside walls, all three curves show a temperature variation across the boiler on the order of 200°F. The variation at 60 MWe is the greatest, and is likely due to the three mills in service operating condition at this load.

The burner retrofit has resulted in a furnace exit gas temperature decrease on the order of 200°F. This has impacted the amount of excess air required to maintain steam temperature at reduced loads. As will be seen, this decrease in temperature has also impacted the performance of the SNCR system.

5.2 System Optimization Tests

Prior to parametrically characterizing the performance of the SNCR system with the low-NO_x combustion system, the optimum operating conditions and settings for the SNCR system were identified. This optimization involved two activities. In the first, the individual coal mills were biased to provide a more even gas composition across the furnace (west to east). In the second, the individual SNCR injection nozzle sizes were varied in order to minimize NH_3 slip. These two optimization exercises were done from the standpoint

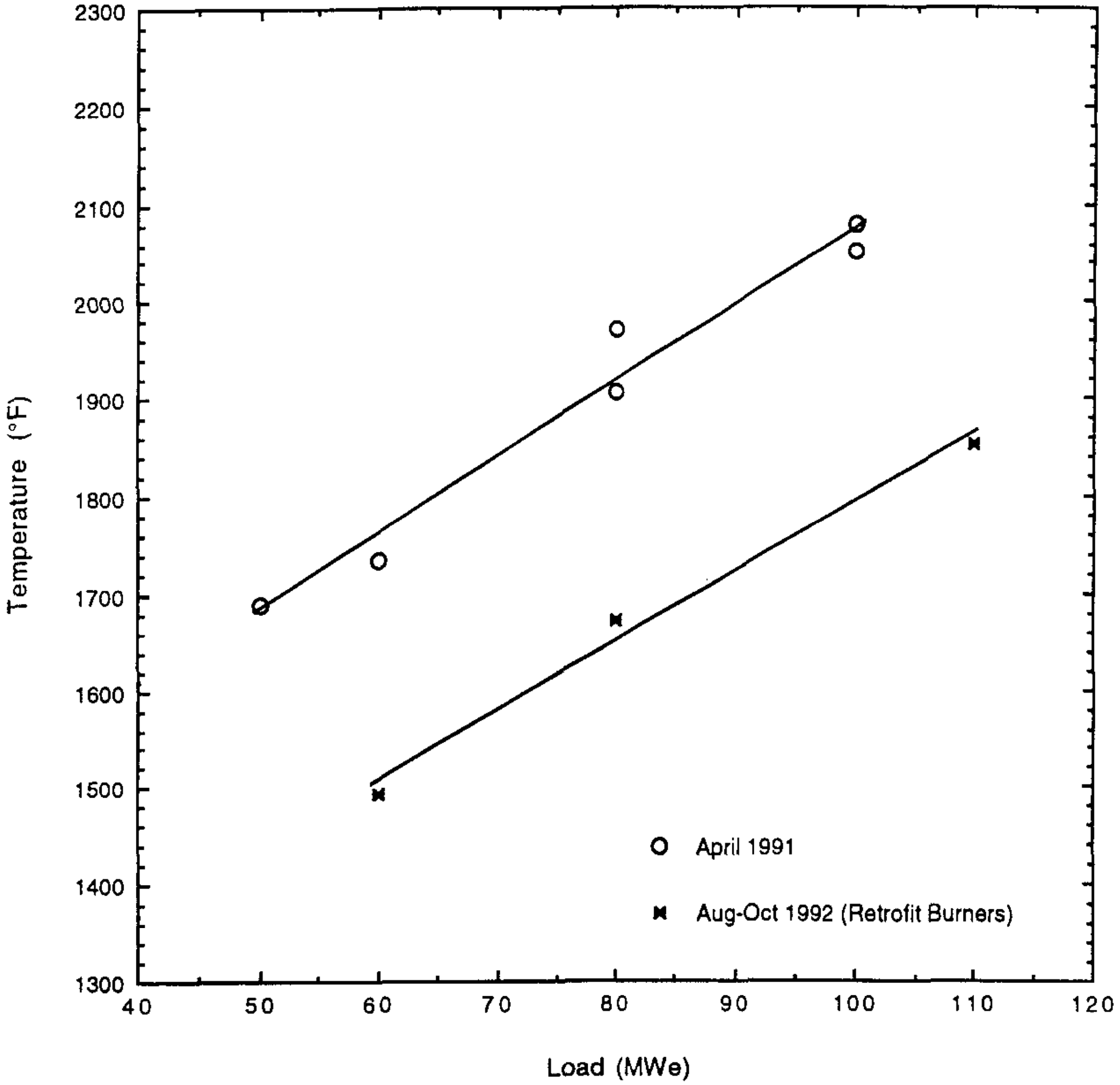


Figure 5-2. Pre- and Post-Retrofit North Port Average Temperatures as a Function of Boiler Load

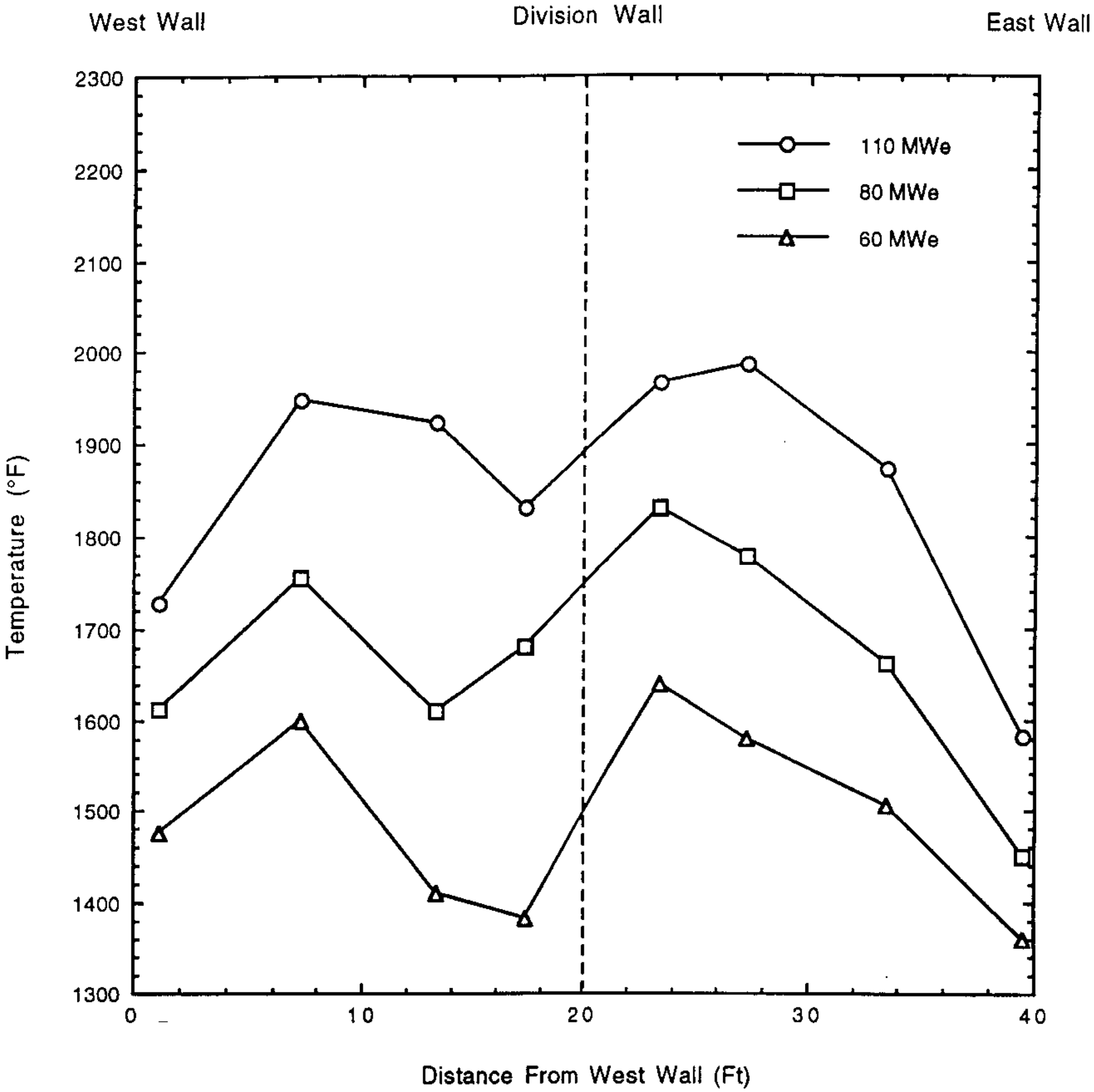


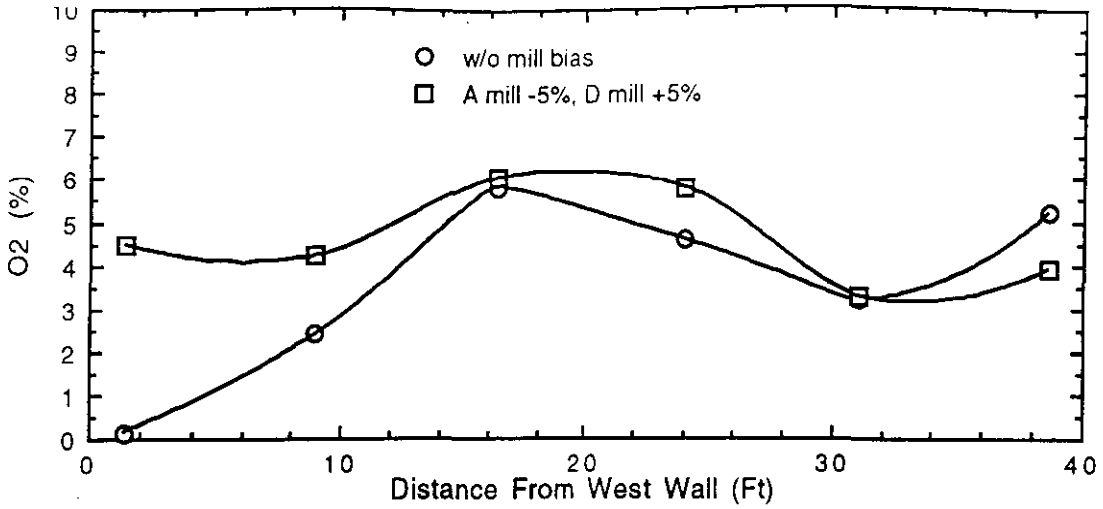
Figure 5-3. Post-Retrofit Average North Port Temperature Profiles at 60, 80 and 110 MWe

of hardware or operational changes that could be easily incorporated into the day-to-day operations of the unit. For instance, the injection nozzle sizes were optimized at the full load condition with all four coal mills in service because this is considered the most common operating condition. Additionally, it also would not be operationally feasible to specify different size nozzles for different loads or mill-in-service conditions, since this would require removing individual injectors and manually changing the nozzles.

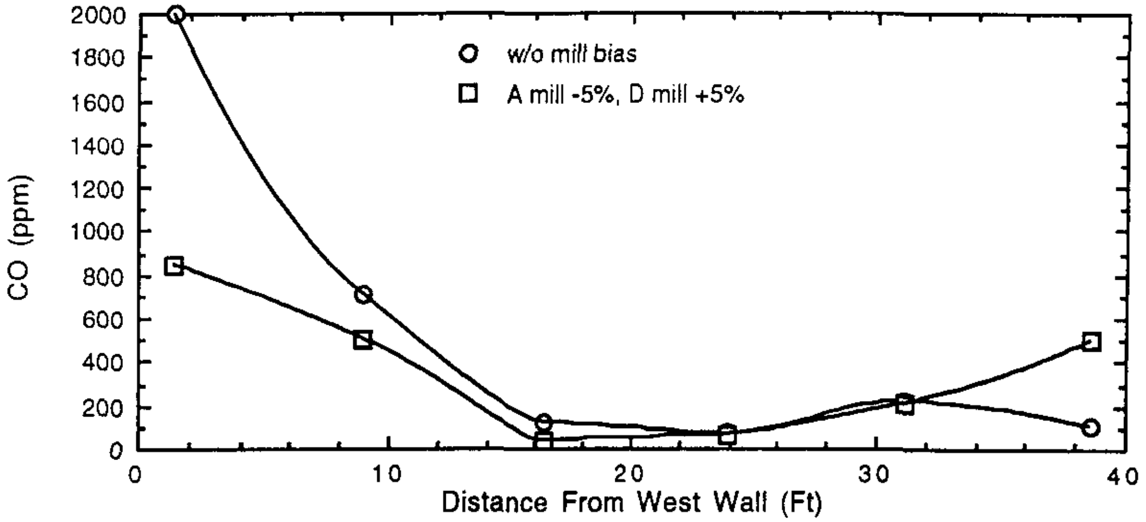
5.2.1 Mill Biasing

During the retrofit burner test program(2), it was found that the west side of the furnace typically yielded high levels of CO. Balancing the secondary air flows to individual burners, while reducing the overall levels, did not completely eliminate this high CO region. Since this was shown to have little effect on NO emissions, this air balancing effort was not further pursued during the retrofit burner test program. In addition, the flue gas temperature measurements showed lower temperatures on the east wall of the furnace (recall Figure 5-3).

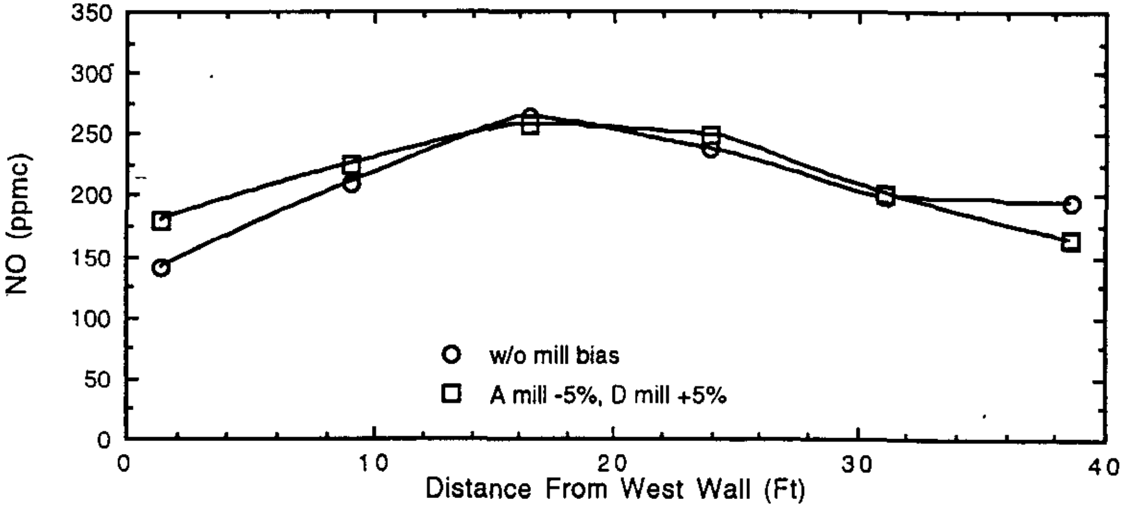
Prior to extensive SNCR testing with the retrofit burners, an effort was made to minimize the high CO region on the west side of the furnace while increasing the flue gas temperature near the east wall. This was accomplished by biasing the fuel feed to the individual coal mills. A number of mill bias patterns were tested. The best result was obtained by biasing A and D Mills. Recall that A Mill supplies coal to two burners on the far west side of the furnace, while D Mill supplies coal to two burners on the far east side (see Figure 2-5). In order to compensate for the high CO levels on the west side and low temperatures on the east side, the fuel feed to A Mill was increased and the feed to D Mill decreased. Biasing in this way would move coal primarily from the west side of the furnace to the east side. Biasing each mill 10 percent (A Mill -10 percent; and D Mill +10 percent) resulted in a large an impact on steam temperatures and a shift of the high CO region from the west wall to the east wall. The bias was reduced until the steam attemperation rates on the east and west sides of the furnace were not markedly different. This was accomplished by a -5 percent bias on the A Mill and a +5 percent bias on the D Mill. Figure 5-4 shows the effect of this level of mill bias on the west-to-



a) O_2 Profiles



b) CO Profiles



c) NO Profiles

Figure 5-4. Effect of Mill Bias at 100 MWe with 3.5 Percent Control O_2

east distribution of O_2, CO and NO. The data shown in Figure 5-4 was collected at 100 MWe with an O_2 control set point of 3.5 percent and no SNCR chemical injection. Biasing the A and D Mills at this condition increased the O_2 on the west side of the furnace as well as decreased the CO level at this location from over 2000 ppm to under 900 ppm. A change in the NO profiles across the furnace is also evident. Reducing the amount of coal fed to the west side of the furnace increased the local NO level near the west wall from nominally 140 ppmc (dry corrected to 3% O_2) to approximately 160 ppmc. Conversely, with the increased coal flow through the D Mill, the local NO level near the east wall decreased from nominally 200 ppmc to 165 ppmc on the east side.

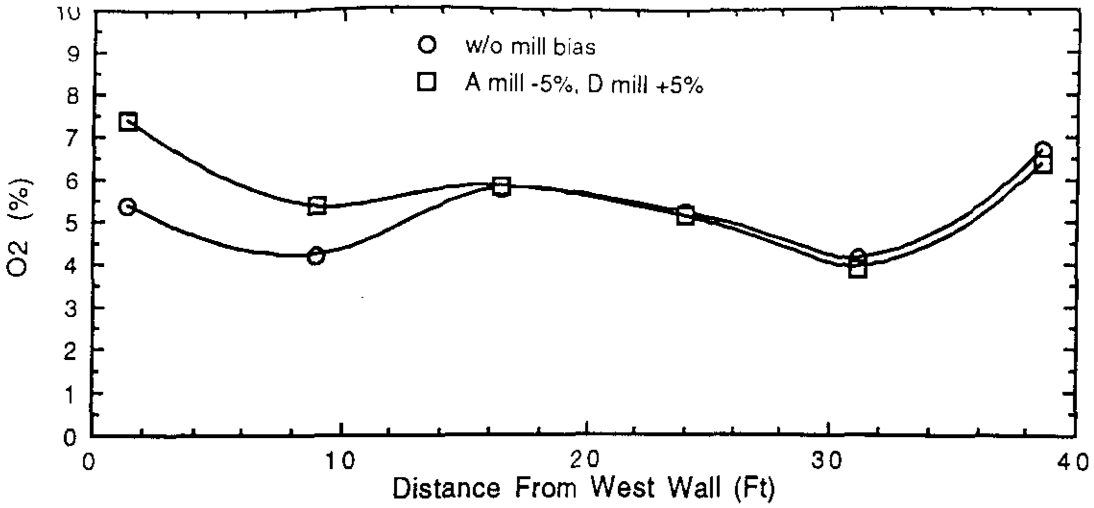
A second set of mill bias tests were performed at a higher O_2 control setpoint of 4.0 percent. The results of these tests are shown in Figure 5-5. At the higher O_2 setting, the same general trends are seen in the CO and NO profiles. However, for this test condition without any mill bias, the furnace did not exhibit the extremely low O_2 behavior near the west wall seen at the previous tests condition. But again, the CO levels in this region were high for the unbiased case, and were reduced by biasing the A and D Mills -5 percent and +5 percent, respectively.

Biasing the mills also had a visual impact on the flue gases at the furnace exit. When viewed from the west side through Port G (recall Figure 3-4), without the mill bias the gases were opaque, typically to the point where one could not see the furnace division wall. The east side, however, was always quite clear. Biasing A Mill down 5 percent, and D Mill up 5 percent, cleared up the west side such that there was no visual difference between the two sides.

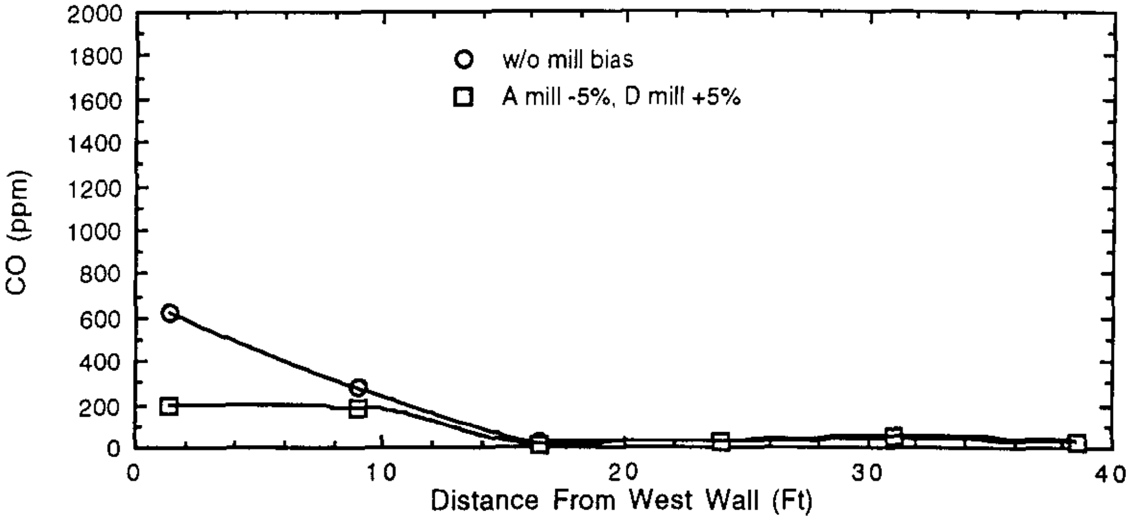
Unless otherwise noted, the SNCR results presented in this report were conducted with a -5 percent bias on A Mill and a + 5 percent bias on D Mill.

5.2.2 SNCR Injector Optimization

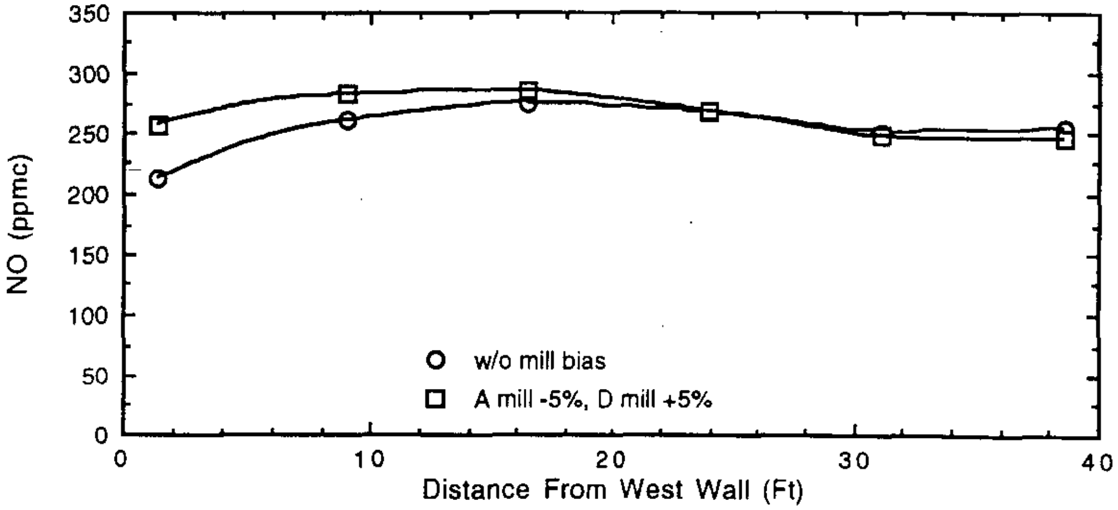
The SNCR system consists of two injection levels, each having 10 injectors running west to east across the furnace. As was shown in Figure 3-13, Injector Number 1 is on the



a) O_2 Profiles



b) CO Profiles



c) NO Profiles

Figure 5-5. Effect of Mill Bias at 100 MWe with 4.0 Percent Control O_2

west side of the furnace, with injector Number 10 on the east side. Even with the optimum mill bias settings discussed above, preliminary testing showed a tendency for higher NH_3 slips on the east side of the unit. In an attempt to reduce the local NH_3 slip on the east side, a test series was conducted at 100 MWe with urea injection, where the liquid orifice size for Injectors 9 and 10 were reduced. Reducing the liquid orifice size on these injectors would locally reduce the urea flow, increasing the flow to the balance of the injectors, and hopefully reduce the overall NH_3 slip levels while increasing the overall NO removals.

The results of these tests are shown in Figure 5-6. Figure 5-6a shows that reducing the liquid orifice size on the Number 10 injector resulted in a significant increase in NO removal (approximately 6 percentage points at a nominal N/NO ratio of 1.15). No further improvement was seen when the liquid orifice in injector Number 9 was also reduced. The NH_3 slip results in Figure 5-6b show similar improvements. A decrease in NH_3 emissions was seen when the Number 10 liquid orifice size was reduced, but no further reductions were realized when the Number 9 liquid orifice diameter was also reduced.

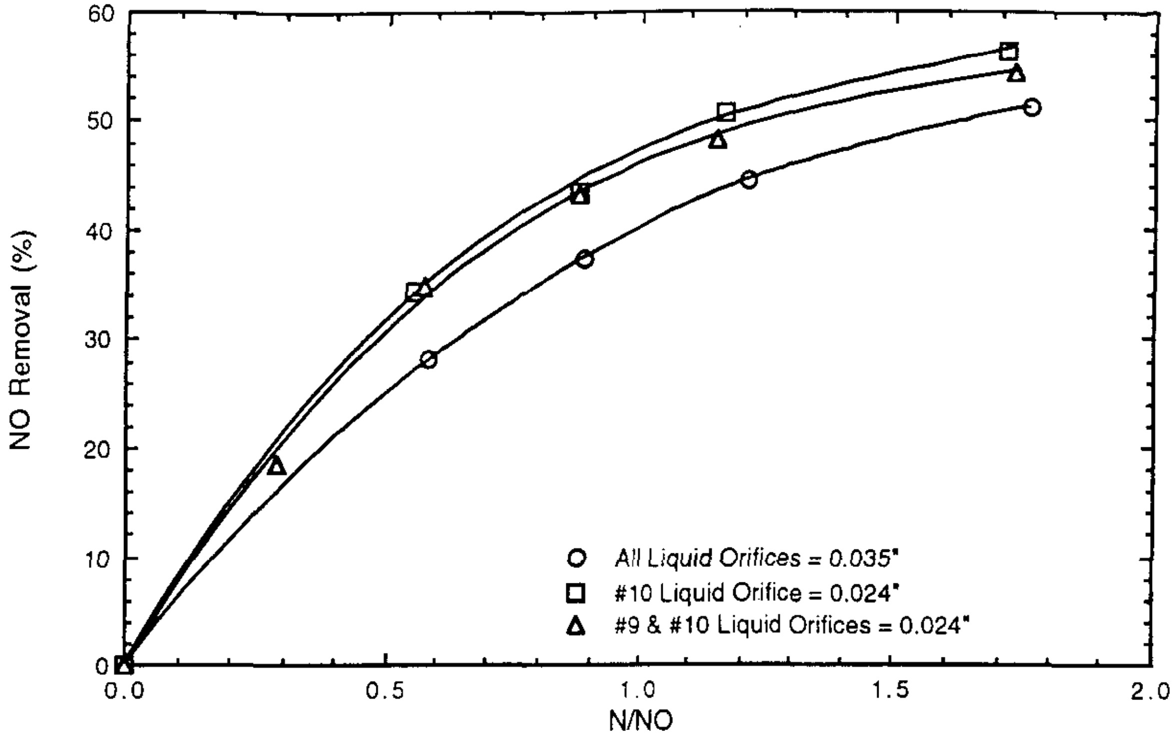
Based on the above tests, using a smaller liquid orifice in the Number 10 injector provided an increase in NO removal while reducing NH_3. The balance of the SNCR testing was conducted with the following liquid orifice configuration:

Injectors 1 through 9:	0.035-inch diameter
Injector 10:	0.024-inch diameter

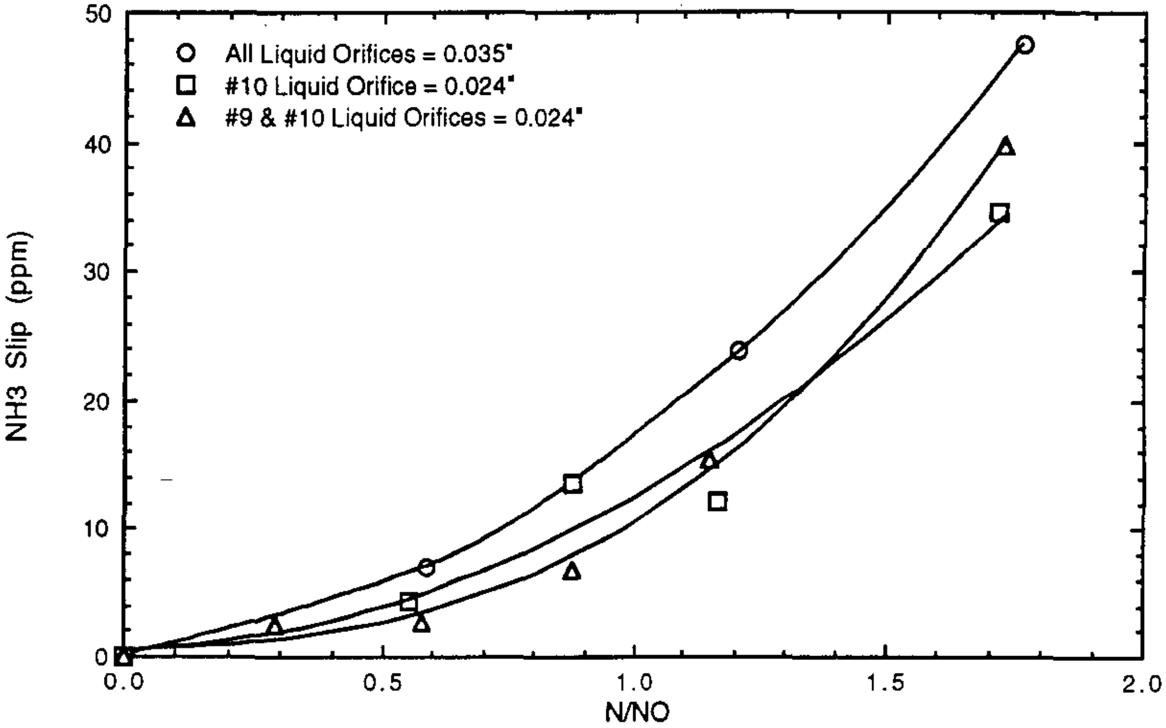
5.3 Urea Injection Test Results

Following completion of the system optimization tests, a series of parametric tests was conducted with urea injection. The results of these tests will be presented in the following subsections:

5.3.1 Point-by-Point Gaseous Traverses
5.3.2 Effect of Boiler Load and Chemical Injection Rate
5.3.3 Effect of Mills Out of Service
5.3.4 Effect of Total Liquid Flow Rate



a) NO Removal



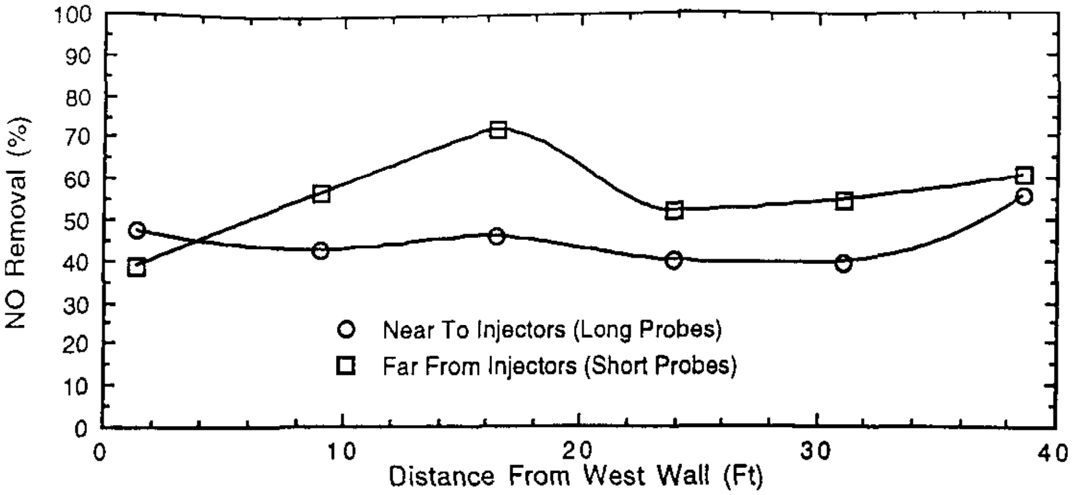
b) NH_3 Emissions

Figure 5-6. Effect of Liquid Orifice Size on Urea Injection at 100 MWe (6.0 gpm total liquid flow, 8 psig air)

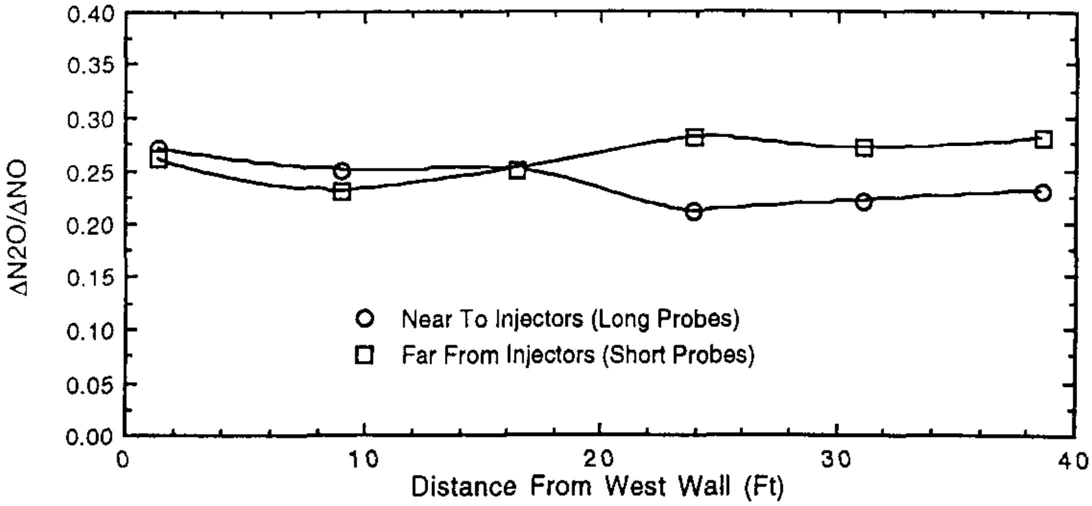
5.3.1 Point-by-Point Gaseous Traverses

In order to provide more insight into how effectively the injection system distributed the urea in the furnace, a test was conducted at a boiler load of 100 MWe with a urea injection rate corresponding to a N/NO ratio of 1.15. Point-by-point measurements were made at the 12-point grid at the economizer exit (recall Figure 4-3) to characterize the local NO removal and N_2O production. In addition, point-by-point measurements of NH_3 slip were made at the six ports located at the air heater exit (recall Figure 4-4). At each air heater exit port the NH_3 measurement was made at a single vertical location at the center of the duct.

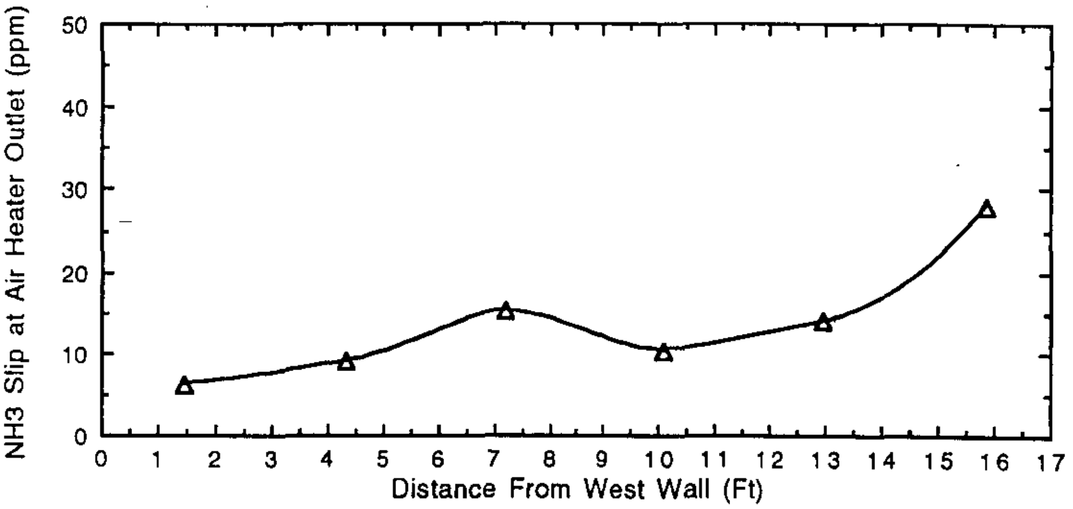
Figure 5-7 shows the results of this test. The NO removals and N_2O production are shown in Figures 5-7a and 5-7b, respectively. Recall that if stream lines were drawn from the point of injection vertically up and over to the tubular air preheater, the "short probes" at the economizer exit location would tend to sample flue gas toward the south wall of the convective section away from the urea injectors. From Figure 5-7a, the local NO removals are highest from the short probes (i.e., the flue gas farthest from the injectors). It is difficult to say whether the higher removals far from the injectors are due to 1) the distribution of more urea out and away from the injectors, or 2) a flue gas temperature stratification in the north-south direction. The HVT temperature measurements made through the north ports during the retrofit burner tests showed the temperature increasing as the probe insertion depth increased. However, due to physical constraints, the suction pyrometer could only probe 8 feet away from the wall, which is only half-way across the 16-foot depth at this location. Acoustic pyrometry measurements(6), on the other hand, have shown a lower temperature region at Port D (recall Figure 3-4), which is in a region beyond the reach of the suction pyrometer through the north ports. As will be discussed in the next subsection, the temperature on average



a) NO Removal



b) N_2O Production



c) NH_3 Emissions

Figure 5-7. Point-by-Point Profiles for Urea Injection at 100 MWe (N/NO = 1.15, 6.0 gpm total liquid flow, 8 psig air) appears to be on the high side of the SNCR temperature window at 100 MWe. This would suggest that the higher NO removals far from the injectors is due to the urea reaching the cooler, more optimum, temperature region in the vicinity of Port D. But again, the effect of differences in chemical distribution cannot be discounted.

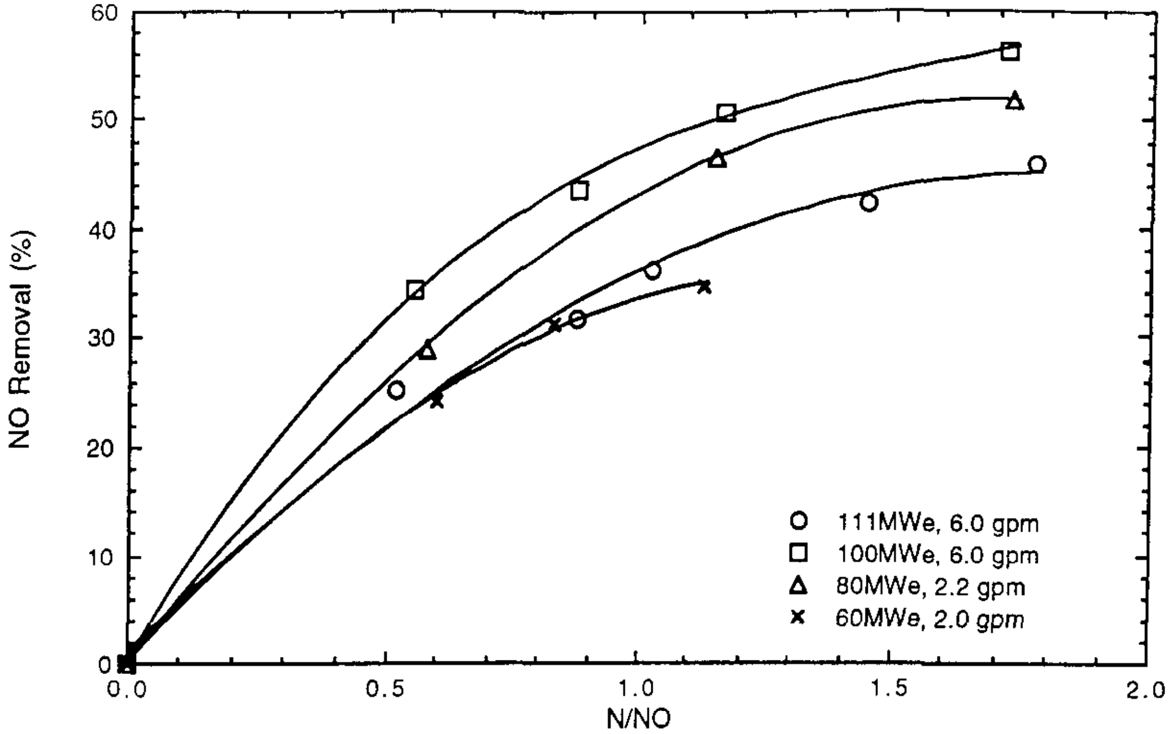
The N_2O production is shown in Figure 5-7b. In this figure, the N_2O is shown as the ratio of the amount of N_2O produced by urea injection divided by the amount of NO reduced (i.e., the fraction of the NO reduction converted to N_2O). The local N_2O production is fairly uniform with somewhat higher N_2O levels for the gas "far" from the injectors on the east side.

The NH_3 slip, profile measured at the air heater exit is shown in Figure 5-7c. The distribution is fairly uniform with a slightly increasing trend west to east with levels less than 15 ppm, except for the far east port where the local NH_3 slip level approaches 30 ppm. This is consistent with the prior discussion indicating lower temperatures on the east side (even though mill biasing helped smooth out the gas species and temperature profiles).

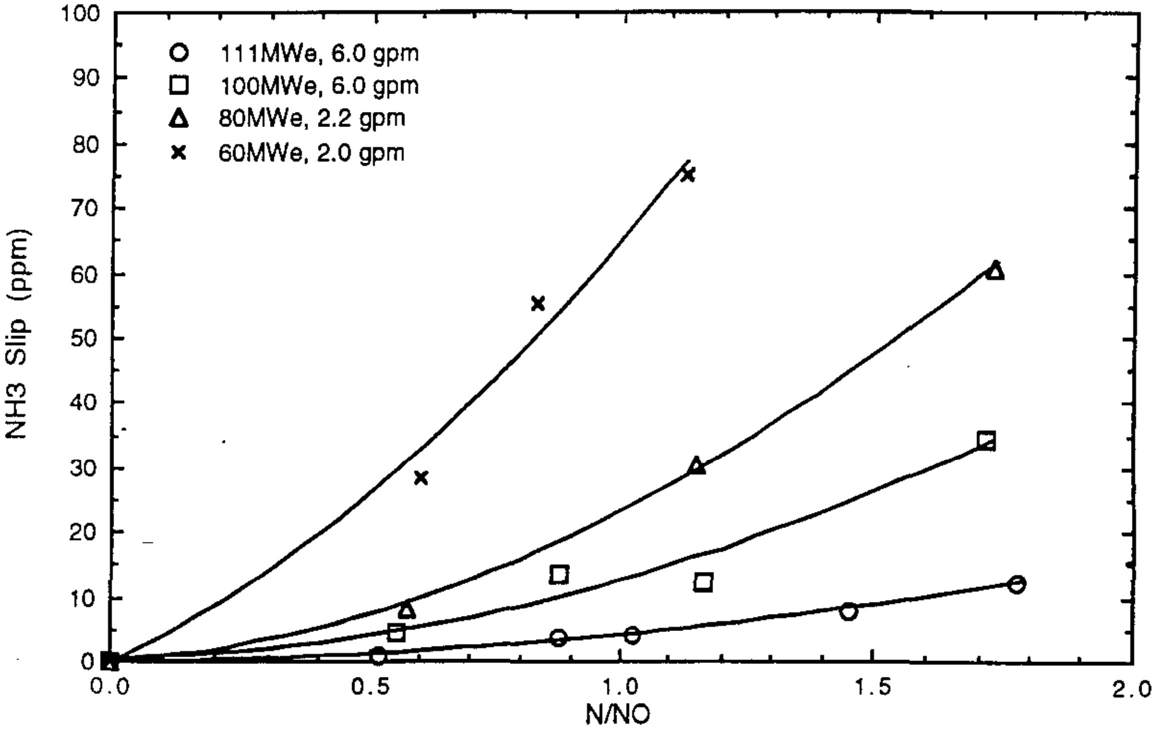
While there appear to be some variations in local SNCR performance that may be attributed to either, or both, chemical distribution and temperature stratification, overall the results indicate that the injection system is performing well in terms of injection and mixing. There don't appear to be any regions in the furnace that are largely devoid of chemical, or any where there is too much chemical.

5.3.2 Effect of Boiler Load and Chemical Injection Rate

The two most important parameters that will affect the SNCR performance are the boiler load and the chemical injection rate (N/NO molar ratio). Boiler load primarily affects the temperature in the region of chemical injection, although changing load will also change the available residence times. The effect of load and N/NO ratio is shown in Figure 5-8. Figure 5-8a shows NO reduction as a function of N/NO ratio for loads of 111, 100, 80 and 60 MWe. Figure 5-8b shows the corresponding levels of NH_3 slip. (The NH_3 slip values



a) NO Removal



b) NH_3 Emissions

Figure 5-8. Effect of Boiler Load and N/NO Ratio for Urea Injection (8 psig air) are a composite wet chemical measurement made through the six ports at the air preheater exit.) For these tests, total liquid flow rates of 6.0 gpm were used for the 100 and 111 MWe tests, while a flow rate of 2.0 to 2.2 gpm was used for the reduced load tests. As discussed in a later subsection, this range total liquid flow rate has a minimal effect on SNCR performance. Also, boiler operation at 80 MWe and above was with all four coal mills in service. The tests at 60 MWe were with three coal mills in service.

The trends in NO reduction and NH_3 slip with increasing N/NO ratio are as expected, as both are shown to increase with increasing N/NO ratio. At 100 MWe, 57 percent NO removal was achieved at a N/NO ratio of 1.7, with a corresponding NH_3 slip of 35 ppm. At a N/NO ratio of 1.15, 51 percent NO removal was achieved with less than 15 ppm NH_3 slip.

The performance at the various boiler loads provides insight into the region of the "SNCR temperature window" at which the injection system is operating. NO removals were maximum at 100 MWe. A slight decrease was seen at 80 MWe, and a larger decrease occurred as the load was further dropped to 60 MWe. Likewise, increasing the load from 100 to 110 MWe resulted in a decrease in NO reduction performance equivalent to the load change from 100 to 60 MWe. This suggests that peak temperatures for SNCR performance with urea occur near the injection level at a load of 90 to 100 MWe.

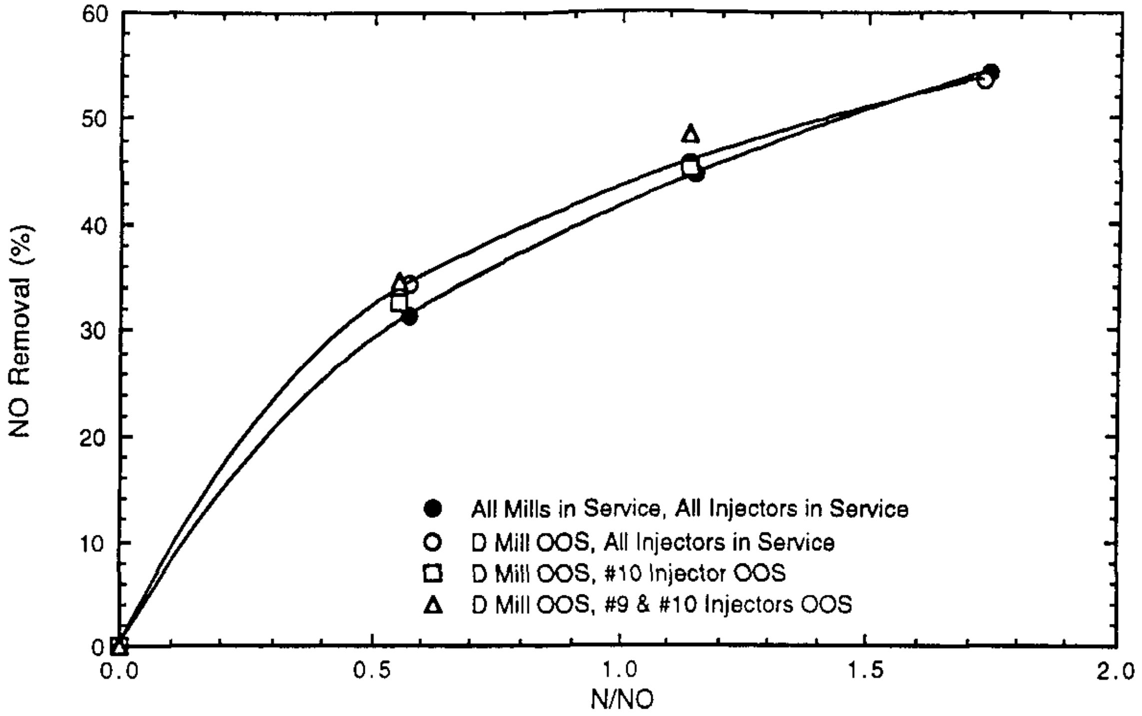
Figure 5-8b shows that the levels of NH_3 slip increase monotonically with decreasing load, consistent with decreasing flue gas temperatures at the point of chemical injection. The large increase in NH_3 slip levels seen between the 60 and 80 MWe cases could be due to two factors, with the primary factor being decreasing flue gas temperatures with decreasing load. A secondary factor could be the 3 mills in service operating condition at the lower load creating greater temperature and gas species non-uniformity at the point of urea injection. The effect of the number of mills in service is discussed in more detail in the section below.

5.3.3 *Effect of Mills Out of Service*

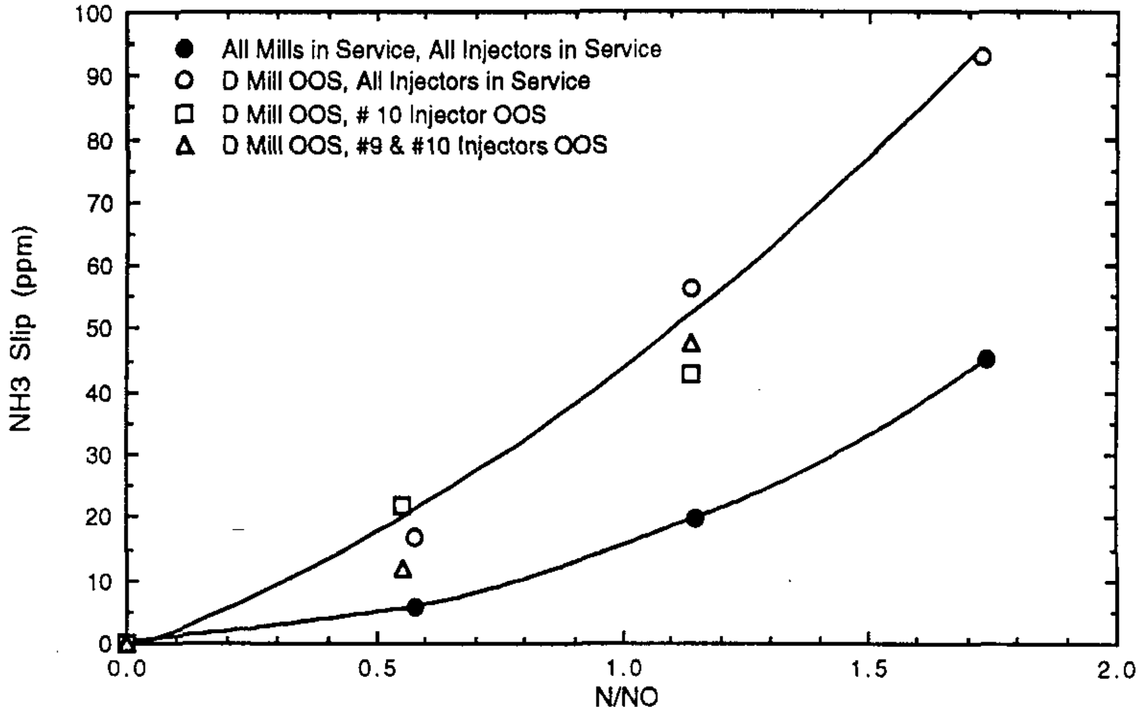
Arapahoe Unit 4 typically operates under normal dispatch conditions over the load range from 80 to 115 MWe with all four mills in service. If extended operation is anticipated at 80 MWe or below, one mill will be removed from service. Long-term operation at 60 MWe or less will typically be with two mills out of service (OOS). Since operation with various mills out of service is typical, it was important to determine the impact on SNCR performance. It was anticipated that various mill out of service operations would primarily affect NH_3 slip. To this end, tests were also conducted to see if it was possible to vary the number of chemical injectors in service to compensate for a particular coal mill being out of service.

Figure 5-9 compares the performance of the SNCR system at 80 MWe with all four mills in operation, to that with only three mills in service (D Mill OOS). Although operating with the three mill condition had essentially no effect on the NO removals, the NH_3 emissions more than doubled. This was not unexpected, as the maldistribution of coal feed to the furnace was expected to increase local temperature variations, thereby negatively impacting the NH_3 slip.

While operating with D Mill out of service, tests were conducted where the urea injectors on the east side of the furnace (Numbers 9 and 10) were taken out of service in an attempt to reduce the NH_3 emissions. Recall that D Mill feeds coal to two burners located on the far east side of the furnace, and likewise, Injectors 9 and 10 are also on the far east side. During these tests, the injection system was operated: 1) with all 10 injectors in service; 2) with injector Number 10 out of service; and 3) with both injectors 9 and 10 out of service. The results in Figure 5-9 indicate that there was no effect on NO removals, and only a marginal affect on NH_3 slip. The valves utilized to remove injectors from service are manually operated and located at the injection levels. The slight reduction in NH_3 slip does not warrant manually changing the number of injectors in service whenever a mill is removed from service. For automatic operation, a more likely approach will be to reduce the N/NO ratio if a constant level of NH_3 slip is to be maintained. However, it must be noted that this will also compromise the NO removals.



a) NO Removal



b) NH_3 Emissions

Figure 5-9. Effect of Mill in Service Pattern and Removal of Select Injectors from Service on Urea Injection at 80 MWe (6 gpm total liquid flow, 8 psig air)

Figure 5-10 shows the results of two tests conducted at a load of 60 MWe. The first test was performed with D Mill out of service and the second test with both A and D Mills out of service. For both tests, the urea was injected at a nominal N/NO ratio of 0.6.

With just D Mill out of service, 30 percent NO removal was achieved with 31 ppm NH_3 slip. With both A and D Mills out of service, the NO removal dropped to 21 percent and the NH_3 slip to 23 ppm. The drop in NO removal might be expected due to greater temperature variations in the furnace. However, the drop in NH_3 slip was not expected. Larger temperature variations at the injection region with two coal mills out-of-service would have expected to create colder regions with higher NH_3 slip. Further testing is warranted during the integrated phase of the test program to confirm this observation.

5.3.4 Effect of Total Liquid Flow Rate

For the current phase of testing, the urea was stored as a nominal 37.5 weight percent solution which was diluted at the pump skid prior to injection. At 100 MWe and an injection rate corresponding to N/NO = 1, the flow rate of the 37.5 percent solution is nominally 1.3 gpm. (This will vary somewhat depending on the initial NO level.) The pump skid can provide dilution water such that the total liquid flow rate can be varied from nominally 2 gpm up to 9 gpm. During the baseline SNCR tests, the injection system was set up to operate from nominally 6 to 28 gpm. From an operational point of view, it is desirable to operate with as little dilution water as possible since this water has a direct impact on heat rate. High dilution water flow will also result in local flue gas cooling which can affect steam temperature control.

Figure 5-11 shows the effect of changing the total liquid flow rate from 2.1 gpm to 6 gpm while maintaining a N/NO ratio of 1.15 at 100 MWe. The NO removal increased from 46 percent to a little over 50 percent with a slight decrease in NH_3 slip. However, the change in NH_3 slip (14 ppm versus 12 ppm) is within the range of experimental repeatability and probably not significant. The data shown in Figure 5-8 suggested that peak NO removals would be expected at a boiler load of 90 to 100 MWe; for the 100 MWe tests reported in Figure 5-8 with a total solution flow of 6 gpm was utilized. As seen

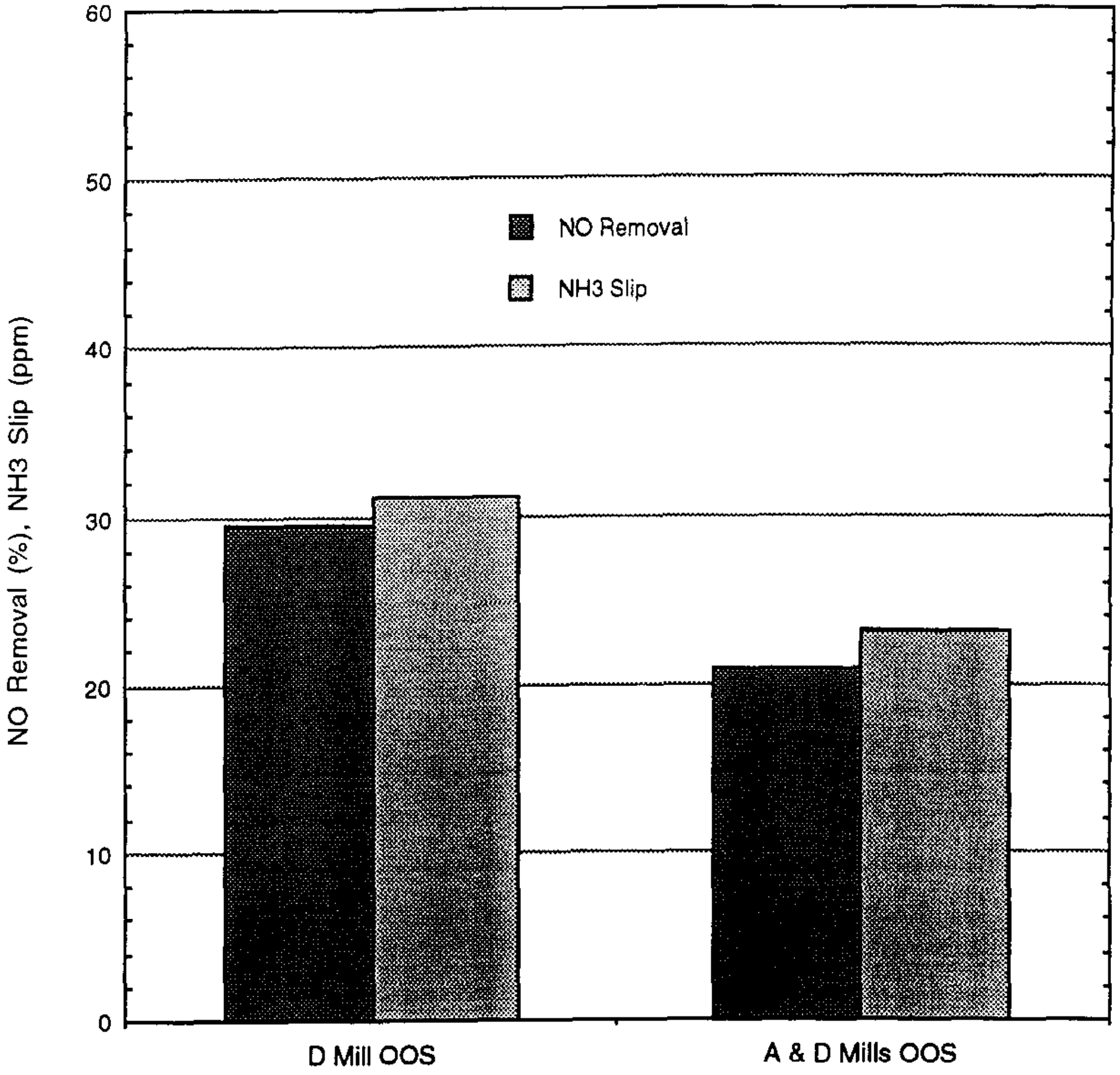


Figure 5-10. Effect of Mill in Service Pattern on Urea Injection at 60 MWe (N/NO = 0.6, 2.1 gpm total liquid flow, 8 psig air)

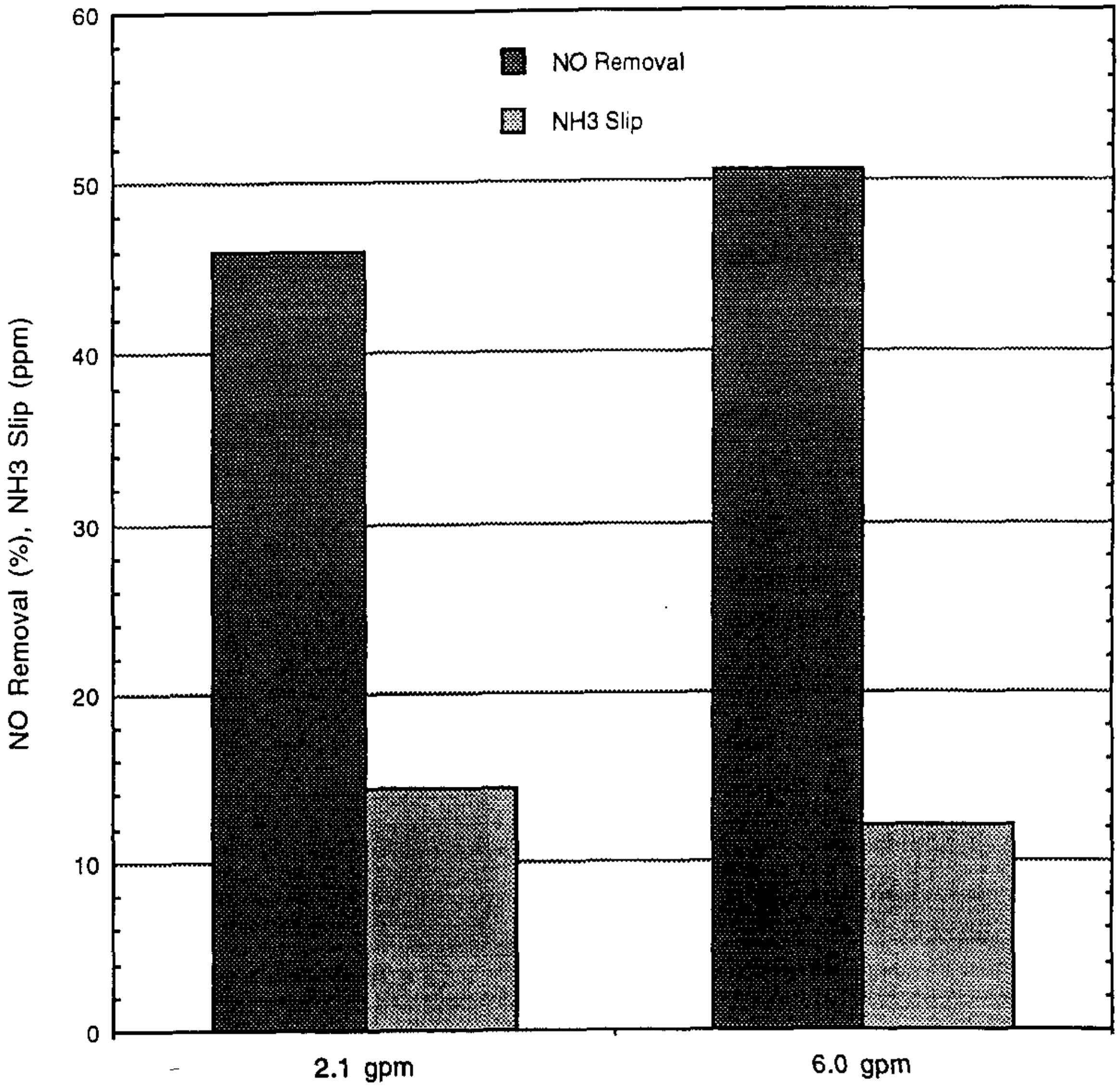


Figure 5-11. Effect of Total Liquid Flow Rate on Urea Injection at 100 MWe (N/NO = 1.15, 8 psig air)

in Figure 5-11, decreasing the solution flow from 6 to 2.1 gpm decreased the NO removal which would be consistent with a decrease in local cooling due to vaporization and heating of the injected solution. For reference, injecting 6 gpm of water at 100 MWe will locally cool the combustion products nominally 18°F during vaporization. The cooling will actually be somewhat less due to the exothermic nature of the urea/NO reactions.

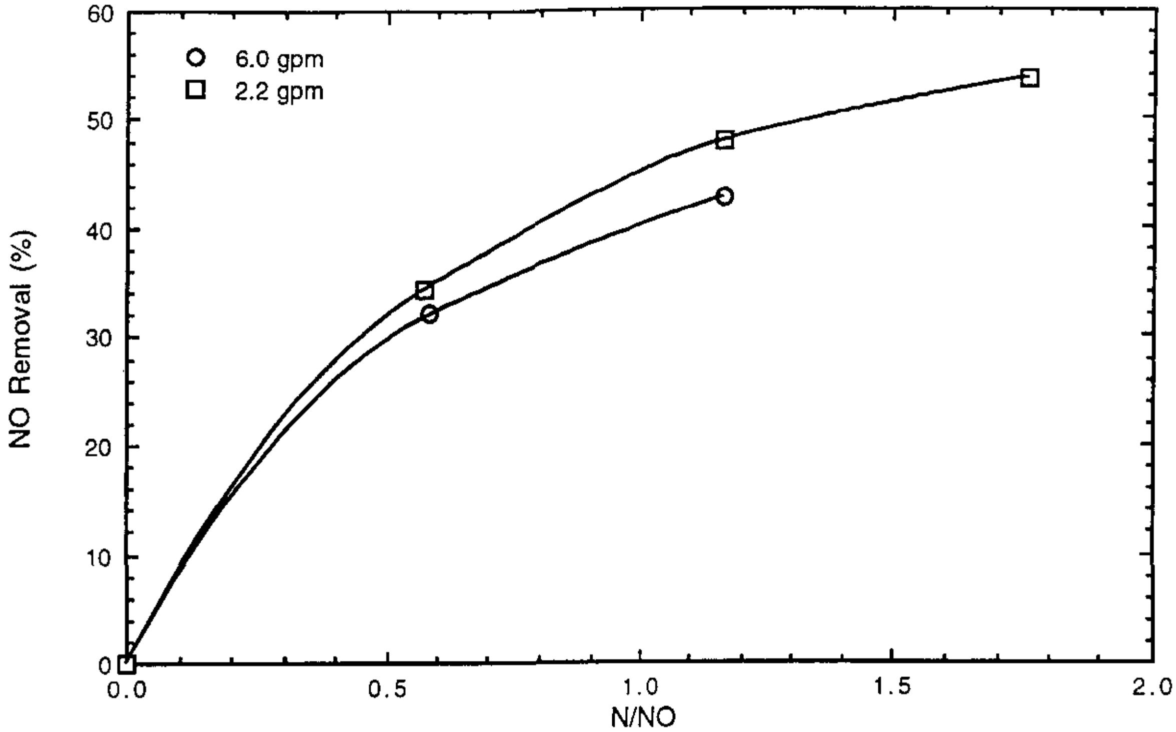
At a reduced load of 80 MWe, decreasing the total liquid flow rate from 6.0 to 2.2 gpm increased NO removal as shown in Figure 5-12. At this load, no impact on NH_3 slip was observed. Consistent with the previous results, this would suggest that 80 MWe is just on the low temperature side of the window. Increasing the total liquid flow rate increased the local cooling effect, thereby decreasing the NO removals.

While the effect of total liquid flow rate can largely be explained by local cooling effects, varying the flow rate can impact other factors. With the NOELL, Inc., SNCR system, mixing is dominated by the transport air used with the injectors. However, varying the solution flow rate could alter the drop size of the spray slightly, or change the evaporation history of the drops. These factors may also be influencing the results shown in Figures 5-11 and 5-12, although there is no definitive way to separate these effects from the local cooling effect.

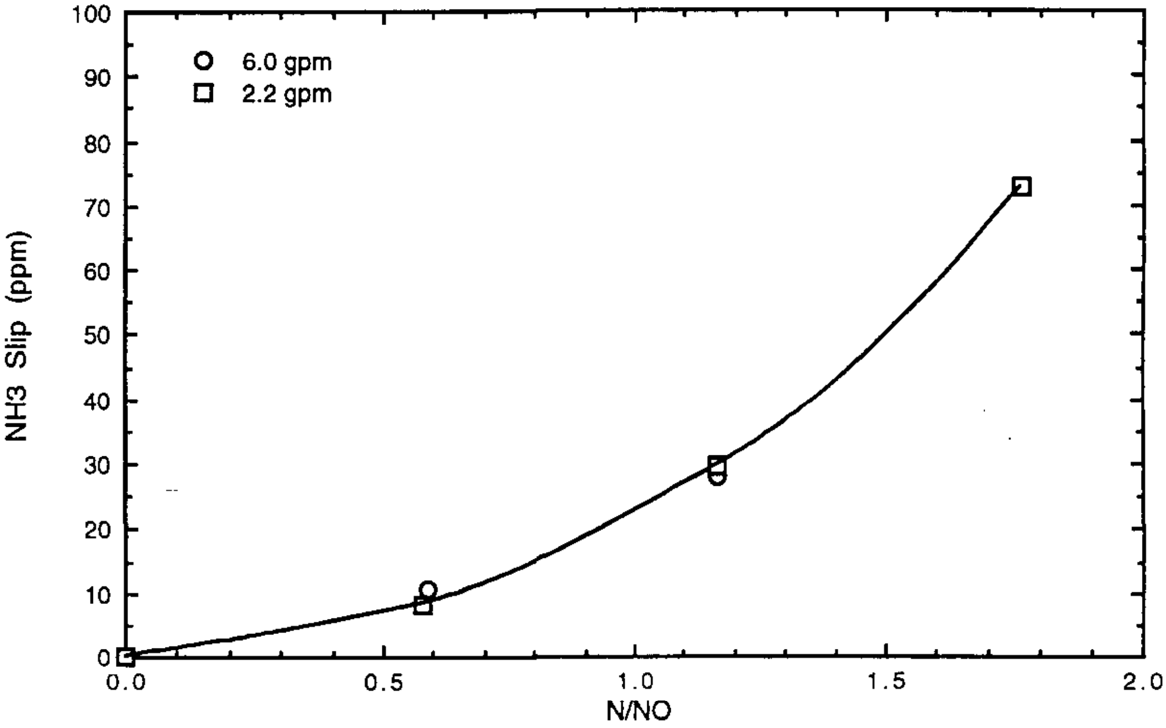
The results shown above indicate that up to a load of 80 MWe, the total liquid flow rate should be kept at the minimum value of nominally 2 gpm. No specific tests varying solution flow rate were conducted at 60 MWe. However, the data shown in Figure 5-8 indicate that the SNCR injectors are clearly on the low side of the temperature window at this boiler load, and the local cooling effect should be minimized.

5.3.5 Effect of Mixing Air Pressure

The NOELL, Inc., SNCR system uses a flow of medium pressure air to provide the primary source of energy to mix the injected chemical with the flue gas. During the current test program, the mixing air pressure was varied from 4 to 12 psig, and the injector air orifice sizes were held constant. Injector air orifice size was shown to have



a) NO Removal



b) NH_3 Emissions

Figure 5-12. Effect of Total Liquid Flow Rate on Urea Injection at 80 MWe (8 psig air) little effect on system performance during the baseline SNCR tests.(3) With fixed air orifice sizes, changing the air supply pressure from 4 to 12 psig increases the mixing air flow rate by approximately 73 percent. The effect of increasing the mixing air pressure at boiler loads of 60, 80 and 100 MWe are shown in Figures 5-13 to 5-15, respectively. At 60 MWe, increasing the air pressure from 5 to 12 psig increased NO removal from nominally 24 to 29 percent. The NH_3 slip also appears to increase with increasing air pressure, although the increase is small.

At 80 MWe (Figure 5-14), increasing air pressure again resulted in increased NO removals. The majority of the increase occurred with a pressure change from 4 to 8 psig, and there was essentially no benefit of a further increase to 12 psig. NH_3 emissions were reduced with an air pressure increase from 4 to 8 psig, and a further increase to 12 psig resulted in a slight increase in the NH_3 slip. Similar trends are seen in Figure 5-15 for a load of 100 MWe, where increasing the air pressure from 8 to 12 psig increased both NO removal and NH_3 slip slightly.

While the impact of mixing air variation on SNCR performance was generally small for pressure variations of 4 to 12 psig, a number of factors could be at play. First, increasing the mixing air flow rate (i.e., pressure) will increase the overall level of mixing. This would be expected to enhance overall SNCR performance. However, the increased mixing air flow can increase local cooling which would tend to degrade SNCR performance at loads under 100 MWe. Finally, it appears that there may be a cool region of the gas, caused by a recirculation zone at the wall opposite the injectors. Increased air flow will increase penetration into this region, which could contribute to the observation of both increasing NO removal and increasing NH_3 slip for some of the tests.

The overall effect of the mixing air flow rate is generally small for the range of air pressures and corresponding flow rates tested. The actual flow rate used for long-term operation will be a trade-off between the modest increases in SNCR performance and the operating costs of providing the air flow. Based on the parametric tests to date, a constant air flow rate corresponding to an air pressure of 8 psig is optimal.

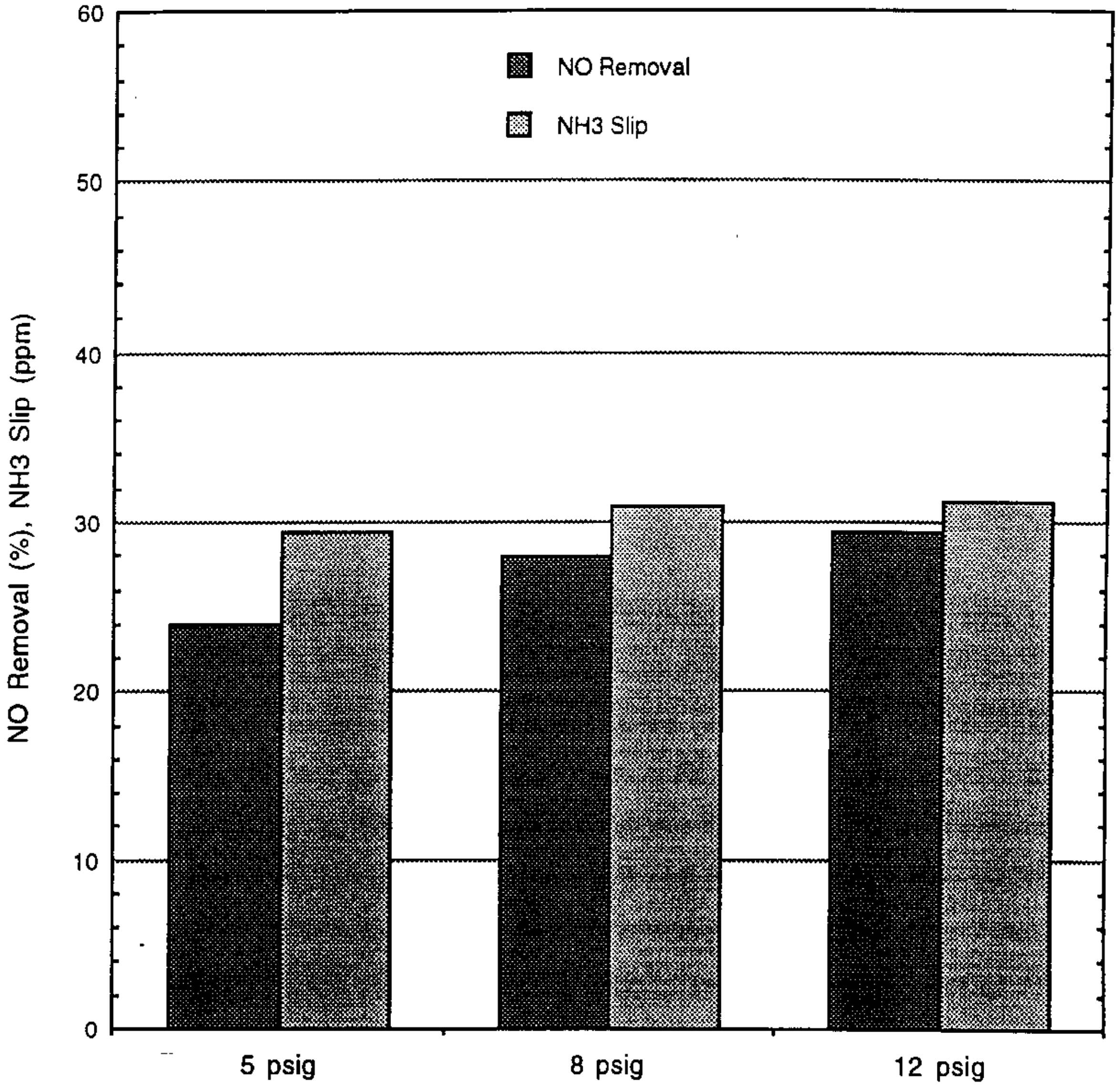


Figure 5-13. Effect of Mixing Air Pressure on Urea Injection at 60 MWe (N/NO = 0.6, 2.1 gpm total liquid flow)

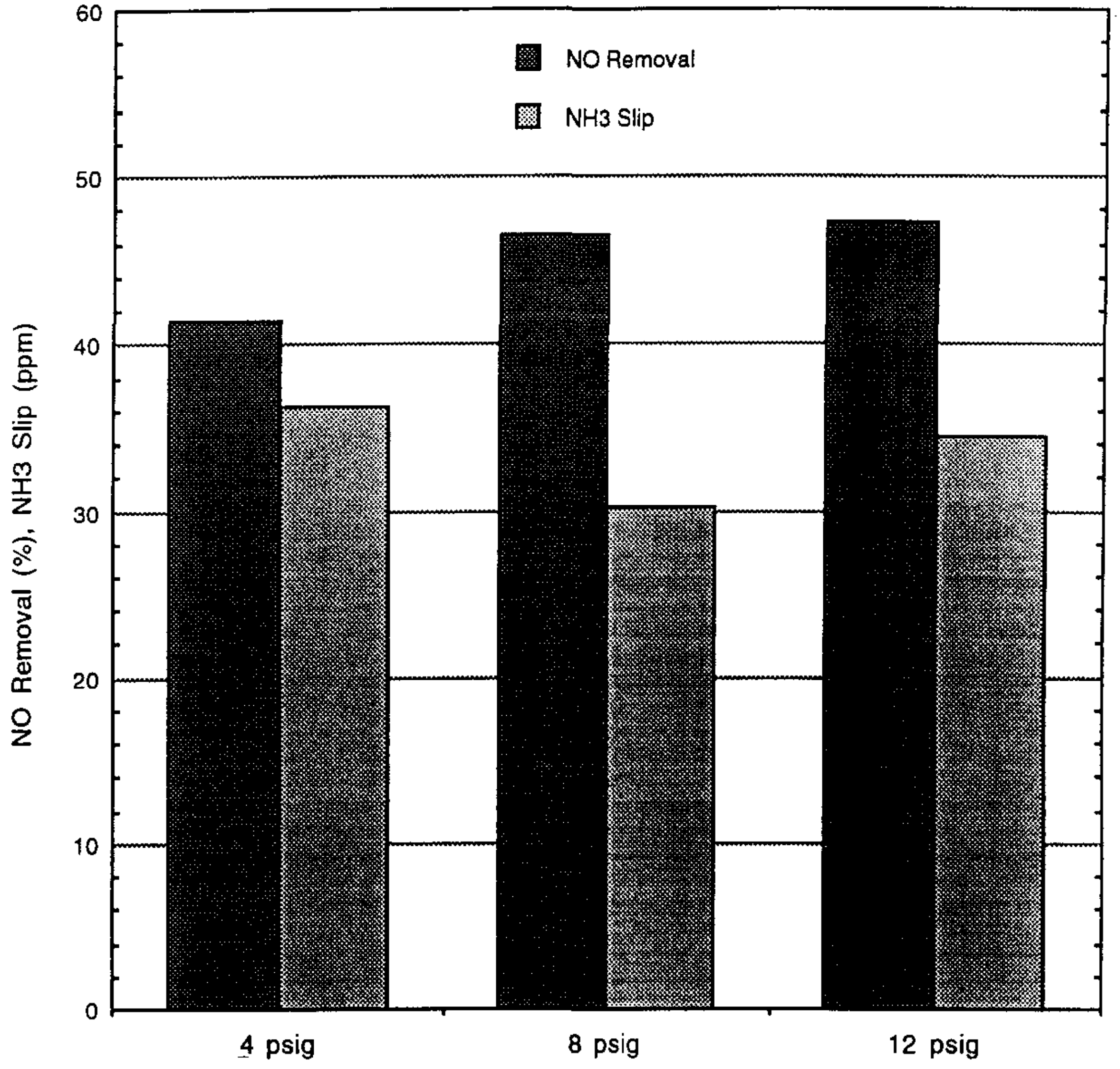


Figure 5-14. Effect of Mixing Air Pressure on Urea Injection at 80 MWe (N/NO = 1.15, 2.2 gpm total liquid flow)

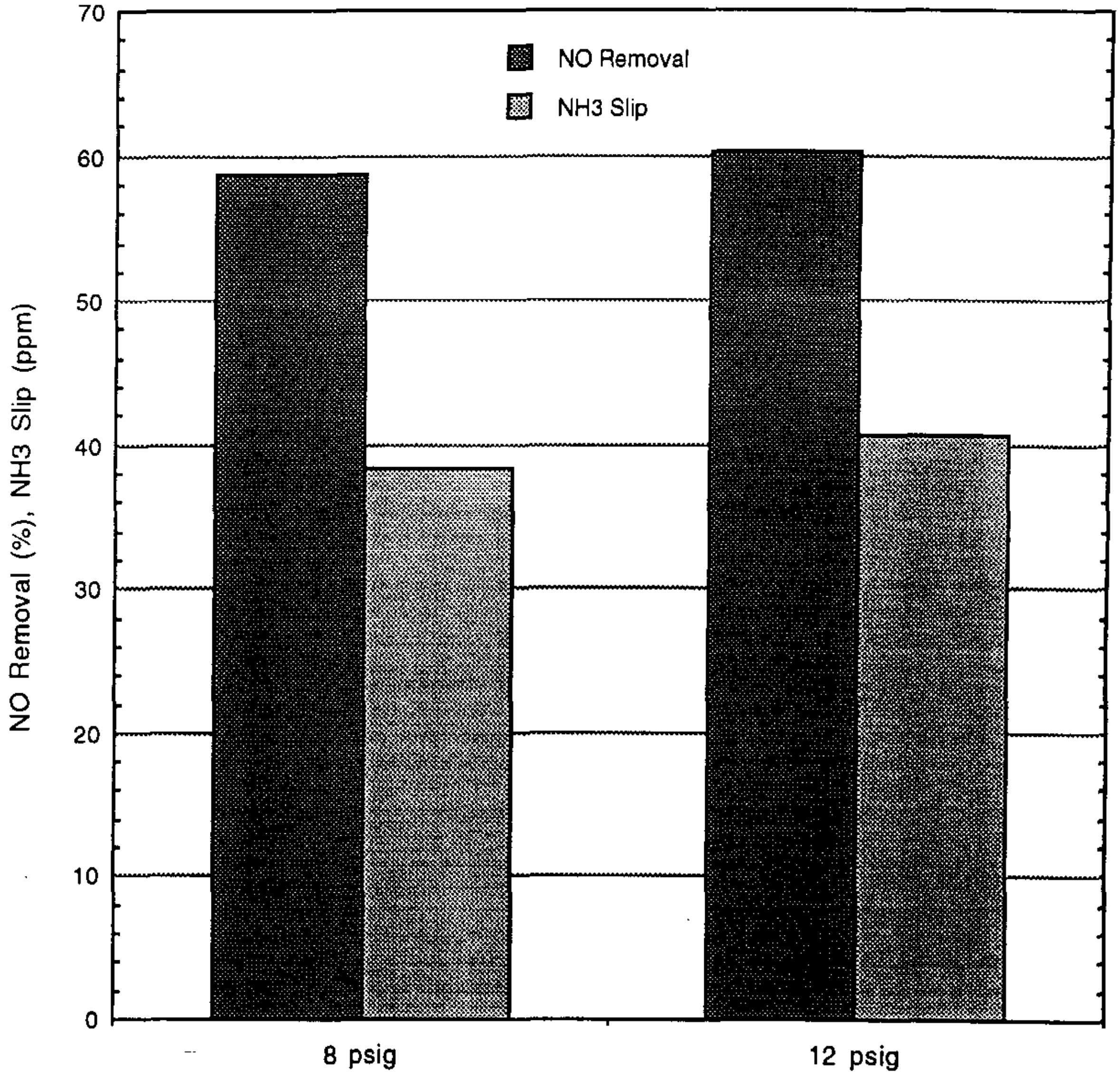


Figure 5-15. Effect of Mixing Air Pressure on Urea Injection at 100 MWe (N/NO = 1.7, 6 gpm total liquid flow)

5.3.6 *Effect of Bi-Level Injection*

During the baseline SNCR test program(3), the upper level of injectors (Level 2) was found to be in too cold a region with limited residence time for effective SNCR performance. Since the combustion product temperatures further decreased with the low-NO_x burner retrofit, there was little expectation that the upper level of injectors would be of much benefit. However, a limited number of tests were conducted to investigate if there was any performance benefit to distributing the urea between both levels of injectors. These tests were conducted at a load of 113 MWe with 6 gpm total liquid flow, and a N/NO ratio of 1.15. These tests were run without biasing the coal mills, and with all Level 1 injectors with 0.035-inch diameter liquid orifices and Level 2 injectors with 0.024-inch orifices. With this arrangement, 67 percent of the solution was injected through the bottom level of injectors and 33 percent through the top level. The tests were conducted at mixing air pressures of 4 and 8 psig (the pressure for both levels being the same). The results (Figure 5-16) showed no benefit to bi-level injection in terms of NO removal. Since no benefit was seen at this high load condition where temperatures are highest, no further bi-level testing was pursued with urea injection.

5.3.7 *N_2O Emissions*

N_2O emissions were also monitored during the urea injection tests. While not a regulated species, there is interest in N_2O emissions due to potential impacts on stratospheric ozone chemistry and potential contributions to the greenhouse effect. Prior pilot-scale and full-scale studies have shown N_2O to be a product of the urea injection process(9,10). As discussed in Section 3.1, N_2O is currently thought to form through a mechanism of the form:

$$NH_2CONH_2 \longrightarrow NH_3 + HNCO \quad (1)$$

$$HNCO + OH \longrightarrow NCO + H_2O \quad (2)$$

$$NCO + NO \longrightarrow N_2O + CO \quad (3)$$

Whether the N_2O remains and is emitted from the stack, or is reduced in the flue gas stream depends primarily on the following destruction reaction mechanism:

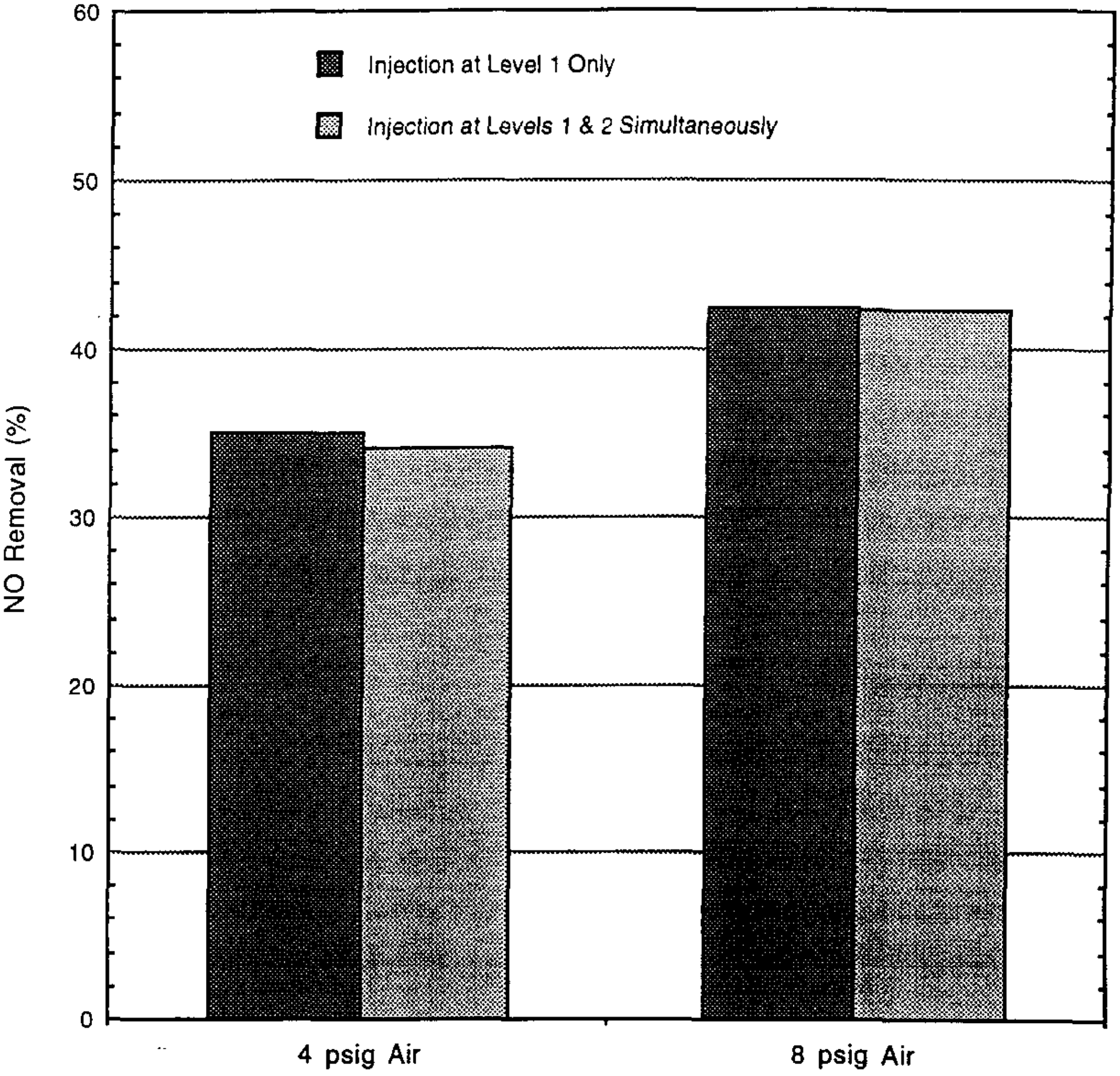


Figure 5-16. Effect of Bi-Level Injection of Urea at 113 MWe
(N/NO = 1.15, 6 gpm total liquid flow)

$$N_2O + H \longrightarrow N_2 + OH \quad (4)$$

$$N_2O + OH \longrightarrow N_2 + HO_2 \quad (5)$$

$$N_2O + M \longrightarrow N_2 + ... \quad (6)$$

In reaction (6), "M" represents one of any number of "general molecules" which can react with N_2O and reduce it to N_2. Reaction (3) shows that N_2O is formed as a direct consequence of a reaction with NO; thus, it is appropriate to quantify the N_2O formation in terms of the amount of N_2O formed divided by the amount of NO reduced. This is essentially the fraction of NO reduced that was converted to N_2O.

The baseline SNCR tests showed that with the original combustion system and initial NO levels of about 850 ppmc, the amount of N_2O produced was 7 to 17 percent of the NO reduced(3). The data also indicated that the highest levels of N_2O were produced at reduced loads.

The N_2O production from urea injection measured during the current phase of testing is shown in Figure 5-17. With the retrofit combustion system, the N_2O conversion ranged from 20 to 35 percent, with the lowest levels occurring at reduced loads. This is markedly different from the results seen with the original combustion system. First, the overall levels of N_2O production are higher in terms of the percent conversion of NO to N_2O. Secondly, with the original combustion system, N_2O production was seen to increase with decreasing boiler load. With the retrofit low-NO_x combustion system, the N_2O production was seen to decrease with decreasing load. While no definitive explanation for this effect can be offered, it can be speculated that it is related to the reduction of the flue gas temperatures in the injection region seen after the retrofit.

N_2O exhibits a temperature window for formation which is similar to the SNCR temperature window for NO reduction(10,11). In the case of the original combustion system, urea injection was likely on the high temperature side of the N_2O formation window so that decreases in boiler load (i.e., flue gas temperature) resulted in increased N_2O production. Recall that the furnace exit gas temperatures were shown to be 180 to 240°F lower after the retrofit than before (Figure 5-1). Therefore, with the retrofit combustion

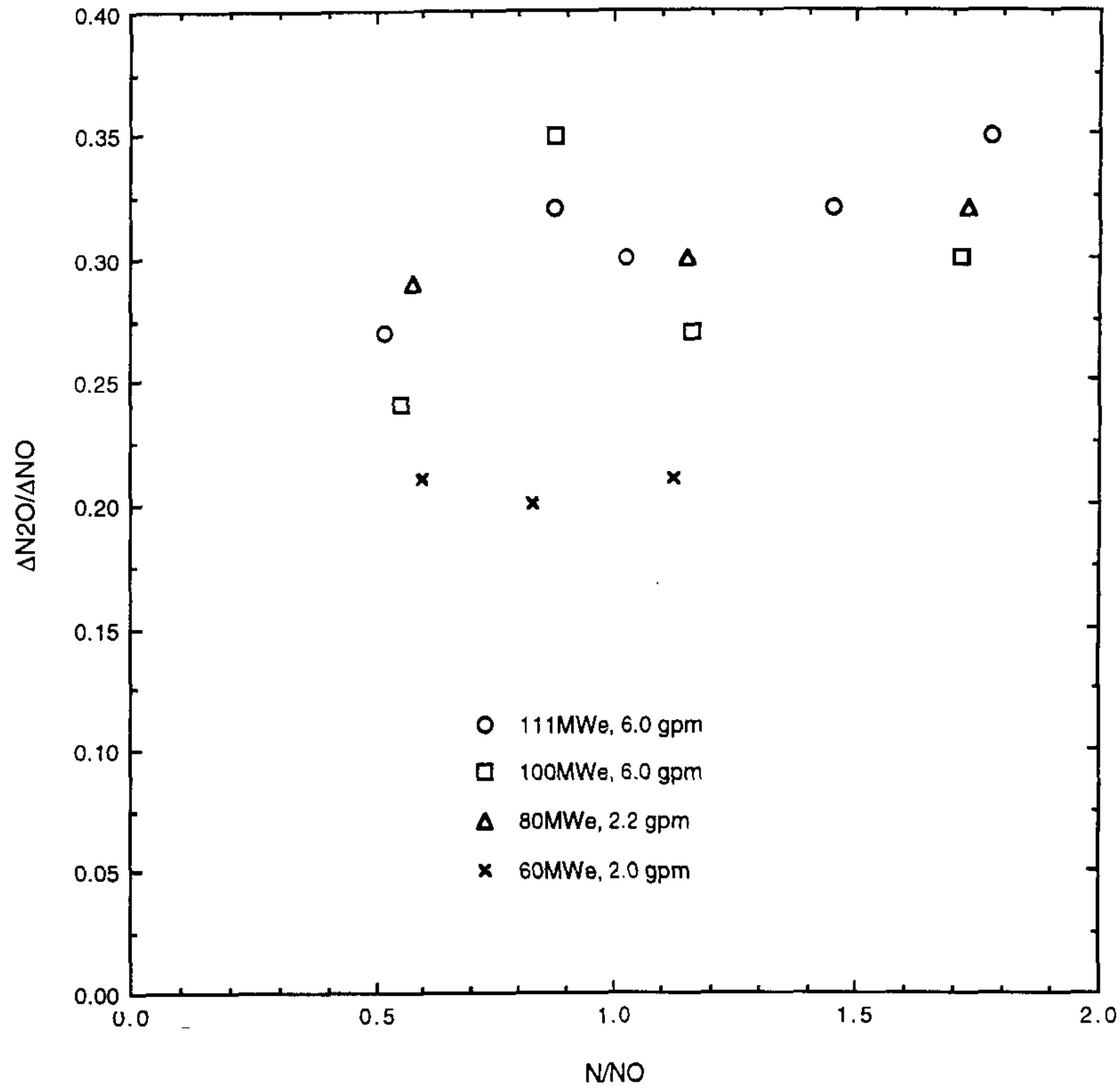


Figure 5-17. N_2O Emissions with Urea Injection (8 psig air)

system, urea injection is now likely on the lower temperature side of the window, resulting in decreasing N_2O production with decreasing load.

Furthermore, it is expected that residence time may also play a role. It has been shown that residence time is important since the N_2O decomposition reactions occur relatively slowly(10). Therefore, changes in available residence times at a given temperature may also be contributing to the higher N_2O production.

A final point to be made is the change in the initial NO level. With the original combustion system, the initial NO level was nominally 850 ppmc and with the retrofit burners it was 250 to 300 ppmc. The role that the initial NO level plays in the fraction of the NO reduced which is converted to N_2O is unclear. However, even with the higher overall conversions, the absolute level of N_2O emissions with the retrofit burners is lower than that measured with the original combustion system. At 100 MWe and a nominal N/NO ratio of 1.0, N_2O emissions with the original combustion system were nominally 54 ppmc, compared to 37 ppmc with the retrofit burner system.

5.3.8 CO Emissions

There is the potential for increases in CO emissions with application of SNCR to a utility boiler. This increase can be due to two mechanisms. First, if urea is used as the SNCR chemical, the carbon present in the urea can contribute to the CO levels. This occurs when the CO released from the urea decomposition reaction is not oxidized to CO_2. Second, CO generated from the combustion process is oxidized to CO_2 primarily through the reaction

$$CO + OH \longrightarrow CO_2 + H \qquad (7)$$

With either urea or ammonia injection, OH is utilized in the SNCR reaction process (recall Figure 3-3). If CO is still being oxidized in the vicinity where the SNCR chemistry is taking place, the SNCR reactions can compete for the OH radicals. This can result in an inhibition in the oxidation of the CO from the combustion process.

The baseline SNCR tests showed that with the original combustion system, CO production for urea injection decreased with increasing boiler load, and increased with increasing N/NO ratio. At a nominal N/NO ratio of 1.0, maximum CO emissions were approximately 35 ppm. With the retrofit low-NO_x combustion system, CO emissions at a N/NO ratio of 1.0 were at most 20 ppm, and there was no obvious trend with either boiler load or N/NO ratio.

5.4 Converted Urea Test Results

In addition to assessing the SNCR system performance with urea, the test program also investigated the SNCR performance when the urea was processed through a catalytic converter before injection. As discussed in Section 3.3, the converter catalytically converts the liquid urea solution to a solution of ammonium compounds. This subsection will present the results of this portion of the test program, and the results will be presented in a manner which generally parallels the previous subsection on the urea injection results:

5.4.1 Converter Performance

5.4.2 Effect of Boiler Load and Chemical Injection Rate

5.4.3 Effect of Total Liquid Flow Rate

5.4.4 Effect of Mixing Air Pressure

5.4.5 Effect of Bi-Level Injection

5.4.6 Effect of Coal Properties

5.4.7 Nitrous Oxide (N_2O) Production

5.4.8 CO Emissions

Before the results of the converted urea tests are presented, it is of value to discuss how the tests were actually run, since it was necessary to modify the test procedure slightly when using the conversion system. During the urea injection tests reported in the previous subsection, the conversion system was bypassed and the urea was pumped directly from the metering skid, where the final dilution occurred, to the injection level on the boiler. An optimum total liquid flow rate was determined for each boiler load based upon where the system was operating on the SNCR temperature curve for urea. Variations in N/NO ratio for a fixed load were achieved by changing the concentration of the injected urea solution (i.e., changing the flow rate of the 37.5 weight percent urea solution while holding the total liquid flow rate constant). Since the internal volume of the liquid transfer lines between the metering skid and the injectors was very small, the time required for the system to react to changes in N/NO ratio was short. However, when the tests with the converted urea solution began, it was found that this approach was not practical because the internal volume of the converter was so much larger than the volume of the liquid transfer lines. The time required for the conversion system to stabilize after a change in solution concentration could be as long as two to three hours depending on the total liquid flow rate. It was decided that the best approach was to hold the concentration of the injected solution constant, and vary the N/NO ratio by changing the total liquid flow rate. Unfortunately, this approach also had its limitations, in that if the total flow rate was changed too quickly, converter temperatures and pressures would become unstable and start to oscillate. Unless otherwise noted, the results presented in this report for injection of the converted urea solution are for operation with total liquid flow rates of nominally 2, 4 and 6 gpm for nominal N/NO ratios of 0.5, 1.0 and 1.5, respectively.

5.4.1 Converter Performance

In an effort to quantify the performance of the conversion system, samples of the converted urea solution were obtained on a regular basis during the current phase of testing. The samples were diluted 1,000:1, and analyzed for ammonia content using a specific ion electrode. A total of twenty seven samples were analyzed, but many of them were collected before consistent and reliable operation of the conversion system was achieved. Calculated conversion efficiencies (urea to ammonium compounds) for the samples collected during the later, more well controlled, tests ranged from 75 to 100 percent (Figure 5-18).

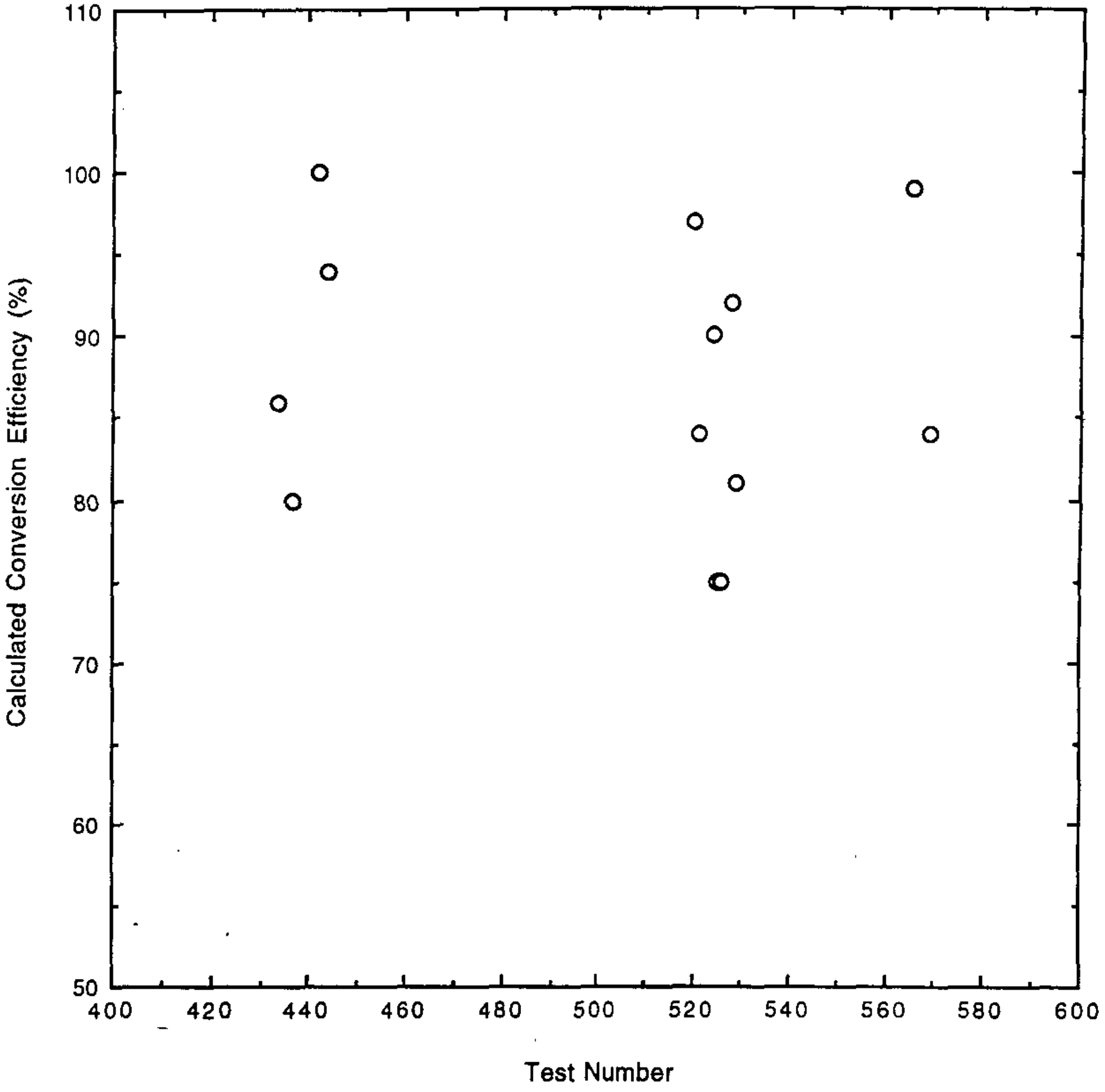


Figure 5-18. Calculated Conversion Efficiencies (Urea to Ammonium Compounds) for Tests 434 to 569

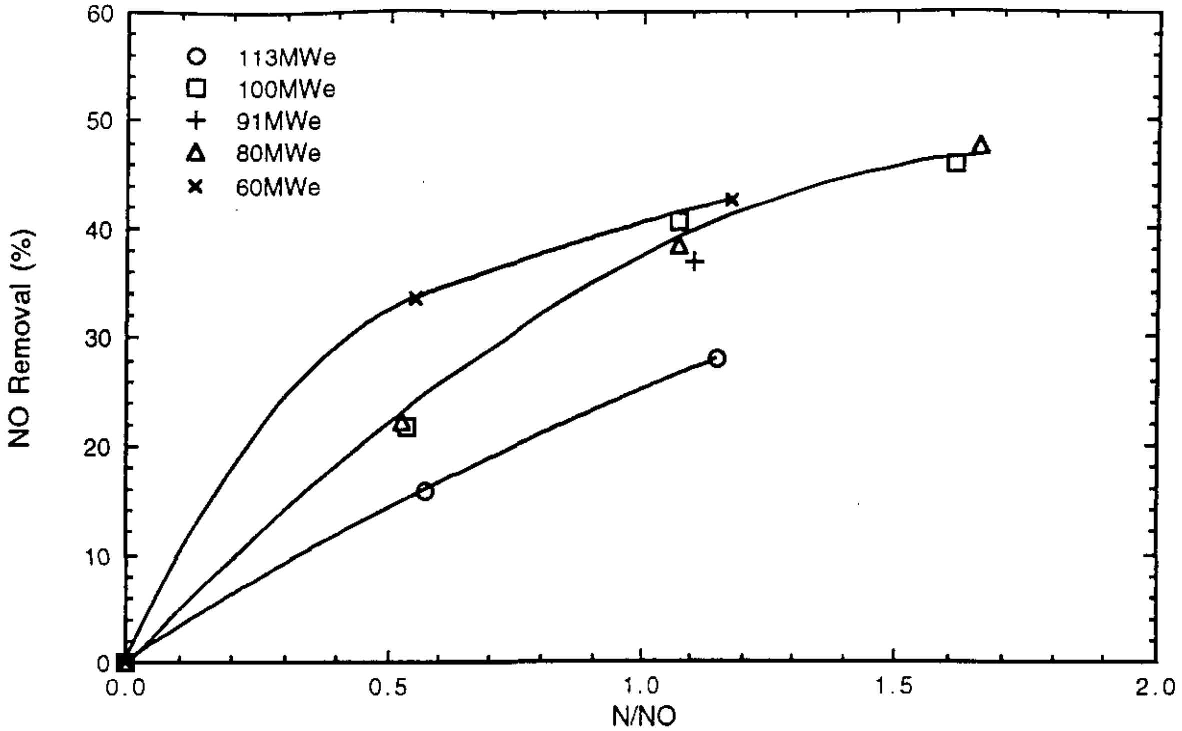
5.4.2 Effect of Boiler Load and Chemical Injection Rate

The effect of boiler load and chemical injection rate (N/NO ratio) is shown in Figure 5-19 for operation with the converted urea solution. As with the urea injection tests, operation at boiler loads of 80 MWe and above was with all four mills in service. The 60 MWe tests were conducted with three mills in service (D Mill OOS). The results shown in Figure 5-19a indicate that maximum NO removals occur at 60 MWe. Although, with the exception of the 60 MWe data point at N/NO = 0.6, there is little difference in the NO reduction performance of the converted urea over the load range from 60 to 100 MWe. At 113 MWe, NO removals decreased due to the higher temperatures at the injection location. Some of the differences in the performance of the converted urea at 60 MWe may be attributed to changes in the performance of the converter. During this phase of testing, operating procedures for the converter were being fine-tuned in terms of controlling converter temperatures and pressures.

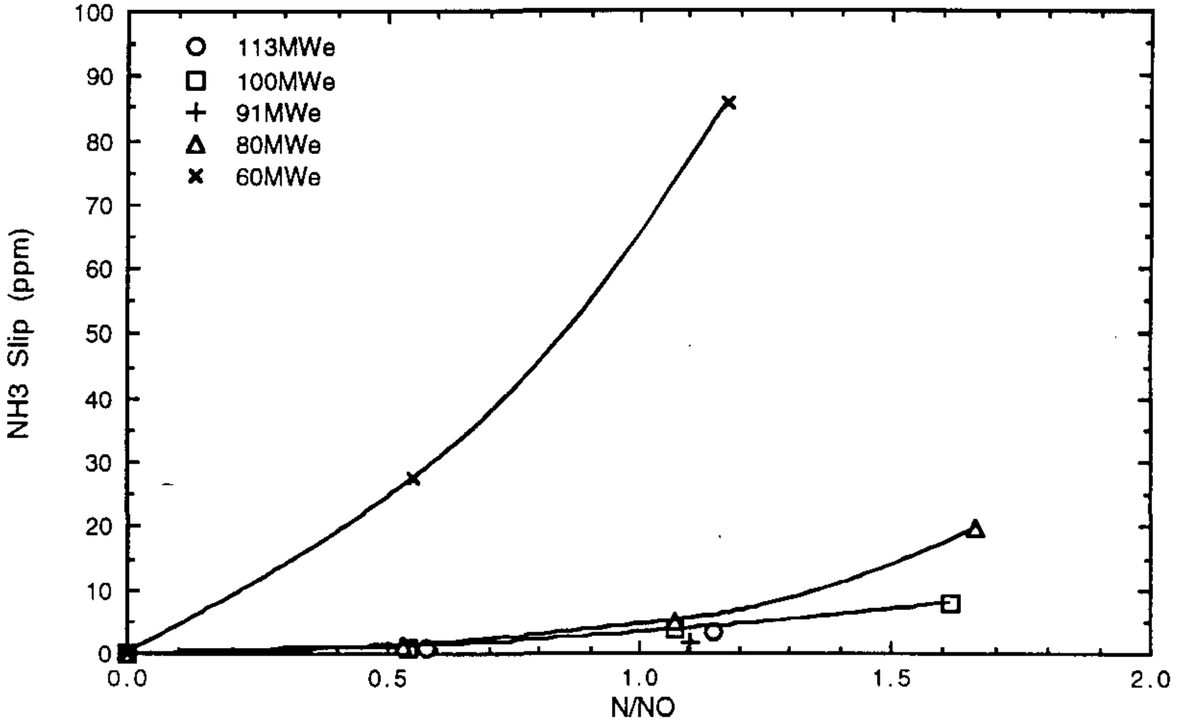
The NH_3 emissions in Figure 5-19b indicate generally low levels of NH_3 with the converted urea solution. Except for the 60 MWe tests, NH_3 emissions were less than 20 ppm even at N/NO ratios approaching 1.7. As with the urea injection results, the higher NH_3 slip levels at 60 MWe can be due to both lower flue gas temperatures at the injection location, and boiler operation with only three mills in service.

5.4.3 Effect of Total Liquid Flow Rate

The effect of total liquid flow rate on SNCR performance with the converted urea solution is shown in Figure 5-20 for boiler loads of 60, 80 and 91 MWe. For all of these tests, the N/NO ratio was nominally 1.15. The data indicate that changing the total liquid flow rate with the N/NO ratio fixed, had little effect on both NO removal and NH_3 emissions. At 60 and 91 MWe, increasing the total liquid flow rate from nominally 2 to 4 gpm resulted in slight increases in NO removal. At 80 MWe, increasing the solution flow rate slightly increased the NH_3 slip levels. Since there has not been a great amount of operating experience with the converter system, it is difficult to conclude whether the differences in Figure 5-20 are 1) significant, 2) due to the impact of total liquid flow rate on furnace



a) NO Removal



b) NH_3 Emissions

Figure 5-19. Effect of Boiler Load and N/NO Ratio on Converted Urea Injection (8 psig air)

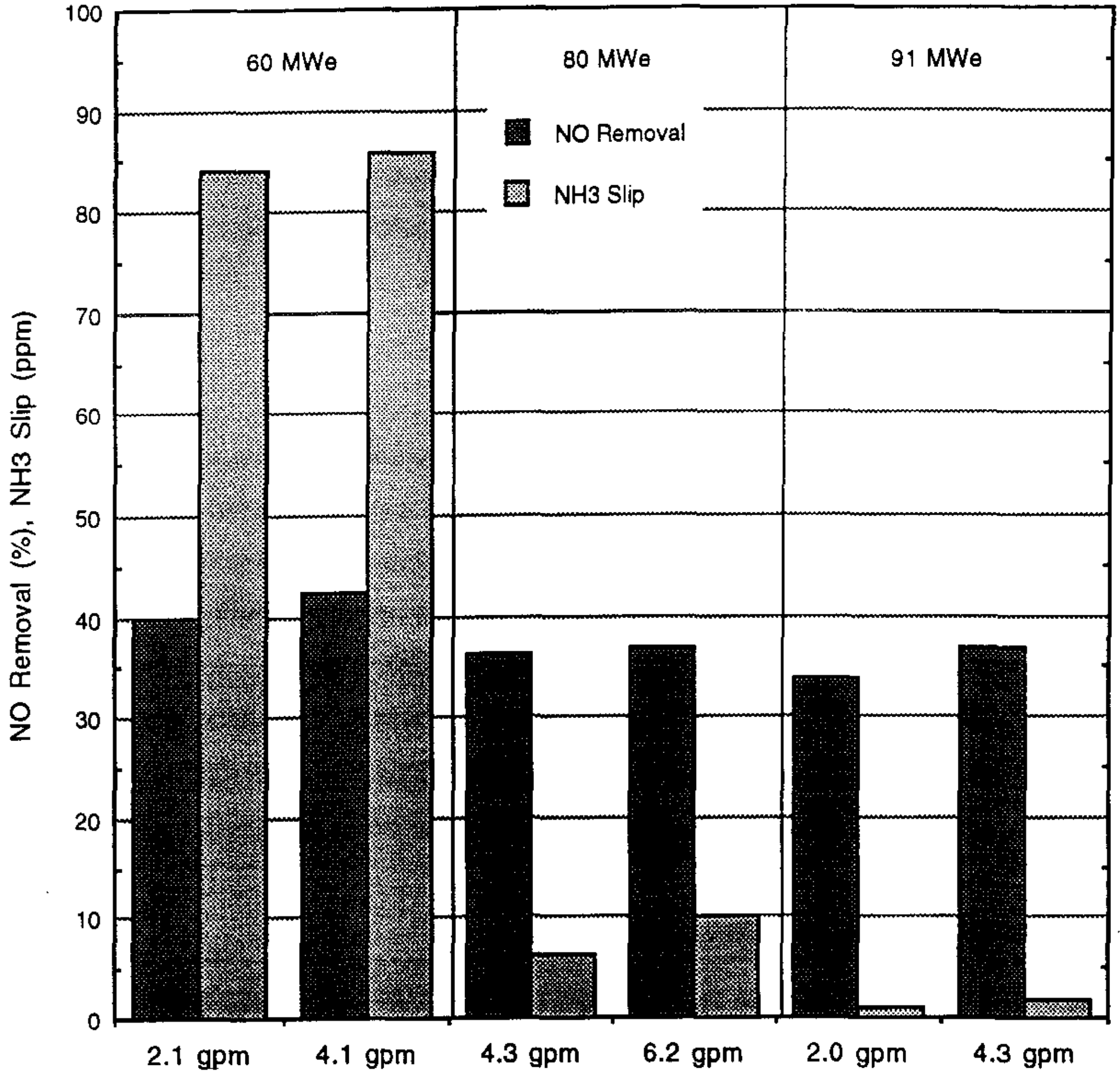


Figure 5-20. Effect of Total Liquid Flow Rate on Converted Urea Injection (N/NO = 1.15, 8 psig air)

parameters, or 3) due to differences in converter performance with different solution concentrations.

5.4.4 Effect of Mixing Air Pressure

The effect of mixing air pressure on SNCR performance with the converted urea solution was assessed at 80 MWe with a nominal N/NO ratio of 1.15. during these tests, the mixing air pressure was varied from 4 to 12 psig. Recall that this increases the mixing air flow rate by nominally 73 percent when the air orifice size remains constant. The results of these tests are shown in Figure 5-21, and indicate no significant impact on either NO reduction performance or NH_3 emissions.

5.4.5 Effect of Bi-Level Injection

Since the converted urea solution appears to operate at a lower temperature window than the baseline urea solution, a test using bi-level injection was conducted at a boiler load of 113 MWe. The injector configuration was identical to that for the bi-level injection tests with urea discussed in Subsection 5.3.6. The results at a nominal N/NO ratio of 1.15 are shown in Figure 5-22, and indicate no beneficial effect on NO reduction performance. Since there was no benefit at the high temperature condition of 113 MWe, one would not expect enhanced performance at lower loads. Thus, additional bi-level injection tests with the converted urea solution at reduced boiler loads were not conducted.

5.4.6 Effect of Coal Properties

Arapahoe Unit 4 burns coal from two different sources. While the properties of the two coals are similar, one has a higher sulfur content and slightly different combustion characteristics. When the higher sulfur coal is burned, SO_2 emissions will typically increase from nominally 440 to 600 ppmc. Also, the higher sulfur coal has a tendency to produce higher CO emissions at an equivalent excess air level.

During the tests with the converted urea, the coal source changed a few times and there appeared to be some impact on the performance of the SNCR system. These

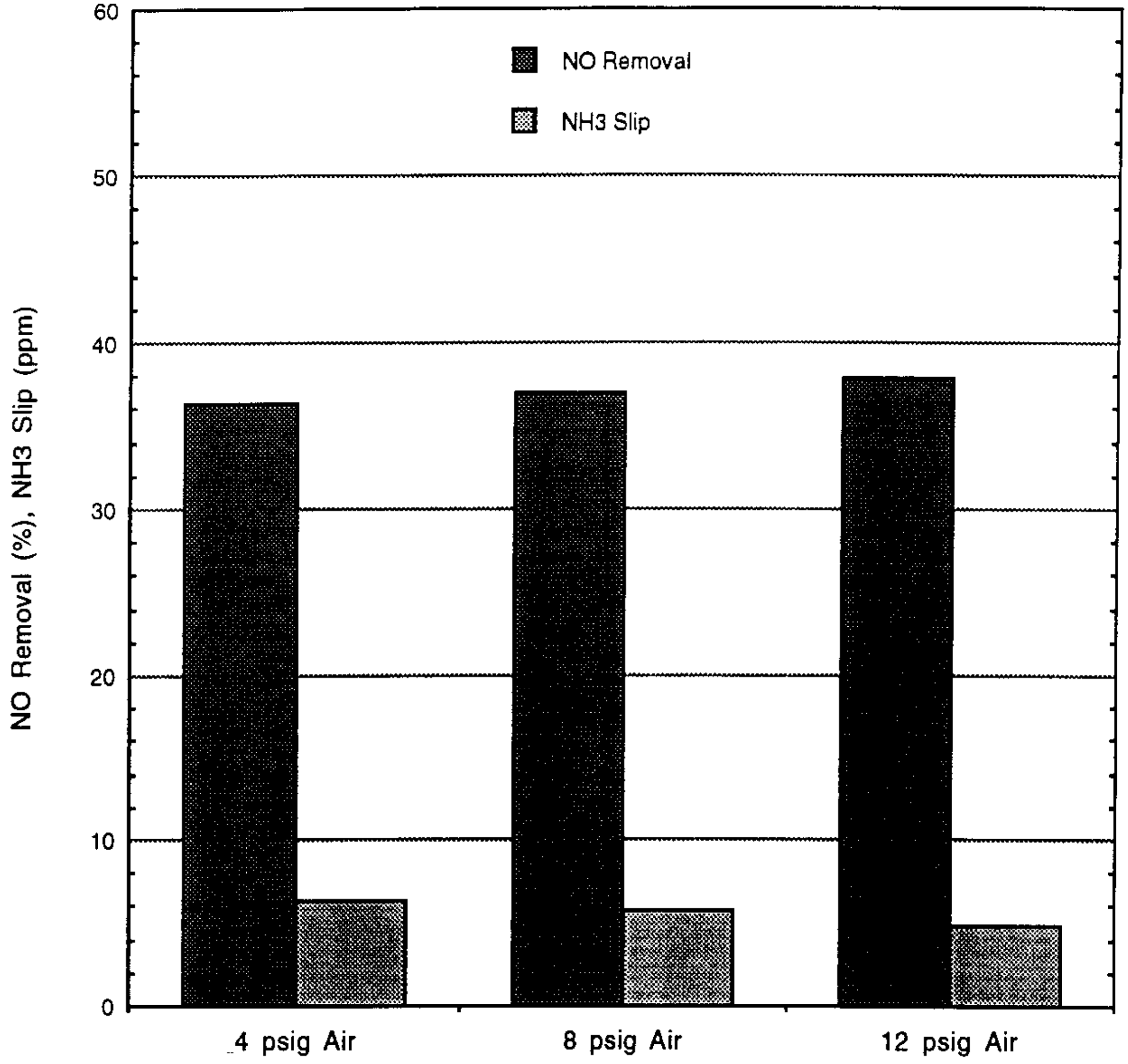


Figure 5-21. Effect of Mixing Air Pressure on Converted Urea Injection at 80 MWe (N/NO = 1.15, 4.3 gpm total liquid flow)

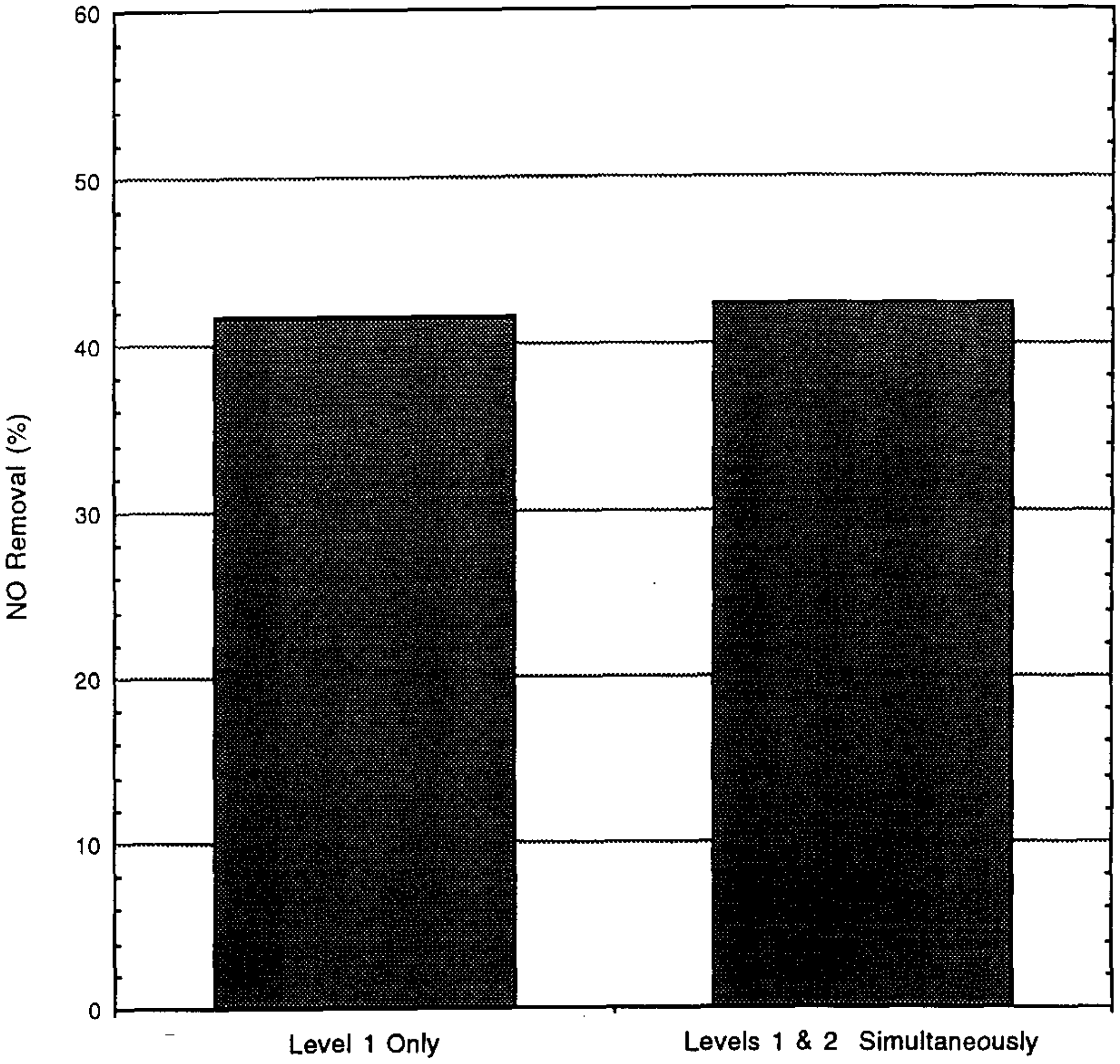


Figure 5-22. Effect of Bi-Level Injection with Converted Urea at 113 MWe (N/NO = 1.15, 6 gpm total liquid flow, 8 psig air)

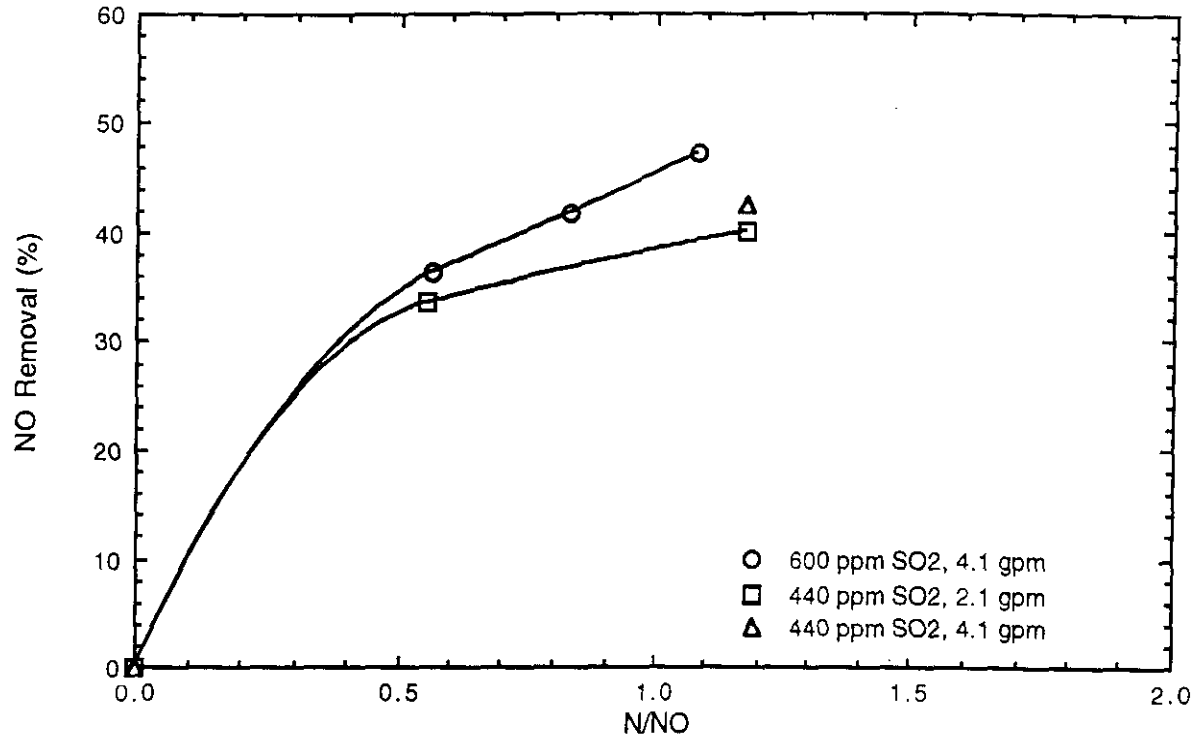
observations are summarized in Figure 5-23 for a boiler load of 60 MWe. In this figure, the two coals are denoted by the differences in SO_2 concentration. This is not to suggest that the SO_2 level is itself responsible for the difference in performance. At 60 MWe, the tests with the higher sulfur coal appear to yield increased NO removals as well as slightly lower levels of NH_3 slip. The factors contributing to this observation are not known and can only be speculated upon. This higher sulfur coal may burn somewhat differently, thereby changing the temperatures at the chemical injection location. Or, since the higher sulfur coal tends to produce higher CO emissions (as measured at the economizer exit), there will likely also be higher levels of CO at the injection level. Pilot-scale tests have shown that elevated levels of CO have the effect of lowering the temperature window for the SNCR process(5).

5.4.7 Nitrous Oxide (N_2O) Emissions

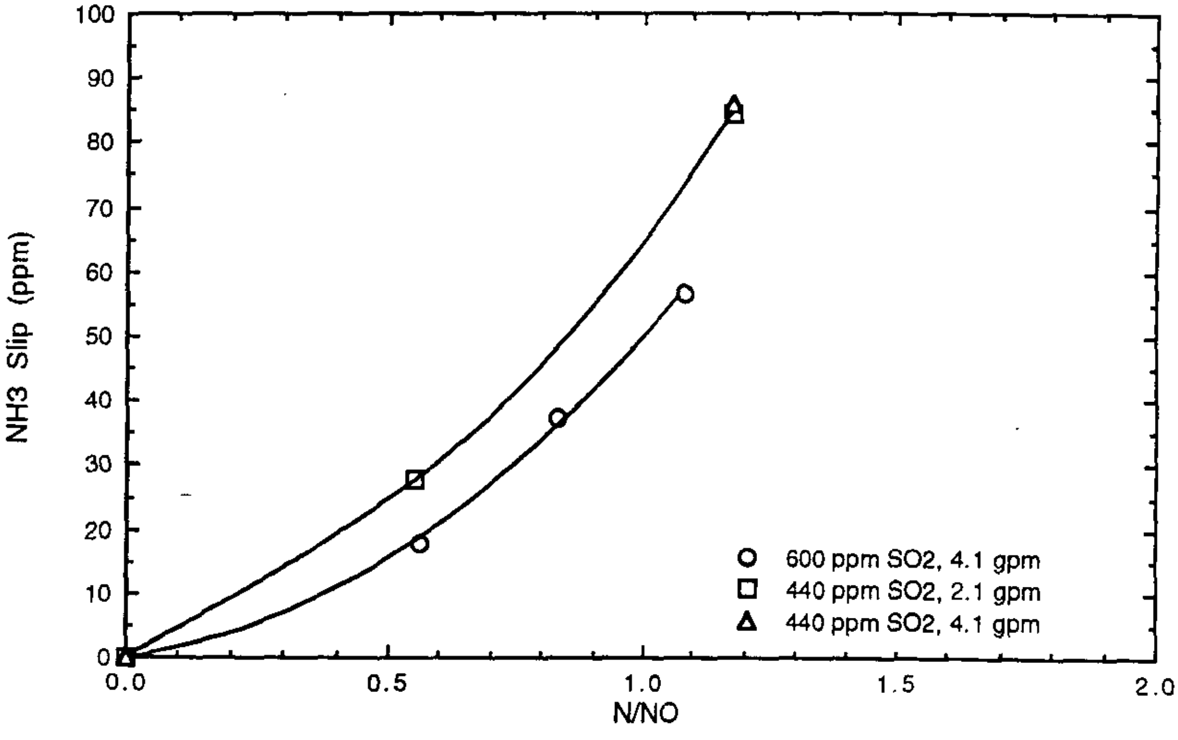
The N_2O production with the converted urea solution over the boiler load range from 60 to 113 MWe is shown in Figure 5-24. The N_2O production is significantly lower than seen with urea injection. With converted urea, 2 to 10 percent of the NO reduced appears as N_2O in the products. There is a slight trend of increasing N_2O with increasing N/NO ratio, although there is no clear trend in N_2O with boiler load. It is not known whether the changes in N_2O shown in Figure 5-24 are primarily related to performance of the urea converter or to processes occurring in the furnace. In any event, injection of the converted urea solution has markedly reduced N_2O production compared to that for the direct injection of urea.

5.4.8 CO Emissions

Increases in CO emissions with the converted urea were found to be small (less than 20 ppm). There was no discernable trend with either N/NO ratio or boiler load. As with the direct injection of urea, it is difficult to ascertain what mechanism contributes to this small increase in CO (see Section 5.3.8). Depending on the ammonium compounds formed in the converter, either or both of the two mechanisms discussed previously could be operative.



a) NO Removals



b) NH_3 Emissions

Figure 5-23. Effect of Coal Properties with Converted Urea at 60 MWe
(8 psig air)

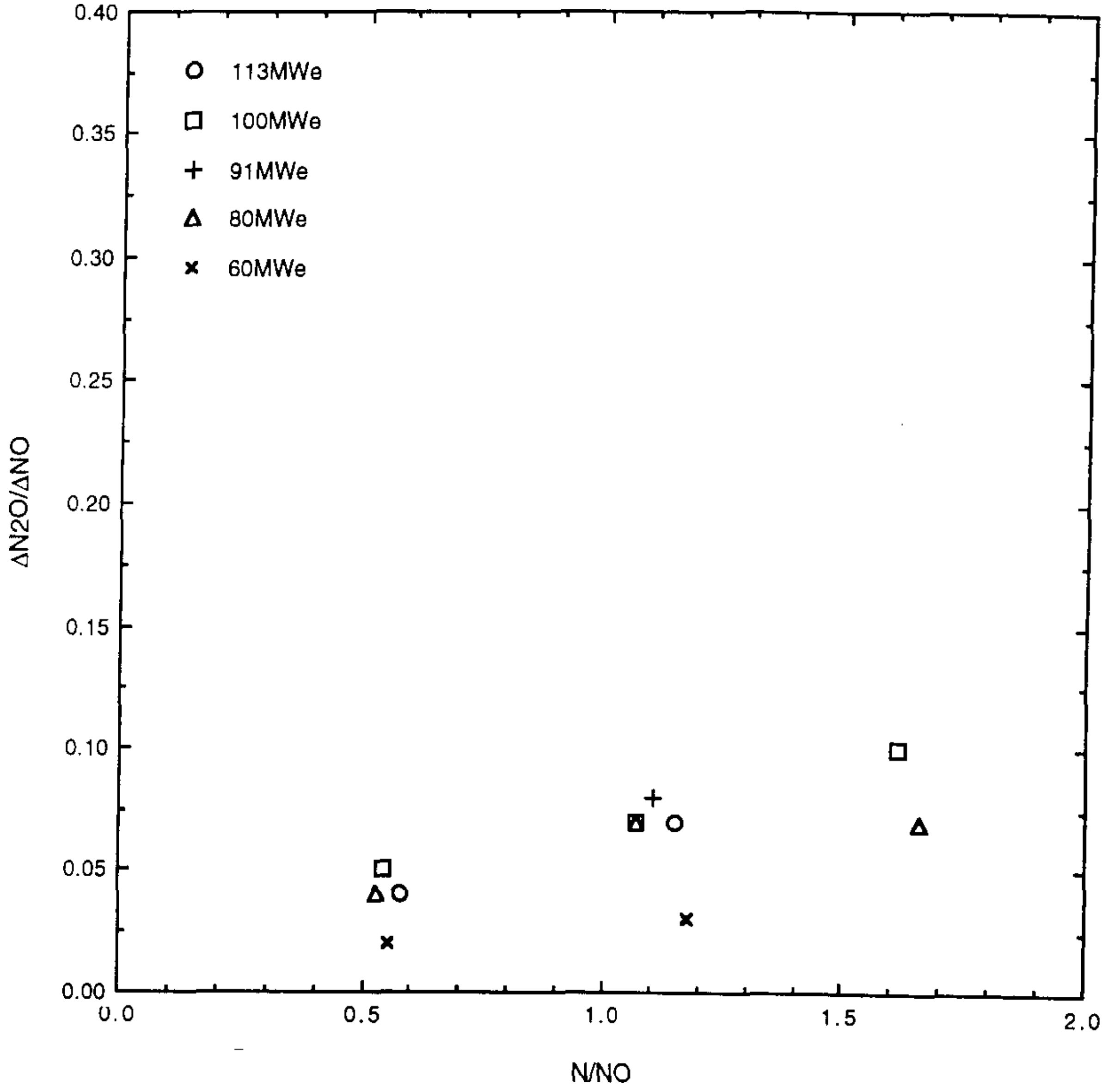


Figure 5-24. N_2O Emissions with Converted Urea Injection (8 psig air)

6

LONG-TERM LOAD FOLLOWING TEST RESULTS

The results of the parametric tests presented in the previous section were obtained at baseloaded operating conditions with testing personnel closely monitoring all boiler variables. However, Arapahoe Unit 4 is generally operated in a load following mode under automatic control. Under these conditions, oxygen levels can vary significantly and rapidly. This mode of operation tends to increase CO emissions and can also lead to higher NO emissions. Following completion of the baseloaded parametric tests, the boiler was operated for a period of five days (April 5 to 9, 1993) under normal load following conditions. A urea injection schedule was established based on the parametric tests, that would limit NH_3 slip to 10 ppm over the load range. This injection schedule is shown in Table 6-1.

Table 6-1

Long-Term Urea Injection Parameters

Injection Level:	Level 1	
Liquid Orifices:	Injectors 1 thru 9, 0.035" dia. Injector 10, 0.024" dia.	
Injection Air Pressure:	8 psig	
Load (MWe)	**Total Liquid Flow Rate (gpm)**	**Target N/NO**
60	2.0	0.2
80	2.2	0.54
100	6.0	0.75
110	6.0	1.39

During this period, the control operators were instructed to operate the boiler as they would normally. There were no specific instructions given as to control room O_2 settings, coal mill biases, overfire air settings, etc. This test period was intended to assess the potential long-term SNCR performance possible without imposing operational constraints on the boiler.

Gaseous emission data were collected automatically with the CEM alternating between the two heated sampling locations at the air heater exit and stack. The CEM was programmed to calculate and record 10-minute averages for all the measured gas species, as well as boiler load. The NO_x data presented in this section are from the stack location only, and have been corrected to dry conditions for comparison to the results from the parametric tests.

The results of these tests are shown in Figure 6-1. In this figure, the data from the four day SNCR load following tests are compared to the long-term data collected over the November-December 1992 time period with the retrofit low-NO_x combustion system(2). For the retrofit burners data, each point represents an hourly average of the 10-minute CEM averages. For the retrofit burner/urea injection tests, each point represents a 10-minute average. The data show that, with or without urea injection, there is a significant amount of scatter in the outlet NO_x levels across the load range. Although there does not appear to be as much scatter with urea injection as without, this is likely due to the much shorter test period with urea. In any event, the scatter is due to transient effects due to load changes during normal dispatch operation, as well as different operator preferences for various boiler control settings. The trends with urea injection do show lower outlet NO_x levels at higher loads, consistent with the higher target N/NO ratios shown in Table 6-1. Note that the control system did not maintain a constant N/NO ratio. Rather, based on the parametric data and an average inlet NO level at a given load, a urea injection rate was specified. The specified urea injection rate should yield, on average, the N/NO ratio shown in Table 6-1. If the actual inlet NO level changed due to varying boiler operations, then there would be a corresponding change in the N/NO ratio.

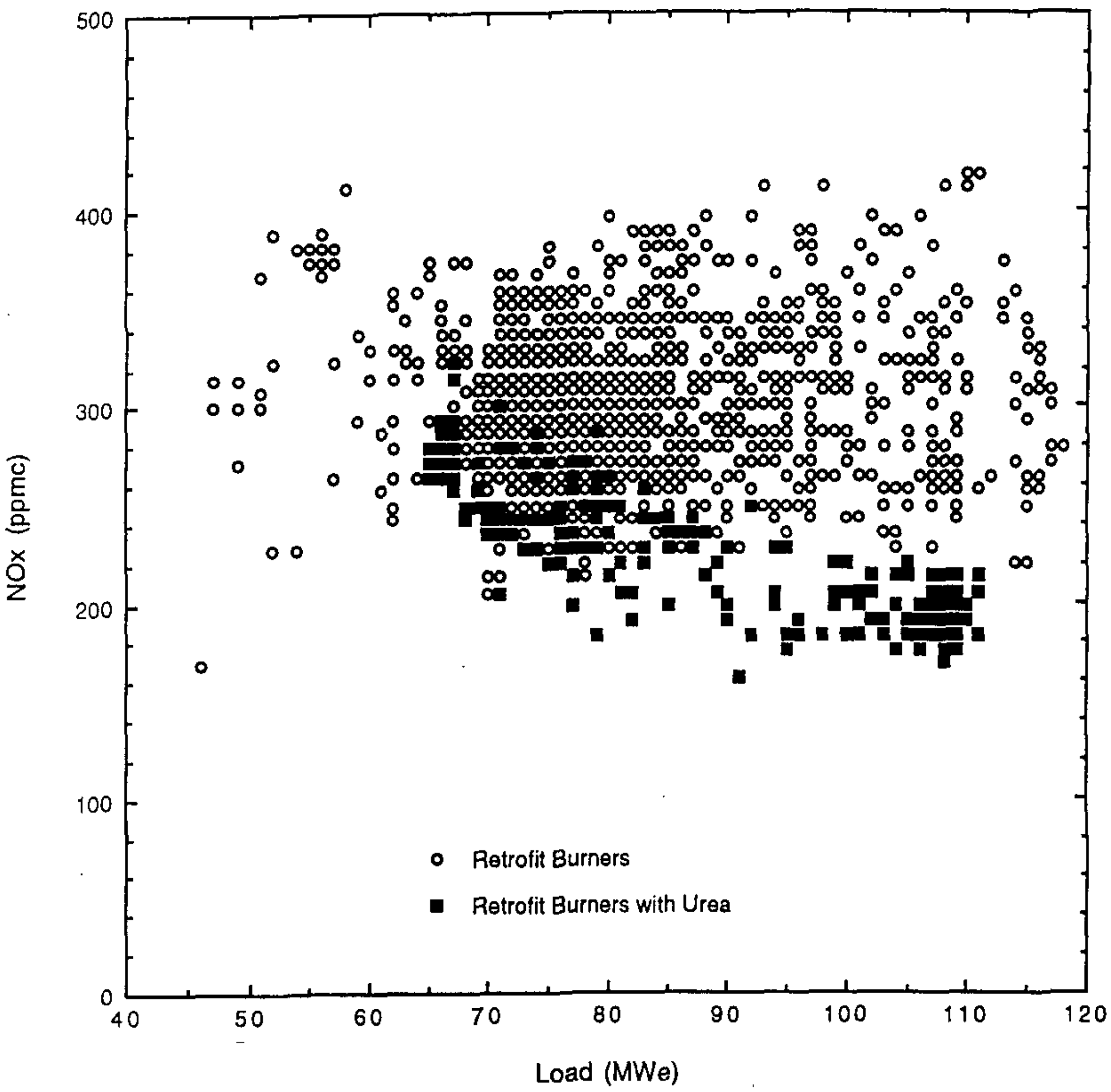


Figure 6-1. Comparison of Long-Term Load Following NO_x Emissions with and without Urea Injection

The individual data points in Figure 6-1 have been averaged and replotted in Figure 6-2. In this figure, each point represents the average of all of the data points shown in Figure 6-1 which are within a 10 MWe range (i.e., the 100 MWe data point is the average of all of the CEM points between 95 and 105 MWe). Based on these averages, the nominal NO reduction is also noted at each load. It should be noted that with the SNCR system continuously operating, it is impossible to obtain a "true" baseline NO value. Therefore, the baseline NO values utilized in calculating the NO removals in Figure 6-2 are estimated and based upon the long-term load following data collected during the Low-NO_x Burner/Overfire Air tests(2). For comparison, the NO removals achieved during the parametric tests (Section 5.3), where boiler operating conditions were closely controlled, are noted in parentheses in Figure 6-2. The results show that the NO removals achieved with long-term unattended operation are lower than those achievable under carefully controlled conditions. It is expected, however, that the difference between the unattended results and controlled results can be made smaller by specifying certain boiler operating conditions at each boiler load. In particular, control room O_2 set point, coal mill biases, overfire air setting. These steps will be pursued during the integrated systems test portion of the test program.

The urea injection schedule shown in Table 6-1 was based upon limiting the NH_3 slip at the air heater exit to 10 ppm. However, as the "baseline" NO levels during the long-term tests were likely different from those during the parametric tests (due to differences in boiler operating practices), it also is likely that the SNCR system was either under- or over-injecting at any one particular time. Figure 6-3 shows the average CEM NH_3 measurements at the air heater exit and stack locations. The data has been averaged in a manner similar to that for Figure 6-2 (i.e., over 10 MWe increments). As discussed in Section 4.3, the single-point CEM NH_3 measurement at the air heater exit is not a valid representation of the average NH_3 slip, due to the non-uniformity of the NH_3 emission profile at that location. However, the CEM data does provide an indication of the general trends of NH_3 emissions in that region. The results show that the emissions at the air heater exit range from 6 to 18 ppm, with an average over the entire boiler load

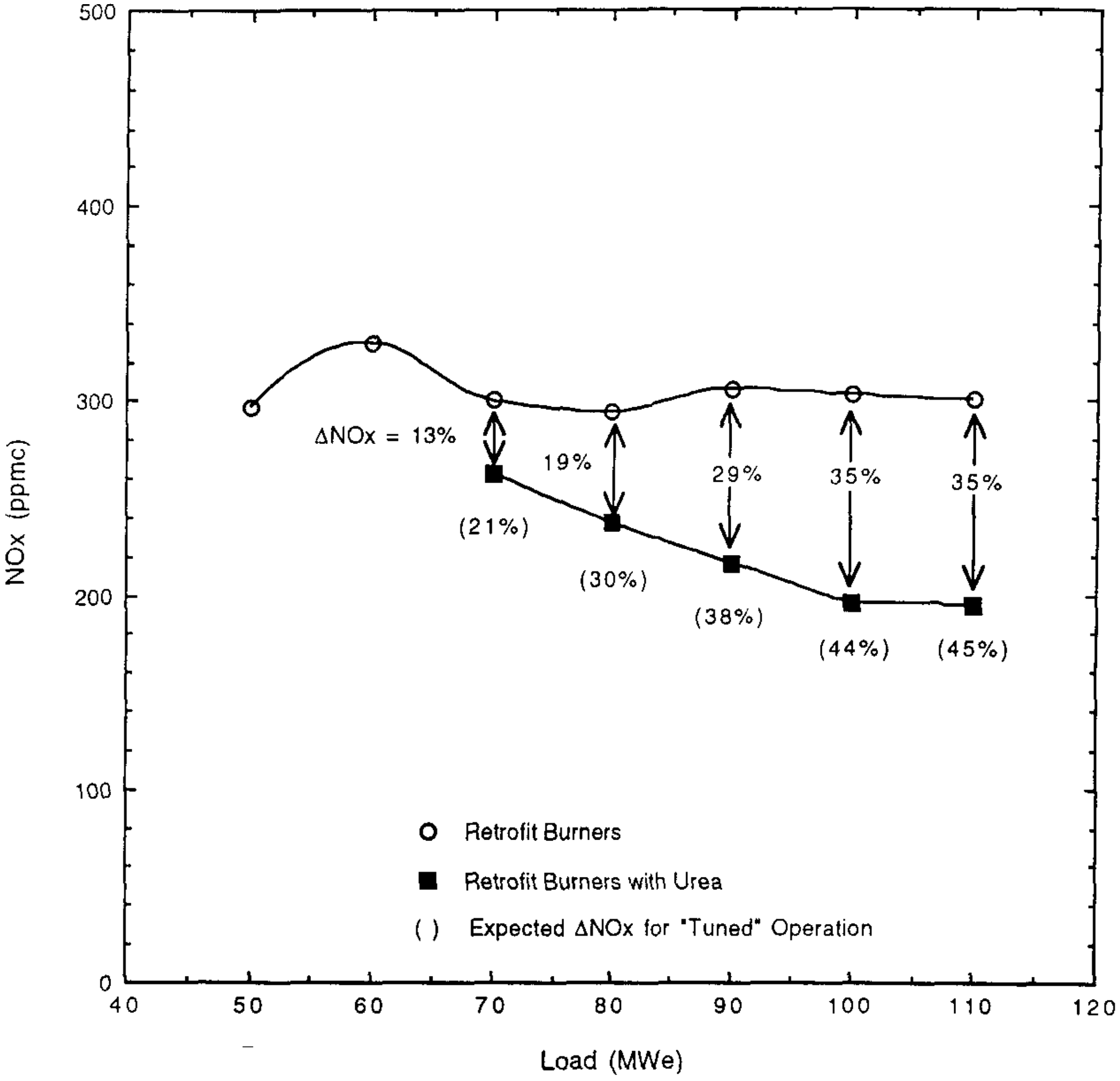


Figure 6-2. Average Long-Term Load Following NO_x Emissions With and Without Urea Injection

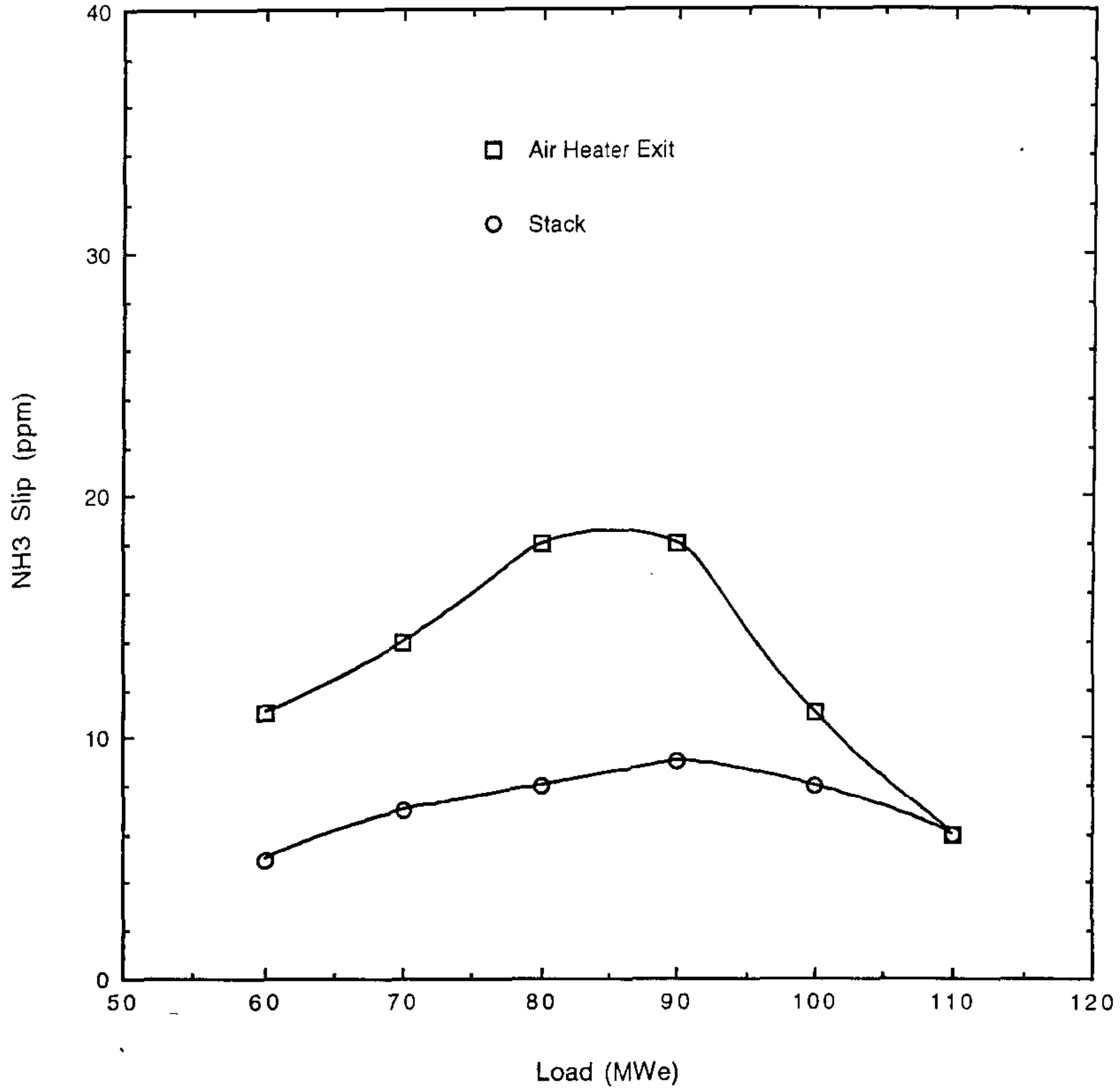


Figure 6-3. Average NH_3 Emissions During the Long-Term Load Following Tests

range of 13 ppm. The NH_3 emissions at the stack are a better indicator of the overall performance, as they are not susceptible to biases due to flue gas stratification in the duct. Figure 6-3 shows that the stack emissions ranged from 5 to 9 ppm, with an average over the entire boiler load range of 7 ppm.

7

DISCUSSION

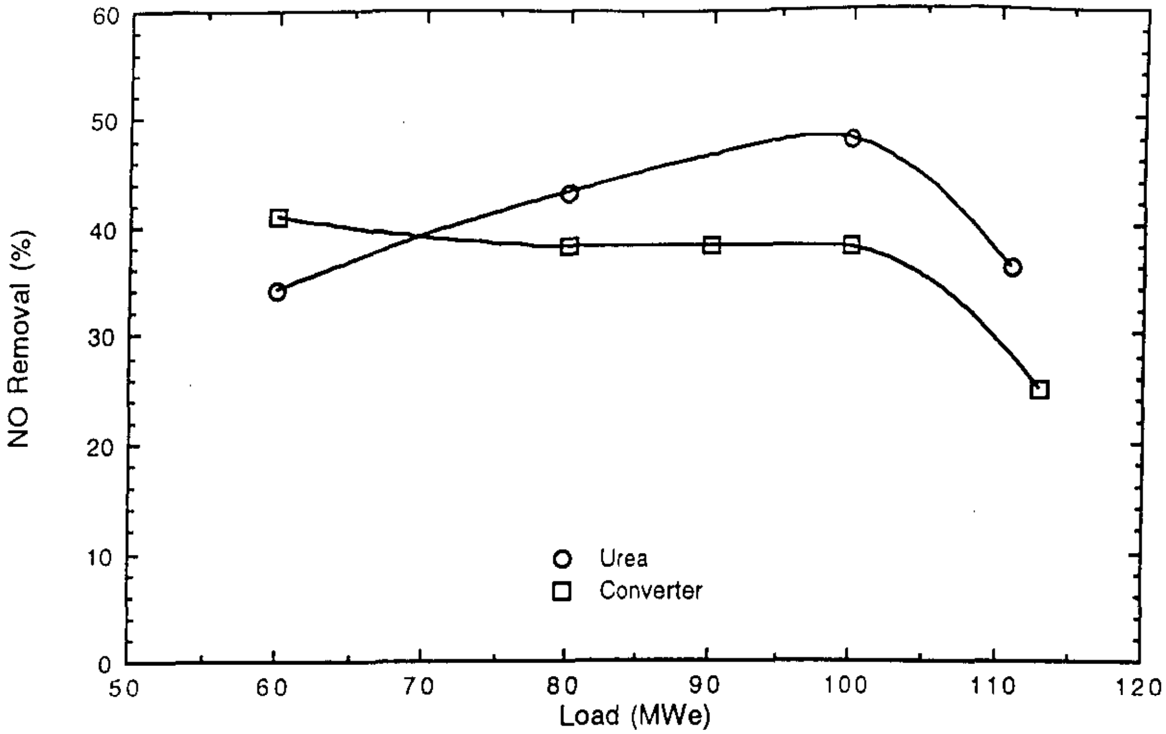
The primary purpose of this section is to present 1) a comparison of the performance of urea to converted urea, and 2) to compare the performance of the SNCR system when operating with the pre- and post-retrofit combustion systems. Before proceeding with the comparison, some discussion is warranted to put the comparisons in context, in particular, when comparing SNCR performance with the pre- and post-retrofit combustion systems. There has been a large change in the initial NO levels, as well as approximately a 200°F reduction in the flue gas temperatures at the chemical injection location. In terms of NO emissions, a 50 percent reduction with SNCR corresponds to an outlet NO emission level of nominally 425 ppmc with the original combustion system. Whereas, with the retrofit low-NO_x combustion system, a 50 percent NO reduction with SNCR corresponds to a NO emission level of nominally 140 ppmc. Thus, it was necessary to inject much more chemical in order to obtain an equivalent percentage NO reduction with the original combustion system. However, to gain further insight into the SNCR processes, it is of interest to compare the relative pre- and post-retrofit performance.

This section will also compare system performance when using ammonia hydroxide (NH_4OH) with the original combustion system, to the performance of the converted urea solution with the retrofit low-NO_x combustion system. It should be kept in mind that for this comparison not only are the combustion systems different (i.e., initial NO_x levels, gas temperatures, etc.) but also the SNCR chemicals. The NH_4OH used during the baseline SNCR tests was a pure 29.4 percent (by weight) aqueous ammonia solution. The converted urea, which to date has not been characterized in terms of the specific types of compounds, is likely a mixture of a variety of ammonium compounds (i.e., ammonium carbonate, ammonium bicarbonate, etc.). This chemical difference may also contribute to differences in performance relative to aqueous ammonia (NH^4OH).

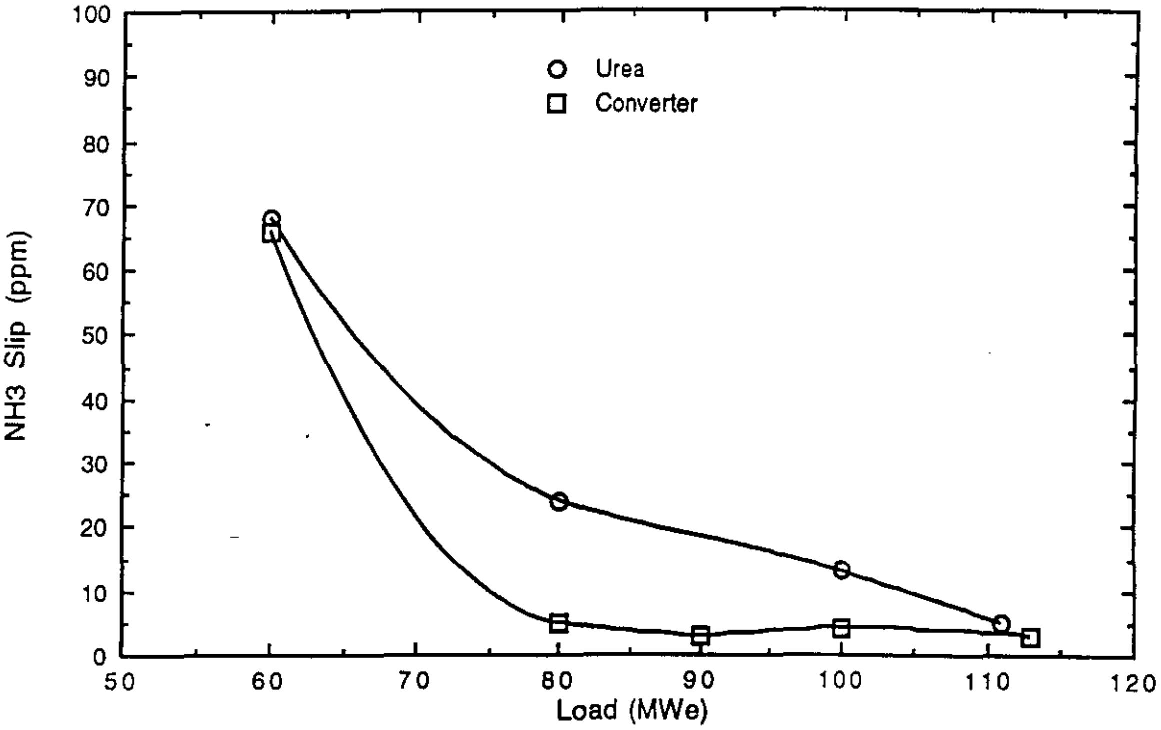
7.1 Comparison of SNCR Performance with Urea and Converted Urea

The first comparison to be addressed is the relative performance of urea and converted urea. Figure 7-1 compares the NO removals and NH_3 emissions for the two compounds over the load range from 60 to 110 MWe at a N/NO ratio of 1.0. In order to provide a more accurate comparison of the performance of the two compounds, the data points in both figures were interpolated from the curves in Figures 5-8 and 5-18 for the "exact" (not "nominal") N/NO ratio of 1.0. With the exception of the 60 MWe point, urea injection yielded consistently higher NO removals over the load range than the converted urea. However, over the load range from 80 to 100 MWe, the NH_3 emissions with the converted urea solution were markedly lower than those for urea. At 60 and 100 MWe, the NH_3 emissions were comparable.

A better comparison of urea and converted urea is shown in Figure 7-2. In this figure, the NO removal attainable with 10 ppm NH_3 slip is plotted versus boiler load. As was done in Figure 7-1, the data points which define these curves were interpolated from the curves in Figures 5-8 and 5-18. The numbers in parentheses denote the corresponding N/NO ratio at each load. Over the load range, the converted urea consistently provided higher NO removals while limiting NH_3 emissions to 10 ppm. However, this increase in NO reduction with the converted urea is at the expense of higher N/NO ratios (i.e., lower urea utilization). For instance, at 100 MWe twice as much chemical is needed to achieve a 47 percent NO removal with the converted urea compared to a 43 percent NO removal with urea alone. This translates to an economic decision as to the tradeoffs between this higher chemical usage rate and the four percentage point increase in NO removal. Another point which may need to be considered is that the production of N_2O with the converted urea solution is much lower than with urea alone.



a) NO Removal



b) NH_3 Emissions

Figure 7-1. Comparison of SNCR Performance with Urea and Converted Urea at N/NO = 1.0

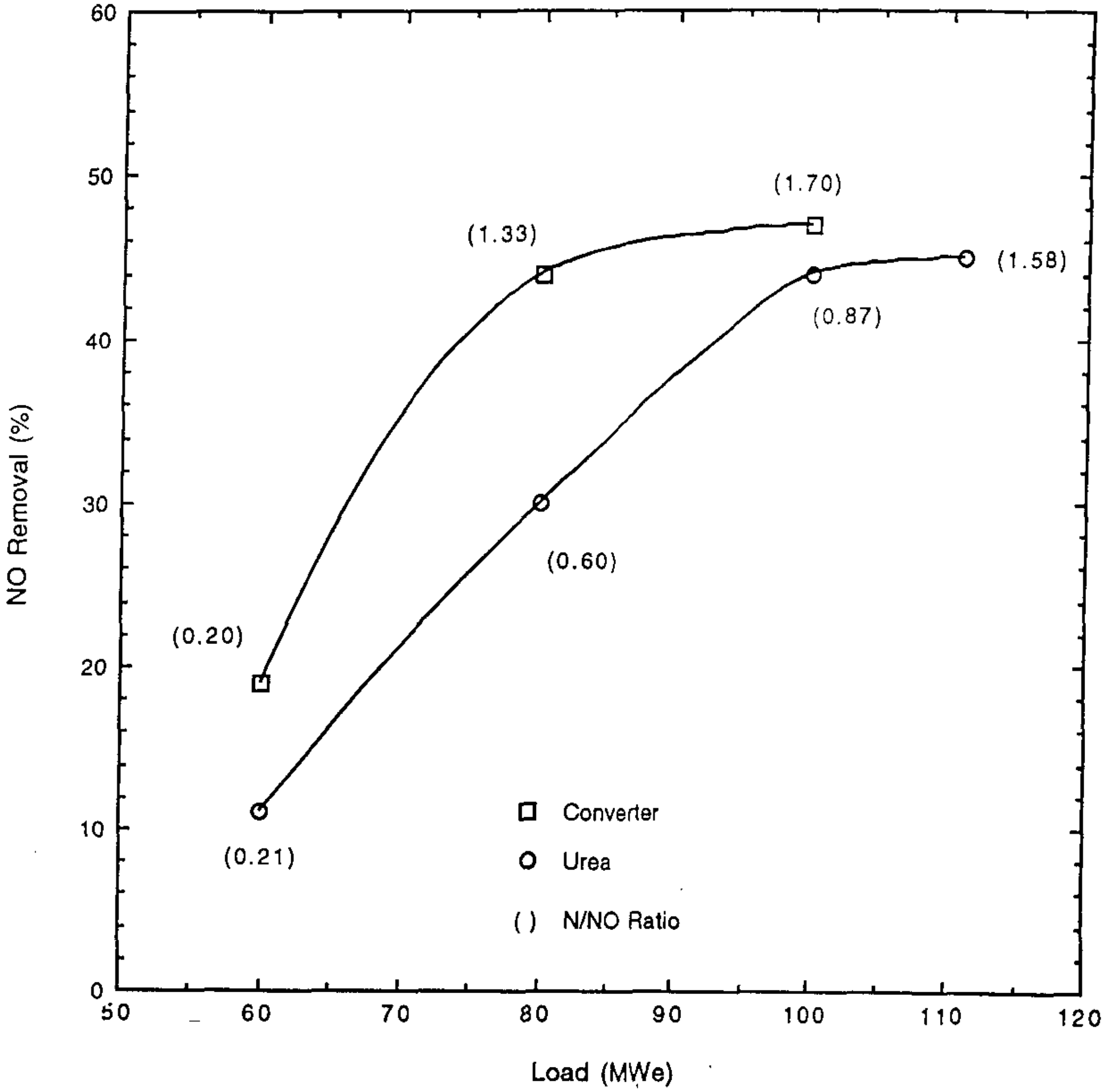


Figure 7-2. Comparison of NO Removals with Urea and Converted Urea for a Fixed NH_3 Slip Level of 10 ppm

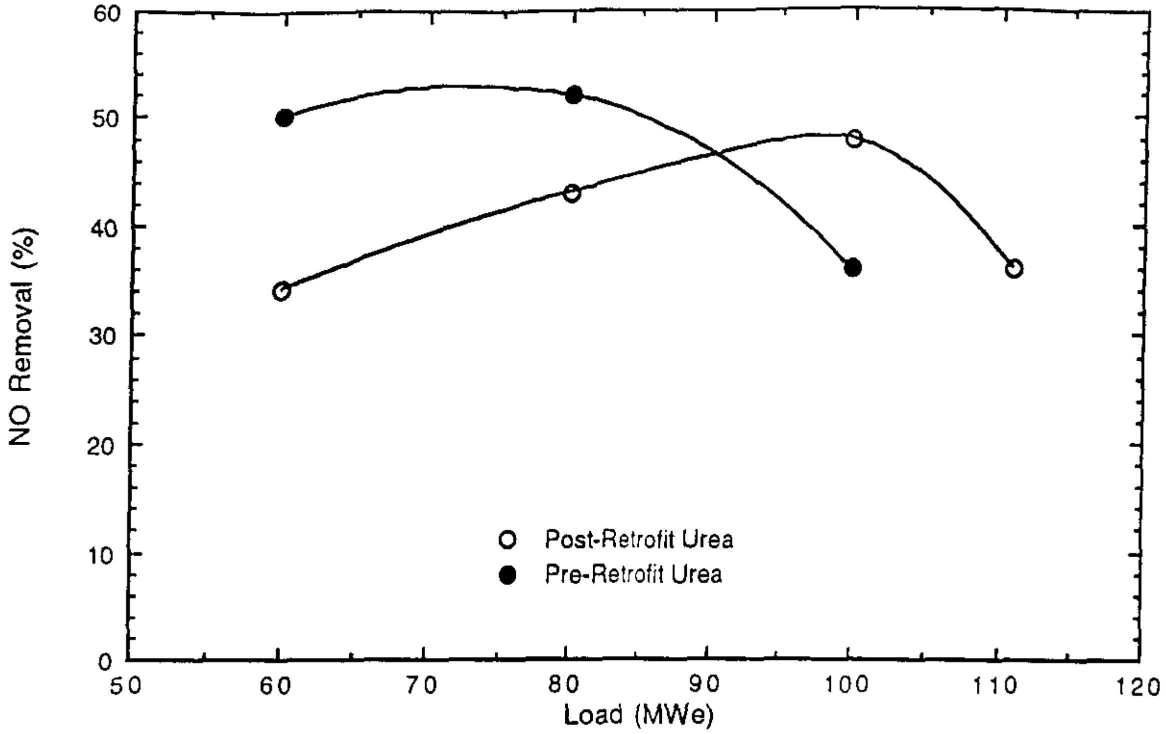
7.2 Pre- and Post-Retrofit SNCR Comparison

7.2.1 Urea Injection

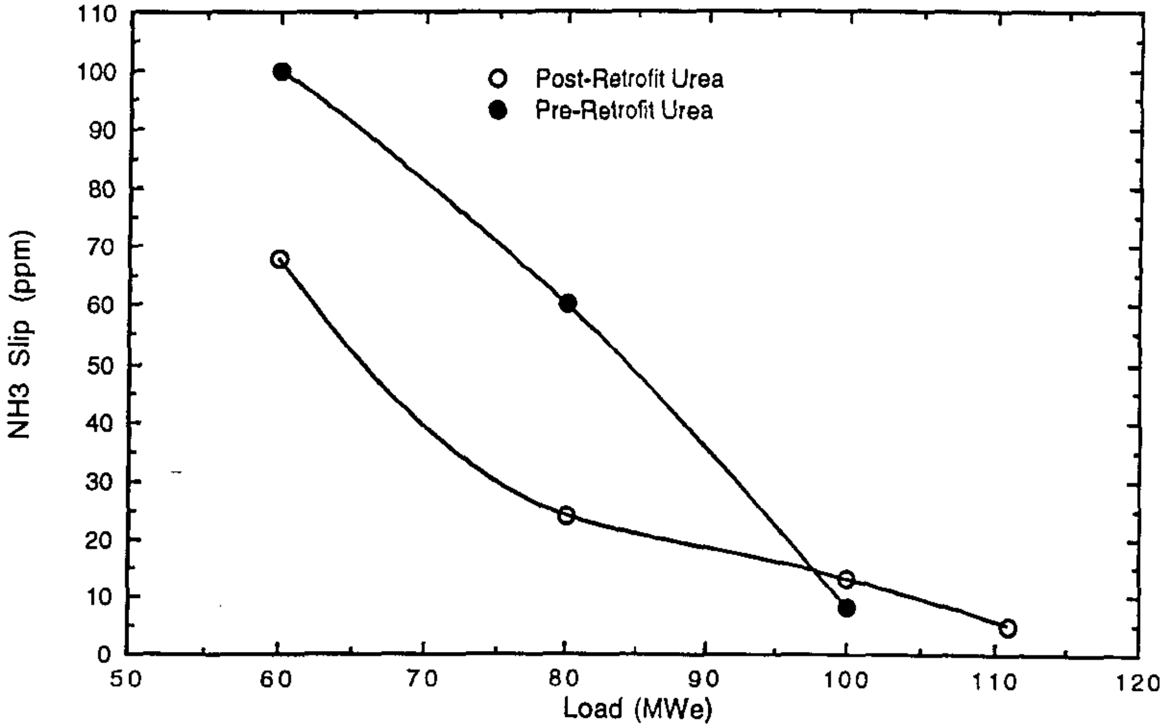
The SNCR performance of urea injection with the pre- and post-retrofit combustion system is shown in Figure 7-3. The data show similar behavior in terms of maximum NO removals achievable, but the boiler load for peak removal is higher with the retrofit low-NO_x combustion system. This effect has been discussed previously and is consistent with the lower furnace exit gas temperatures with the new combustion system.

The comparison of NH_3 emissions on an absolute part per million basis is shown in Figure 7-3b. Two factors affect the NH_3 slip. First, with the pre-retrofit combustion system, over three times as much urea is being injected due to the higher initial NO level. Second, the gas temperatures at a given load have shifted with the retrofit. At a load of 100 MWe, the lower NH_3 slip with the original burners is due to the higher gas temperatures. At lower loads, the NH_3 slip is higher with the original combustion system. This effect is dominated by the higher initial NO level and higher urea injection rate. To afford a better comparison of the NH_3 slip behavior, the data in Figure 7-3b has been normalized by the initial NO level (NO_i) and replotted in Figure 7-4. On this normalized basis, the NH_3 slip is higher with the retrofit low-NO_x combustion system, over the entire load range. Again, this is likely due to the shift in flue gas temperatures discussed previously.

Figure 7-5 shows another comparison of the performance of urea between the pre- and post-retrofit combustion systems. In this figure, the NO reduction performance is compared over the load range at a constant 10 ppm level of NH_3 slip. On this basis, the retrofit combustion system provides higher NO removal over the load range from 65 to 110 MWe. At 60 MWe, urea injection with the original combustion system yielded higher NO removals with a 10 ppm NH_3 slip level. This can be attributed to flue gas temperatures which are closer to the optimal temperature at this load with the original combustion system. The most likely reason for the better overall SNCR performance seen after the retrofit, when compared on a 10 ppm NH^3 slip basis, is the lower initial NO level as discussed in the introduction to this section.



a) NO Removal



b) NH_3 Emissions

Figure 7-3. Comparison of Urea Injection with Pre- and Post Retrofit Combustion Systems at N/NO = 1.0

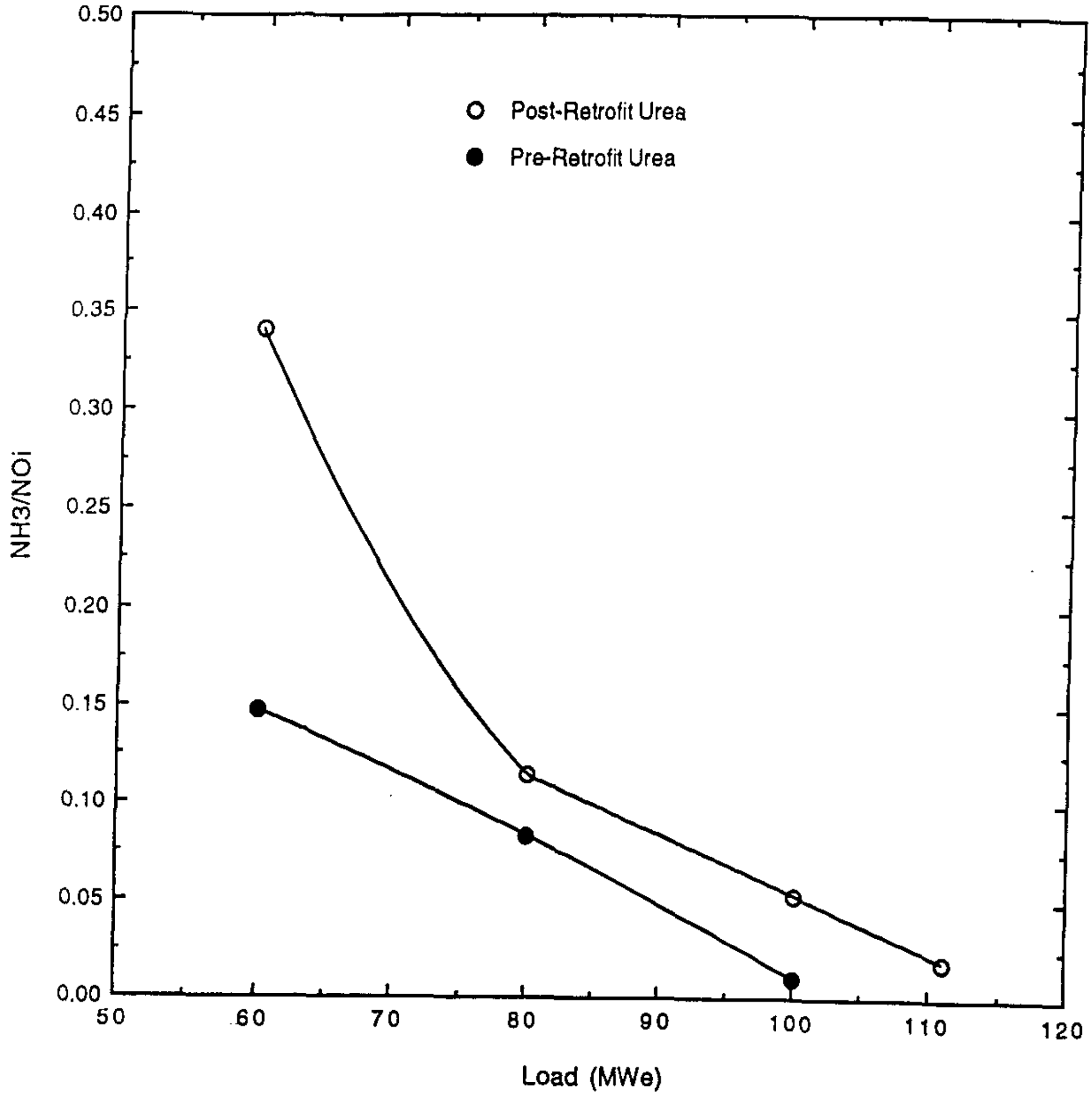


Figure 7-4. Comparison of Normalized NH_3 Emissions for Urea Injection with the Pre- and Post-Retrofit Combustion Systems at N/NO = 1.0

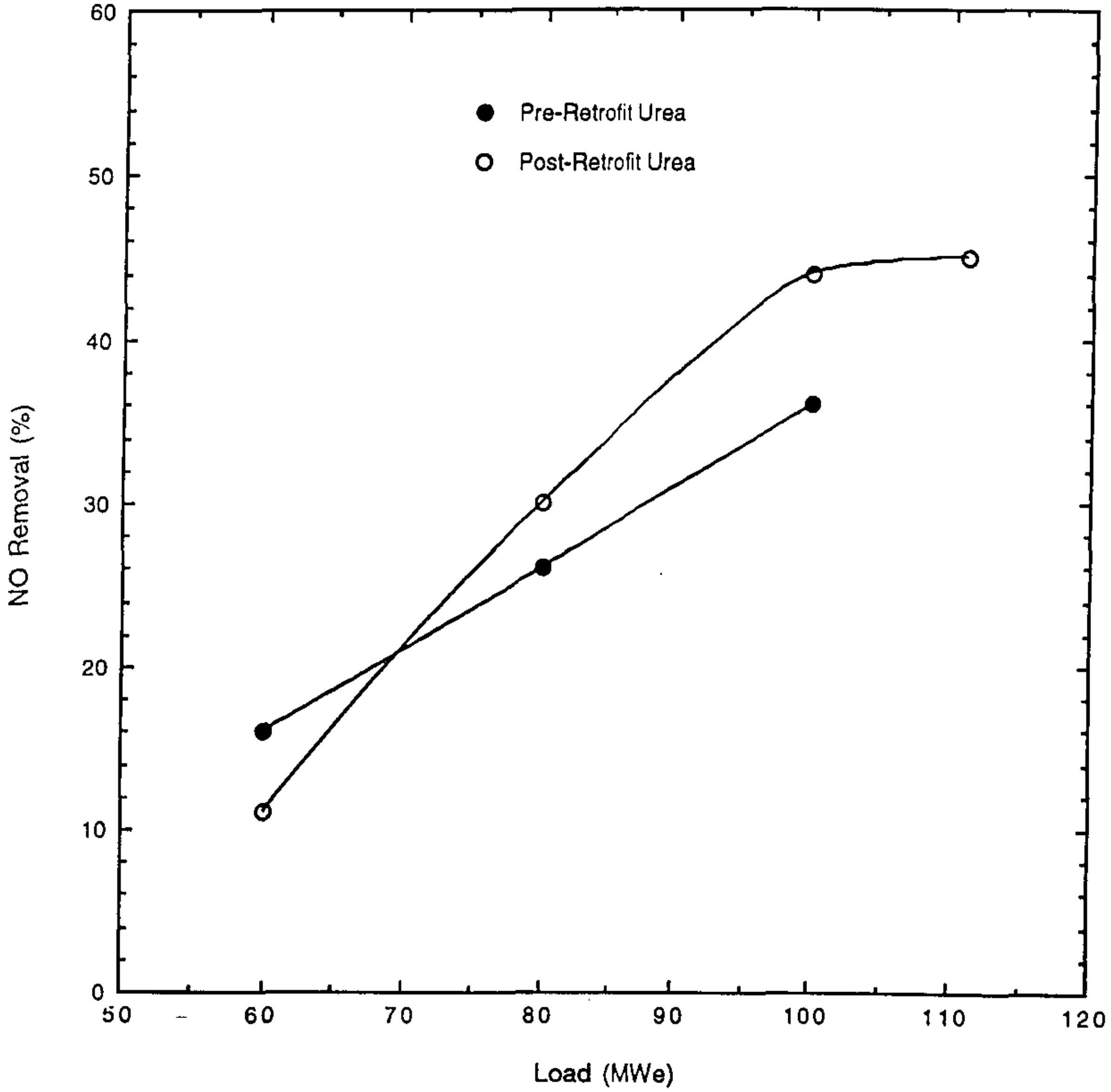


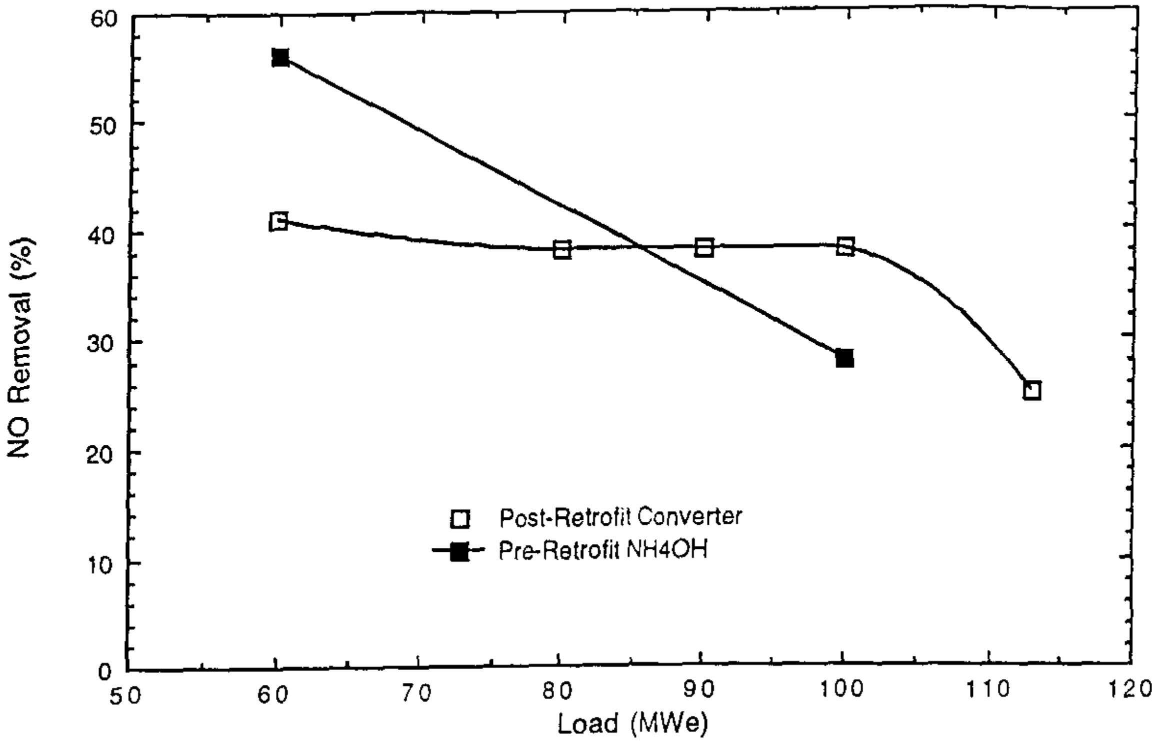
Figure 7-5. Comparison of Pre- and Post-Retrofit SNCR Performance with Urea at a Fixed NH_3 Slip of 10 ppm

7.2.2 Converted Urea and Aqueous Ammonia

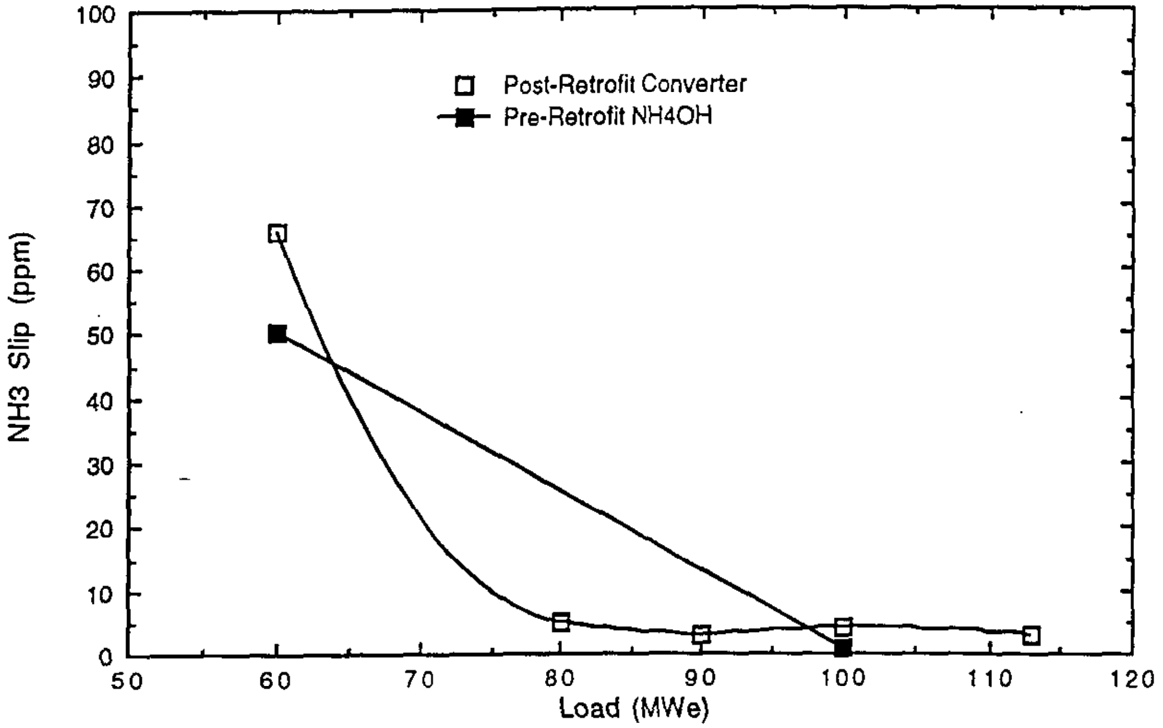
A pre- and post-retrofit comparison can also be made between the tests with aqueous ammonia (original burners) and converted urea (retrofit low-NO_x burners). Figure 7-6 shows this comparison over the load range at a N/NO ratio of 1.0. In addition to the initial NO level and the temperature effects discussed in Section 7.2.1, the converted urea differs chemically from the aqueous ammonia used during the baseline SNCR tests with the original burners. With the converted urea, the NO reduction performance was fairly flat from 60 to 100 MWe, decreasing at boiler loads above 100 MWe because of the higher flue gas temperatures. The performance of aqueous ammonia with the original combustion system was quite different. As seen in Figure 7-6a, NO removals increased as the load decreased from 100 to 60 MWe. It does not appear that these differences can be explained solely by a change in gas temperatures with the burner retrofit, as could be done with the comparison of urea performance (Section 7.2.1). With urea, peak removals were comparable but shifted to a higher boiler load with the burner retrofit. With converted urea, the NO removals were never as high as achieved with aqueous ammonia at 60 MWe. Thus, it might be speculated that the different mix of ammonium compounds exiting the converter may be contributing to this difference in performance.

The comparison of NH_3 emissions is shown in Figure 7-6b on an absolute parts per million basis, and in Figure 7-7 where the NH_3 emission values have been normalized by the initial NO levels. While the amount of data is not extensive, the normalized NH_3 slip data (Figure 7-7) show comparable low slip levels down to a boiler load of 80 MWe. At 60 MWe, the NH_3 emissions with the converted urea and retrofit combustion system is higher than for aqueous ammonia and the original combustion system. Even on an absolute basis, the NH_3 slip is higher at 60 MWe with the converted urea and retrofit combustion system. It is not possible to assess whether this is primarily a temperature affect or chemical difference between aqueous ammonia and the covered urea.

Finally, Figure 7-8 compares the NO removals achievable with aqueous ammonia to those for converted urea at a constant 10 ppm level of NH_3 slip. Except at the low load condition, converted urea with the retrofit burners yields higher NO removals with a



a) NO Removal



b) NH_3 Emissions

Figure 7-6. Comparison of SNCR Performance with NH_4OH (Pre-Retrofit) and Converted Urea (Post-Retrofit) at N/NO = 1.0

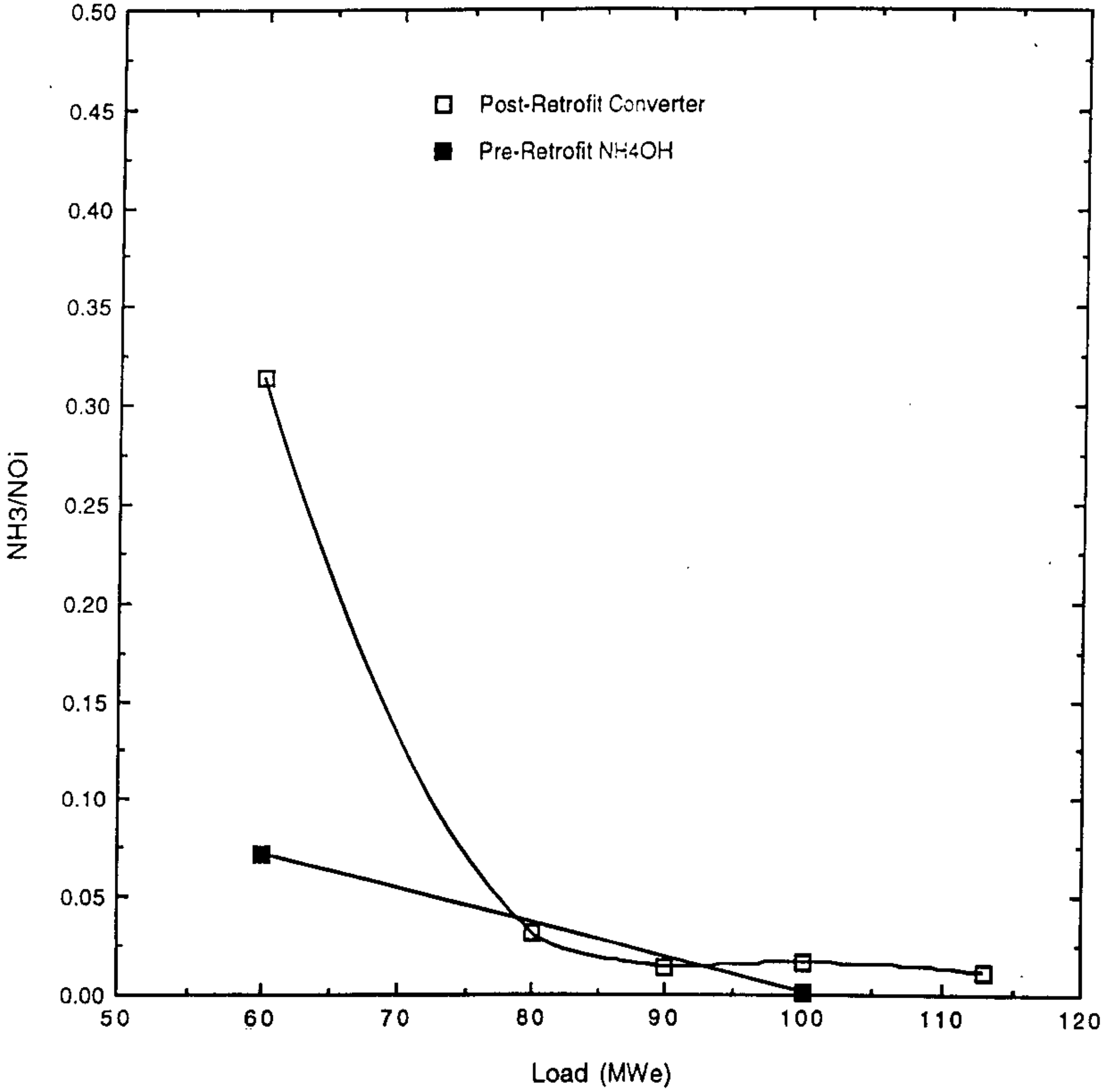


Figure 7-7. Comparison of Normalized NH_3 Emissions for NH_4OH (Pre-Retrofit) and Converted Urea (Post-Retrofit) at N/NO = 1.0

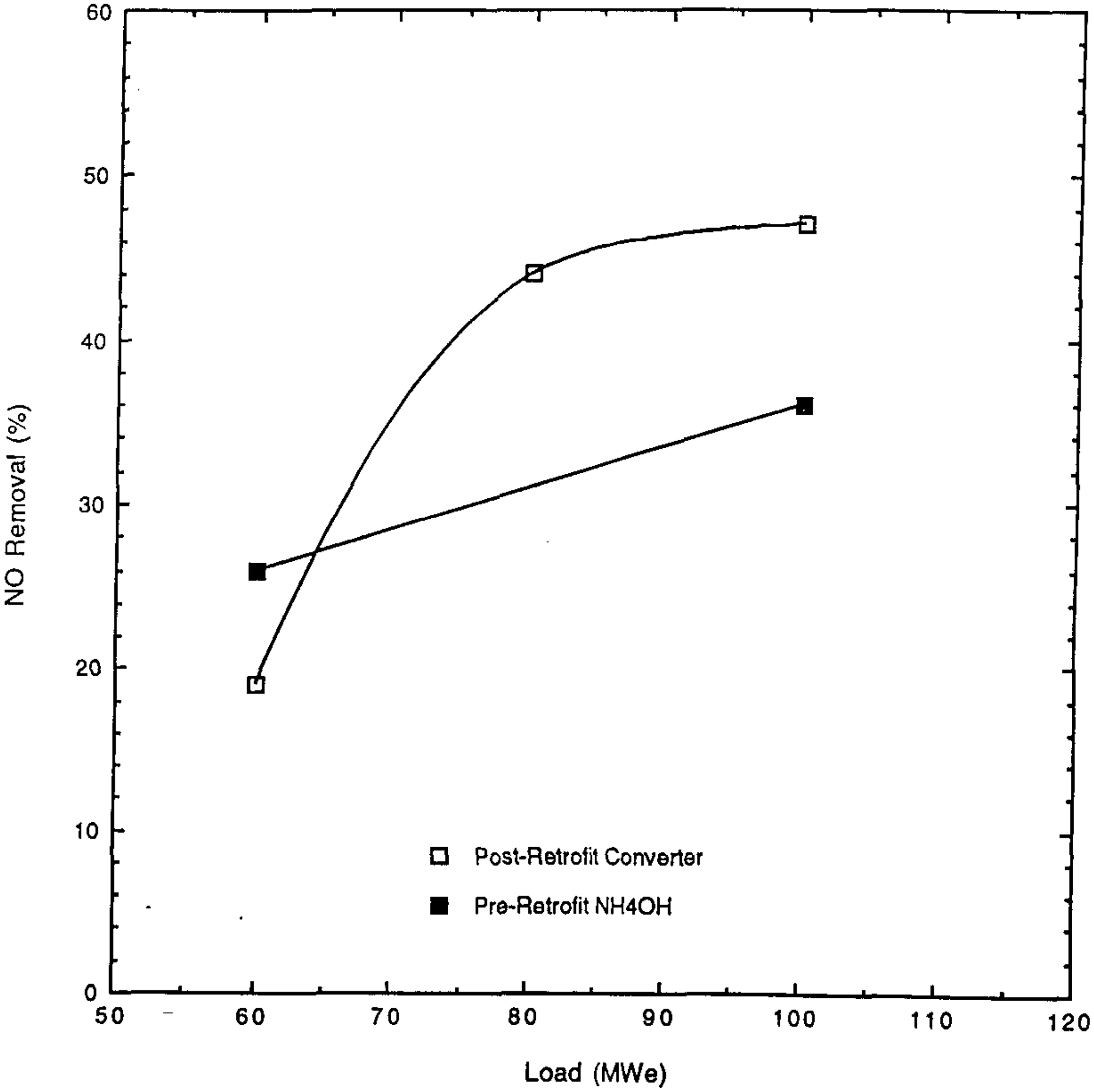


Figure 7-8. Comparison of NO Removals for NH_4OH (Pre-Retrofit) and Converted Urea (Post-Retrofit) at a Fixed NH_3 Slip of 10 ppm

10 ppm NH_3 slip limit than aqueous ammonia and the original burners. Again, this is likely due to the much higher initial NO levels with the original burners, and the associated higher chemical injection rate.

8

SYSTEM IMPACTS

Integrating an SNCR system into a utility boiler operation can result in a number of impacts to the balance of plant. While the SNCR testing to date at Arapahoe Unit 4 has not involved extensive long-term testing, there is sufficient data to at least address a number of the potential impacts that have occurred, or might occur, with long-term operation. In particular, this section of the report will discuss the following impacts and system integration issues:

- plume visibility
- NH_3 absorption in fly ash
- SO_3/NH_3 reactions and air preheater deposition
- boiler efficiency impacts, including steam temperature control.

8.1 Plume Visibility

As reported in the report documenting the baseline SNCR tests(3), a detached visible plume was frequently encountered when NH_3 slip levels were relatively high. During the initial baseline SNCR tests, it was speculated that the detached plume was due to NH_3 reactions with either HCl or SO_2 resulting in the formation of an ammonium salt aerosol. Reactions between NH_3 and SO_3 are not a likely source of plume visibility since the measured levels of SO_3 in the Arapahoe Unit 4 flue gas is low (less than 1 ppm)(1,3). Even if reactions between NH_3 and SO_3 were to occur, these reactions will take place upstream of the air heater where the flue gas temperatures are in the range of 400 to 600°F, and the products of these reactions (ammonium sulfate or ammonium bisulfate) would be removed in the baghouse.

Reaction between HCl and NH_3 would occur via the following reaction

$$NH_3 + HCl \rightarrow NH_4Cl \tag{8}$$

Thermochemical calculations indicate that the solid ammonium chloride (NH_4Cl) will form in the post-stack region when the plume has entrained sufficient air to reduce the temperature to 200 to 230°F.

A number of chemical reactions can occur between NH_3 and SO_2:

$$2NH_3 + 2SO_2 + H_2O \rightarrow (NH_4)_2S_2O_5 \tag{9}$$

$$2NH_3 + SO_2 + H_2O \rightarrow (NH_4)_2SO_3 \tag{10}$$

$$2NH_3 + SO_2 + 2H_2O \rightarrow (NH_4)_2SO_3 \cdot H_2O \tag{11}$$

$$NH_3 + SO_2 + H_2O \rightarrow NH_4HSO_3 \tag{12}$$

Thermochemical calculations using the data in Reference 12 indicate that reactions (10) and (11) will lead to solid aerosol formation at the highest temperatures and concentrations of NH_3 and SO_2. Although for typical flue gas conditions at Arapahoe Unit 4 (275°F, 10 percent moisture, and 400 ppm SO_2), the plume would only form a solid aerosol if the entrained ambient air were less than about 30°F.

During the SNCR testing with the retrofit burners, there were still instances of a detached visible plume. Measurements of HCl concentrations in the stack gas showed concentrations of less than 2 ppm. Four HCl measurements were less than 0.5 ppm, with one at 1.9 ppm. These levels of HCl when reacted with NH_3 would not be expected to result in plume visibility. This seemed to suggest that the primary source of the plume visibility was an aerosol formed in the detached plume due to reactions between SO_2 and NH_3. This was further substantiated by the following observation. On test days late in winter, ambient temperatures in the morning would frequently vary between 15 and 30°F. During the cold mornings, a detached visible plume would occur when the SNCR system was operating with NH_3 slip levels of 10 ppm or above. During the course of the day, as the ambient temperature increased into the 30 to 50°F range, the detached visible plume would disappear, even though the SNCR system was still operating with comparable NH_3 slip levels. If the plume were due to HCl/NH_3 reactions, this change in ambient temperature would have little effect on the post stack aerosol formation. Thus, the available data and observations suggest detached visible plume formation is due to SO_2/NH_3 reactions and the entrainment of low temperature (i.e., less than 30°F) ambient air.

8.2 NH_3 Absorption by Fly Ash

At Arapahoe Unit 4, the fly ash collected in the fabric filter is not sold for secondary use, so the absorption of NH_3 on the fly ash poses primarily a personnel problem during ash handling and disposal. During the baseline SNCR testing, the NH_3 content of fly ash samples taken from the fabric filter hoppers ranged from 11 to 40 ppm (by weight) when the SNCR system was operated with an NH_3 slip of 8 to 10 ppm(3). During the current phase of testing, fly ash samples were collected by Western Research Institute during the four day period of "long-term" urea tests (see Section 6). NH_3 concentrations for these samples ranged from 72 to 108 ppm (by weight). While the urea injection system was set up to operate with 10 ppm NH_3 slip, the continuous NH_3 measurement at the outlet of the fabric filter indicated time periods when the NH_3 slip levels were over 20 ppm. Additional fly ash samples were collected under more well controlled and documented conditions during the air toxics test conducted with urea injection. The report documenting these results is forthcoming.

8.3 SO_3/NH_3 Reactions with Air Heater Deposition

Air preheater deposition and plugging can occur due to reactions between SO_3 and NH_3. These reactions occur in the temperature region of 330 to 375°F, where the formation of ammonium bisulfate occurs. The actual reaction temperature depends on the concentrations of SO_3 and NH_3. Deposition and plugging will be more severe with regenerative air preheaters because the flow passages are small when compared to those for tubular air preheaters. Arapahoe Unit 4 has a tubular air preheater and the flue gas SO_3 concentrations are low (less than 1 ppm)(1,2). As a consequence, with the SNCR operation to date, no change in air preheater performance has been observed. However, if the SNCR system is operated on a long-term basis, (i.e., months), air preheater performance (heat transfer, and pressure drop) should be documented to insure that no long-term effects occur.

8.4 Boiler Efficiency Impacts

Boiler efficiency will be impacted by the SNCR system due to 1) power to run the mixing air compressor, liquid pumps, and heaters, 2) additional dry gas losses in the boiler due to the mixing air, and 3) additional water vapor losses due to the injection of the aqueous chemical. (Note: depending on the actual solution concentration, the exothermic energy released by the NO reduction reactions will partially offset the vaporization losses.)

Mixing Air

Based on the parametric tests, the recommended operating pressure for the mixing air is 8 psig, which corresponds to a mixing air flow rate of 3900 scfm. The energy needed to operate the compressor is nominally 260 kW (i.e., 350 hp) or 0.26 to 0.43 percent of the unit output over the load range from 100 to 60 MWe, respectively. In terms of additional dry gas stack losses, 3900 scfm corresponds to 2.4 to 1.8 percent of the total flow over the boiler load range from 60 to 100 MWe. This additional air flow through the unit will produce an efficiency loss of 0.09 to 0.05 percent.

Vaporization Losses

Efficiency penalties due to the net effect of vaporization of the aqueous solutions and exothermic energy release of the SNCR reactions will depend on the total liquid flow rate and operating N/NO ratio. Based on the parametric test results with urea injection, the total liquid flow rates will be 2 gpm at boiler loads of 60 to 80 MWe and 6 gpm at loads above 80 MWe. Operating N/NO ratios, based upon an NH_3 slip limit of 10 ppm (Figure 7-2) will be 0.20 and 1.70 for boiler loads of 60 and 100 MWe, respectively. The net effect will be boiler efficiency penalties of nominally 0.15 percent at 60 MWe and 0.10 percent at 100 MWe.

Total Efficiency Penalties

Including the electrical power to run the liquid pumps (injection and recirculation), the boiler efficiency penalties due to use of the SNCR system will vary with load and be on the order of 0.71 percent at 60 MWe and 0.44 percent at 100 MWe. At both loads, the dominant factor is the mixing air. Although, as the load is increased from 60 to 100 MWe, the vaporization losses associated with the increasing total liquid flow rate become more important.

8.5 Steam Temperature Control

With the retrofit burner system, slagging in the radiant furnace was reduced(2). This resulted in some difficulties maintaining design steam temperatures, particularly during low load operation. To compensate for the reduced furnace exit gas temperatures, the operating excess air level has been increased at low loads. The use of the SNCR system can potentially further aggravate this problem. With the SNCR system, both the mixing air and the vaporization of the aqueous solutions will result in local cooling of the flue gas at the entrance to the convective section. If the unit is already operating with the steam attemperators closed, then steam temperature control may be compromised. Recall that for urea injection at boiler loads of 80 MWe and below the recommended total solution flow rate was 2 gpm (compared to 6 gpm at higher loads). This flow rate was chosen for two reasons. First, at reduced loads, the SNCR system is operating on the low side of the temperature window and additional cooling of the flue gas is undesirable. Second, operating with the minimum total solution flow rate had the minimum effect on steam temperatures. For reference, order of magnitude estimates of the local cooling effect of the mixing air and vaporization are summarized in Table 8-1.

Table 8-1

Approximate Local Gas Cooling Effects Due to SNCR Injection

			Local Gas Cooling		
Load (MWe)	Mixing Air Flow Rate (scfm)	Solution Flow Rate (gpm)	Mixing Air (°F)	Vaporization (°F)	Total Cooling (°F)
60	3900	2	40-45	8	48-53
100	3900	6	30-35	18	48-53

9

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and observations can be made regarding the performance of the SNCR system on the Arapahoe Unit 4 boiler with the retrofit low-NO_x combustion system.

Urea

- Optimum NO reduction performance occurred at a boiler load of 100 MWe. For a nominal N/NO ratio of 1.0, the NO removal was 48 percent with a NH_3 slip of 14 ppm.
- Boiler load was the parameter which was shown to have the largest effect on system performance, as it was the predominant factor in determining the local flue gas temperature at the injection location.
- Variations in total liquid flow and mixing air flow had small effects on both NO removal and NH_3 emissions over the range of flows tested (nominally 2.0 to 6.0 gpm and 2800 to 4800 scfm, respectively).

Converted Urea

- At a nominal N/NO ratio of 1.0, peak NO removals of 38 to 42 percent occurred over the boiler load range of 60 to 100 MWe. NH_3 emissions were at or below 5 ppm for loads of 80 to 100 MWe. At 60 MWe, NH_3 emissions increased to nominally 65 ppm.

Comparison of Urea and Converted Urea

- Although NO removals were found to be higher with urea than with converted urea for a fixed N/NO ratio over nearly the entire load range (70 to 113 MWe). NH_3 emissions were also found to be higher.

- On an equal ammonia slip basis, converted urea provides higher NO removals than urea. For a 10 ppm NH_3 emission limit, NO removals of 19 to 47 percent were achievable with converted urea over the load range of 60 to 100 MWe, while urea injection resulted in removals of 11 to 45 percent. However, the increased NO removals with converted urea required higher chemical injection rates (i.e., higher N/NO rates), and therefore, at boiler loads of 80 MWe and greater, urea was the most efficient chemical.

- N_2O emissions with converted urea were lower than those for urea. For converted urea, the fraction of NO converted to N_2O at a nominal N/NO ratio of 1.0 ranged from 3 to 8 percent, depending on boiler load. With urea, the conversion ranged from 29 to 35 percent.

Comparison of Pre- and Post-Retrofit SNCR Performance

- Peak NO removals for urea injection with the retrofit combustion system were similar to those seen with the original burners, but the boiler load at which the peak occurred increased from approximately 70 to 100 MWe. This shift was a result of the decrease in furnace exit gas temperature seen after the retrofit.

- On a normalized basis, the NH_3 emissions for urea injection with the retrofit combustion system were higher than those for the original burners, over the entire load range. This is also attributable to lower furnace exit temperatures.

- With urea injection, N_2O emissions, in terms of percent of the NO reduction converted to N_2O, were higher with the retrofit combustion system.

10

REFERENCES

---

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

2. Smith, R.A., Muzio, L.J., Hunt, T., *Integrated Dry NO_x/SO_2 Emissions Control System Low-NO_x Combustion System Retrofit Test Report*, DOE Contract Number DE-FC22-91PC90550, October 1993.

3. Smith, R.A., Shiomoto, G.H., Muzio, L.J., Hunt, T., *Integrated Dry NO_x/SO_2 Emissions Control System Baseline SNCR Test Report*, DOE Contract Number DE-FC22-91PC90550, September 1993.

4. Muzio, L.J., Arand, J.K., *Homogeneous Gas Phase Decomposition of Oxides of Nitrogen*, EPRI FP-253, August 1976.

5. Teixeira, D.P., Muzio, L.J., Montgomery, T.A., *N_2O Emissions from SNCR Processes*, presented at the First International Conference on Combustion Technologies for a Clean Environment, Vilamoura, Portugal, September 1991.

6. Smith, R.A., *Flue Gas Temperature Measurement, Trip Report, Public Service Company of Colorado*, Fossil Energy Research Corp., June 1991.

7. Martz, T.D., *Evaluation of Urea Injection System Designs for Arapahoe Unit 4 through Cold Flow Modeling*, Fossil Energy Research Corp., July 1991.

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

9. Teixeira, D.P., et al., *Selective Non-Catalytic Reduction (SNCR) Field Evaluation in Utility Natural Gas-Fired Boilers*, GR192-0083, March 1992.

10. Muzio, L.J., et al., *N_2O Formation in Selective Non-Catalytic NO_x Reduction Processes*, presented at the American Flame Research Committee 1990 Fall International Symposium, November 1990.

11. Muzio, L.J., Montgomery, T.A., Quartucy, G.C., Teixeira, D.P., *The Effect of Residence Time on SNCR Processes*, presented at the EPRI/EPA 1993 Joint Symposium on Stationary Combustion NO_x Control, May 1993.

12. Hjuler, K., *The Reaction Between Sulphur Dioxide and Ammonia in Flue Gas*, Ph.D. Thesis, Department of Chemical Engineering, Technical University of Denmark, 1991.

APPENDIX

DATA SUMMARY

PSCC Arapahoe Unit 4   LOW NOx BURNER/Urea Test Data

																									Baseline										
Test	Date & Time		Comments	Load MWe	CR O2 % wet	Mills OOS	Steam e4pph	Tank Urea wt %	Cnvtr Temp °F	Urea Flow gpm	Total Flow gpm	Inject Air P psig	O2 ave %	CO ave ppm	H2O % (1)	NO ppm	NO ppmc d	CO2 %	SO2 ppm	SO2 ppmc d	N2O ppm	Altech NH3-adj ppm dry	Nessler NH3 comp ppm dry	Spec Ion NH3 comp ppm dry	O2 %	H2O %	NO ppm	NO ppmc d	N2O ppmc	N2Oc ppmc d	ΔNO %	N NO FERCo	Utiliz %	N2O ppmc d	ΔN2O ΔNO
384	01/11/93	13.42	UREA STARTUP (unit regulating 112-114)	113	2.70		983	37.4		2.43	8.05	8.0	2.60	600	0.0	127	124	14.20	322	315	43	9.7			2.40	0.0	247	239	9.7	9.4	48.0	1.97	24.4	41.6	0.29
																						AHE4	19.7	17.8											
385	01/11/93	16.10	CONV STARTUP (unit swinging 85-114MW)	?																		97.8													
386	01/12/93	14.20	UREA N/NO=0.5	114	3.30		983	37.4		0.75	6.00	8.0	4.10	291	0.0	186	198	14.46	363	387	17	0.0	1.7	2.0	4.20	0.0	258	276	1.9	2.0	28.3	0.52	54.3	17.6	0.20
																						AHE4	1.1	1.2											
387	01/12/93	15.50	CONV N/NO=0.5 300F	114	3.24		953	37.4	300	0.75	6.00	8.0	4.20	203	0.0	195	209	14.41	350	375	12				4.20	0.0	258	276	1.9	2.0	24.3	0.52	46.5	13.1	0.16
388	01/12/93	16.51	CONV N/NO=0.5 360F	114	3.48		952	37.4	360	0.75	6.00	8.0	4.70	240	0.0	203	224	14.03	337	372	7				4.20	0.0	258	276	2.0	2.1	18.9	0.52	36.2	7.3	0.10
389	01/12/93	18.07	CONV N/NO=0.5 420F	114	3.24		949	37.4	420	0.75	6.00	8.0	3.70	388	0.0	193	201	14.34	353	367	6				4.20	0.0	258	276	2.0	2.1	27.4	0.52	52.4	6.3	0.06
390	01/12/93	19.30	BASELINE CHECK	114	3.57		960	37.4		0.00	0.00	0.0	4.40	60	8.1	252	228	12.94	323	293	4	0.0													
391	01/13/93	12.27	UREA N/NO=0.75	112	3.74		985	37.4		1.35	6.00	8.0	5.00	178	0.0	154	173	13.83	403	453	25	0.3	19.2	15.4	5.00	0.0	254	286	1.2	1.4	39.4	0.92	42.6	28.4	0.24
																						AHE4	21.1	29.0											
392	01/13/93	13.51	UREA N/NO=1.0	112	3.74		967	37.4		1.80	6.00	8.0	5.00	167	0.0	143	161	13.70	423	476	29	2.2	26.0	21.5	5.00	0.0	254	286	1.0	1.1	43.7	1.23	35.4	32.1	0.25
393	01/13/93	15.45	UREA N/NO=1.5	112	3.74		967	37.4		2.70	6.00	8.0	4.90	155	0.0	129	144	14.10	425	475	37	15.4	44.0	36.1	5.00	0.0	254	286	1.0	1.1	49.5	1.85	26.8	41.3	0.28
394	01/13/93	19.00	CONV ON (ABORT)	112	3.28		965	37.4	350	2.70	6.00	8.0	4.20	50	8.0	150	136	13.10	461	418	6	6.6			4.80	8.2	244	221	1.0	0.9	38.4	1.95	19.7	5.4	0.05
395	01/14/93	13.27	UREA N/NO=1.25	111	4.19		956	37.4		2.10	6.00	8.0	5.90	170	0.0	133	159	13.06	429	511	33	13.2	41.9	33.4	5.30	0.0	248	284	1.2	1.4	44.2	1.46	30.3	39.3	0.30
																						STACK	29.7	20.9											
																						AHE4	11.9	10.9											
396	01/14/93	19.07	CNV N/NO=1.25 350F	111	3.29		954	37.4	350	2.10	6.00	8.0	4.60	174	0.0	136	149	13.94	462	507	17	12.9	26.7	27.9	5.30	0.0	248	284	1.2	1.4	47.5	1.46	32.6	18.2	0.12
																						AHE4		14.8											
397	01/14/93	20.45	CNV N/NO=0.75 402F	111	3.57		960	37.4	402	1.30	3.70	8.0	4.60	232	0.0	171	188	13.98	478	525	6	3.5			5.30	0.0	248	284	1.2	1.4	34.0	0.90	37.6	6.0	0.05
398	01/15/93	11.45	UREA N/NO=1.0	113	3.72		949	37.4		1.60	3.00	8.0	4.30	392	0.0	152	164	13.78	392	423	30	1.5		12.4	4.40	0.0	244	265	2.8	3.0	38.1	1.17	32.5	32.1	0.29
																						AHE1		4.5											
																						AHE2		3.5											
																						AHE3		3.1											
																						AHE4		4.5											
																						AHE5		28.5											
																						AHE6		64.4											
399	01/18/93	12.00	UREA N/NO=1.0 8psi	113	3.54		978	37.4		1.65	6.00	8.0	4.10	387	0.0	133	142	13.56	453	482	31	1.2		9.4	3.70	0.0	228	237	5.4	5.6	40.3	1.35	29.9	33.2	0.29
			E1	113	3.54		978	37.4		1.65	6.00	8.0	6.20	743	0.0	124	151	9.70	327	398	34				2.60	0.0	198	194	8.5	8.3	22.1	1.65	13.4	41.0	0.76
			E2	113	3.54		978	37.4		1.65	6.00	8.0	4.20	2271	0.0	140	150	12.42	422	452	68	AHE1		5.4	3.80	0.0	185	194	47.0	49.2	22.5	1.65	13.6	73.2	0.55
			E3	113	3.54		978	37.4		1.65	6.00	8.0	3.60	596	0.0	168	174	13.98	460	476	31				3.90	0.0	247	260	16.1	16.9	33.2	1.23	26.9	32.2	0.18
			E4	113	3.54		978	37.4		1.65	6.00	8.0	6.00	49	0.0	137	164	12.54	419	503	34	AHE2		6.7	5.30	0.0	246	282	2.7	3.1	41.7	1.13	36.8	40.9	0.32
			E5	113	3.54		978	37.4		1.65	6.00	8.0	4.70	179	0.0	153	169	13.33	453	500	27				5.30	0.0	240	275	2.6	3.0	38.6	1.16	33.2	29.6	0.25
			E6	113	3.54		978	37.4		1.65	6.00	8.0	5.60	27	0.0	96	112	13.18	457	534	42	AHE3		7.9	5.90	0.0	251	299	2.0	2.4	62.5	1.07	58.4	49.3	0.25
			E7	113	3.54		978	37.4		1.65	6.00	8.0	4.30	31	0.0	199	214	14.03	476	513	18				4.90	0.0	255	285	2.1	2.3	24.8	1.12	22.1	19.7	0.25
			E8	113	3.54		978	37.4		1.65	6.00	8.0	4.80	28	0.0	130	144	13.78	469	521	26	AHE4		6.3	4.50	0.0	213	232	3.3	3.6	37.8	1.38	27.5	28.8	0.29
			E9	113	3.54		978	37.4		1.65	6.00	8.0	2.60	87	0.0	202	198	15.72	534	522	14				3.10	0.0	237	238	2.5	2.5	17.1	1.34	12.7	13.7	0.27
			E10	113	3.54		978	37.4		1.65	6.00	8.0	3.60	44	0.0	122	126	14.85	512	530	29	AHE5		15.8	3.40	0.0	214	219	2.7	2.8	42.3	1.46	28.9	29.8	0.29
			E11	113	3.54		978	37.4		1.65	6.00	8.0	4.00	79	0.0	117	124	14.38	478	506	34				3.80	0.0	218	228	2.7	2.8	45.7	1.40	32.6	36.1	0.32
			E12	113	3.54		978	37.4		1.65	6.00	8.0	6.30	68	0.0	73	89	12.51	411	503	40	AHE6		17.2	6.50	0.0	178	221	2.4	3.0	59.5	1.45	41.1	49.2	0.35
			E1-12 REPEAT	113	3.54		978	37.4		1.65	6.00	8.0	3.60	413	0.0	132	137	13.82	413	427	33				3.70	0.0	228	237	5.4	5.6	42.4	1.35	31.5	33.8	0.28
400	01/18/93	16.00	UREA N/NO=1 12psi	113	3.54		978	37.4		1.65	6.00	12.0	4.20	310	0.0	132	141	13.88	486	521	30	2.6		10.5	3.60	0.0	239	247	3.1	3.2	42.8	1.29	33.1	31.7	0.27
401	01/18/93	16.19	UREA N/NO=1.0 4psi	113	3.54		978	37.4		1.65	6.00	4.0	4.20	324	0.0	150	161	13.88	493	528	26	8.1		13.5	3.60	0.0	239	247	3.1	3.2	35.0	1.29	27.0	28.1	0.29
402	01/18/93	17.15	BILEVEL AIR N/NO=1	113	3.54		978	37.4		1.65	6.00	8.0	4.40	41	8.6	153	140	12.69	477	435	24	7.1			4.50	8.1	233	210	0.0	0.0	33.6	1.26	26.7	22.2	0.31
403	01/18/93	17.35	BILEVEL UREA 8psi	113	3.54		978	37.4		1.65	6.00	8.0	4.30	50	8.7	133	122	12.82	476	435	25	14.1			4.50	8.1	233	210	0.0	0.0	42.2	1.26	33.5	23.1	0.26
404	01/18/93	17.46	BILEVEL UREA 10psi	113	3.54		978	37.4		1.65	6.00	10.0	4.20	75	8.8	133	122	12.92	476	436	25	12.3			4.50	8.1	233	210	0.0	0.0	42.1	1.26	33.4	22.7	0.26
405	01/18/93	18.06	BILEVEL UREA 4psi	113	3.54		978	37.4		1.65	6.00	4.0	4.40	53	8.5	152	139	12.76	488	445	23	19.8			4.50	8.1	233	210	0.0	0.0	34.1	1.26	27.0	20.7	0.29
406	01/18/93	18.40	BASELINE CHECK	113	3.54		978	37.4		0.00	0.00	0.0	3.60	427	0.0	239	247	14.07	524	542	3	0.0			3.60	0.0	239	247	3.1	3.2	0.0	0.00	-	3.2	
407	01/19/93	14.19	CONV N/NO=0.5 410F	113	3.82		982	37.4	410	0.82	3.00	8.0	4.10	375	0.0	196	209	13.90	470	501	6	0.6	0.6		5.30	0.0	251	288	2.8	3.2	27.5	0.55	49.7	6.2	0.04
408	01/19/93	15.28	CNV N/NO=0.75 390F	113	3.82		982	37.4	390	1.28	4.50	8.0	5.30	208	0.0	169	194	13.11	436	500	8	0.0	0.6	4.1	5.30	0.0	251	288	2.8	3.2	32.7	0.86	37.9	9.1	0.06
409	01/19/93	18.12	CONV N/NO=1.0 375F	113	3.82		982	37.4	375	1.70	6.00	8.0	4.30	384	0.0	156	168	13.69	410	442	14	2.8	10.0	7.9	5.30	0.0	251	288	2.8	3.2	41.6	1.15	36.3	14.9	0.10
410	01/19/93	18.58	BILEVEL CNV N/NO=1	113	3.82		982	37.4	375	1.70	6.00	8.0	4.50	324	0.0	143	156	13.87	408	445	10	37.7			5.00	0.0	241	271	3.7	4.2	42.5	1.22	34.9	10.4	0.05
																						AHE4	40.1	39.9											
411	01/20/93	11.01	UREA N/NO=0.5	102	4.43		874	37.4		0.81	6.00	8.0	5.90	50	0.0	166	197	13.07	347	414	22	3.2	10.7	8.6	5.90	0.0	252	300	0.9	1.1	34.3	0.58	59.2	26.3	0.25
																						AHE4	0.5	4.6											
412	01/20/93	11.20	UREA N/NO=0.75	102	4.43		874	37.4		1.22	6.00	8.0	5.80	64	0.0	142	168	13.18	342	405	28	15.9	20.5	24.5	5.90	0.0	252	300	0.9	1.1	44.2	0.87	50.6	33.0	0.24
413	01/20/93	14.18	UREA N/NO=1.0	102	4.43		885	37.4		1.62	6.00	8.0	6.00	57	0.0	131	157	12.92	321	385	32	33.0	41.4	42.1	5.90	0.0	252	300	0.9	1.1	47.9	1.16	41.3	38.3	0.26
																						AHE4	34.1	31.2											
414	01/20/93	15.00	UREA N/NO=1.25	102	4.43		885	37.4		2.00	6.00	8.0	6.00	66	0.0	122	147	12.87	301	361	37	40.1	60.0	52.3	5.90	0.0	252	300	0.9	1.1	51.2	1.43	35.8	44.3	0.28
415	01/20/93	16.30	UREA N/NO=1.5	102	4.43		885	37.4		2.40	6.00	8.0	6.00	55	0.0	116	139	13.04	287	344	39	56.1	83.0	75.9	5.90	0.0	252	300	0.9	1.1	53.7	1.72	31.3	46.4	0.28
416	01/20/93	17.15	UREA N/NO=1.0 RPT	102	4.43		885	37.4		1.62	6.00	8.0	6.00	57	0.0	132	158	13.04	312	374	32	25.9	51.0	43.1	5.90	0.0	252	300	0.9	1.1	47.3	1.16	40.8	38.4	0.26
417	01/21/93	12.34	UREA N/NO=1.0	101	4.39		885	37.4		1.62	6.00	8.0	6.00	61	0.0	130	156	13.42	299	359	32	25.2	80.1	50.0	6.10	0.0	253	306	0.8	1.0	48.9	1.15	42.5	38.8	0.25
			E1	101	4.39		885	37.4		1.62	6.00	8.0	7.90	125	0.0	119	164	11.46	273	375	30				9.10	0.0	197	298	3.1	4.7	45.1	1.18	38.2	41.5	0.27
			E2	101	4.39		885	37.4		1.62	6.00	8.0	7.20	135	0.0	139	181	11.84	281	367	21	AHE1	14.2	13.6	6.30	0.0	198	242	5.7	7.0	25.2	1.45	17.4	27.4	0.33
			E3	101	4.39		885	37.4		1.62	6.00	8.0	5.50	69	0.0	168	195	13.70	323	375	29				4.40	0.0	272	295	5.7	6.2	33.9	1.19	28.4	33.2	0.27
			E4	101	4.39		885	37.4		1.62	6.00	8.0	7.10	38	0.0	122	158	12.20	282	365	35	AHE2	32.4	23.5	6.80	0.0	264	335	1.6	2.0	52.8	1.05	50.2	45.8	0.25
			E5	101	4.39		885	37.4		1.62	6.00	8.0	7.10	26	0.0	131	170	12.25	295	382	30				6.60	0.0	253	316	1.2	1.5	46.4	1.11	41.7	38.6	0.25
			E6	101	4.39		885	37.4		1.62	6.00	8.0	7.00	36	0.0	81	104	12.43	254	327	43	AHE3	40.5	32.2	6.30	0.0	257	315	0.8	1.0	66.9	1.12	59.9	55.7	0.26
			E7	101	4.39		885	37.4		1.62	6.00	8.0	8.00	21	0.0	154	213	11.66	278	385	18				5.60	0.0	269	314	0.8	0.9	32.2	1.12	28.8	25.2	0.24
			E8	101	4.39		885	37.4		1.62	6.00	8.0	7.00	18	0.0	123	158	12.51	303	390	30	AHE4	37.6	26.2	5.20	0.0	257	293	1.8	2.1	46.0	1.20	38.3	38.6	0.27
			E9	101	4.39		885	37.4		1.62	6.00	8.0	5.80	31	0.0	133	158	13.51	323	383	29				4.00	0.0	267	283	1.5	1.6	44.3	1.24	35.6	34.8	0.27
			E10	101	4.39		885	37.4		1.62	6.00	8.0	7.10	22	0.0	94	122	12.37	294	381	36	AHE5	92.1	70.3	5.20	0.0	240	273	1.8	2.1	55.5	1.29	43.1	46.9	0.30
			E11	101	4.39		885	37.4		1.62	6.00	8.0	7.80	48	0.0	107	146	11.58	207	282	26				5.20	0.0	248	283	1.6	1.8	48.4	1.24	38.9	35.6	0.25
			E12	101	4.39		885	37.4		1.62	6.00	8.0	9.60	44	0.0	90	142	10.02	133	210	23	AHE6	134.4	104.2	7.60	0.0	210	282	2.3	3.1	49.6	1.25	39.8	35.8	0.23

PSCC Arapahoe Unit 4 LOW NOx BURNER/Urea Test Data

								Tank	Cnvrtr	Urea	Total	Inject										Altech	Nessler	Spec Ion	Baseline										
Test	Date & Time		Comments	Load	CR O2	Mills	Steam	Urea	Temp	Flow	Flow	Air P	O2 ave	CO ave	H2O	NO	NO	CO2	SO2	SO2	N2O	NH3-adj	NH3 comp	NH3 comp	O2	H20	NO	NO	N2O	N2Oc	ΔNO	N/NO	Utiliz	N2O	ΔN2O
				MWe	% wet	OOS	e4pph	wt %	°F	gpm	gpm	psig	%	ppm	% (1)	ppm	ppmc.d	%	ppm	ppmc d	ppm	ppm.dry	ppm dry	ppm dry	%	%	ppm	ppmc d	ppmc	ppmc.d	%	FERCo	%	ppmc.d	ΔNO
	01/21/93	15:30	UREA N/NO=1 CHECK	101	4.39		885	37.4		1.62	6.00	8.0	6.00	48	0.0	124	149	13.27	289	347	34		54.1	37.0	6.10	0.0	253	306	0.8	1.0	51.3	1.15	44.6	41.3	0.26
418	01/21/93	16:00	12psi (LOST UNIT)	102	4.39		885	37.4		1.62	2.24	12.0	5.40	23	8.0	122	110	12.36	299	268	37	14.6													
419	01/21/93	17:21	UREA N/NO=0.5	48	8.46	B,C	406	37.4		0.45	2.24	8.0	9.10	41	0.0	182	275	9.40	188	284	9	48.4	56.2		10.30	0.0	214	360	5.4	9.1	23.5	0.57	41.2	13.8	0.06
420	01/21/93	18:57	UREA N/NO=0.5 8psi	57	7.70	B,C	469	37.4		0.45	2.24	8.0	9.80	31	0.0	197	317	9.90	200	321	8	38.1			9.50	0.0	245	383	4.3	6.7	17.4	0.45	38.6	13.3	0.10
421	01/21/93	19:45	UREA N/NO=.5 12psi	57	7.70	B,C	469	37.4		0.45	2.24	12.0	8.80	33	6.6	205	175	9.74	230	196	11	38.3			8.50	6.5	245	209	2.8	2.4	16.4	0.49	33.3	9.6	0.21
422	01/22/93	11:38	UREA?(CAT HEATING)	48	7.96	B,C	407	37.4	?	0.77	4.20	8.0	8.70	30	6.5	172	147	9.60	228	194	5	86.4			8.80	6.2	226	191	3.6	3.0	23.2	1.05	22.0	3.9	0.02
423	01/22/93	12:42	CONV N/NO=1.0 350F	48	7.96	B,C	407	37.4	335	0.77	4.20	8.0	9.60	27	0.0	158	249	9.72	142	224	4	86.9	109.6	76.0	9.40	0.0	218	338	3.2	5.0	26.3	1.04	25.3	6.6	0.02
																						AHE1	15.8	14.4											
																						AHE2	46.5	32.6											
																						AHE4	152.2	100.2											
																						AHE6	256.6	203.1											
																						AHE5	204.9	167.6											
																						AHE3	82.8	58.3											
424	01/22/93	16:02	CONV N/NO=0.5 350F	48	7.96	A,D	407	37.4	335	0.39	2.10	8.0	9.90	40	0.0	152	246	9.67	202	328	7	33.6	48.8	34.0	9.80	0.0	183	294	6.0	9.6	16.2	0.61	26.7	11.4	0.04
																						AHE4	14.6	10.4											
																						AHE6	129.4	99.2											
																						AHE1	29.2	20.5											
																						AHE5	84.7	70.9											
																						AHE2	23.1												
																						AHE3	20.5	14.8											
425	01/25/93	10:12	UREA N/NO=1 12psi	100	4.33		861	37.4		1.50	6.01	12.0	5.85	28	0.0	113	134	13.40	474	563	32	9.7	31.1	27.2	5.70	0.0	241	284	0.8	0.9	52.6	1.16	45.4	38.5	0.25
																						AHE4	9.8	10.5											
426	01/25/93	14:29	UREA N/NO=1 8psi	100	4.46		862	37.4		1.50	6.01	8.0	5.50	28	0.0	128	149	13.70	468	543	29	10.3	22.6		5.70	0.0	241	284	0.8	0.9	47.6	1.16	41.0	33.4	0.24
427	01/25/93	15:24	UREA N/NO=1 6psi	100	4.42		862	37.4		1.50	6.01	6.0	5.40	35	0.0	131	151	13.80	467	539	28	12.9	21.9	24.5	5.70	0.0	241	284	0.8	0.9	46.7	1.16	40.3	32.2	0.24
428	01/25/93	16:28	UREA N/NO=1 4psi	100	4.35		862	37.4		1.50	6.01	4.0	5.80	26	0.0	137	162	13.50	447	529	28	14.0	21.4		5.70	0.0	241	284	0.8	0.9	42.8	1.16	36.9	33.6	0.27
429	01/26/93	09:34	UREA N/NO=1 8psi	100	4.45		862	37.4		1.55	6.01	8.0	5.70	28	0.0	133	156	13.70	452	532	29	22.4			5.80	0.0	250	296	0.0	0.0	47.1	1.15	41.1	34.5	0.25
	01/26/93	11:08	E1&2							1.55	6.01	8.0	7.20	441	0.0	132	172	11.70	441	575	26	AHE1	1.7	6.4											
	01/26/93	11:19	E3&4							1.55	6.01	8.0	6.00	124	0.0	142	170	12.90	427	512	30	AHE2	7.1	8.5											
	01/26/93	11:32	E5&6							1.55	6.01	8.0	6.35	34	0.0	108	133	12.60	406	499	37	AHE3	22.9	20.2											
	01/26/93	11:47	E7&8							1.55	6.01	8.0	5.40	23	0.0	124	143	13.40	428	494	36	AHE4	23.4	20.4											
	01/26/93	12:02	E9&10							1.55	6.01	8.0	4.45	23	0.0	132	144	14.30	455	495	32	AHE5	42.9												
	01/26/93	12:15	E11&12							1.55	6.01	8.0	6.30	38	0.0	126	154	12.60	327	400	27	AHE6	72.2	84.2											
	01/26/93	12:26	E1-12 RPT	100	4.34		865	37.4		1.55	6.01	8.0	5.65	31	0.0	125	147	13.50	399	468	32	AVG	28.4		5.80	0.0	250	296	0.0	0.0	50.5	1.15	44.0	37.6	0.25
430	01/26/93	13:47	same w/#10 INJ OOS	100	4.46		864	37.4		1.55	6.01	8.0	5.70	26	0.0	133	158	13.45	402	473	32	25.7	27.2		5.80	0.0	250	296	0.0	0.0	47.1	1.15	41.1	38.0	0.27
																						AHE6	28.5												
431	01/26/93	14:49	same w/#9&10 OOS	100	4.43		863	37.4		1.55	6.01	8.0	5.85	26	0.0	142	167	13.56	391	459	31	28.7	21.4	17.6	5.80	0.0	250	298	0.0	0.0	43.8	1.15	38.1	38.0	0.28
																						AHE6	4.5												
432	01/26/93	16:35	10 inj w/D mill+15%	100	4.87		869	37.4		1.55	6.01	8.0	5.70	46	0.0	134	158	13.35	343	404	30	23.9	33.9	30.3	5.80	0.0	250	296	0.0	0.0	46.8	1.15	40.7	35.4	0.26
																						AHE6	58.4	54.6											
433	01/27/93	11:22	CONV N/NO=1 8psi	100	4.27		874	37.4	380	1.60	6.01	8.0	5.40	25	0.0	141	163	13.59	311	359	8				5.70	0.0	260	306	0.8	0.9	46.8	1.15	40.8	9.0	0.06
	01/27/93	13:02	E1&2										7.30	297	0.0	154	202	11.44	291	382	8	AHE1	1.0	1.5											
	01/27/93	13:14	E3&4										5.60	126	0.0	174	203	12.98	330	386	7	AHE2	0.1	0.8											
	01/27/93	13:24	E5&6 ABORT TEST										6.10	26	0.0	149	180	12.63	325	393	9	AHE3	0.6	0.8											
434	01/27/93	14:28	CONV N/NO=1 8psi	100	4.28		860	37.4	380	1.60	6.01	8.0	5.20	35	0.0	127	145	13.90	289	329	10	6.4			5.70	0.0	260	306	0.8	0.9	52.7	1.15	46.0	11.4	0.06
	01/27/93	14:50	E1&2, Pump2 Bad										8.60	173	0.0	153	222	10.42	267	388	6	AHE1	1.6	0.8											
	01/27/93	15:04	E3&4, Pump2 Bad										5.70	58	0.0	191	225	12.93	331	389	6	AHE2	0.3	1.1											
	01/27/93	15:14	E5&6, Pump2 Bad										6.00	17	0.0	141	169	12.69	332	398	9	AHE3	0.7	1.7											
	01/27/93	15:24	E7&8, Pump2 Bad										5.30	19	0.0	147	169	13.27	342	392	9	AHE4	17.8	15.2											
	01/27/93	15:38	E9&10, Pump2 Bad										4.40	24	0.0	142	154	14.20	331	359	9	AHE5	7.0	8.8											
	01/27/93	15:54	E11&12, Pump2 Bad										6.60	36	0.0	90	113	12.08	98	123	10	AHE6	77.9	197.0											
	01/27/93	17:28	1-12, Pump Fixed	100	4.23		861	37.4	380	1.60	6.01	8.0	6.00	49	0.0	161	193	13.04	193	232	6	AVG	17.6	37.4	6.30	0.0	254	311	1.8	2.2	37.9	1.13	33.6	7.4	0.04
435	01/28/93	13:27	CONV N/NO=1 8psi	100	4.36		860	37.4	365	1.60	6.01	8.0	5.50	85	0.0	163	189	13.63	338	383	7	0.0			6.10	0.0	253	306	0.0	0.0	38.1	1.15	33.2	8.1	0.07
	01/28/93	13:40	E1&2, Injctr#5 Bad?										6.80	368	0.0	158	200	11.77	296	375	3	AHE1	5.4	8.3											
	01/28/93	13:47	E3&4, Injctr#5 Bad?										5.80	59	0.0	182	218	13.18	326	386	5	AHE2	2.1												
	01/28/93	13:53	E5&6, Injctr#5 Bad?										6.10	26	0.0	129	156	13.29	332	401	10	AHE3	1.2	5.6											
	01/28/93	14:01	E7&8, Injctr#5 Bad?										5.30	25	0.0	151	173	13.95	350	401	10	AHE4	9.9	10.1											
	01/28/93	14:08	E9&10,Injctr#5Bad?										4.10	27	0.0	173	184	15.16	380	405	8	AHE5	1.0												
	01/28/93	14:16	E11&12,Injctr5Bad?										6.40	32	0.0	132	163	13.00	321	396	7	AHE6	15.5	14.0											
	01/28/93	14:23	E1-12 REPEAT	100	4.28		860	37.4	365	1.60	6.01	8.0	5.70	127	0.0	149	175	13.59	339	399	9	AVG	5.9		6.10	0.0	253	306	0.0	0.0	42.6	1.15	37.2	10.9	0.08
436	01/28/93	16:27	CONV N/NO=1 8psi	100	4.28		872	37.4	365	1.60	6.01	8.0	5.90	86	0.0	148	176	13.57	322	384	8	1.9			5.70	0.0	255	300	-0.6	-0.7	41.2	1.17	35.2	9.2	0.08
	01/28/93	16:36	E1&2										6.50	419	0.0	148	184	12.28	310	385	9	AHE1	1.6	2.4											
	01/28/93	16:43	E3&4										5.40	66	0.0	166	192	13.59	338	390	8	AHE2	0.7												
	01/28/93	16:52	E5&6										6.20	22	0.0	160	195	13.43	335	407	7	AHE3	0.5												
	01/28/93	17:00	E7&8										5.10	20	0.0	189	214	14.03	351	397	7	AHE4	2.2	4.6											
	01/28/93	17:07	E9&10										4.10	24	0.0	172	183	15.00	379	404	7	AHE5	23.0												
	01/28/93	17:26	E11&12										6.80	39	0.0	103	131	12.80	228	289	7	AHE6	46.1	44.1											
	01/28/93	17:34	E1-12 REPEAT	100	4.30			37.4		1.60	6.00	8.0	5.90	68	0.0	148	176	13.54	324	386	9	AVG	12.4		5.70	0.0	255	300	-0.6	-0.7	41.2	1.17	35.2	11.1	0.10
437	02/01/93	11:23	CONV N/NO=1 8psi	100	3.50		866	37.4	360	1.33	6.00	8.0	4.40	209	0.0	152	165	13.90	404	438	8	0.3	8.5	5.9	4.90	0.0	223	249	1.6	1.8	33.9	1.17	29.0	8.7	0.08
																						AHE4	0.6	0.9											
438	02/01/93	13:24	same w/#10 INJ OOS	100	3.50		866	37.4	360	1.33	6.00	8.0	5.00	113	0.0	144	162	13.97	441	496	8		0.6		4.90	0.0	223	249	1.6	1.8	35.0	1.17	29.9	9.0	0.08
																						AHE4	0.9												
439	02/01/93	13:45	10 INJ INCREASE O2	100	4.40		858	37.4	335	1.33	6.00	8.0	6.10	60	0.0	159	192	13.03	413	499	8		3.5		6.40	0.0	237	292	0.5	0.6	34.3	1.00	34.3	9.8	0.09
440	02/01/93	15:00	same w/#10 INJ OOS	100	4.40		858	37.4	335	1.33	6.00	8.0	6.00	31	0.0	157	188	13.12	425	510	9		0.7	0.9	6.40	0.0	237	292	0.5	0.6	35.5	1.00	35.6	11.3	0.10
441	02/01/93	15:41	same w/ 4.5 gpmT	100	4.40		858	37.4	360	0.95	4.50	8.0	6.00	36	0.0	185	222	13.18	430	516	4		0.5	0.5	6.40	0.0	237	292	0.5	0.6	24.0	0.71	33.7	4.3	0.05
442	02/01/93	16:20	10 INJ 4.5 gpmT	100	4.40		858	37.4	390	0.95	4.50	8.0	6.00	31	0.0	178	214	13.18	424	509	4		0.9		6.40	0.0	237	292	0.5	0.6	26.9	0.71	37.7	4.4	0.05

PSCC Arapahoe Unit 4 LOW NOx BURNER/Urea Test Data

Test	Date & Time		Comments	Load MWe	CR O2 % wet	Mills OOS	Steam e4pph	Tank Urea wt. %	Cnvrtr Temp F	Urea Flow gpm	Total Flow gpm	Inject Air P psig	O2 ave %	CO ave ppm	H2O % (1)	NO ppm	NO ppmc,d	CO2 %	SO2 ppm	SO2 ppmc,d	N2O ppm	Altech NH3-adj ppm,dry	Nessler NH3 comp ppm,dry	Spec Ion NH3 comp ppm,dry	Baseline						ΔNO %	N/NO FERCo	Utiliz %	N2O ppmc,d	ΔN2O/ΔNO
																									O2 %	H20 %	NO ppm	NO ppmc d	N2O ppmc	N2Oc ppmc,d					
443	02/01/93	17 14	10 INJ 7 5 gpmT	100	4.40		858	37 4	350	1 66	7 50	8 0	6 40	31	0 0	143	176	12 95	423	522	8		3 3	2 6	6 40	0 0	237	292	0 5	0 6	39 7	1 25	31 8	9 2	0 07
444	02/01/93	17 53	#10 INJ OOS 4 5gpmT	100	4.40		858	37 4	350	1 66	7 50	8 0	6 40	30	0 0	144	178	12 95	426	525	6		2 3		6.40	0 0	237	292	0 5	0 6	39 2	1 25	31 5	7 9	0 06
445	02/02/93	08 30	100MW as found	100	3.50		857						1.80	804	0 0	203	190	14 46	487	457	10													
			E1,2									0.15	2000+	0.0	163	141																	
			E11,12									5.20	105	0 0	170	194																	
			E3,4									2.40	708	0.0	217	210	14 09	470	455															
			E9,10									3.20	221	0 0	197	199		516	522															
			E5,6									5.80	127	0.0	223	264		446	528															
			E7,8									4 80	68	0.0	216	237																	
	02/02/93	09 35	E1-12 REPEAT									3.30	524	0.0	204	207	14.43	493	501	7														
446	02/02/93	09 47	Mills A-10%,D+10%	100	3.50		857						2.30	803	0 0	197	190		486	468															
			E1,2									5.80	522	0 0	168	199																	
			E3,4									5 20	167	0.0	212	242																	
			E11 12									0 70	1480	0 0	143	127																	
			Mills.A-5%,D+5%	100	3 50								4 40	287	0 0	205	222																	
			E11,12									3 90	500	0 0	156	164																	
			E1 2									4 50	850	0 0	165	180																	
			E5 6									6 00	37	0 0	215	258																	
			E7 8									5 80	66	0 0	210	249																	
	02/02/93	11 10	E9 10									3 30	211	0 0	199	202																	
			E3,4									4 20	506	0 0	210	225																	
447	02/02/93	11 10	A-5% B&C&D+5%	100	3 50		858						4 90	169	0 0	203	227																	
	02/02/93	12 07	E1,2									4 40	635	0 0	181	196																	
	02/02/93	12 13	E11,12									5 00	125	0 0	175	197																	
	02/02/93	12 17	E3,4									4.40	121	0 0	232	252																	
			E7,8									3.90	77	0.0	222	234																	
			E9,10									2 30	187	0 0	213	205																	
	02/02/93	12 45	E5,6									5 30	37	0 0	223	256																	
448	02/02/93	12 52	same w/ HIGHER O2	100	4 40		858						6.90	33	0 0	220	281	12 38	402	513	2														
			E1,2									7 70	66	0 0	200	271																	
			E11,12									6.80	25	0 0	198	251																	
449	02/02/93	15 31	U N/NO=1 5 A-5,D+5	100	4 40		859	37.4		2 15	6 00	8 0	6.10	57	0 0	119	144	13 21	384	464	34		21 6	19 9	6.30	0 0	226	277	1 3	1.6	48 1	1 70	28 2	40 7	0 29
				(FROM NOW ON, MILLS																		AHE1	4 9	7 8											
				AT: A-5%,D+5%)																		AHE6	10 5	14 1											
450	02/02/93	16 30	UREA N/NO=2 0	100	4 40		859	37 4		2 98	6 00	8 0	6 00	51	0 0	108	130	13 31	364	437	36				6 10	0 0	229	277	0 8	1 0	53 2	2 38	22 5	48 1	0 31
451	02/03/93	11 00	UREA N/NO=1 0	100	4 14		855	37 4		1 50	6 00	8 0	6 00	52	0 0	126	151	13 30	328	394	31		25 3	23 8	5 90	0 0	228	272	0 6	0 7	44 4	1 21	38 7	37 0	0 30
			(#451-454 Possible																			AHE1	10 6	7 9											
			Leaking Liquid Hoses)																			AHE2	24 2	20.0											
																						AHE3	53.3	49.2											
																						AHE4		75.6											
																						AHE5	21 5	19.8											
																						AHE6	28 6	22 8											
452	02/03/93	13 29	UREA N/NO=0 5	100	4 29		855	37.4		0 73	6 00	8 0	5 80	52	0 0	165	195	13 24	337	399	20		8 8	7 0	5 90	0 0	228	272	0 6	0 7	28 1	0 59	47 7	23 2	0 29
453	02/03/93	13 52	UREA N/NO=1 5	100	4.29		855	37 4		2 25	6 00	8 0	6 10	56	0.0	113	137	13 28	312	377	40		39 7	47 6	6 00	0 0	233	280	0 6	0 7	51 2	1 76	29 0	47 8	0 33
454	02/03/93	14 29	UREA N/NO=0 75	100	4 29		855	37 4		1 13	6 00	8.0	6 00	62	0 0	146	175	0 37	334	401	26				6 00	0 0	233	280	2 0	2 4	37 3	0 89	42 1	31 0	0 27
455	02/04/93	12.07	UREA N/NO=1 0	100	4.23		866	37.4		1 55	6 00	8.0	5.90	60	0.0	124	148	13.71	337	402	33		20 2	26 6	6.00	0.0	246	295	0 7	0.8	49 8	1 15	43 2	38.7	0 26
																						AHE1	12 5	14 3											
																						AHE2	12 4	14.9											
																						AHE3	23 1	25.8											
																						AHE4	15 5	17.6											
																						AHE5	31.6	31 0											
																						AHE6	68 6	65 9											
																						AVG	24 1	28 3											
456	02/04/93	15:00	UREA N/NO=1.0 (#10	100	4.20			37.4		1.56	6.00	8.0	6.00	46	0.0	121	145	13 74	346	415	34		15 4	12 1	6.00	0.0	246	295	0.7	0.8	50.7	1 16	43 7	40 7	0 27
			Liq Orifice=0.024")																			AHE6	25.9	31 1											
457	02/04/93	16:00	Small#10 N/NO=0.75	100	4.20			37.4		1.17	6 00	8.0	5.90	38	0.0	140	167	13 76	357	426	38		11 1	13.5	6.00	0.0	246	295	0 7	0.8	43 4	0 87	49 8	44 9	0 35
458	02/04/93	17:00	Small#10 N/NO=0.5	100	4.20			37.4		0.75	6 00	8.0	5.90	33	0.0	162	193	13 66	357	426	21		4 5	4.4	6 00	0 0	246	295	0.7	0 8	34 4	0 56	61 7	25 2	0 24
459	02/04/93	17 45	Small#10 N/NO=1.5	100	4.20			37.4		2.31	6 00	8.0	6.00	43	0.0	107	128	13.55	340	408	42		24 1	34 6	6.00	0 0	246	295	0.7	0 8	56 4	1 72	32 8	50 6	0.30
460	02/04/93	18 44	As #456 w/2.1gpmT	100	4.20		870	37.4		1.58	2.10	8.0	6.30	35	0.0	130	159	13.30	340	416	33		14 1	14.3	6 00	0.0	246	295	0 7	0.8	46 0	1 18	39 1	40.4	0 29
461	02/05/93	13.19	REPEAT456	100	4.16		854	37.4		1.55	6 00	8 0	5.60	40	0 0	128	150	13.96	342	400	35		15 5	15 4	6.10	0 0	242	292	0.6	0 7	48.8	1 18	42 0	40 6	0 28
																						AHE6	26 4	33.4											
462	02/05/93	14 45	REPEAT 459	100	4 20		862	37 4		2 33	6 00	8 0	5.80	42	0 0	102	121	13 82	337	399	42		32 5	38 4	6.10	0 0	242	292	0.6	0 7	58.7	1 75	33 6	49.7	0 29
463	02/05/93	15 49	As 462 w/ 12psi	100	4.20		858	37.4		2.30	6 00	12.0	5.90	43	0 0	97	116	13 69	327	390	44		37 6	40 6	6 10	0 0	242	292	0.6	0 7	60.3	1 72	35 0	52.5	0 29
464	02/08/93	09.42	Baseline Unbias Mills	100	4.01		862	37.4		0.00	0 00	0.0	5.30	150	0.0	218	250	13 50	437	501	1				5.75	0 0	224	264	2.3	2 7	5 5	0 00	-	1 0	-0 12
			E1,2									5.40	620	0 0	184	212	11 79	385	444	9														
			E3,4									4.20	275	0.0	243	260	13.62	446	478	1														
			E5,6									5.75	20	0.0	233	275	13.34	433	511	1														
			E7,8									5.20	24	0.0	234	267	13.86	439	500	2														
			E9,10									4 10	34	0 0	236	251	15.00	473	504	2														
			E11,12									6 70	21	0 0	202	254	12 65	408	514	2														
	02/08/93	10 41	E1-12 REPEAT									5 75	170	0.0	224	284	13 16	418	493	2														
465	02/08/93	10 58	Basew/Bias A-5,D+5	100	3 95		865	37.4					5 80	87	0 0	220	261	13 45	422	500	3														
			E1 2									7 40	200	0 0	194	257	11 73	380	503	5														
			E3 4									5.35	187	0 0	245	282	13 42	430	495	1														
			E5 6									5 80	13	0 0	241	285	13 48	424	502	1														

PSCC Arapahoe Unit 4 LOW NOx BURNER/Urea Test Data

							Tank	Cnvrtr	Urea	Total	Inject										Altech	Nessler	Spec Ion	Baseline										
Test	Date & Time	Comments	Load	CR O2	Mills	Steam	Urea	Temp	Flow	Flow	Air P	O2 ave	CO ave	H2O	NO	NO	CO2	SO2	SO2	N2O	NH3-adj	NH3 comp	NH3 comp	O2	H20	NO	NO	N2O	N2Oc	ΔNO	N/NO	Utiliz	N2O	ΔN2O/
			MWe	% wet	OOS	e4pph	wt %	°F	gpm	gpm	psig	%	ppm	% (1)	ppm	ppmc,d	%	ppm	ppmc d	ppm	ppm,dry	ppm,dry	ppm dry	%	%	ppm	ppmc,d	ppmc	ppmc,d	%	FERCo	%	ppmc d	ΔNO
		E7,8										5.10	27	0.0	237	268	14.08	439	497	2														
		E9,10										3.90	50	0.0	235	247	15.17	472	497	2														
		E11,12										6.40	30	0.0	199	245	13.07	410	505	2														
	02/08/93 11:50	E1-12 REPEAT										5.65	83	0.0	219	257	13.45	427	501	3														
466	02/08/93 12:30	Air & Water Only	100	4.00		868	37.4		0.00	6.00	8.0	5.60	68	0.0	213	249	13.47	418	489	4				5.65	0.0	219	257	2.8	3.3	3.1	0.00		4.4	0.15
467	02/08/93 14:22	UREA N/NO=1.0	100	3.99		873	37.4		1.34	6.00	8.0	5.55	53	0.0	119	139	13.40	382	445	30		8.7	7.1	5.65	0.0	219	257	2.8	3.3	46.0	1.14	40.2	34.4	0.26
		Noz#10=0.024																			AHE6	21.7	18.2											
																					AHE5	9.5	7.1											
468	02/08/93 15:24	UREA N/NO=1.0	100	4.00		871)	37.4		1.34	6.00	8.0	5.50	62	0.0	128	149	13.49	391	454	28		10.6	8.7	5.65	0.0	219	257	2.8	3.3	42.1	1.14	36.8	31.9	0.26
		Noz#9,10=0.024																			AHE6	12.5	11.2											
																					AHE5	6.5	4.8											
469	02/08/93 17:05	Base Check (Bad)	100	4.00		868	37.4		0.00	0.00	0.0	5.50	49	0.0	227	264	13.47	371	431	2				5.50	0.0	227	264	1.5	1.7	0.0	0.00	-	1.7	
470	02/09/93 08:43	Baseline	100	3.95		868	37.4		0.00	0.00	0.0	5.60	38	0.0	233	272	13.35	352	411	2				5.60	0.0	233	272	1.6	1.9	0.0	0.00	-	1.9	
471	02/09/93 09:50	Base w/ Higher O2	100	4.21		861	37.4		0.00	0.00	0.0	5.90	34	0.0	239	285	13.16	352	420	2				5.90	0.0	239	285	2.0	2.4	0.0	0.00	-	2.4	
472	02/09/93 10:26	9,10=.024,N/NO=.5	100	4.26		868	37.4		0.75	6.00	8.0	5.85	40	0.0	157	186	13.28	362	430	22		4.7	2.7	5.90	0.0	239	285	2.0	2.4	34.7	0.58	60.2	25.8	0.24
473	02/09/93 11:03	9,10=.024,N/NO=.8	100	4.16		868	37.4		1.13	6.00	8.0	5.80	51	0.0	137	162	13.22	361	428	28		8.5	6.7	5.90	0.0	239	285	2.0	2.4	43.3	0.87	49.8	33.2	0.25
474	02/09/93 12:40	9,10=.024,N/NO=1	100	4.12		867	37.4		1.50	6.00	8.0	5.75	48	0.0	125	148	13.23	354	418	34		18.6	15.5	5.90	0.0	239	285	2.0	2.4	48.2	1.15	41.8	40.0	0.27
475	02/09/93 13:29	9,10=.024,N/NO=1.5	100	4.20		865	37.4		2.25	6.00	8.0	5.90	46	0.0	109	130	13.05	327	390	41		38.8	39.7	5.90	0.0	239	285	2.0	2.4	54.4	1.73	31.4	49.4	0.30
476	02/09/93 14:59	N/NO=1.0, 2.1 gpmT	100	4.15		870	37.4		1.50	2.10	8.0	5.70	44	0.0	130	153	13.34	345	406	32		13.4	13.7	5.90	0.0	239	285	2.0	2.4	46.3	1.15	40.1	37.3	0.26
		(#9,10=0.024)																																
477	02/09/93 16:07	N/NO=1.0, 7.9 gpmT	100	4.23		871	37.4		1.50	7.90	8.0	5.90	38	0.0	129	154	13.07	340	405	33		16.0	18.0	5.90	0.0	239	285	2.0	2.4	46.0	1.15	39.9	39.6	0.28
		(#9,10=0.024)																																
478	02/09/93 17:16	N/NO=0.25, 6 gpmT	100	4.26		870	37.4		0.38	6.00	8.0	5.80	33	0.0	196	232	13.10	345	409	12		2.6	2.5	5.90	0.0	239	285	2.0	2.4	18.5	0.29	64.2	14.7	0.23
		(#9,10=0.024)																																
479	02/09/93 18:16	Baseline Check	100	4.19		871	37.4		0.00	0.00	0.0	5.70	31	0.0	247	291	13.27	345	406	2				5.70	0.0	247	291	1.8	2.1	0.0	0.00	-	2.1	
480	02/10/93 10:33	UREA N/NO=1 (#10=	100	4.23		866	37.4		1.50	6.00	8.0	5.50	56	0.0	127	147	13.61	337	391	32				5.60	0.0	242	283	1.8	2.1	47.9	1.16	41.2	37.6	0.26
	02/10/93 10:41	E1 0.024)	100	4.23			37.4		1.50	6.00	8.0	8.20	64	0.0	112	156	11.18	286	402	30				7.80	0.0	219	299	3.1	4.2	47.3	1.10	42.9	42.6	0.27
	02/10/93 10:51	E2	100	4.23			37.4		1.50	6.00	8.0	6.60	135	0.0	135	169	12.31	308	385	26	AHE1	7.0	6.2	7.00	0.0	214	275	3.2	4.1	38.7	1.20	32.4	32.0	0.26
	02/10/93 10:56	E3	100	4.23			37.4		1.50	6.00	8.0	4.40	54	0.0	155	168	14.41	362	393	31				4.50	0.0	268	292	2.5	2.7	42.5	1.12	37.8	33.4	0.25
	02/10/93 11:02	E4	100	4.23			37.4		1.50	6.00	8.0	5.60	37	0.0	114	133	13.29	338	395	36	AHE2	9.9	9.0	5.80	0.0	258	306	2.0	2.4	56.4	1.08	52.4	42.1	0.23
	02/10/93 11:08	E5	100	4.23			37.4		1.50	6.00	8.0	6.20	29	0.0	138	168	12.91	324	394	30				6.40	0.0	250	308	1.5	1.8	45.5	1.07	42.7	36.4	0.25
	02/10/93 11:14	E6	100	4.23			37.4		1.50	6.00	8.0	5.60	39	0.0	71	83	13.50	341	399	46	AHE3	15.2	15.2	5.40	0.0	252	291	1.7	2.0	71.5	1.13	63.2	53.6	0.25
	02/10/93 11:22	E7	100	4.23			37.4		1.50	6.00	8.0	4.60	37	0.0	175	192	13.90	352	386	26				5.50	0.0	275	319	1.8	2.1	39.9	1.03	38.7	28.5	0.21
	02/10/93 11:28	E8	100	4.23			37.4		1.50	6.00	8.0	4.60	36	0.0	120	132	14.31	364	400	38	AHE4	9.3	10.4	4.50	0.0	251	274	2.3	2.5	51.9	1.20	43.2	42.1	0.28
	02/10/93 11:36	E9	100	4.23			37.4		1.50	6.00	8.0	3.00	90	0.0	170	170	15.81	409	409	27				3.30	0.0	276	281	2.5	2.5	39.4	1.17	33.7	27.1	0.22
	02/10/93 11:41	E10	100	4.23			37.4		1.50	6.00	8.0	3.30	50	0.0	110	118	15.40	392	399	40	AHE5	11.0	[illegible]	3.80	0.0	248	260	2.9	3.0	54.5	1.27	43.1	40.7	0.27
	02/10/93 11:47	E11	100	4.23			37.4		1.50	6.00	8.0	4.50	62	0.0	115	125	14.27	350	382	36				4.80	0.0	255	283	2.5	2.8	55.7	1.18	48.0	39.7	0.23
	02/10/93 11:52	E12	100	4.23			37.4		1.50	6.00	8.0	7.40	68	0.0	77	101	11.67	267	353	35	AHE6	22.3	28.1	7.00	0.0	198	255	2.4	3.1	60.2	1.29	46.8	46.3	0.28
	02/10/93 12:01	E1-12 REPEAT	100	4.23		-	37.4		1.50	6.00	8.0	5.60	52	0.0	125	146	13.63	349	408	34	AVG	12.8	13.8	5.60	0.0	242	283	1.8	2.1	48.3	1.16	41.6	39.7	0.28
481	02/10/93 12:42	BASELINE	100	4.21		864						5.60	42	0.0	242	283	13.55	358	418	2														
	02/10/93 12:48	E1	(FROM NOW ON,									7.80	51	0.0	219	299	11.38	307	419	3														
	02/10/93 12:55	E2	#10=0.024" &									7.00	58	0.0	214	275	11.86	310	399	3														
	02/10/93 13:01	E3	#1-9=0.035")									4.50	55	0.0	268	292	14.18	375	409	3														
	02/10/93 13:07	E4										5.80	23	0.0	256	303	13.10	352	417	2														
	02/10/93 13:13	E5										6.40	18	0.0	250	308	12.57	338	417	2														
	02/10/93 13:18	E6										5.40	18	0.0	252	291	13.67	371	428	2														
	02/10/93 13:24	E7										5.50	18	0.0	275	319	13.11	369	429	2														
	02/10/93 13:30	E8										4.50	29	0.0	251	274	14.21	380	415	2														
	02/10/93 13:41	E9										3.30	39	0.0	276	281	15.19	418	425	3														
	02/10/93 13:46	E10										3.80	30	0.0	248	260	14.90	402	421	3														
	02/10/93 13:51	E11										4.80	29	0.0	255	283	13.94	383	428	3														
	02/10/93 13:56	E12										7.00	25	0.0	198	255	11.98	302	388	2														
	02/10/93 14:01	E1-12 REPEAT										5.90-	25	0.0	257	306	13.29	365	435	2														
482	02/10/93 16:49	CONV,N/NO=1.0,370F	100	4.23		868	37.4	370	1.50	4.00	8.0	5.60	45	0.0	156	182	13.67	376	439	9		5.1	3.6	5.90	0.0	257	306	1.5	1.8	40.5	1.07	37.7	10.6	0.07
483	02/10/93 17:49	CONV,N/NO=0.5,370F	100	4.18		871	37.4	370	0.75	2.00	8.0	5.70	44	0.0	204	240	13.67	379	446	4		1.4	1.0	5.90	0.0	257	306	1.5	1.8	21.7	0.54	40.4	5.2	0.05
484	02/10/93 19:06	CONV,N/NO=1.5,370F	100	4.26		871	37.4	370	2.25	6.00	8.0	6.00	44	0.0	138	166	13.27	387	464	13		9.2	7.8	5.90	0.0	257	306	1.5	1.8	45.9	1.61	28.5	15.6	0.10
485	02/10/93 19:36	Baseline Check	100	4.20		865	37.4		0.00	0.00	0.0	5.80	31	0.0	263	311	13.33	379	449	2				5.80	0.0	263	311	1.5	1.8	0.0	0.00	-	1.8	
486	02/11/93 08:14	Baseline w/Air&H2O	100	4.23		866	37.4		0.00	6.00	8.0	5.70	35	0.0	250	294	13.53	401	472	3				5.70	0.0	250	294	2.7	3.2	0.0	0.00	-	3.2	
487	02/11/93 10:10	Baseline w/Air&H2O	113	3.80		979	37.4		0.00	6.00	8.0	5.30	37	0.0	279	320	13.91	405	464	2				5.30	0.0	279	320	2.1	2.4	0.0	0.00	-	2.4	
488	02/11/93 14:20	CONV,N/NO=1.0,360F	113	3.77		979	37.4		1.89	4.00	8.0	5.50	44	0.0	199	231	13.62	403	468	7		4.1	3.3	5.30	0.0	279	320	2.1	2.4	27.8	1.15	24.2	8.6	0.07
489	02/11/93 15:09	CONV,N/NO=0.5,360F	113	3.84		979	37.4		0.95	2.00	8.0	5.20	36	0.0	236	269	13.86	410	467	4		1.7	0.8	5.30	0.0	279	320	2.1	2.4	15.9	0.58	27.7	4.4	0.04
490	02/16/93 14:07	Baseline	113	3.41		978	37.4		0.00	0.00	0.0	2.60	535	0.0	217	212	14.25	450	440	4				2.50	0.0	213	207	0.6	0.6	-2.4	0.00	-	4.0	-0.68
	02/16/93 14:15	E1,2										2.80	929	0.0	192	190	12.12	382	378	12														
	02/16/93 14:32	E3,4										0.80	917	0.0	246	219	16.70	441	393	17														
	02/16/93 14:41	E5,6										5.50	32	0.0	247	287	13.48	417	484	1														
	02/16/93 14:49	E7,8										4.30	113	0.0	233	251	14.34	424	457	4														
	02/16/93 14:58	E9,10										1.20	388	0.0	220	200	16.13	475	432	7														
	02/16/93 15:08	E11,12										4.20	149	0.0	179	192	14.55	447	479	1														
	02/16/93 15:21	E1-12 REPEAT	113	3.41		978						2.50	566	0.0	213	207	14.33	446	434	1														
491	02/16/93 16:20	UREA,N/NO=1,ABORT	113	3.57		976	37.4		1.23	6.00	8.0	2.20	667	0.0	158	151	14.33	435	416	20		17.7	14.8	2.50	0.0	213	207	0.6	0.6	27.0	1.15	23.5	18.9	0.33
492	02/17/93 09:38	Frozen Liquid Pipes	113	3.89		972	37.4					4.90	161	0.0	232	259	13.87	387	433	3				5.30	0.0	279	320	2.1	2.4	18.9	0.00	-	3.2	0.01
493	02/18/93 11:22	UREA, N/NO=1.0	111	3.81		965	37.4		1.52	6.00	8.0	5.30	55	0.0	164	188	14.01	392	449	29		5.6	4.1	5.20,	0.0	258	294	1.3	1.5	36.0	1.02	35.3	33.1	0.30
494	02/18/93 11:35	UREA, N/NO=0.5	111	3.81			37.4		0.77	6.00	8.0	5.30	36	0.0	192	220	14.00	390	447	19		2.5	1.0	5.20	0.0	258	294	1.3	1.5	25.1	0.52	48.5	21.3	0.27
495	02/18/93 12:36	UREA, N/NO=1.5	111	3.81		961	37.4		2.64	6.00	8.0	5.60	44	0.0	136	159	13.53	379	443	42		16.6	12.4	5.20	0.0	258	294	1.3	1.5	45.9	1.77	25.9	49.3	0.35
496	02/18/93 13:26	UREA, N/NO=0.75	111	3.81			37.4		1.31	6.00	8.0	5.60	36	0.0	172	201	13.60	382	446	26		5.4	3.6	5.20	0.0	258	294	1.3	1.5	31.6	0.88	35.9	30.9	0.32

PSCC Arapahoe Unit 4 LOW NOx BURNER/Urea Test Data

Test	Date	Time	Comments	Load MWe	CR O_2 % wet	Mills OOS	Steam e4pph	Tank Urea wt %	Cnvrtr Temp °F	Urea Flow gpm	Total Flow gpm	Inject Air P psig	O_2 ave %	CO ave ppm	H_2O % (1)	NO ppm	NO ppmc,d	CO_2 %	SO_2 ppm	SO_2 ppmc,d	N_2O ppm	Altech NH_3-adj ppm,dry	Nessler NH_3 comp ppm,dry	Spec Ion NH_3 comp ppm,dry	Baseline O_2 %	Baseline H_2O %	Baseline NO ppm	Baseline NO ppmc d	Baseline N_2O ppmc	Baseline N_2Oc ppmc,d	ΔNO %	N/NO FERCo	Utiliz %	N_2O ppmc d	$\Delta N_2O/\Delta NO$
497	02/18/93	14:17	UREA, N/NO=1.25	111	3.81		963	37.4		2.15	6.00	8.0	5.40	40	0.0	147	170	13.80	383	442	36		10.1	7.8	5.20	0.0	258	294	1.3	1.5	42.3	1.44	29.3	41.7	0.32
498	02/18/93	16:00	UREA, N/NO=1.0	80	5.13		677	37.4		1.10	6.00	8.0	6.80	44	0.0	114	145	12.62	336	426	31		24.4	19.7	6.50	0.0	210	261	1.2	1.3	44.6	1.16	38.5	39.4	0.33
499	02/18/93	16:18	UREA, N/NO=0.5	80	5.13			37.4		0.55	6.00	8.0	6.70	37	0.0	142	179	12.67	345	434	21		7.2	5.6	6.50	0.0	210	261	1.2	1.3	31.4	0.58	54.4	26.9	0.31
500	02/18/93	18:58	UREA, N/NO=1.5	80	5.13		678	37.4		1.65	6.00	8.0	6.60	56	0.0	95	119	12.82	367	459	40		47.0	45.2	6.50	0.0	210	261	1.2	1.3	54.4	1.73	31.4	50.5	0.35
501	02/19/93	08:25	Baseline, Lose D Mill																																
502	02/19/93	10.02	U, N/NO=1.0, 6gpm	80	5.00	D	668	37.4		1.20	6.00	8.0	6.70	64	0.0	122	154	12.71	327	412	32		44.9	43.4	6.90	0.0	224	286	2.5	3.2	46.3	1.15	40.3	40.0	0.28
503	02/19/93	10:30	U, N/NO=0.5, 6gpm	80	5.00	D		37.4		0.60	6.00	8.0	6.80	62	0.0	148	188	12.60	350	444	22		19.1	16.7	6.90	0.0	224	286	2.5	3.2	34.4	0.57	59.8	27.8	0.25
504	02/19/93	11:02	U, N/NO=1.5, 6gpm	80	5.00	D		37.4		1.80	6.00	8.0	6.60	76	0.0	106	133	12.67	297	371	40		111.5	92.9	6.90	0.0	224	286	2.5	3.2	53.7	1.72	31.1	50.1	0.31
505	02/19/93	12:00	As 502 w/#10 OOS	80	5.00	D	668	37.4		1.19	6.00	8.0	7.10	61	0.0	121	157	12.26	320	414	32		46.1	42.8	6.90	0.0	224	286	2.5	3.2	45.2	1.14	39.6	41.1	0.29
506	02/19/93	12:30	As 503 w/#10 OOS	80	5.00	D		37.4		0.58	6.00	8.0	7.10	106	0.0	148	192	12.21	339	439	20		25.4	21.8	7.10	0.0	220	285	2.8	3.6	32.7	0.56	58.7	26.2	0.24
507	02/19/93	13:00	As 503 w/9&10 OOS	80	5.00	D	668	37.4		0.58	6.00	8.0	6.90	82	0.0	146	186	12.39	350	447	23		13.9	12.0	7.10	0.0	220	285	2.8	3.6	34.6	0.56	62.0	29.9	0.27
508	02/19/93	14:53	As 502 w/9&10 OOS	80	5.00	D		37.4		1.19	6.00	8.0	6.80	100	0.0	116	147	12.54	330	418	33		45.8	47.8	7.10	0.0	220	285	2.8	3.6	48.4	1.14	42.3	41.6	0.28
																						AHE6	55.2	54.4											
509	02/19/93	16:04	502 REPEAT (10INJ)	80	5.00	D	668	37.4		1.19	6.00	8.0	6.90	110	0.0	121	154	12.46	318	406	30		61.6	56.2	7.10	0.0	220	285	2.8	3.6	45.8	1.14	40.0	38.8	0.27
																						AHE6	83.2	43.6											
510	02/22/93	14:17	U, N/NO=1.0, 2.2gpm	80	5.00		677	37.4		1.09	2.15	8.0	6.30	70	0.0	114	140	13.22	367	449	31		32.9	30.2	6.50	0.0	210	261	1.3	1.6	46.5	1.15	40.5	38.0	0.30
511	02/22/93	15:02	U, N/NO=0.5, 2.2gpm	80	5.00		677	37.4		0.55	2.15	8.0	6.60	41	0.0	148	185	12.95	383	479	19		12.4	8.3	6.50	0.0	210	261	1.3	1.6	29.0	0.57	50.7	23.5	0.29
512	02/22/93	15:40	U, N/NO=1.5, 2.2gpm	80	5.00		677	37.4		1.64	2.15	8.0	6.60	54	0.0	101	126	12.96	346	433	36		89.1	60.7	6.50	0.0	210	261	1.3	1.6	51.8	1.72	30.1	45.4	0.32
513	02/22/93	16:18	As 510 w/12psi	80	5.00		677	37.4		1.08	2.15	12.0	6.60	48	0.0	110	138	13.01	396	495	29		39.3	34.5	6.50	0.0	210	261	1.3	1.6	47.3	1.14	41.6	36.0	0.28
514	02/22/93	17:00	As 510 w/4psi	80	5.00		677	37.4		1.08	2.15	4.0	6.50	43	0.0	123	153	13.07	392	487	26		57.9	36.2	6.50	0.0	210	261	1.3	1.6	41.4	1.14	36.5	32.3	0.28
515	02/23/93	15:25	U, N/NO=1.0, 6gpm	80	5.00		670	37.4		1.09	6.02	8.0	6.60	50	0.0	118	147	13.16	422	528	25		33.2	27.9	6.60	0.0	205	256	-1.7	-2.1	42.7	1.17	36.6	30.8	0.30
516	02/23/93	15:45	U, N/NO=0.5, 6gpm	80	5.00		669	37.4		0.55	6.02	8.0	6.80	45	0.0	140	174	12.97	439	549	17		12.0	10.7	6.60	0.0	205	256	-1.7	-2.1	32.0	0.59	54.3	20.8	0.28
517	02/23/93	16.25	U, N/NO=0.5, 2.2gpm	80	5.00		669	37.4		0.54	2.20	8.0	6.60	45	0.0	135	168	13.07	457	571	17		9.4	8.4	6.60	0.0	205	256	-1.7	-2.1	34.3	0.58	59.4	21.1	0.26
518	02/23/93	16:55	U, N/NO=1.0, 2.2gpm	80	5.00			37.4		1.09	2.20	8.0	6.60	55	0.0	107	134	13.13	436	545	27		37.5	29.6	6.60	0.0	205	256	-1.7	-2.1	47.8	1.17	41.0	34.0	0.29
519	02/23/93	17:38	U, N/NO=1.5, 2.2gpm	80	5.00		669	37.4		1.85	2.20	8.0	6.50	62	0.0	96	119	13.11	407	505	33		96.9	72.8	6.60	0.0	205	256	-1.7	-2.1	53.6	1.76	30.4	41.1	0.31
520	02/24/93	10:36	C, N/NO=1.0, 4.3gpm	80	5.00		658	37.4	350	0.95	4.30	8.0	6.50	41	0.0	119	148	12.98	452	561	5		6.2	5.0	6.50	0.0	193	240	-0.2	-0.2	38.3	1.09	35.3	6.1	0.07
521	02/24/93	11:40	As 520 w/ 12psi	80	5.00			37.4	380	0.94	4.30	12.0	6.60	33	0.0	119	149	12.97	456	570	5		5.9	4.9	6.50	0.0	193	240	-0.2	-0.2	37.9	1.08	35.3	5.8	0.07
522	02/24/93	12:20	As 520 w/ 4psi	80	5.00			37.4	380	0.94	4.30	4.0	6.60	29	0.0	122	153	12.85	450	563	5		8.6	6.3	6.50	0.0	193	240	-0.2	-0.2	36.3	1.08	33.8	6.5	0.08
523	02/24/93	12:40	520 REPEAT	80	5.00		657	37.4	380	0.94	4.30	8.0	6.60	33	0.0	121	151	12.76	451	564	5		9.1	5.7	6.50	0.0	193	240	-0.2	-0.2	36.9	1.08	34.3	6.1	0.07
524	02/24/93	14:00	C, N/NO=0.5, 2.1gpm	80	5.00		658	37.4	370	0.47	2.08	8.0	6.50	34	0.0	150	186	12.92	465	577	2		1.4	1.2	6.50	0.0	193	240	-0.2	-0.2	22.3	0.53	41.9	2.1	0.04
525	02/24/93	15.29	C, N/NO=1.5, 6.2gpm	80	5.00		666	37.4	375	1.45	6.20	8.0	6.50	43	0.0	101	125	13.06	453	562	7		22.1	19.6	6.50	0.0	193	240	-0.2	-0.2	47.7	1.66	28.7	8.1	0.07
526	02/24/93	17:12	C, N/NO=1.0, 6.2gpm	80	5.00			37.4	380	1.00	6.20	8.0	6.50	32	0.0	122	151	13.03	463	575	3		13.2	10.2	6.50	0.0	193	240	-0.2	-0.2	36.8	1.14	32.2	4.2	0.05
527	*02/25/93*	*10.49*	*C, N/NO=1.0, 2gpm*	*91*	*4.53*		*762*	*37.4*	*330*	*1.10*	*1.98*	*8.0*	*5.95*	*40*	*0.0*	*137*	*164*	*13.37*	*462*	*553*	*6*		*1.8*	*0.8*	*5.90*	*0.0*	*208*	*248*	*0.2*	0.2	33.8	1.07	31.6	6.7	0.08
528	02/25/93	12:00	C, N/NO=1.0, 4.3gpm	91	4.53		762	37.4	380	1.13	4.28	8.0	5.90	50	0.0	131	156	13.47	471	561	5		2.8	1.8	5.90	0.0	208	248	0.2	0.2	36.9	1.10	33.6	6.0	0.06
529			ABORT, HOSE LEAK	91	4.53			37.4		1.70	6.00	8.0	5.90		0.0	119	142								5.90	0.0	208	248	0.2	0.2	42.7	1.65	25.8	0.0	0.00
530	03/02/93	22:00	Baseline	60	6.96	D	499	37.4		0.00	0.00	0.0	8.90	39	0.0	195	290	10.80	335	498	0				8.90	0.0	195	290	0.2	0.3	0.0	0.00	-	0.0	
531	03/03/93	00:00	U,N/NO=0.5,PlgdNzle	60	7.02	D	498	37.4		0.40	2.10	8.0	9.00	42	0.0	150	225	10.70	322	483	5		14.5	11.9	8.90	0.0	195	290	0.2	0.3	22.4	0.50	44.5	7.8	0.12
532	03/03/93	00.50	U,N/NO=1.0,PlgdNzle	60	6.98	D	498	37.4		0.89	2.10	8.0	9.10	38	0.0	141	213	10.60	281	425	8		67.3	68.2	8.90	0.0	195	290	0.2	0.3	26.5	1.12	23.6	11.9	0.15
533	03/03/93	02:05	U,N/NO=.75,PlgdNzle	60	6.98	D	499	37.4		0.67	2.10	8.0	8.90	33	0.0	147	219	10.60	323	480	7		65.6	65.4	8.90	0.0	195	290	0.2	0.3	24.8	0.84	29.2	10.6	0.14
534	03/03/93	04:00	532 REPEAT,PlgdNzle	60	7.03	D	498	37.4		0.89	2.10	8.0	9.00	34	0.0	140	210	10.72	292	438	9		100.8	102.7	8.90	0.0	195	290	0.2	0.3	27.8	1.12	24.6	13.8	0.17
535	03/03/93	04:37	531 REPEAT,PlgdNzle	60	7.11	D	497	37.4		0.45	2.10	8.0	9.00	31	0.0	151	227	10.65	327	491	6		45.3	38.4	8.90	0.0	195	290	0.2	0.3	21.9	0.57	38.7	9.2	0.14
536	03/03/93	05:21	As531w/4psi,PgdNzl	60	7.02	D	498	37.4		0.45	2.10	4.0	9.00	32	0.0	159	239	10.80	342	513	5		46.1	42.4	8.90	0.0	195	290	0.2	0.3	17.8	0.57	31.4	6.9	0.13
537	03/03/93	21.57	Baseline	60	6.52	D	499	37.4		0.00	0.00	0.0	8.60	29	0.0	200	295	11.16	265	420	0				8.80	0.0	200	295	0.2	0.3	0.0	0.00	-	0.0	
538	03/03/93	22:23	UREA, N/NO=0.5	60	6.49	D	497	37.4		0.45	2.01	8.0	8.60	41	0.0	152	224	11.10	264	390	10		15.3	12.7	8.80	0.0	200	295	0.2	0.3	24.0	0.56	43.1	14.8	0.20
539	03/04/93	00.26	UREA, N/NO=1.0	60	6.49	D	499	37.4		0.91	2.01	8.0	8.60	48	0.0	133	193	11.28	224	325	15	69.4	71.0	74.9	8.80	0.0	200	295	0.2	0.3	34.8	1.13	30.7	21.5	0.21
																						AHE4	71.2	68.0											
540	03/04/93	01:31	UREA, N/NO=0.75	60	6.57	D	501	37.4		0.67	2.01	8.0	8.60	49	0.0	140	203	11.32	236	343	13	52.9	58.9	55.2	8.80	0.0	200	295	0.2	0.3	31.1	0.83	37.5	18.9	0.20
																						AHE4	68.8	56.3											
541	03/04/93	04:22	538 REPEAT	60	6.22	D	503	37.4		0.45	2.01	8.0	8.60	39	0.0	144	209	11.09	252	366	10	38.2	57.8	43.6	8.60	0.0	190	276	0.2	0.3	24.2	0.60	40.6	14.4	0.21
																						AHE4	32.9	25.3											
																						ALT PRB	39.2	34.2											
542	03/04/93	05:56	Baseline Check	60		D		37.4		0.00	0.00	0.0	8.60	33	0.0	190	278	11.23	278	404	0				8.60	0.0	190	276	0.2	0.3	0.0	0.00	-	0.0	
543	03/04/93	21:43	Baseline	60	6.52	D	500	37.4		0.00	0.00	0.0	8.60	20	0.0	200	290	11.12	341	495	0	0.0			8.60	0.0	200	290	0.2	0.3	0.0	0.00	-	0.0	
544	03/04/93	23:46	UREA, N/NO=0.5	60	6.61	D	497	37.4		0.44	2.10	8.0	8.60	25	0.0	153	222	11.05	360	523	7	31.9	23.0	26.1	8.60	0.0	200	290	0.2	0.3	23.5	0.55	42.4	10.5	0.15
																						AHE4	17.1	24.6											
545	03/05/93	02.34	UREA, N/NO=0.75	60	6.54	D	497	37.4		0.67	2.10	8.0	8.70	33	0.0	139	203	10.99	319	467	11	66.0	53.2	67.0	8.60	0.0	200	290	0.2	0.3	29.9	0.84	35.5	15.8	0.18
																						AHE4	49.9	61.7											
546	03/05/93	04:03	UREA, N/NO=1.0	60	6.50	D	497	37.4		0.91	2.10	8.0	8.80	32	0.0	134	198	10.98	288	425	12	102.6	77.3	81.3	8.60	0.0	200	290	0.2	0.3	31.9	1.15	27.9	17.7	0.19
																						AHE4	92.0	111.3											
																						STACK	35.3	40.3											
547	03/05/93	22:34	Baseline	60	6.57	D	499	37.4		0.00	0.00	0.0	8.60	20	0.0	203	295	11.17	405	588	0	0.0			8.60	0.0	203	295	-1.9	-2.8	0.0	0.00	-	0.0	
548	03/05/93	23.50	UREA, N/NO=0.5	60	6.50	D	499	37.4		0.44	2.10	8.0	8.20	39	0.0	151	212	11.40	418	588	6	28.6	20.1	30.9	8.60	0.0	203	295	-1.9	-2.8	27.9	0.55	51.2	8.4	0.14
																						AHE4	22.2	24.7											
549	03/06/93	02.22	As 548 w/ 12psi	60	6.50	D	498	37.4		0.44	2.10	12.0	8.20	38	0.0	148	208	11.40	406	571	7	31.3	33.0	31.2	8.60	0.0	203	295	-1.9	-2.8	29.4	0.55	53.8	9.6	0.14
																						AHE4	21.0	22.7											
550	03/06/93	03.28	As 548 w/ 5psi	60	6.49	D	498	37.4		0.42	2.10	5.0	8.30	37	0.0	158	224	11.30	393	557	4	34.5	28.4	29.8	8.60	0.0	203	295	-1.9	-2.8	24.0	0.52	46.1	6.1	0.13
																						AHE4	25.2	29.3											
551	03/06/93	04:42	UREA,N/NO=.5,2Mills	60	6.98	A,D	499	37.4		0.45	2.10	8.0	8.70	33	0.0	190	278	11.00	388	568	9	29.2	25.8	23.1	8.70	0.0	240	351	0.0	0.0	20.8	0.47	44.5	12.7	0.17
																						AHE4	22.6	24.9											
552	03/06/93	06:05	Baseline w/ 2 Mills	60	7.02	A,D	499	37.4		0.00	0.00	0.0	8.70	19	0.0	240	351	11.00	397	581	0				8.70	0.0	240	351	0.0	0.0	0.0	0.00	-	0.0	
553	3/8/93	PM	AirTox(NrmlMillBias)	100	4.15		854	37.4		0.00	0.00	0.0	5.72	50	0.0	233	274	13.58	412	485	0				5.63	0.0	234	274	-0.8	-0.9	-0.2	0.00	-	0.0	-2.15
554	3/9/93	AM	AirTox(NrmlMillBias)	100	4.22		852	37.4		0.00	0.00	0.0	5.63	50	0.0	237	278	13.55	358	419	0				5.63	0.0	237	278	-0.2	-0.2	0.0	0.00	-	-0.2	
555	3/9/93	PM	AirTox(NrmlMillBias)	100	4.25		850	37.4		0.00	0.00	0.0	5.87	39	0.0	238	283	13.47	341	406	0				5.87	0.0	238	283	-1.0	-1.2	0.0	0.00	-	0.0	
556	3/10/93	AM	AirTox(NrmlMillBias)	100	4.23		846	37.4		1.07	6.00	8.0	5.81	79	0.0	138	164	13.60	330	391	23				5.71	0.0	236	278	0.0	0.0	41.1	0.84	48.7	27.3	0.24
																						12PT AVG	26.6	17.8											

PSCC Arapahoe Unit 4 LOW NOx BURNER/Urea Test Data

																									Baseline										
Test	Date & Time		Comments	Load MWe	CR O2 % wet	Mills OOS	Steam e4pph	Tank Urea wt %	Cnvrtr Temp °F	Urea Flow gpm	Total Flow gpm	Inject Air P psig	O2 ave %	CO ave ppm	H2O % (1)	NO ppm	NO ppmc,d	CO2 %	SO2 ppm	SO2 ppmc,d	N2O ppm	Altech NH3-adj ppm,dry	Nessler NH3 comp ppm,dry	Spec Ion NH3 comp ppm,dry	O2 %	H20 %	NO ppm	NO ppmc,d	N2O ppmc	N2Oc ppmc,d	ΔNO %	N/NO FERCo	Utiliz %	N2O ppmc,d	ΔN2O/ΔNO
																						STACK	7 1	5 6											
557	3/10/93	PM	AirTox(NrmlMillBias)	100	4.29		855	37 4		1 07	6 00	8 0	5 87	60	0 0	145	173	13 47	325	387	22				5 71	0 0	236	278	0 0	0 0	37 9	0 84	44 9	26 2	0 25
558	3/11/93	AM	AirTox(A&D@-5%)	100	'4.37		870	37 4		1 04	6 00	8.0	6.08	60	0.0	150	181	13 38	320	386	23		23 2	17 4				0		0 0				27 7	-0 15
																						STACK	12 2	11 7											
559	3/11/93	PM	AirTox(D@-10%)	111	4 19		951	37.4		1.20	6 00	8.0	6.00	73	0 0	165	198	13 50	329	395	23		18 2	18 6				0		0 0				27 6	-0 14
560	3/15/1993	AM/PM	AirTox(NrmlMillBias)	100	4 20		846	37 4		0.00	0.00	0.0	5.84	54	0.0	236	280	13 70	462	549	0				5 84	0 0	236	280	0 0	0 0	0 0	0 00		0 0	
561	03/16/93	23'46	**Baseline**	60	6.51	D	496	37.4		0 00	0.00	0 0	9 10	12	0 0	216	327	11 50	426	644	0	0 0			9.10	0 0	216	327	0 0	0 0	0 0	0 00	-	0 0	
562	03/17/93	00 50	C, N/NO=1 0, 4 1gpm	60	6 51	D	496	37.4		0 97	4 10	8 0	9 10	20	0 0	125	189	11 50	373	564	2	32 3	34 4	36 4	9 10	0 0	216	327	0 0	0 0	42 1	1 08	38 8	2 9	0 02
563	03/17/93	02 36	C, N/NO=0 5, 4 1gpm	60	6.61	D	496	37 4		0.50	4.10	8 0	8.90	18	0 0	140	208	11 50	414	616	0	13 7	19 2	17 6	9 10	0 0	216	327	0 0	0 0	36 3	0 56	64 8	0 1	0 00
																						AHE4	13 0	11 4											
564	03/17/93	04 27	C, N/NO=.75, 4 1gpm	60	6.51	D	497	37 4		0 74	4 10	8 0	8 90	17	0 0	128	190	11 60	390	580	1	34 4	39 4	37 0	9 10	0 0	216	327	0 0	0 0	41 7	0 83	50 4	1 5	0 01
																						AHE4	32 1	30 0											
565	03/17/93	05.50	562 REPEAT	60	6.63	D	497	37.4		0.97	4.10	8.0	8.90	21	0 0	116	173	11.60	369	549	2	54 0	59 0	56 6	9.10	0 0	216	327	0 0	0 0	47 2	1 08	43 5	3 4	0 02
566	03/17/93	21 45	**Baseline**	60	6.52	D	494	37.4		0 00	2.10	0 0	9.00	13	0.0	210	315	10 90	291	437	0	0 0			9 00	0 0	210	315	0 2	0.3	0 0	0 00	-	0 3	
567	03/18/93	01 08	C, N/NO=1.0, 2 1gpm	60	6 49	D	491	37.4		1.01	2.10	8 0	8.80	21	0.0	128	189	11 00	217	320	3	85 2	91.3	84 2	9 00	0 0	210	315	0 2	0 3	40 0	1 17	34 2	3 7	0 03
																						AHE4	75 3	62 3											
568	03/18/93	03.51	C, N/NO=0.5, 2.1gpm	60	6.47	D	492	37.4		0.48	2.10	8.0	8.80	21	0.0	142	210	11 00	270	398	1	28 9	27 9	27 5	9 00	0 0	210	315	0 2	0 3	33 5	0 56	60 2	1 9	0 02
569	03/18/93	05 28	C, N/NO=1 0,4 1gpm	60	6.54	D	492	37.4		1.01	4.10	8.0	8.80	21	0.0	123	181	11.00	218	322	3	85 5	84 9	85 8	9 00	0 0	210	315	0 2	0 3	42 4	1 17	36 2	4 6	0 03

(1) Value indicates if flue gas was measured on a dry or wet basis If value is 0 0, measurement was on a dry basis If other than 0 0, measurement was on a wet basis, and value indicates flue gas moisture content